IN THE MATTER OF the Utilities Commission Act, SBC 1980, c. 60

and

IN THE MATTER OF an Application for a Certificate of Public Convenience and Necessity by the British Columbia Hydro and Power Authority dated December 22, 1980

REASONS FOR DECISION
September 16, 1981

The Application of the British Columbia Hydro and Power Authority dated December 22, 1981 for a Certificate of Public Convenience and Necessity related to the Falls River Redevelopment Project, was heard in public in Prince Rupert, on May 5th to 8th, 1981 inclusive and in Vancouver on May 27th to 29th, 1981 inclusive.

The Division of the Commission was comprised of J.D.V. Newlands, Division Chairman; D.B. Kilpatrick, Commissioner; and B.M. Sullivan, Commissioner.

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APPEARANCES

R.J. GIBBS	Commission Counsel
W.D. MITCHELL/W.H. MCQUEEN	for Applicant, British Columbia Hydro and Power Authority
R.A. BELL-IRVING	for Government of Canada, Fisheries and Oceans, Water Use Unit, Field Services Branch, Fisheries - Pacific Region
A.C. MICHELSON	Hearing Secretary
R.J. FLETCHER S.S. WONG	Commission Staff
AUDIOTRON ENTERPRISES LTD. (W.G. Bemister)	Court Reporter

LIST OF EXHIBITS

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(con't)

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(con't)

INTRODUCTION

The British Columbia Hydro and Power Authority ("B.C. Hydro"), by letter dated November 17, 1980 to the Minister of Energy, Mines and Petroleum Resources, made application for exemption from the provisions of Part 2 of the B.C. Utilities Commission Act, with respect to planned redevelopment and expansion of an existing small hydro-electric facility on the Falls River in an isolated wilderness location some 33 air miles southeast of Prince Rupert.

Exemption was requested on the basis that the proposed expansion in generating capacity to 22 MW was insignificant in terms of B.C. Hydro's total installed capacity of some 7,900 MW, that the project would make use of otherwise wasted water from an already developed river, that rehabilitation work approved by the Controller of Water Rights for safety reasons was already underway, and that the effects of the project on the environment would be minimal.

In September of 1980, B.C. Hydro's natural gas and electric operations became subject to regulation under the Utilities Commission Act and, pursuant to the Act, the Minister by letter to the Commission dated December 22, 1980 ordered that the Application be dealt with under Part 3, Section 19(1)(b), as an application for a Certificate of Public Convenience and Necessity. Subsequently, pursuant to Section 3 of the Act the Government of British Columbia by Special Direction B.C. Hydro No. 1, dated March 19, 1981, instructed the Commission to ensure that B.C. Hydro's rates are designed to achieve a 1.3 to 1 interest coverage.

During the course of the hearing at Prince Rupert and on the invitation of B.C. Hydro, on May 6, 1981 the Commission and the representative of Fisheries and Oceans Canada flew to Falls River and inspected the site. Fisheries and Oceans Canada, represented by Mr. R.A. Bell-Irving and assisted by Mr. L. Dutta, was the only Intervenor at the hearing. B.C. Hydro was represented by Mr. W.A. Best, Vice-President Corporate, as policy witness. Operating and technical witnesses included Mr. E.E. Parry, Production Manager - Northern Division, and Mr. G.M. Salmon, Manager of the Development Department - Hydro-electric Design Division. Mr. R.M. Bradley and Mr. C.E. Walker, professional biologists employed by B.C. Hydro, were the expert witnesses on wildlife, fish and environmental matters.

DIRECTIVES - RE FALLS RIVER REDEVELOPMENT

By Commission Order No. C-3-81 dated July 30, 1981 (Appendix A), the Commission approved B.C. Hydro's Application dated December 22, 1980 for a Certificate of Public Convenience and Necessity to permit the redevelopment of the Falls River hydro-electric facilities. As noted in the Order, the Commission's decision to approve the Certificate was subject to the Applicant's compliance with directives to be contained in the related Reasons for Decision. Accordingly, the Commission herewith directs B.C. Hydro as follows:

1. The Applicant will conduct such further observations and environmental fieldwork with respect to the effects of the approved redevelopment at Falls River on the salmon fishing, as may be required by the Federal Department of Oceans and Fisheries.

2. The Applicant will undertake such mitigative measures as may be recommended or required by the Federal Department of Oceans and Fisheries, to maintain the fish habitat below the dam to the standards indicated by any further fieldwork undertaken by either the Applicant or Oceans and Fisheries as per Item 1 above.

3. The Applicant will undertake to remove the dead or dying trees currently standing in the reservoir and forebay, as part of the approved redevelopment project.

1. BACKGROUND

1.1 Application for an Energy Project Certificate

B.C. Hydro has made application to the Minister of Energy, Mines and Petroleum Resources for an Energy Project Certificate for the Falls River Redevelopment Project in accordance with Regulation 388/80. This application was made by Mr. E.H. Martin, Executive Vice President, Operations, of B.C. Hydro in his letter, and attachments, of November 17, 1980 to the Minister of Energy, Mines and Petroleum Resources.

The application by Mr. E.H. Martin on behalf of B.C. Hydro included the following documents:

- Application for an Energy Project Certificate requested on January 17, 1980, (Exh. 1) and appendices as follows:
- Falls River Rehabilitation/Redevelopment Study - Memorandum on Condition of Existing Facilities, May 1979, B.C. Hydro Report H1065 (Exh. 9).
- Falls River Rehabilitation/Redevelopment - Engineering Assessment, October 1979, B.C. Hydro Report H1120 (Exh. 10).
- Falls River Redevelopment - Preliminary Design Studies - Memorandum on revision to Reservoir Level and Installed Capacity, February 1980, B.C. Hydro Report H1203 (Exh. 12).
- Falls River Redevelopment - Memorandum on Design, Cost and Scheduling of New Generating Facilities, July 1980, B.C. Hydro Report H1242 (Exh. 13).

During the course of the hearings a further 45 exhibits were filed. Although all have relevance, the key additional exhibits were:

- 1981 Ten Year Electric System Plans, November 24, 1980 (Exh. 46).
- Falls River Project Financial Studies, Summary of Annual Costs of Services, originally filed as Exh. 32 with a revised version dated June 5, 1981, designated as a counterpart to Exh. 32 and hereafter in this report referred to as Exh. 32B.
- Additional information submitted as answers to questions prepared by Shawinigan Engineering, April 6, 1981 (Exh. 15).

1.2 Alternatives for the Future

Present Conditions

The existing plant near Prince Rupert was first commissioned in 1930 with a single 3.2 MW generating unit, expanded with a second 3.7 MW unit in 1960, and purchased by B.C. Hydro in 1964. The plant presently produces about 43 Gwh of energy annually, using approximately 50% of the water available from the Big Falls River.

Redevelopment

The plant has been allowed to deteriorate through time and some facilities have proven inadequate. Certain essential parts are presently being replaced or rehabilitated, and B.C. Hydro in their application proposed to redevelop the generating facilities to maintain the station in service. Although B.C. Hydro recognized that rehabilitation of the existing generating facilities is a possible alternative, their studies concluded that the plant could be more economically redeveloped to increase capacity by 15 MW and thereby increase the average annual energy production by 48 Gwh.

The proposed redevelopment scheme would involve replacing the existing penstocks and the powerhouse containing two units, with a single larger penstock and a powerhouse containing a single 22MW unit, and modifying the existing dam intakes (Exh. 1, page iv).

Rehabilitation

The Applicant had earlier considered a rehabilitation alternative (Exh. 10, page 1-2), involving improvements to the dam to improve the integrity and the flood discharge capability of the structure, as well as repairing the intakes, penstocks and powerhouse facilities (Exh. 10, page 6-1). This alternative was only presented in the application (and appendices) as partial economic justification for the 22 MW redevelopment project.

In the original comparison study (Exh. 10) the modifications to the dam were assumed to be the same for both alternatives, except for minor differences in gate automation and gate hoist replacement. The essential difference in work scope was that for the rehabilitation project the existing penstocks and powerhouse would be retained.

Minimum Scheme

Evaluation of the 22 MW project by the Applicant, did not consider the least cost alternative of making minimum maintenance repairs and making the dam safe, in respect to major floods, by removing the existing flashboards and sluice stoplogs, thereby reverting to pre-1942 conditions which provided adequate flood discarge capacity.

Abandonment

The further alternative of retiring the project was not analyzed by B.C. Hydro, since they concluded from their studies that both the 22 MW redevelopment scheme and the 7 MW rehabilitation project were economic relative to alternative thermal energy (incremental energy cost of about 22 mills/kWh (Exh. 15, Table 1-1). The comparison with Hat Creek shows both alternatives cheaper than Hat Creek for net interest rates up to about 6% (Exh. 14, Table C-4 for 22 MW scheme and Exh. 15, Table 2-6 for 7 MW scheme).

During the hearing B.C. Hydro suggested that abandonment costs would be $1-3,000,000 (Exh. 22, also Salmon Cr-Ex by Gibbs, Transcript page 266).

Summary of Alternatives

During the hearings the Applicant agreed that there were three alternatives that should be considered (Salmon Cr-Ex by Gibbs, Transcript pages 175-185), and for which costs of service were provided (Exh. 32).

- Alternative #1 - Continued Maintenance

  Includes site access work already done, anchors in the dam, removal of stoplogs and flashboards, repair to penstocks, draft tubes, turbines, etc. with later turbine and other equipment replacements in years 2003 and 2013. Generation would be 38.5 GWh pa.

  In effect this returns the project to pre 1942 conditions, meets safety requirements and assumes major equipment replacements are delayed until service lives are exhausted. The economic analysis assumes a 120 year life for the dam and turbine/generator lives of 50 and 70 years.

- Alternative #2 - 7 MW Rehabilitation

  Essentially as above, but with the dam crest raised to elevation 305 feet, as an alternative means of achieving safety for the dam, and to increase head. Generation is about 45 GWh pa.[1]

- Alternative #3 - 22 MW Redevelopment

  Assumes the dam crest is raised to elevation 305 feet, and new penstocks and powerhouse. The economic analysis assumes a 70 year life for the new turbine/generator. Generation is about 91 GWh.[2]

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[1] Generation values are net after transmission losses between the plant and Prince Rupert.

[2] Ibid.

The Commission notes that the Applicant's "economic comparisons" as represented by the project financial studies (annual costs of service, Exh. 32) did not assess the further alternative of "continued maintenance" and project retirement after 20 years. The Commission concludes, however, that it is important that B.C. Hydro recognize that the foregoing three alternatives do in fact require comparison to justify selection of the 22 MW Redevelopment Project.

1.3 Major Issues and Concerns

The submission filed by B.C. Hydro and the hearings themselves covered a great deal of information peripheral to the question of whether the redevelopment project should be approved. Related matters with significance, apart from the direct engineering and economic comparisons, included

- the Applicant's internal project evaluation and approval procedures
- allocation of overhead costs to capital projects (thereby financing these through revenues from customers on a capitalized basis)
- accounting procedures relating to maintenance costs
- load forecasting
- approach to environmental considerations

Although the scope of information with respect to the above provided during the application and hearing process was broad, the Commission concludes that the immediate issue is the question of the justification of the redevelopment project. The

Commission has therefore dealt with the foregoing issues and concerns under the heading "Other Matters" commencing on page 74.

Since the terms of reference or rules governing the assessment and approval of a Certificate of Public Convenience and Necessity are not normally specifically defined in advance, the Commission has based its decision on its evaluation of certain specific matters usually considered in project evaluation. The selection of these specific areas of prime interest reflects the nature and quality of the information provided to the Commission by the Applicant as the basis for its decision on the proposed project. The Decision itself is therefore based on the Commission's conclusions with respect to three considerations:

1. The Need for the Project
2. Safety Requirements
3. Economic Justification

Need for the Project

The various submissions, particularly including Exh. 1 (Application) and indirectly Exh.'s 46 and 50 (load forecasts) together with the Applicant's testimony (Best page 108) have suggested that there is a direct need for the redevelopment project to reduce energy deficits for the B.C. Hydro system as a whole in the 1985-87 period that will result from the realization of a 6.1% energy demand growth rate (B.C. Hydro most probable) and critical water year constraints on hydro generation.

During the period 1986-88 (fiscal years) B.C. Hydro is forecasting inadequate energy generation capability to meet forecast load requirements if,

(a) energy demand grows at the forecast "probable" rate of 6.1% pa.; and

(b) a critical water supply position occurs.

During this period, even in an average water supply year, B.C. Hydro believes it will be required to generate from the Burrard plant.

The Commission recognizes that the Applicant has not claimed that implementation of this redevelopment project would remove the potential shortage problem, thereby ensuring B.C. Hydro's security of supply. The Applicant has, however, stated that this need forms part of the justification for this project (Best, Transcript pages 109-112).

The issue to be considered under the subject of "Need" is whether the suggested energy supply shortfall in 1985-87 is realistic, i.e. whether the energy demand forecast is realistic, and whether, if so, the implementation of the 22 MW project, with an additional energy component of about 48 GWh pa is significant as a mitigative procedure. More specifically, if indeed the proposed capital expenditures will have any significant impact on alternative arrangements and costs involved in meeting any such energy supply shortfalls.

It is the Commission's duty, in the public interest, to satisfy itself that there is a demonstrated need for each project proposed by a regulated utility. In the case of Falls River, B.C. Hydro offered its latest available load forecast for the period 1980-90 as evidence of the need for the expanded Falls River project. The B.C. Hydro forecast has not yet been subjected to independent scrutiny for validity, either publicly or privately, in the detail required to either support or reject it. The Commission concluded that the Falls River hearing was not the appropriate forum for such an important, extensive undertaking. Accordingly, in the Commission's view, B.C. Hydro has been unable to conclusively demonstrate the need for the expanded Falls River energy supply from the proposed redevelopment project, in terms of longer-term overall demand on its system.

The Commission further concludes that the redevelopment scheme cannot be justified on the basis of direct need to meet short term possible energy deficiencies, since if such deficiencies should occur it would not materially alter the arrangements for alternative supplies. The redevelopment project would, however, improve the security of electrical power supply to the Prince Rupert area and, in the case of energy supply shortfalls, would serve to reduce the requirements for energy from alternative sources.

The Commission concludes that the justification of the Falls River redevelopment project must therefore be based upon safety considerations and on the economics of long-term replacement by thermal generation, i.e. on whether the proposed redevelopment will produce lower cost energy than the lowest cost alternative energy supply, which the Applicant submits is Hat Creek.

Safety Requirements

Initiation of the redevelopment program appears to have stemmed from concern over the safety of the project (Exh. 9 and 10). It is not clear whether the redevelopment (or as initially investigated, the rehabilitation scheme, Exh. 10) would have been followed up if the safety question and the need to "fix up" the project had not been initiated by the Applicant's own internal inspection report (Exh. 9). There appears little doubt that the further study of alternatives for this project was precipitated by this inspection report which detailed physical deterioration to the facilities, and potential danger to operating staff. Safety factors relating to the integrity of the project against dam failures were also noted in Exh. 15, page 6-1, which showed that under present conditions hydrostatic loadings on the dam failed to meet accepted safety standards.

Economic Justification

B.C. Hydro conducts its project economic evaluations on the basis of net interest rate (actual borrowing costs less prevailing inflation rate), thereby excluding future inflation effects (Ref. Exh. 15 and Kuiper, Transcript page 560). While this concept is widely used by utilities and financing agencies, the ground rules for its application can differ significantly. For example, while the current B.C. Hydro application is based on a net interest or discount rate of 3%, other Canadian utilities use rates ranging from 3 to 6%. Related issues which have significant affects on alternative project comparisons are assumptions with respect to service life, relative operating costs, maintenance costs and other "capital charges".

The Commission therefore concludes that it is necessary to demonstrate that the net effect to the consumer is that the proposed scheme will result in lower long-term average energy costs than from the next best alternative. In future facilities applications by B.C. Hydro the Commission will expect the Applicant to so demonstrate, and on that basis the selection of the net cost of capital (or interest rate) for the evaluation must be realistic and the results expressed in terms of actual cost of service.

The Applicant has selected the redevelopment project as the preferred option for the future of the Falls River plant, on the basis of unit cost comparisons with other remedial measures (Exh. 10) and with Hat Creek (Exh. 10, 15, Kuiper, Transcript page 560). These comparisons depend for their validity on the interest rate used, the service life assumed and the estimated marginal cost of Hat Creek generation. Accordingly, the Commission's concern is whether the parameters used in the comparisons are realistic and likely to result in lower actual generation costs than those from other alternatives.

2. NEED FOR THE PROJECT

The proposed 22 MW redevelopment project is justified by B.C. Hydro on several grounds (Exh. 1, page C-1)

- projected possible energy deficiency in 1986/87
- project economics based on marginal cost of alternative future generation
- maximizing the utilization of an already developed resource
- improving the security of power supply to Prince Rupert

The Commission concludes that the need for the proposed redevelopment scheme should be assessed in terms of:

- short term possible energy supply deficiencies
- long term requirements for new energy
- security of supply to Prince Rupert

2.1 Load Forecast and New Plant Additions

The B.C. Hydro summary "1981 Ten Year Electric System Plans", Exh. 46 provides the 1981 B.C. Hydro load forecasts. It is apparent that the Applicant has and will continue to have significant surplus capacity, with supply well in excess of system demands plus reserve requirements. All future projects are presently being scheduled on the basis of meeting energy demands. Chart 1 of the (1981) 10 year plan provides three forecasts for future energy demands.

Forecast	Average Annual Growth Rate after 1979/80
High	8.2%
Probable	6.1%
Low	4.5%

The "probable" forecast has been adopted by the Applicant for project planning and justification.

Using the 6.1% growth rate, energy demand in the integrated system is forecast to increase from 33,985 Gwh pa in 1981/82 to 48,015 Gwh pa in 1986/87. In the event of a critical water year the energy deficit in 1986/87 is estimated at 2,315 Gwh.

The Commission notes that the total energy requirements include new supplies to West Kootenay Power and Light Company, Limited and Cominco Ltd. The total of these in 1986/87 is about 1400 Gwh. In addition, bulk sales are assumed to grow from 11,080 Gwh in 1981/82 to 17,800 Gwh in 1986/87 (an increase of 61%, equivalent to a compound rate of about 10% annually). Forecast new bulk growth rates are based on current expansion plans for existing customers and provision for new load (Exh. 15A, page 21 and Table PE2 on page 24).

The Applicant has highlighted the importance of bulk sales in their overall load growth forecast and notes that either a source of purchased energy for the 1986-89 period must be found or a restrictive industrial strategy adopted (Exh. 46, page 1)

As indicated heretofore in this Decision no assessment was made of the validity of this forecast at the Falls River proceedings. The Commission, however, has noted the following points:

- the forecast in 1980 showed a 5.8% growth rate (Best, page 1021)
- the actual growth rate for the last six years has been 5% and from 1969/70 - 73/74 was 7.3% (Exh. 15A, page 18)
- the Ministry of Energy, Mines and Petroleum Resources in their February/1980 forecast suggest a long-term growth rate of 3% in electrical energy requirements from 1978-1996 (Best, pages 1023 and 1025)

There is no evidence to suggest that B.C. Hydro has considered the effect on load growth of the higher tariffs that will be necessary to generate the required equity position for future major projects. These higher tariffs will be required to meet the 1983-84 target interest coverage of 1.3 to 1 established by the Government's Special Direction No. 1 (Appendix B).

The Applicant's historic and probable projections of power requirements from Exh. 15A are shown as Table 2.1.1 .

TABLE 2.1.1

B. C. HYDRO AND POWER AUTHORITY

HISTORIC AND PROBABLE PROJECTIONS OF ELECTRIC POWER REQUIREMENTS BY SALES CATEGORIES

Fiscal Year	Residential		Other		W.K.P. & L. Co. Ltd. Load Requirements		Cominco[4] Load Requirements		Total Sales Less Bulk		Bulk Sales		Total Billed Sales		Losses & Accruals		Total Gross Requirements[1] (Including W.K.P. & L. Co. Ltd. & Cominco Requirements) Energy		Peak	
	GW·h	Annual % Growth	GW·h	Annual % Growth	GW·h	Annual % Growth	GW·h	Annual % Growth	GW·h	Annual % Growth	GW·h	Annual % Growth	GW·h	Annual % Growth	GW·h	% of Total Sales	GW·h	Annual % Growth	MW[3]	Annual % Growth
1969/70	3 664	5.0	4 718	9.4					8 382	7.5	5 062	11.4	13 444	8.9	1 407	10.5	14 851	9.2	2 716	6.2
70/71	4 044	10.4	5 041	6.8					9 085	8.4	5 278	4.3	14 363	6.8	1 666	11.6	16 029	7.9	2 972	9.4
71/72	4 465	10.4	5 863	16.3					10 328	13.7	5 860	11.0	16 188	12.7	1 684	10.4	17 872	11.5	3 130	5.3
72/73	4 739	6.1	6 112	4.2					10 851	5.1	7 066	20.6	17 917	10.7	2 366	13.2	20 283	13.5	3 653	16.7
73/74	5 176	9.2	6 848	12.0					12 024	10.8	7 776	10.0	19 800	10.5	2 493	12.6	22 293	9.9	3 739	2.4
1974/75	5 685	9.8	7 180	4.8					12 865	7.0	7 714	-0.8	20 579	3.9	2 775	13.5	23 354	4.8	3 957	5.8
75/76	6 258	10.1	7 594	5.8					13 852	7.7	6 808[2]	-11.7	20 660	0.4	2 765	13.4	23 425	0.3	4 232	6.9
76/77	6 625	5.9	8 133	7.1					14 758	6.5	8 166	19.9	22 924	11.0	3 034	13.2	25 958	10.8	4 421	4.5
77/78	7 051	6.4	8 634	6.2					15 685	6.3	8 479	3.8	24 164	5.4	3 328	13.8	27 492	5.9	4 800	8.6
78/79	7 492	6.3	9 095	5.3					16 587	5.8	9 133	7.7	25 720	6.4	3 584	13.9	29 304	6.6	5 122	6.7
1979/80	7 727	3.1	9 574	5.3					17 301	4.3	9 217	0.9	26 518	3.1	3 395	12.8	29 913	2.1	5 231	2.1
10 Yr. Average % 1969/70 - 1979/80	7.7		7.3						7.5		6.2		7.0				7.3		6.8	
Projections																				
1980/81	8 069	4.4	10 063	5.1	-		-		18 132	4.8	9 600	4.2	27 732	4.6	3 718	13.4	31 450	5.1	5 540	5.9
81/82	8 365	3.7	10 549	4.8	176		-		19 090	5.3	11 080	15.4	30 170	8.8	3 990	13.2	34 160	8.6	6 040	9.0
82/83	8 688	3.9	11 007	4.3	331	88.1	-		20 026	4.9	13 0[illegible]	17.6	33 051	9.5	4 289	13.0	37 340	9.3	6 600	9.3
83/84	9 107	4.8	11 545	4.9	555	67.7	-		21 207	5.9	14 710	12.9	35 917	8.7	4 593	12.8	40 510	8.5	7 150	8.3
84/85	9 561	5.0	12 127	5.0	911	64.1	-		22 599	6.6	16 185	10.0	38 784	8.0	4 906	12.6	43 690	7.8	7 680	7.4
1985/86	9 988	4.5	12 690	4.6	1 061	16.5	-		23 739	5.0	17 135	5.9	40 874	5.4	5 136	12.6	46 010	5.3	8 090	5.3
86/87	10 424	4.4	13 314	4.9	1 215	14.5	120		25 073	5.6	17 800	3.9	42 873	4.9	5 377	12.5	48 250	4.9	8 560	5.8
87/88	10 877	4.3	14 018	5.3	1 545	27.2	270	-	26 710	6.5	18 775	5.5	45 485	6.1	5 645	12.4	51 130	6.0	9 020	5.4
88/89	11 355	4.4	14 759	5.3	1 691	9.4	300	11.1	28 105	5.2	19 160	2.1	47 265	3.9	5 885	12.5	53 150	4.0	9 410	4.3
89/90	11 846	4.3	15 544	5.3	1 830	8.2	450	50.0	29 670	5.6	19 405	1.3	49 075	3.8	6 095	12.4	55 170	3.8	9 830	4.5
1990/91	12 347	4.2	16 368	5.3	1 974	7.9	850	88.9	31 539	6.3	19 675	1.4	51 214	4.4	6 366	12.4	57 580	4.4	10 300	4.8
11 Yr. Average % 1979/80 - 1990/91	4.4		5.0						5.6		7.1		6.2				6.1		6.4	

Notes:
(1) Excludes Thermal Station Service at Burrard, Pt. Mann, Georgia, Keogh and Prince Rupert.
(2) Bulk sales in 1975/76 abnormally depressed by approximately 1400 GW·h as a direct result of 3 months pulp and paper strike.
(3) Projected peak loads are based on normal weather conditions.
(4) Cominco has requested possible amounts of power which are approximately twice the amounts tabulated here. For this projection and in discussion with Cominco the Company's possible requirements were given a probability of slightly under fifty percent.

5 September 1980

New Plant Additions

B.C. Hydro is now scheduling the following projects to come on line between 1982-89.

Plant	Year	Firm Energy (Gwh)
Revelstoke	1983/84	3,000
	1984/85	3,700
Peace Site C	1987/88	1,350
	1988/89	3,140
Hat Creek	1988/89	1,900
	1989/90	2,850

A more detailed scheduling of individual units is shown in Tables 2.1.2a and 2.1.2b .

2.2 Forecast Energy Deficiencies

In Exh. 46, Table 4, the Applicant is forecasting that, if the 6.1% rate of load growth is realized and critical water conditions develop, energy deficiencies will occur during the period 1985/86 to 1988/89. Given such conditions it is apparent that if Site C or Hat Creek were to be delayed these deficiencies would increase drastically.

By comparison they show that, under average water conditions, deficits will only occur if Burrard thermal is not utilized.

TABLE 2.1.2a

1981/82 SYSTEM PLAN

ENERGY LOAD AND RESOURCE BALANCE
PROBABLE FORECAST - AVERAGE WATER CONDITIONS

Fiscal Year	Month	Projects Added	Integrated System Nameplate Capacity (MW)	Energy Forecast (GWh)	System Hydro (1)(2) Capability (GWh)	Hat Creek (3) Thermal (GWh)	Surplus/ (4)(5) (Deficit) (GWh)
1981/82	-	-	8 735	33 985	36 820	-	2 835
1982/83	-	-	8 735	37 155	38 820	-	1 665
1983/84	Dec Mar 15	Revelstoke 1 & 2 Revelstoke 3	10 130	40 315	42 220	-	1 905
1984/85	Sep 15	Revelstoke 4	10 591	43 485	46 510	-	3 025
1985/86	-	-	10 591	45 790	46 510	-	720
1986/87	-	-	10 591	48 015	46 510	-	(1 505)
1987/88	Oct Jan	Peace Site C 1 & 2 Peace Site C 3	11 039	50 880	47 890	-	(2 990)
1988/89	Apr Jul Aug Oct	Peace Site C 4 Peace Site C 5 Hat Creek 1 Peace Site C 6	12 049	52 885	50 955	1 900	(30)
1989/90	Aug Oct Jan	Hat Creek 2 Murphy Creek 1 & 2 Murphy Creek 3 & 4	12 769	54 890	51 430	4 750	1 290
1990/91	Apr Jul Oct	Murphy Creek 5 & 6 Murphy Creek 7 & 8 Murphy Creek 9 & 10	13 009	57 280	52 680	5 700	1 100

NOTES:
(1) Includes energy purchase to December 1983 under existing contract with Alcan.
(2) Hydro capability in 1981/82 and 1982/83 has been adjusted to reflect the storage deficit in Williston Lake in the fall of 1980.
(3) Expected generation under average water conditions.
(4) Exclusive of Burrard Thermal which is required to augment the system hydro capability under below average water conditions.
(5) No allowance is included for energy deliveries to the United States in lieu of water releases that may be required due to the initial filling of Revelstoke Reservoir.

Generation Planning Department
November 1980

TABLE 2.1.2b

1981/82 SYSTEM PLAN

ENERGY LOAD AND RESOURCE BALANCE
PROBABLE FORECAST - CRITICAL WATER CONDITIONS

Fiscal Year	Month	Projects Added	Integrated System Nameplate Capacity (MW)	Energy Forecast (GWh)	Firm Hydro[1][2] Capability (GWh)	Thermal Energy Available (GWh)	Total Firm Energy Capability (GWh)	Surplus/[3] (Deficit) (GWh)
1981/82	-	-	8 735	33 985	33 830	3 170	37 000	3 015
1982/83	-	-	8 735	37 155	35 830	3 170	39 000	1 845
1983/84	Dec	Revelstoke 1 & 2	10 130	40 315	38 830	3 170	42 000	1 685
	Mar 15	Revelstoke 3						
1984/85	Sep 15	Revelstoke 4	10 591	43 485	42 530	3 170	45 700	2 215
1985/86	-	-	10 591	45 790	42 530	3 170	45 700	(90)
1986/87	-	-	10 591	48 015	42 530	3 170	45 700	(2 315)
1987/88	Oct	Peace Site C 1 & 2	11 039	50 880	43 885	3 170	47 055	(3 825)
	Jan	Peace Site C 3						
1988/89	Apr	Peace Site C 4	12 049	52 885	47 025	5 070	52 095	(790)
	Jul	Peace Site C 5						
	Aug	Hat Creek 1						
	Oct	Peace Site C 6						
1989/90	Aug	Hat Creek 2	12 769	54 890	47 500	8 060	55 560	670
	Oct	Murphy Creek 1 & 2						
	Jan	Murphy Creek 3 & 4						
1990/91	Apr	Murphy Creek 5 & 6	13 009	57 280	48 705	9 375	58 080	800
	Jul	Murphy Creek 7 & 8						
	Oct	Murphy Creek 9 & 10						

NOTES:
(1) Includes energy purchase to December 1983 under existing contract with Alcan.
(2) Hydro capability in 1981/82 and 1982/83 has been adjusted to reflect the storage deficit in Williston Lake in the fall of 1980.
(3) No allowance is included for energy deliveries to the United States in lieu of water releases that may be required due to the initial filling of Revelstoke Reservoir.

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November 1980

Project Energy Deficiencies (Surplus) Gwh

Year	Critical Water Conditions with Burrard	Average Water Conditions without Burrard	Average Water Conditions with Burrard
1985/86	2315		
1986/87	3825	1505	(1685)
1987/88	790	2990	(180)
1988/89		30	(3140)

(Ref. Tables 4 and 6, Exh. 46 or Tables 2.1.2a and 2.1.2b of this report)

B.C. Hydro is permitted to operate the Burrard plant in the event of an emergency, such as transmission line failure or critical water conditions. The Burrard plant may also be used to relieve the demands on Williston Lake (allowing it to refill) in the event that critical water conditons are anticipated (Best, Transcript page 248/249).

It is apparent from the foregoing that a delay in approval of Site C or Hat Creek would increase the projected deficiencies dramatically (a delay of one year for Site C would increase the potential 1987/88 deficiency from 790 to 2140 Gwh). The Commission further recognizes that there is a 50% probability that water supply will be less than average.

In respect to the above deficits, however, the Commission notes that these would <u>not</u> occur if the actual energy demand growth rate proved to be only in the order of 5.5%. Even then, however, the Burrard plant would still be required in a critical water year.

Year	Energy Available Gwh (with Burrard)	Energy Demand Gwh 5.5% growth
1981/82	37,000	33,985
1986/87	45,700	44,417
1987/88	47,055	46,860

The Commission considers a further relevant matter to be the maximum growth rate that can be supported without Burrard.

Year	Energy Available Gwh (without Burrard)	Energy Demand Gwh 5.5% growth
1981/82	33,830	33,985
1985/86	42,530	40,527
1986/87	42,530	42,351
1987/88	43,885	44,257

The above comparison shows that the Falls River additional generation would have a role in replacing Burrard generation in a critical water year for an energy growth rate as low as 4.5% in 1987/88, i.e. immediately before full energy benefits are obtained from Site C, and from the first units at Hat Creek.

2.3 Falls River Energy Capability

The existing project has an average energy capability of 43 Gwh per annum. The proposed 22 MW redevelopment project would have an average energy capability of 91 Gwh. (Exh. 1, page B-7).

If the Applicant had pursued the "continued maintenance" program the energy generation would have dropped to 38.5 Gwh (Exh. 32, Table III-3). The reduction from the present level of energy generation is presumably due to the slightly reduced head (forebay 295 vs 302 feet) and probable increased spillage due to reduced pondage.

The available energy from the project at any time depends on runoff conditions. Typical plant operation is illustrated in Exh. 21 and in Exh. 14, page 15 in terms of plant outflows (and hence generation). Exh. 21 shows that shutdowns, particularly in the critical winter months, would be more frequent for the 22 MW scheme than under present conditions. Exh. 14 indicates winter shutdowns for 59% of the time.

While the interruptable nature of the energy supply would normally suggest that it be classed as secondary energy, and not considered part of the firm energy supply, the presence of Williston Lake effectively allows secondary energy from Falls River, and other B.C. Hydro projects, to be used as firm energy. On the basis of Falls River runoff during the critical 1940-45 period as compared with the average, B.C. Hydro estimates that 93% of the average energy may be considered as firm. (Exh. 15, Page 4-1).

The validity of this assumption cannot be tested since it depends on the extent to which Williston Lake is used to compensate for other hydro projects. For the purpose of this assessment, the Commission has accepted it as reasonable.

The capacity and energy contributions of the Falls River alternatives to the system (excluding transmission losses) are summarized as follows:

	Capacity MW	Average Energy Gwh	Firm Energy* Gwh
Present Conditions	6.9	43	40
Continued Maintenance	6.4	38.5	36
7 MW Rehabilitation	7.0	45	42
22 MW Redevelopment	22.0	91	85

* assumed as 93% of average

2.4 Alternative Sources of Short-Term Supply

Based on the Applicant's assumptions of critical water conditions and a 6.1% load growth rate the committed and planned new generation additions up to 1990 may not be sufficient to meet energy demands in the period 1985/86 to 1987/88, as outlined in Section 3.2 herein, and the deficiency could reach nearly 4,000 Gwh.

The contribution from an enlarged Falls River project, which would provide an increase of 45 Gwh in firm energy, would clearly have no impact on a 4000 Gwh shortfall. It would, however, serve to make a modest reduction in power purchased from elsewhere. Moreover, even under average water conditions it would reduce the need to operate Burrard and again would reduce the need for purchases.

The Applicant recognizes that Falls River redevelopment cannot therefore be justified on the basis of absolute necessity arising from of a possible overall energy shortage, but assumes that the energy thereby produced will be cheaper than power purchases, or energy from Burrard (Best, Transcript pages 108 and 110).

During cross-examination the Applicant testified that possible alternatives for meeting an energy deficit include

- purchase from Alcan
- purchase from Calgary Power
- energy from Burrard
- energy from Gas turbines

The Commission notes that no definite agreements are in effect or apparently contemplated that would cover either of the first two options (Best, Transcript page 111) and concludes that the latter two options either run counter to provincial policy or are likely to be more costly than Falls River redevelopment.

2.5 Power Supply to Prince Rupert

The Application (Exh. 1, page C-1) indicates that, from a regional standpoint, the redeveloped Falls River project would provide a useful benefit by improving the power supply to the Prince Rupert area. This area is currently supplied by

- the existing 7 MW Falls River project
- 57 MW of Gas Turbine energy
- the 287 kV transmission from the Skeena Substation
- the Alcan Interconnection (no contract) (Parry, Transcript page 41).

The energy demand in Prince Rupert for the year 1979/80 was 290 Gwh (Parry, Transcript page 27), and the capacity or peak demand was 66 MW (Parry, Transcript page 38). The historical load growth rate was 9.9% pa and B.C. Hydro expect this to increase to 11.4% up to 1990 (Parry, Transcript page 27).

The redevelopment project, by providing an additional 15 MW and 48 Gwh will therefore reduce the requirement to supply power from the grid. It will also improve the security of power supply to the area since the reliability/availability of the other sources will remain the same. No evidence was provided on the present quality of electrical supply in Prince Rupert. The Commission therefore views the effect of the redevelopment project as a definite but unqualified benefit to Prince Rupert. The Commission further notes that the forced outage rate for the Falls River project will not improve with redevelopment, since its transmission facilities will not be changed and a single unit will be used instead of two units.

2.6 Long Term Justification

The primary reason given by the Applicant as justification for the 22 MW redevelopment project appears to be that the increase in energy supply to the system from the project is economic, as related to alternative power supply sources. The validity of that reasoning depends on the answers to two related questions applying to average system power availability conditions

- can the additional power be used
- what is its cost, as related to alternatives.

The additional power from Falls River would become available in 1984, when in an average year, with the 6.1% growth rate, there would be surplus hydro energy in the system (as a result of Revelstoke).

As' is shown in Exh. 46, Table 6, under average water conditions, the additional energy from Falls River could be used to reduce Burrard generation during the years 1986/87 - 1988/89. In 1988/89 the first Hat Creek unit is proposed to be in service and consequently it can be argued that generation from Falls River will serve to reduce Hat Creek generation, and should be valued at the marginal cost thereof. If it is assumed that Hat Creek will always be a source of firm power to the system, as distinct from some form of standby, then Falls River generation will continue to have a value related to replacement thermal generation.

The Commission concludes that it is fair to assume that additional energy from Falls River will probably serve to replace Burrard generation from 1984-88, depending in part on actual load growth and water supply conditions, and that thereafter it will serve to reduce Hat Creek generation. The Commission further concludes that for the purpose of evaluating this additional energy, over the long-term it is appropriate to assume a realistic marginal cost of Hat Creek energy. (Noting that Hat Creek would be required to generate in an average water year if an average energy growth rate of more than 5.5% is experienced).

3. PROJECT SAFETY

3.1 Present Conditions

The present condition of the plant is described in Exh. 9 (1979 report) which details the findings of a plant inspection in April 1979 and concrete testing in November 1978. It was also summarized by Parry (Transcript pages 48-51).

Apart from the generally run-down and poorly maintained condition of the plant observed by the Commission during its visit on May 6, 1981, there are a number of specific deficiencies which have resulted from age, neglect, and from the raising of the forebay in 1942. (Exh. 9 Synopsis)

Problems Associated with Raising Forebay

In 1942 flashboards were added to the overflow spillway crest, and stoplogs placed in the lower part of the gated sluices, thereby raising the normal maximum forebay level from elevation 295 to 302 feet. Subsequently the maximum level was raised to elevation 305 and then reduced to 303 (current). (Exh. 9, page 1-2). The net effect of raising the forebay level was to severely reduce the flood flow that could be passed without overtopping the concrete structures (El 305).

The spillway discharge capability was reduced from about 44,000 cfs, under the pre-1942 conditions (Exh. 15, page 6-2) to about 13,000 cfs. (The maximum probable flood is estimated by B.C. Hydro as 44,000 cfs, the maximum recorded flood is about 22,000 cfs (Parry, Transcript page 17).

There were two consequences of the 1942 flashboard installation:

- the dam was frequently overtopped (128 times for a total of 7,000 hours, in the last 16 years - Parry, Transcript page 346)

- periodic high water levels infringed upon the acceptable safety factors against sliding (Salmon, Transcript page 163; Exh. 15, pages 6-3/4).

	Present Conditions		Pre 1942	
Condition	Forebay Elevation	Safety Factor	Forebay Elevation	Safety Factor
Normal	303 ft.	1.6 (1.5)	295 ft.	3.0
Unusual*	312 ft.	1.0 (1.2)	305 ft.	1.4

* Inferred as the maximum probable flood conditions based on quoted forebay levels.

() Mimimum acceptable factor of safety against sliding. (Exh. 15, page 6-3).

It should be noted that the frequency and extent of overtopping over the past 16 years was probably compounded due to:

- removal of the reservoir level alarm (Exh. 9, page 2-3),

- the fact that the gates were operated from the gate hoist structure, requiring operator access across the dam, and making gate opening impossible if the dam was already overtopped (Salmon, Transcript page 158).

The Commission notes that the frequent overtopping of the dam resulted from improper installation of the flashboards, normally designed to fail as soon as abnormal forebay levels occur (Exh. 9, page 2-4, also Salmon, Transcript pages 157 and 159). No explanation was offered as to why B.C. Hydro has not improved the flashboard arrangements since 1964.

The B.C. Hydro report on the condition of the structures concluded that, assuming further operation for about 20 years, the spillway problem should be solved by raising the dam. (Exh. 9 Synopsis). The Applicant did not consider the alternative of reverting to pre-1942 conditions, since it was felt that the present live storage of 7200 acre feet was already inadequate from a operational standpoint. (Exh. 9, page 2-2).

Reservoir Level	Live Storage - Acre feet
303	7,200
295	2,000
290	0

The Commission notes that the soffit of Intake No. 2 is at 291.5 feet, consequently the No. 2 turbine cannot operate at forebay levels of less than about 292 feet (Exh. 15, page 1-3).

Deterioration Due to Age

The inspection report (Exh. 9) recommends that for extended future operation of the existing facility (20 years) repairs or replacements should include:

- draft tube concrete
- penstock cleaning and painting
- turbine overhaul (both units)
- transformer replacement

The Applicant's 1979 report stated that the structural integrity of the dam was not affected by the very visible spalling of the concrete. Parry (Transcript pages 48-49), however, described specific deterioration and leakage personally observed by the Commission at:

- the undersluice
- the sluices
- the spare intakes
- the log chute
- the penstock footings

The Commission concludes that while these may not affect the safety of the structure, implementation of a major repair or replacement program is clearly necessary to significantly extend the service life of the project.

3.2 Alternative Remedial Measures

The safety of the dam is presently affected by its inadequate discharge capacity, resulting in unacceptably high loadings. There are two acceptable solutions.

1. To revert to pre 1942 conditions, thereby providing a flood discharge capacity of about 44,000 (B.C. Hydro's estimate of maximum probable flood) or a forebay level of 305 feet (present top of structure).

   The Applicant recognized that this is a safe solution (Exh. 15, page 6-3, also Salmon, Transcript page 163). This alternative would still require replacement of the gate hoists and gates, installation of remote sluice gate controls, and other repairs to the dam to prevent leakage and to repair erosion (Exh. 32B, Table III-1).

2. To preserve the present live storage by raising the dam overflow crest to 305 feet as described for the redevelopment scheme, and the top of the non-overflow structure to above maximum flood levels (from the present 305 feet to about 314 feet, Exh. 32B, Table I-1).

   To implement this solution the gates and hoists would require repair/replacement, remote gate controls would be needed, as well as extensive concrete work to prevent leakage and to repair erosion.

The Commission concludes that present conditions are unacceptable, if risk to the structure and the operating staff is to be avoided. The fact that B.C. Hydro has accepted and indeed contributed to the present conditions over the past 16 years does not mean that it should continue to do so.

Finally, in light of the foregoing, the Commission concludes that the choice of the preferred alternative for the project is entirely a matter of economics.

4. ECONOMIC EVALUATION

4.1 B.C. Hydro Criteria

The selection by the Applicant of the 22 MW Redevelopment project as compared with the alternative of rehabilitation has been based on an "engineering economic evaluation of direct costs" (Kuiper, Transcript page 550). The Application also evaluates the project in terms of social costs, using the ELUC guidelines.

The essentials of these two methods are (Kuiper, Transcript page 551/2)

- engineering economic evaluation of direct costs includes such costs as water licence fees, school taxes, etc. and basic annual costs based on net interest rates (more or less borrowing costs net of inflation)

- evaluation using social costs excludes taxes and license fees from annual charges, and employs higher interest rates to reflect the "perceived social opportunity cost of capital".

Conventionally, either of these methods can be used to develop average energy costs, excluding inflation, for a series of assumed interest rates, and the results can then be used to determine up to what rate of return one alternative is cheaper than another. These results take into account alternative or different services lives. They can, however, provide misleading results when comparing projects of different size. Moreover, of particular importance to the Commission is the fact that the resulting unit energy costs do not represent average financial costs.

The Applicant's method has been to estimate energy costs, then evaluate generation, in terms of revenue, using an assumed marginal cost of Hat Creek energy or alternative nuclear, then calculate net annual benefits as revenues less costs. The alternatives are then compared in terms of net benefits.

Irrespective of whether the comparisons are made using the engineering economic evaluation or the social benefit cost method, the Commission believes there are three criteria that are critical to the results:

(1) Marginal Cost of Energy
(2) Service Lives
(3) Interest Rate

(1) Marginal Cost of Energy

By the Engineering Economic Evaluation Method

According to B.C. Hydro guidelines for project optimization (Exh. 28) energy should be valued at

Firm Energy	19.8 mills/kwh
Secondary Energy	14.9 mills/kwh

based on the estimated costs from nuclear generation, 1979 rates.

On this basis the Applicant values Falls River energy at 19.4 mills (weighted for firm and secondary) then includes 2.4 mills/kwh for capacity, and escalates the total by 5% to give a 1980 price of 22.8 mills/kwh (Exh. 15, Table 4-1). The Applicant then employs this value in the benefit/cost comparison shown in Exh. 15, Table 2-4, which is their engineering economic evaluation (based on the 3% net interest rate).

By the Social Cost, Benefit/Cost Evaluation Method

For the alternative benefit/cost analyses based on social costs, the Applicant used marginal costs for Hat Creek, which vary with the assumed interest rate (Exh. 15, Table 2-6 and Exh. 14, Table C-4). Resulting energy values are:

	3%	6%	10%
Hat Creek Unit Energy value Mills/kwh	20.6	25.7	34.3

These are assumed by the Commission to include a capacity component. The Commission believes that for the Falls River project the capacity component for the power plant itself should be deleted, since B.C. Hydro has not assumed Falls River capacity in its planning (Exh. 50, page 81) and in any case the system has surplus unusable capacity. The Commission therefore believes that a rate of 19.4 x 1.05 (escalation) or 20.4 mills/kwh should be used for all alternatives.

If the marginal cost of energy from nuclear generation for engineering economic evaluation is an internal B.C. Hydro measure to avoid complication with varying Hat Creek estimates (Exh. 15, Table 2.6, Note 1), in the context of justifying a project the Commission concludes that the use of such a cost is only appropriate if a clear margin of preference is demonstrated for the project being tested.

(2) Service Lives

The amortization periods used for comparing the Falls River alternatives have a significant effect on the comparisons, particularly if higher interest rates are assumed.

Amortization Rates

Interest Rate	3%	6%	10%
20 year life	.03722	.02718	.01746
50 year life	.00887	.00344	.00086
70 year life	.00434	.00103	.00013

The Applicant's economic comparisons have assumed a 70 year service life for the redevelopment project. This means that the project would be retired in year 2053. At that time the dam would be 123 years old and the turbine/generator 70 years old.

Conventional practice assumes that the economic life of a facility is less than the theoretical physical life, because the facility will be retired when repair and operating costs make further operation uneconomic. This is more or less the situation of the plant today, after a 50 year life.

The Applicant's justification for these long total service lives was that the concrete tests on the dam (after 50 years) showed that it is sound, and that the original turbine/generator is in reasonable condition. Under cross-examination the Applicant indicated that it might be possible to purchase a turbine with an exceptionally long life, if a low speed were specified, (Salmon, Transcript page 170). This would be consistent with the performance of the original turbine (1930) as compared with the (1960) later unit. There was no evidence, however, that the Applicant had allowed for a premium turbine/generator cost to meet such criteria. In general, turbine/generator life without major repairs is normally assessed at about 35-40 years, based on current design and marketing practice resulting from competitive bidding.

The Commission finds it relevant that the United States Federal Regulatory Commission (USFERC) normally assigns a 100 year life to federally licensed dam projects. Insofar as economic studies are concerned, it would seem appropriate that the dam be assigned a maximum life of 100 years and the replacement (redevelopment project) turbine/generator a life of less than 50 years. On this basis, the economics of the project should assume a project retirement date of say 2035, at which time the new turbine generator set would be 50 years old and the dam 105 years old.

In any event, the Commission concludes that reasonable amortization rates at a more or less acceptable opportunity cost of capital would show little difference in annual costs between a 50 year and 70 year assumed economic project life.

(3) Interest Rate

The engineering economic assessment provided by the Applicant (e.g. Exh. 15, Table 2-4,) assumes a net interest rate of 3% exclusive of inflation. The support for this is given in Exh. 15, Table 5-1, which shows that, historically, the actual interest rate net of inflation has been less than 3%. This specific analysis is ascribed to the Applicant (Kuiper, Transcript page 597) and follows the format of the modified Fisher equation, which was based on experience during the depression years when interest rates were about 3%, and inflation was zero.

A significant ramification of this is that, although current B.C. Hydro interest rates are about 15% and inflation rates about 12%, B.C. Hydro must also, pursuant to Special Direction No. 1 by the B.C. Government, implement its projects to a target interest coverage of 1.3 to 1 by the Applicant's fiscal year 1983/84 and to raise its equity position (Exh. 49). On this basis the Commission concludes that B.C. Hydro should be incorporating in its economic studies a rate of return, net of inflation, that meets this requirment. Consequently, if the overall premise of a net interest rate is accepted, then this rate should probably not be 3% but some higher rate. Although this matter was not raised during the hearings, it will be an issue of significance in future B.C. Hydro hearings. In the meantime the Commission's view on this subject are expressed in this Decision under "Other Matters".

Finally, the Commission notes that the ELUC guidelines, which have been specified in the Terms of Reference for Site C, suggest the use of a net interest rate of 10% for benefit cost studies involving social costs (Exh. 15, page 5-7).

Methodology - General

It is conventional utility practice to assess projects, in terms of social costs (that is, excluding taxes which are essentially intergovernment transfer payments), and to compare these costs up to a rate of return acceptable to the evaluating or regulating agency criteria. In this Application the Commission concludes that generation costs, as a function of rate of return should have been assessed using the following parameters:

- Interest rate - 3% to 10%
- Service life - 50 years - Redevelopment
  - 20 years - Rehabilitation
- 1981 Capital Cost Estimates
- Comparative marginal fuel costs for Hat Creek

It is also necessary to draw some conclusions from Exh. 32B regarding the average financial cost of the alternatives.

4.2 Capital Cost of Alternatives

The Application by B.C. Hydro is for the 22 MW redevelopment project. As justification for this proposal capital costs were also introduced for two other alternatives:

- 7 MW rehabilitation
- Minimum rehabilitation (or continued maintenance)

Various values for the estimated capital costs of these alternatives appear in the testimony and exhibits. To avoid confusion, any evaluation should consider two sets of costs:

(A) Costs shown in Exh. 15

(B) Costs shown in Exh. 32B

(A) Capital Costs per Exh. 15 (April 1980 prices)

Minimum Rehabilitation Scheme ($ million)

Interest Rate	3%	6%	10%
Capital Cost	4.47(1)	4.47	4.47
Corporate Overhead (25%)	1.12	1.12	1.12
Energy loss during Contruction	0.17	0.17	0.17
Subtotal	5.76	5.76	5.76
IDC	0.10	0.20	0.33
Total	5.86	5.96	6.09

(1) Cost provided Exh. 15, page 1-3, other values assumed same or prorated from 7 MW rehabilitation alternative, as shown in Exh. 15, Table 2-3.

7 MW Rehabilitation Project ($ million)

Interest Rate	3%	6%	10%
Capital Cost	5.79	5.79	5.79
Corporate Overhead (25%)	1.45	1.45	1.45
Energy Loss during Construction	0.17	0.17	0.17
Subtotal	7.41	7.41	7.41
IDC	0.13	0.26	0.43
Total (2)	7.54	7.67	7.84

(2) All values taken from Exh. 15, Table 2-5

22 MW Redevelopment Project ($ million)

Interest Rate	3%	6%	10%
Capital Cost	20.19	20.19	20.19
Corporate Overhead (16%)	3.25	3.25	3.25
Energy Loss during Construction	-	-	-
Subtotal	23.44	23.44	23.44
IDC	0.94	1.88	3.13
Total (3)	24.38	25.32	26.57

(3) All values from Exh. 14, Table C-2.

(B) Capital Costs per Exh. 32B (April 1981 prices)

Minimum Rehabilitation
(Continued Maintenance Project ($ million)

Interest Rate	3%	6%	10%
Capital Cost (4)	6.05	6.05	6.05
Energy Loss during Construction (5)	0.17	0.17	0.17
Subtotal	6.22	6.22	6.22
IDC (6)	0.11	0.22	0.36
Total	6.33	6.44	6.58

(4) From Exh. 32B, Table III-2, includes corporate overhead.
(5) Assumed the same as Exh. 15, Table 2-3.
(6) Prorated from Exh. 15, Table 2-5.

7 MW Rehabilitation project ($ million)

Interest Rate	3%	6%	10%
Capital Cost (7)	10.27	10.27	10.27
Energy Loss during Construction (8)	0.17	0.17	0.17
Subtotal	10.44	10.44	10.44
IDC (9)	0.18	0.37	0.61
Total	10.62	10.81	11.05

(7) From Exh. 32B, Table II-2, includes corporate overhead.
(8) Assumed the same as Exh. 15, Table 2-3.
(9) Prorated from Exh. 15, Table 2-5.

22 MW Redevelopment Project ($ million)

Interest Rate	3%	6%	10%
Capital Cost (10)	29.17	29.17	29.17
IDC (11)	1.17	2.34	3.89
Total	30.34	31.51	33.06

(10) From Exh. 32B, Table I-2, includes corporate overhead.
(11) Prorated from Exh. 14, Table C-2.

The difference between those costs shown in Exh. 15 and those shown in Exh. 32B is due to

- escalation for one year
- certain changes in work scope and costs, particularly related to concrete costs and repairs/replacement of sluice gate equipment.

As a reference point for consistency these costs may be compared (I = 10%) as follows:

	Capital Cost ($ million)			
	Exh. 15	Exh. 32B	Diff.	Ratio
Continued Maintenance	6.09	6.58	0.49	1.08
7 MW Rehabilitation	7.84	11.05	3.21	1.41
22 MW Rehabilitation	26.57	33.06	6.49	1.244

The significant relative change in these estimates (1981 Exh. 32B vs 1980 Exh. 15) is that the rehabilitation scheme cost has been increased relative to that for continued maintenance, and that the costs for the redevelopment scheme have been increased relative to both the alternatives. The probable reason is that, in addition to escalation and basic re-estimating, some extra contingency has been applied to the redevelopment project estimate. It may be assumed that the $3,210,000 increase for the rehabilitation scheme is also true of the 22 MW redevelopment scheme, and essentially applies to dam modifications. The additional (6.49 - 3.21 or) $3,280,000 for the 22 MW redevelopment scheme has to appear as a supplementary overall contingency or be applied to the new penstock/powerhouse costs.

With respect to the minimum rehabilitation scheme (or continued maintenance) there was a change in assumed scope during the hearings, as evidenced by Exh. 39. It would appear that the estimates for the minimum scheme (per Exh. 15) was overestimated, presumably due to interpretation over the required scope of work. Comparing Exh. 39 with Exh. 15 for the alternative yields the following (capital cost and corporate overhead only):

Capital Costs ($ million)

	Exh. 15	Exh. 39
Minimum Scheme	5.59	4.986
7 MW Rehabilitation	7.37	7.239
22 MW Redevelopment	23.44	23.420

4.3 Energy Costs from Alternatives

Costs Based on 1980 Estimates and B.C. Hydro Criteria

Based on Social costs, and expressed in constant 1980 dollars, the energy costs from the alternatives as presented by B.C. Hydro, are as follows:

Average Generation costs (1980 Estimate) - mills/kWh

Interest Rate	3%	6%	10%
22 MW Redevelopment (1)	11.4	19.2	31.5
7 MW Rehabilitation (2)	14.9	18.2	24.1
Continued Maintenance (3)	14.5	17.8	22.8
Hat Creek (Unadjusted) (4)	20.6	25.7	34.3
(Adjusted) (5)	16.3	17.7	19.3

(1) Exh. 14, Table C-2, assumes 70 year life.
(2) Exh. 15, Table 2-6, assumes 20 year life.
(3) Derived assuming capital costs per Section 4.2 above (e.g. $5,860,000 with IDC at 3%), assumes same O and M costs as 7 MW rehabilitation scheme, 38.5 Gwh generation.
(4) Exh. 14, Table C-4.
(5) Adjusted by subtracting assumed approximate capacity cost, based on assumed cost of $700/kW plus IDC. These (approximate) adjusted costs would only be valid if the unadjusted costs include full capacity cost.

It can logically be argued that the project should be developed up to the point where the last increment of energy costs the same as alternate thermal energy. Incremental energy costs are as follows:

Incremental Energy costs (1980 Estimate)

7 MW Rehabilitation vs Continued Maintenance	3%	6%	10%
7 MW Rehabilitation - Annual Cost ($000) (6)	671	833	1085
Continued Maintenance Annual Cost ($000) (7)	558	684	879
Incremental Annual Cost ($000)	113	149	206
Incremental Energy Gwh (8)	6.5	6.5	6.5
Incremental Unit Energy Cost - mills/kWh	17.4	22.9	31.7

22 MW Redevelopment vs Continued Maintenance	3%	6%	10%
22 MW Redevelopment - Annual Cost ($000) (9)	1031	1739	2854
Continued Maintenance, Annual Cost ($000)	558	684	879
Incremental Annual Cost ($000)	473	1055	1975
Incremental Energy - Gwh (10)	52.2	52.2	52.2
Incremental Unit Energy Cost - mills/kWh	9.1	20.2	37.8
Hat Creek Unit Energy Cost - Unadjusted	20.6	25.7	34.3

(6) Exh. 15, Table 2-5.
(7) Derived assuming capital cost with IDC at 3% of $5,800,000 etc.
(8) 45 Gwh - 38.5 Gwh.
(9) Exh. 14, Table C-2
(10) 90.7 Gwh. - 38.5 Gwh.

As is shown in Figure 4.3.1, using 1980 costs and the B.C. Hydro evaluation criteria (70 year life and average Hat Creek energy costs), average generation cost for all alternatives is cheaper than the alternative thermal cost up to a net interest rate of about 11%. The 22 MW scheme is also cheaper than the other alternatives (rehabilitation and continued maintenance) for interest rates up to 5-1/2%. The continued maintenance scheme is cheaper than the 7 MW rehabilitation scheme for all interest rates.

Considering incremental costs (Figure 4.3.2), the 22 MW scheme as compared with continued maintenance, is cheaper than the 7 MW scheme (as compared with continued maintenance) for interest rates up to 7%, and is cheaper than Hat Creek up to 8-1/2%. The question of whether the Hat Creek costs include the full capacity costs (capital charges as distinct from variable energy generation costs) is critical.

Comparison with Hat Creek costs reduced by the full capacity charges (which may or may not be in the costs provided by B.C. Hydro) would mean that only the 22 MW scheme was viable and only up to a 5-1/2% net interest rate.

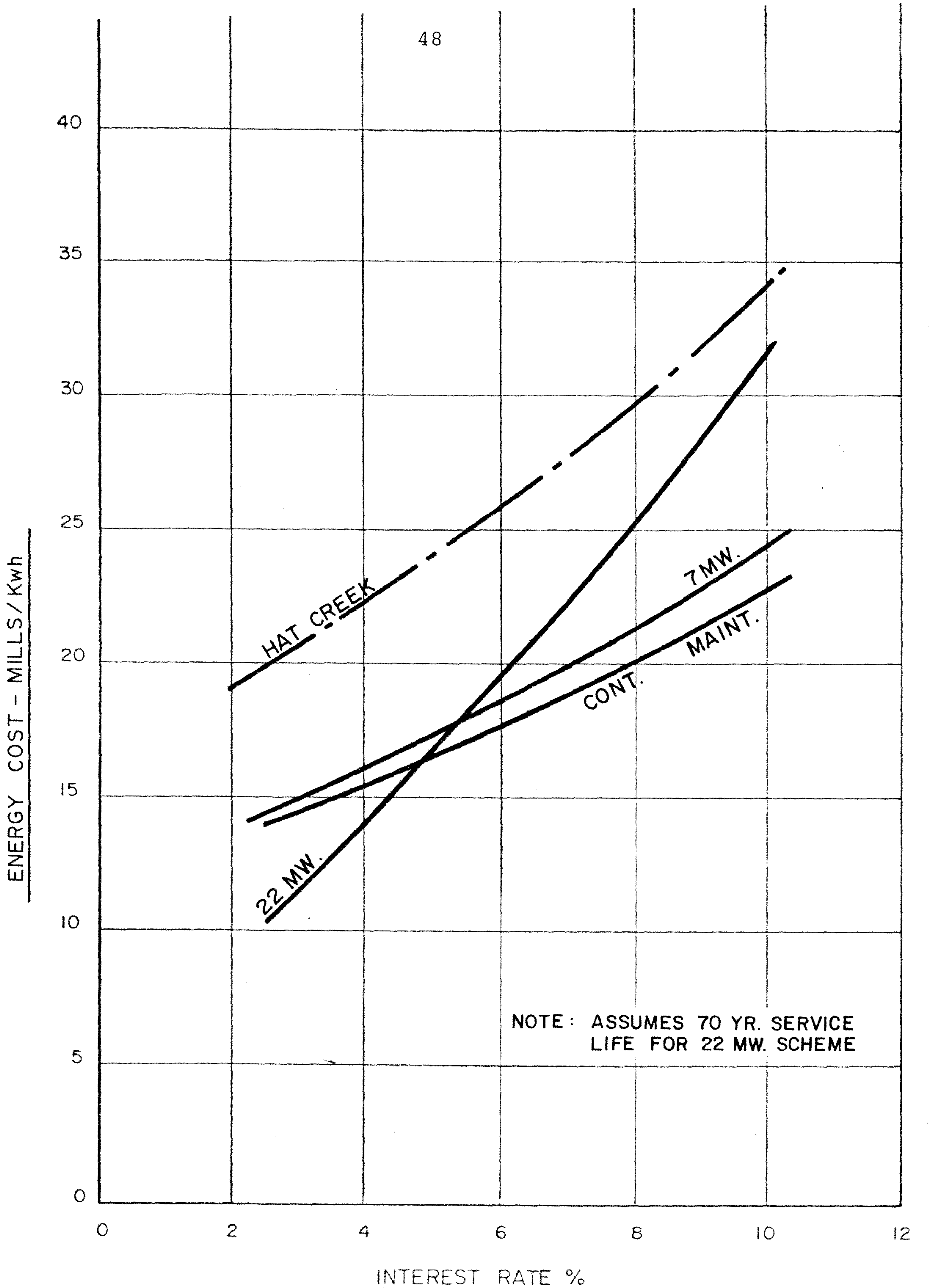


FIGURE 4.3.1

AVERAGE GENERATION COSTS
1980 ESTIMATE (70 YR. LIFE)

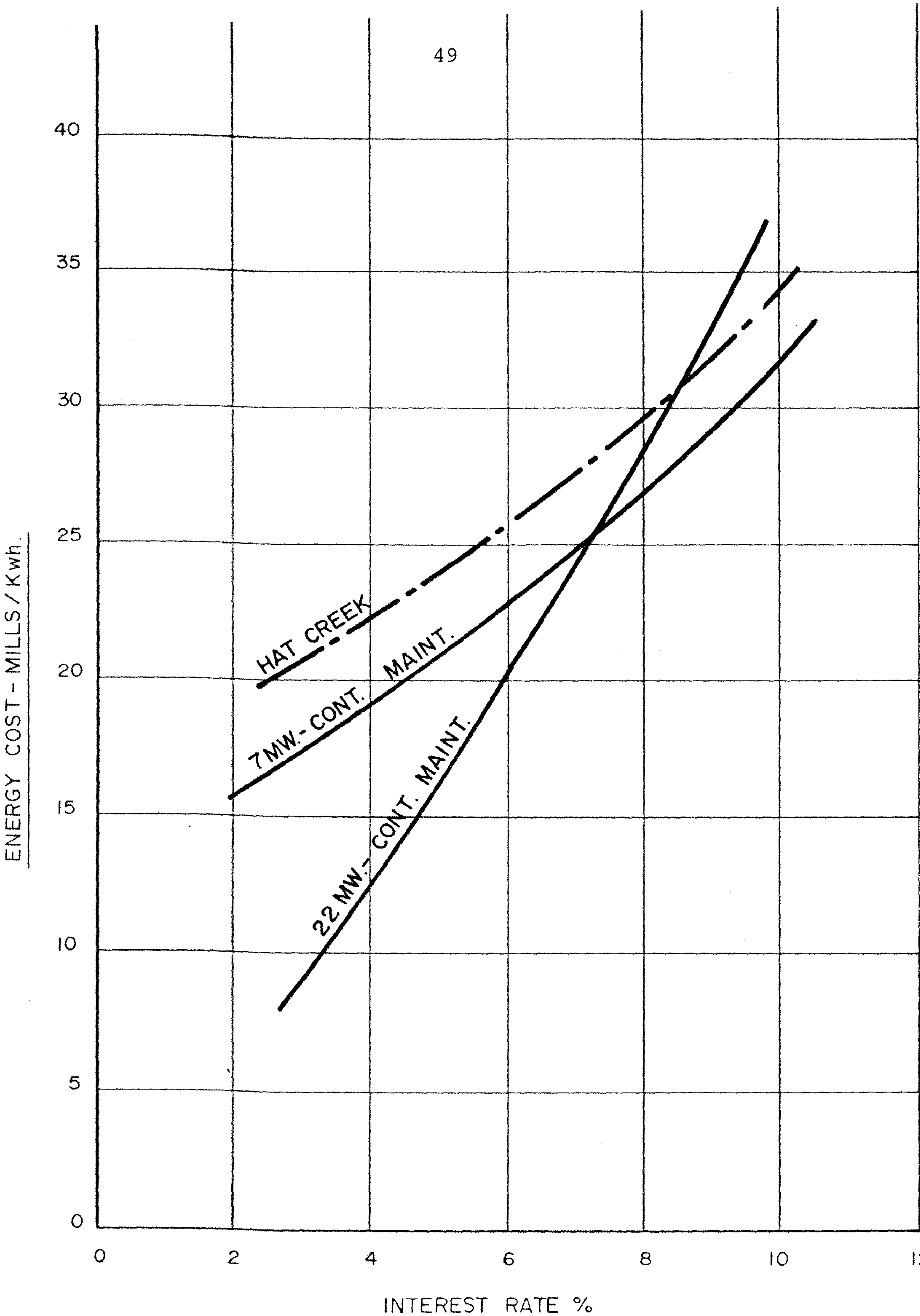


FIGURE 4.3.2

INCREMENTAL ENERGY COSTS
1980 ESTIMATE (70 YR. LIFE)

Costs Based on 1981 Estimates and Revised Criteria

The foregoing values of course change using the 1981 capital cost estimate and a shorter (50 year) service life for the 22 MW redevelopment scheme. In calculating annual costs, non-capital costs have been increased by 10% to reflect inflation from 1980 rates.

Average Generation Costs 1981 Estimates - Mills/kWh

Interest Rate	3%	6%	10%
22 MW Redevelopment	15.4	24.4	39.1
7 MW Rehabilitation	19.9	24.9	32.8
Continued Maintenance	15.7	19.3	24.8
Hat Creek (Unadjusted) (1)	22.7	28.3	37.7

(1) Escalated at 10% from 1981 values.

The calculations of these revised generation costs and corresponding incremental costs are as follows:

22 MW Redevelopment Project
Revised Average Generation Costs (1981 Estimate)

Interest Rate	3%	6%	10%
Capital Cost	29.17	29.17	29.17
IDC	1.17	2.34	3.89
Total Cost ($ million)	30.34	31.51	33.06
Annual Costs ($)			
Interest	910,200	1,890,600	3,306,000
Depreciation (50 years)	269,116	108,394	28,413
Annual Operating Costs	213,400	213,400	213,400
Total Annual Cost	1,392,716	2,212,394	3,547,813
Average Generation - Gwh	90.7	90.7	90.7
Unit Generation Cost Mills/Kwh	15.4	24.4	39.1

7 MW Rehabilitation Scheme
Revised Average Generation Cost (1981 Estimate)

Interest Rate	3%	6%	10%
Capital Cost (1)	10.44	10.44	10.44
IDC	0.18	0.37	0.61
Total Cost ($ million)	10.62	10.81	11.05
Annual Costs ($)			
Interest	318,600	648,600	1,105,000
Depreciation (20 years)	395,276	293,816	192,933
Annual Operating Costs	180,000	180,000	180,000
Total Annual Cost ($)	893,876	1,122,416	1,477,933
Average Generation Gwh	45	45	45
Unit Generation Cost Mills/kWh	19.9	24.9	32.8

(1) Includes energy loss during construction

Continued Maintenance
Revised Average Generation Costs (1981 Estimate)

Interest Rate	3%	6%	10%
Capital Cost (1)	6.23	6.23	6.23
IDC	0.11	0.22	0.36
Total ($ million)	6.34	6.45	6.59
Annual Costs ($)			
Interest	190,200	387,000	659,000
Depreciation	235,975	175,311	115,061
Annual Operating Cost	180,000	180,000	180,000
Total Annual Cost	606,175	742,311	954,061
Average Generation Gwh	38.5	38.5	38.5
Unit Generation Cost Mills/kWh	15.7	19.3	24.8

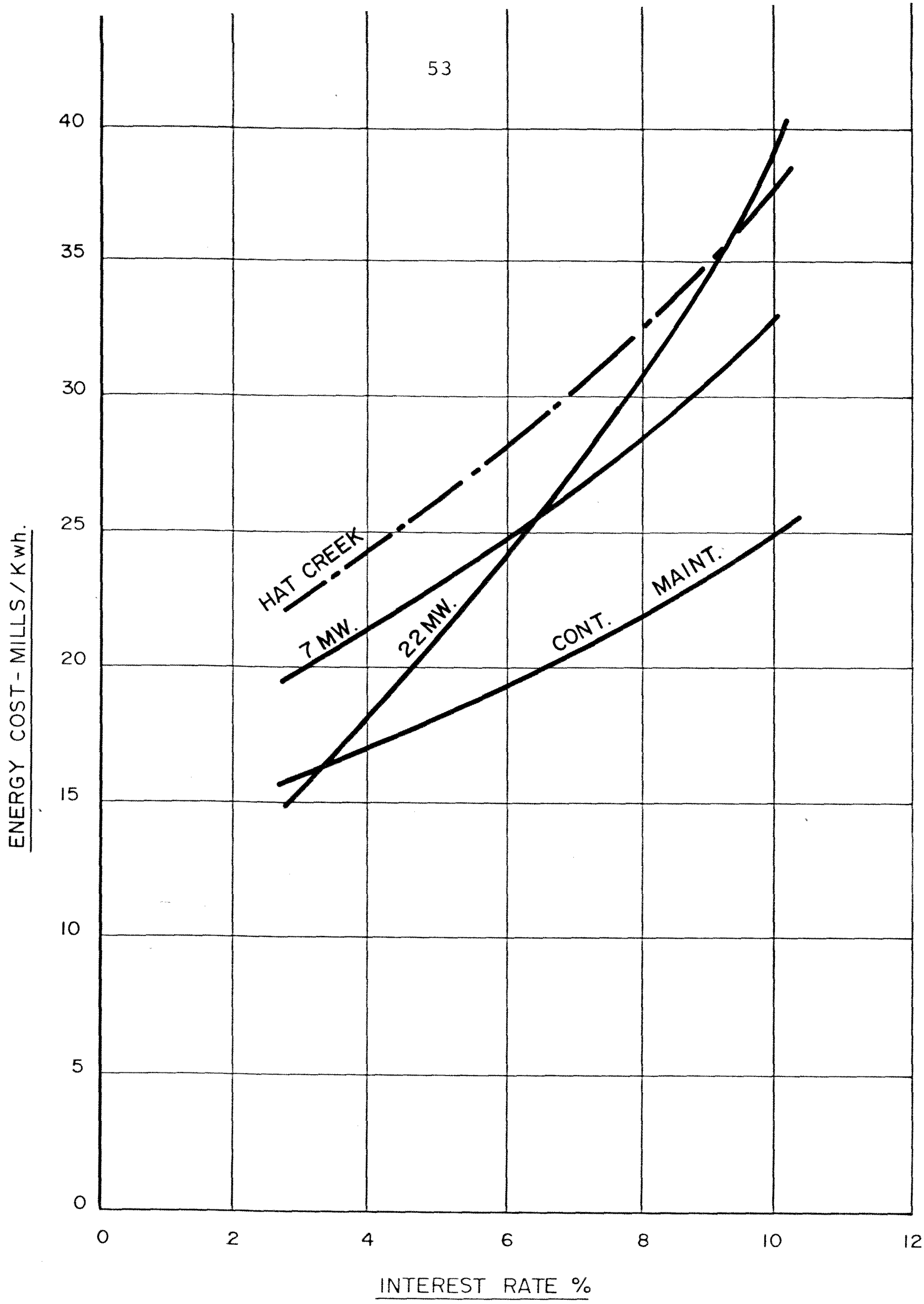
(1) Includes energy loss during construction

Incremental Energy Costs (1981 Estimate) Mills/kWh

	3%	6%	10%
7 MW Rehabilitation vs Continued Maintenance			
7 MW Rehabilitation - Annual Cost ($,000)	894	1,122	1,478
Continued Maintenance Annual Cost	606	742	954
Incremental Annual Cost ($,000)	288	380	524
Incremental Energy Gwh	6.5	6.5	6.5
Incremental Unit Energy Cost Mills/kWh	44.3	58.5	80.6
22 MW Redevelopment vs Continued Maintenance			
22 MW Redevelopment - Annual Cost ($,000)	1,393	2,122	3,548
Continued Maintenance Annual Cost	606	742	954
Incremental Annual Cost ($,000)	787	1,470	2,594
Incremental Energy - Gwh	52.4	52.2	52.2
Incremental Unit Energy Cost	15.1	28.2	49.7
Hat Creek Energy Cost	22.7	28.3	37.7

The revised comparison of average (Figure 4.3.3) and incremental (Figure 4.3.4) energy costs for the Falls River alternatives as compared with Hat Creek show a significant change in relative project economics. Specifically this results from the change in service life for the 22 MW project and the significant increases in capital costs for the 7 MW Rehabilitation scheme ($3,210,000 or 41% increase) and the 22 MW Redevelopment scheme ($6,490,000 or 24% increase) as compared with the continuing maintenance arrangement (increase $490,000 or 8%). As a result the 7 MW rehabilitation scheme becomes significantly more expensive than continued maintenance at all

FIGURE 4.3.3



AVERAGE GENERATION COSTS
1981 ESTIMATE (50 YR. LIFE)

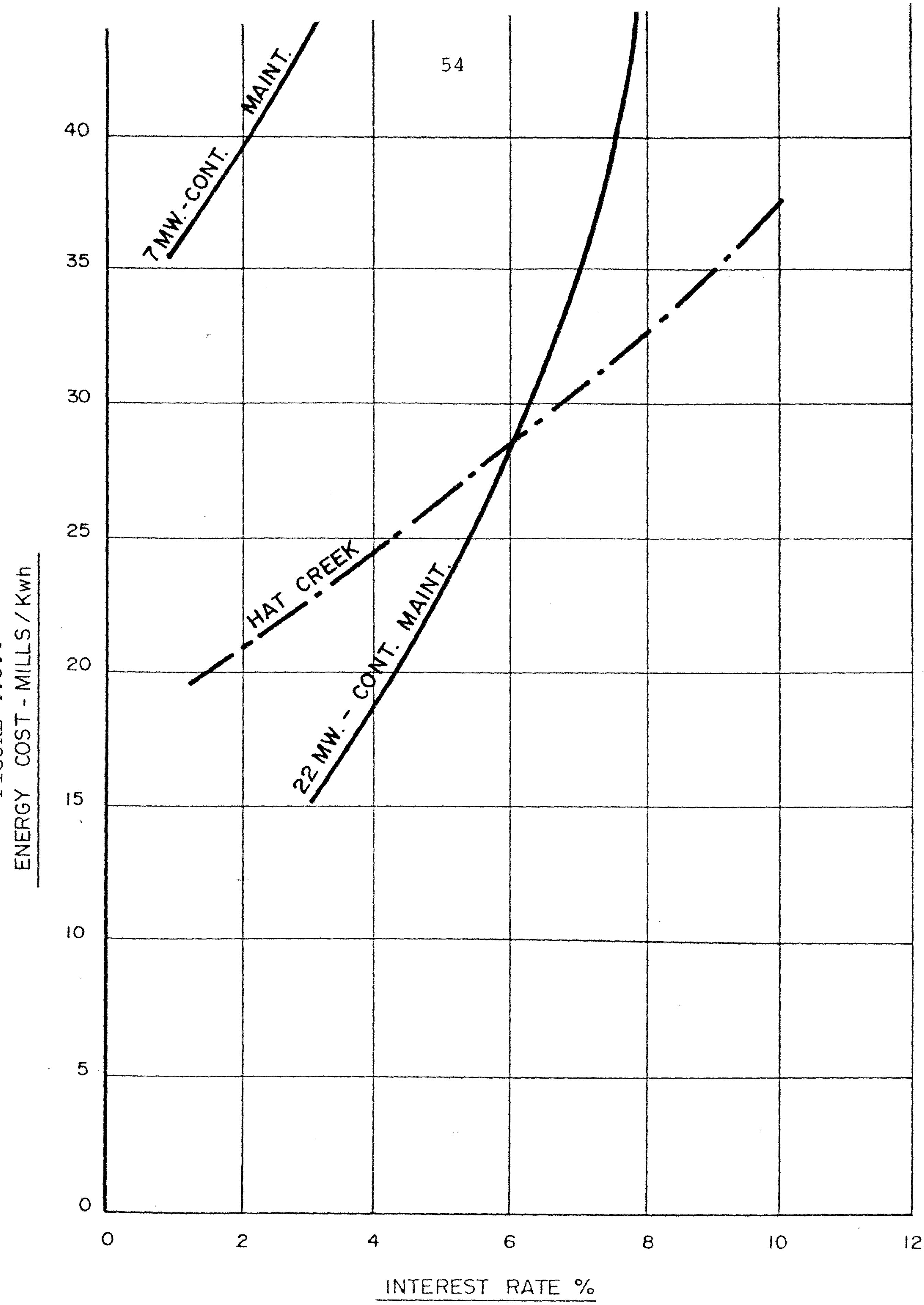


FIGURE 4.3.4

INCREMENTAL ENERGY COST
1981 ESTIMATE (50 YR. LIFE)

interest rates. The average costs for the 22 MW redevelopment scheme are less than alternative (1981) costs for Hat Creek for interest rates up to 9% (as compared with 11-1/2% with the 1980 estimates). In terms of incremental costs the 7 MW scheme is not competitive for any interest rate, and the 22 MW redevelopment scheme is only viable up to 6%.

In summary, the results show that assuming the decision to proceed with the 22 MW redevelopment scheme was made using 1980 costs, the 22 MW scheme is viable on the basis of incremental costs as compared with (undefined) Hat Creek costs, for rates of return up to 9%. This probably exceeds the criteria that can be justified at this stage. By comparison, if the 1981 cost estimates are used, the 22 MW project is only viable for rates of return up to 6%, which is a marginal situation.

In reference to the 7 MW rehabilitation scheme, this type of analysis provides a negative bias, in that the improved facilities have been completely utilized. The analysis assumes a service life of 20 years, whereas the improved dam would have (to be consistent) a further useful life of about 30 years.

The two reasonably comparable options are continued maintenance and the 22 MW redevelopment project. While the analysis on the basis of social costs suggests that the 22 MW redevelopment project is viable for net interest rates up to 6%, which may be marginally acceptable, the revised costs for the 22 MW scheme may be artificially inflated to provide supplementary contingency factors, and the capital costs for the continued maintenance scheme include a major cost already incurred, that would not have been spent if the 22 MW scheme had not been already selected by B.C. Hydro as its preferred alternative.

It should be noted that this analysis essentially compares two alternatives which provide a different service, both in terms of energy production and length of service. The conclusions regarding the 22 MW scheme as compared to continued maintenance, however, are valid and conservative providing that the marginal cost of alternative thermal generation exceeds that for the continued maintenance scheme for rates of return in excess of the breakeven interest rates. That means, if offsetting thermal generation was used to provide equivalent service in terms of total energy and service life, then the cost of the continued maintenance scheme (plus offsetting thermal generation) would be higher than stated in the comparisons.

Financial Evaluation

As an alternative to the engineering economic comparisons of generation costs, at the request of the Commission B.C. Hydro also provided a "financial" comparison (Exh. 32B). This analysis showed estimated cost of service and corresponding unit energy costs on a year by year basis for the period 1980-2053, assuming an interest rate of 12%, straight line depreciation and for inflation rates of 9% and 7%. The required interest coverage of 1.3 to 1 was also provided for.

For the 7 MW rehabilitation and continued maintenance alternatives it was assumed that major equipment replacements would be made as required to keep the plant in service for the same period as the 22 MW scheme.

The results of this analysis are shown in terms of "equivalent uniform real average costs", as follows:

	Average Energy Costs Mills/Kwh	
	Inflation Rate	
	7%	9%
22 MW Redevelopment	21.5	17.1
7 MW Rehabilitation	24.7	22.2
7 MW Continued Maintenance	26.2	24.8

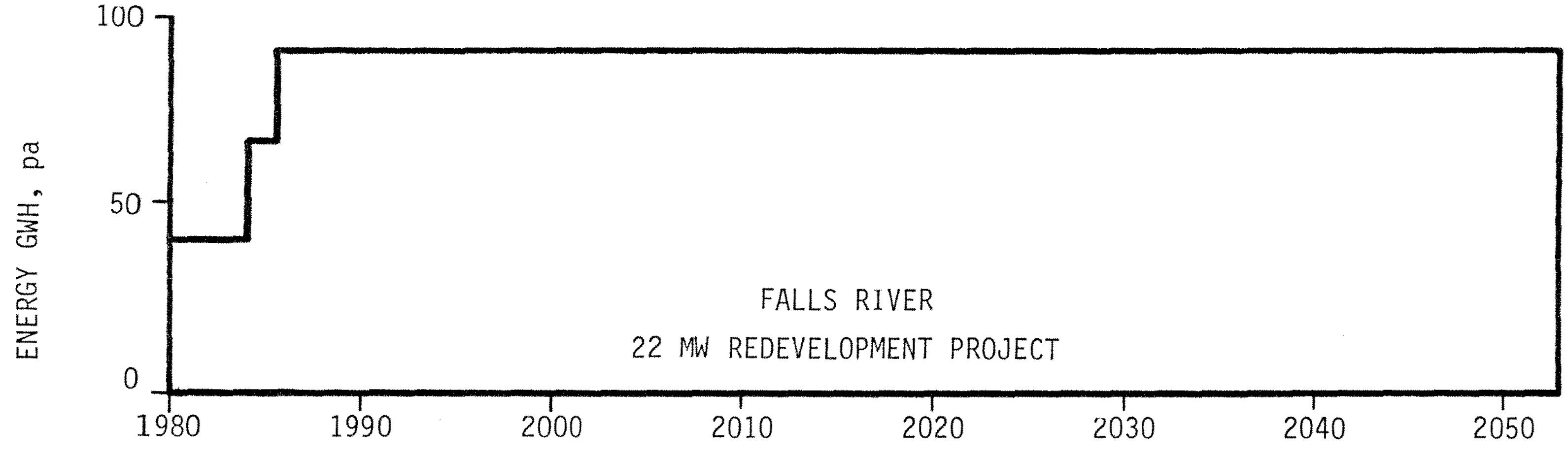
These values presumably reflect net costs of capital corresponding to: 12% interest with 9% inflation
12% interest with 7% inflation

These values show that the 22 MW scheme would provide lower average costs. They may be affected by the assumption that the continued maintenance project is kept in service after year 2003. It may be noted that if alternative thermal energy costs are assumed as 20 mills/kWh and escalated at 9% annually then thermal power costs in say year 2010 would be about 300 9ills/kWh as compared with the derived cost for the continued maintenance alternative of 397 mills/kWh.

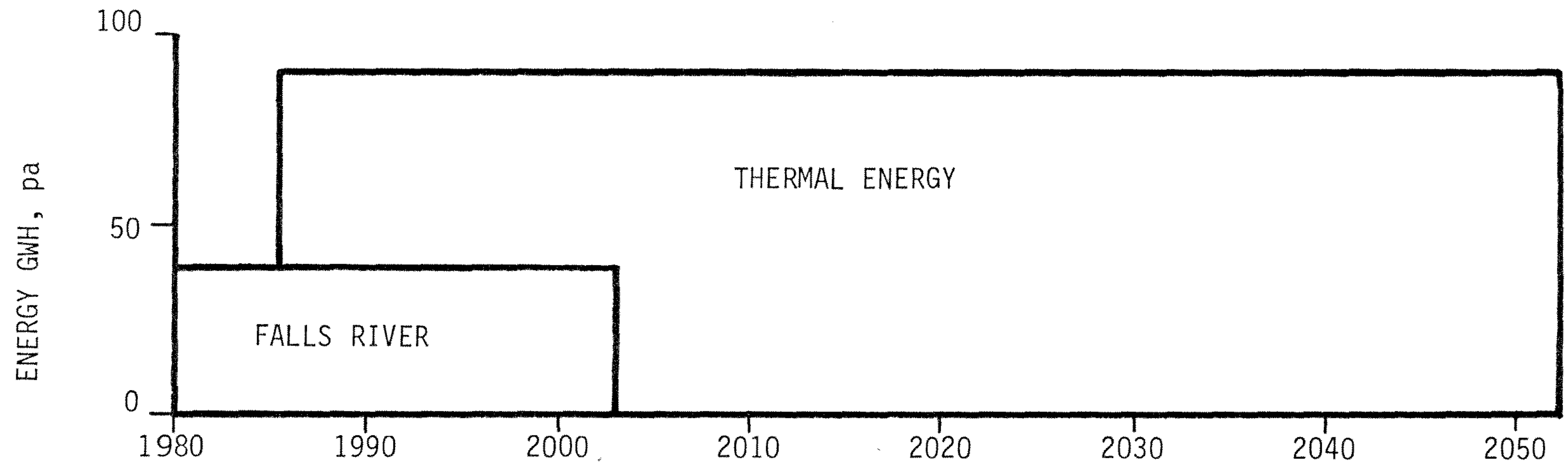
In order to check the further alternative of retiring the project in year 2003 (Figure 4.3.5) a simplified analysis was made which assumed

- plant retired after year 2003
- the difference in energy between the 22 MW scheme and the continued maintenance scheme was made up by thermal power

FIGURE 4.3.5



A. 22 MW REDEVELOPMENT



B. CONTINUED MAINTENANCE

EQUIVALENT SUPPLY ALTERNATIVES

- thermal energy was assumed to cost 20 mills/Kwh in 1980 (Hat Creek adjusted to remove capacity portion) and escalated at 9% annually

- all other costs as shown in Tables I-4 and III-4, Exh. 32B.

The equivalent average cost of energy was derived as the present worth of year-by-year cost of service, divided by the present worth of the annual energy amount. The cost of service for the 22 MW project was taken directly from Table I-4. The cost of service for the continued maintenance alternative was taken from Table III-4 for the period up to 2003. Thermal energy costs for the period 1984-2003 (53 gwh pa) and the period 2004-2053 (91 gwh pa) were added to the cost of service (which for the plant itself would be zero after 2003). The present worth amount was calculated at 12%.

The derived average energy costs were

22 MW Redevelopment	66 mills/kwH
Continued Maintenance with thermal energy	92 mills/kWh

This approximate analysis provided confirmation that actual average energy costs will be lower with redevelopment, based on a more or less realistic interest and escalation rates.

4.4 Effect of Costs Already Incurred

The above comparisons were based on cost estimates for the various Falls River alternatives that include costs already incurred. These costs primarily related to

- design engineering (including preliminary studies)
- construction of access road to dam
- construction of new wharf

With the exception of the engineering studies the above costs are only applicable to the 22 MW redevelopment project. These expenditures would not have been incurred if the 22 MW project had not been approved. The testimony did not establish the date on which the 22 MW project and consequent expenditure of funds was approved by management in B.C. Hydro. It is assumed that this was in 1980, prior to the effective date of regulation of the Applicant by this Commission.

There is no direct information on the costs that have already been incurred. Reference to Exh. 32B shows the following recent scheduled costs.

Costs (1)

Year (2)	1980	1981
Continued Maintenance	$ 194,000	$ 2,824,000
7 MW Rehabilitation	175,000	2,824,000
22 MW Redevelopment	194,000	2,824,000

(1) Costs from Tables 1-2, 11-2 and 111-2 Exh. 32B.
(2) Financial year ending March 31.

From these costs it may be assumed that a total of about $3,000,000 has been spent on the Continued Maintenance or 7 MW scheme that is not really required. This value may be arbitrarily reduced by say $500,000 to allow for preliminary studies and field investigations that led to the decision on the

22 MW scheme (Note Exh. 32B, Table 1 shows costs for completed or committed work as $3,410,000).

The annual costs for the continued maintenance scheme have been adjusted accordingly, as shown in the Table below. The corresponding average generation costs and incremental costs are also shown.

CONTINUED MAINTENANCE

Energy Costs Based on Reduced Capital Costs (1981 Estimate)

Interest Rate	3%	6%	10%
Basic Capital Cost ($ million)	6.34	6.45	6.59
Cost already incurred	2.5	2.5	2.5
Reduced Capital Cost ($ million)	3.84	3.95	4.09
Annual Costs			
Interest	115,200	237,000	490,000
Depreciation	142,948	107,361	71,411
Annual Operating Cost	180,000	180,000	180,000
Total Annual Cost	438,148	524,361	660,411
Average Generation Gwh	38.5	38.5	38.5
Unit Generation cost Mills/kWh	11.4	13.6	17.2

Revised Comparison of Energy Generation Costs

Interest Rate	3%	6%	10%
22 MW Redevelopment	15.4	24.4	39.1
Continued Maintenance	11.4	13.6	17.2
Thermal Energy	22.7	28.3	37.7

The corresponding revised incremental costs are as follows (Figure 4.4.1):

22 MW Redevelopment vs
Continued Maintenance

Interest	3%	6%	10%
22 MW Redevelopment Annual Cost ($,000)	1,393	2,212	3,548
Continued Maintenance Annual Cost	438	524	660
Incremental Annual Cost	955	1,688	2,888
Incremental Energy Gwh	52.2	52.2	52.2
Incremental Unit Energy Cost Mills/kWh	18.3	32.3	55.3

The revised incremental energy costs for the 22 MW scheme are significantly increased by reducing the costs for the base case (continued maintenance).

The Commission therefore concludes that the 22 MW project would only be viable, relative to alternative thermal, for rates of return up to about 4%.

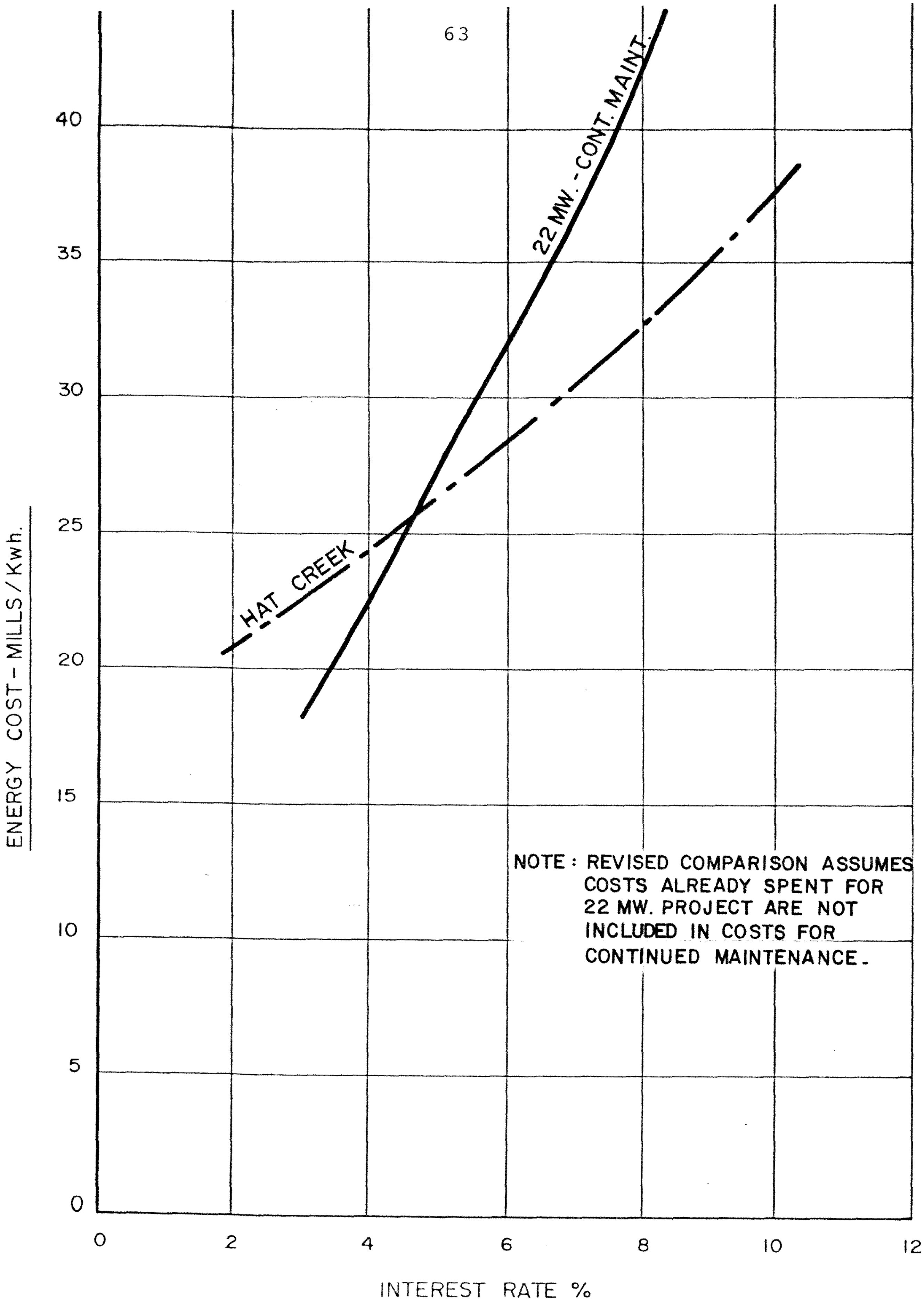


FIGURE 4.4.1

INCREMENTAL ENERGY COSTS
1981 ESTIMATE - REVISED

5. PUBLIC INTEREST

As indicated in in Section 1.3 the Commission has considered the matter of public interest in the following areas:

- the utilization of a renewable resource
- the cost of electricity to the consumer
- local benefits
- environmental factors

In the Commission's view all of the above relate to the question of whether the project should be enlarged, or maintained as is and retired early.

5.1 Resource Utilization

The Application indicates that currently approximately 50% of the average annual inflow to the plant is wasted through spillage, and that with redevelopment to 22 MW this wastage would be reduced to 10% (Exh. 1, pages B-6/7).

During the hearings the Applicant testified that, since the river was already developed and since the significant environmental changes or damage from the project had already taken place, this renewable resource should be utilized to the maximum extent to which it can be shown to be economic to do so (Best, Transcript pages 112/113 and 127/128).

The Commission believes this is a conventional and valid argument, providing that any further environmental changes are acceptable, that the proposed project is economic, and that the additional energy can be utilized in the system by replacing or deferring thermal generation. Given these conditions, the Commission concludes that the additional energy obtained from Falls River by better utilization of the available runoff, will reduce (albeit only very marginally) the depletion of non-renewable resources (gas or coal) and will reduce consequent thermal generation pollution effects.

The fact that the project is very small, in terms of the total B.C. Hydro system, does not affect this conclusion. Moreover, it is relevant that other utilities, as well both levels of the Government, are supporting the principle of small hydro as a fuel conservation measure, as well as on cost grounds. It would therefore be contrary to presently accepted public policy not to make best use of this resource, providing the project meets the other required tests.

5.2 Cost of Electricity

One of the most basic issues is the Applicant's responsibility to provide power to its customers at the lowest possible cost. Accordingly, each time it selects a new project for implementation the Applicant must satisfy the Commission that the proposed project will provide power at a lower cost than any other available new source. This is recognized by B.C. Hydro (Best, Transcript pages 111/112). The essential question is whether the way the Applicant makes the selection (Section 4.1) will yield the project with the lowest power costs. In the case of large projects other factors, such as timing of "on power" dates and installation size, affect system power costs.

The Commission does not believe that the Falls River project will displace or defer any future project, in terms of new plant additions. Further expenditures on the project (irrespective of which alternative is selected) can only be justified on economic grounds on the basis of replacement of thermal generation at Burrard and Hat Creek. Consequently it is necessary to prove

a) that energy from redevelopment is cheaper than the marginal cost of thermal energy

b) that the average energy costs from redevelopment is lower than that from the other alternatives for the project.

It is the Applicant's mandate and declared objective to provide electric energy to the province at the minimum <u>long-term</u> cost (Exh. 15, page 5-1). In the case of the alternatives for Falls River the expression "long-term" would appear to relate more to the 70 year life of the proposed Redevelopment project than to the other alternatives. In terms of utility regulation, however, it is the Commission's duty to ensure security of supply and reasonable standards of service at reasonable prices to the consumers. To this end and in the real world this would appear to require the Commission to recognize and leave open the opportunity for cheaper and socially desirable alternative sources of energy in the very long run, e.g. 70 years.

From the evidence (Exh. 32 and 32B), it is apparent that the financial cost of energy from the Rehabilitation alternative is cheaper than that from the proposed Redevelopment until the year 2002, i.e. for the next 20 years. It can reasonably be argued, in terms of the probable pace of scientific achievement in the future development of energy alternatives (solar, wind, geothermal, etc.) that even 20 years could qualify as "long-term" and quite clearly 70 years certainly does.

Thus, the choice of Redevelopment at this time represents a decision affecting future generations of consumers for 70 years down the road, who may not require this particular source of energy because other cheaper and more desirable sources have emerged to replace it. Moreover, in the meantime, the choice of Redevelopment over Rehabilitation means that the Applicant's present customers will pay a premium for energy produced at Falls River for at least 20 years.

Although the foregoing is an argument against approval of the Redevelopment alternative, the Commission believes that the best interests of the province will be served, in this instance, by taking the long view. The Commission is not expected to gamble or speculate on the pace or outcome of future scientific achievements with respect to new sources of renewable energy. Moreover, as demonstrated heretofore by Section 4 by the Applicant's analyses as presented, and confirmed by the supplementary tests initiated by the Commission, the redevelopment project clearly provides energy at a lower average cost over the long-term than the other alternatives for the project, and at a lower cost than the marginal cost for Hat

Creek energy. The Commission therefore concludes that redevelopment of the project will in fact result in lower average system energy costs than if the project was not redeveloped, and will therefore approve that alternative as presented by the Applicant. In so doing, however, the Commission again cautions the Applicant that, had expenditures relating only to Redevelopment not been made in advance of the Hearing, the economics relating to other alternatives would have been improved and the Commission's conclusions accordingly might have been different.

5.3 Local Benefits

The Commission concludes that tangible benefits from the redevelopment project to Prince Rupert will probably be minimal, apart from the somewhat theoretical improvement to the security of power supply to the area.

Such benefits, however, would normally include:

- local purchase of lumber and fuel during construction;
- direct or indirect additional employment (noting however that virtually all B.C. Hydro labour is unionized and the work would probably be done by Hydro Force Contractors);
- increase in payments in lieu of school taxes (from about \$150,000 pa to \$550,000 pa based on year 1986, Exh. 32B; and
- possible aesthetic improvements to the site.

The matter of local benefits was not specifically addressed in the hearings and no local interest was evident.

5.4 Environmental Factors

B.C. Hydro provided information and conclusions resulting from their environmental assessment of the proposed redevelopment scheme. The Application, (Exh. 1, pages B-10/11), while making no reference to wildlife, does indicate that there may be negative impacts on salmon in the tailrace pond and that studies are continuing. In general, the Applicant concluded that effects on wildlife will be minimal since it is believed that little wildlife is present in the reservoir area, and that any negative impacts on fisheries can be satisfactorily mitigated.

Wildlife

The Applicant's assessment of the environmental impact on wildlife was made on the basis of a two day inspection of the plant and reservoir area (6 hours on foot and helicopter reconnaissance), in February 1980 (Bradley, Transcript pages 66 and 71) and reference to general/regional public information (Bradley, Transcript pages 69 and 82). The Applicant concluded that the wildlife habitat was of poor quality, with animals and birds occurring in low numbers. It was further concluded that the minor increase in reservoir levels would have a minimal impact on vegetation around the reservoir (Bradley, Transcript page 66). The Applicant testified that the B.C. Ministry of Environment (Fish and Wildlife Branch) had raised no objections to the proposed project (Exh. 16).

With regard to birds B.C. Hydro concluded that the raising of the water level would improve the habitat in the existing extensive marsh area and in the new flooded area, where the normal depth would be about 2 feet (Bradley, Transcript pages 74 and 75).

The question of forebay level variations in the non-winter months was not addressed. As indicated in Exh. 21, under present conditions there is virtually no drawdown of the reservoir since runoff is usually in excess of the plant discharge capacity at full output. By comparison, with the redevelopment project the forebay levels will vary frequently over the 10 foot live storage range. Presumably this will affect habitats for birds and aquatic fur bearers. More importantly this could affect fish species dependant on littoral food supplies (e.g. trout).

Fisheries

An assessment of fisheries potentially affected by the project was made in 1980. The field program was carried out over a number of short periods between July 16 and October 8. A total of 8 surveys were made, involving some 25 man days. Specifically the program included, (Walker, Transcript pages 367 and 368)

- observation from the shore
- traverses by boat
- search for salmon reds (nests)

In respect to this field program difficulties were encountered, due to water turbidity and turbulence. It was also acknowledged that the minimal presence of fish and the lack of evidence of spawning may have been affected by blasting and excavation carried out by B.C. Hydro during 1980 in connection with construction of the new wharf (Walker, Transcript pages 372 and 374). The fact that B.C. Hydro was unable to provide a diver for the fish counts in August (Walker, Transcript page 367) further weakened the validity of the field observations.

As a result of this assessment program B.C. Hydro findings were as follows (Walker, Transcript pages 362-365):

- some 5-10 chinook salmon were observed in late August in the tailrace pond, but there was no evidence of spawning. No pink salmon were observed.

- it was concluded that the observed salmon were transient. This is based on chinook preference for warmer stable water, and absence of evidence that chinook spawn in B.C. tidal waters. It was noted, however, that pink salmon are known to spawn in tidal waters.

- the present conditions in Falls River are poor for natural propagation of Pacific salmon, particularly due to the poor substrate conditions, movement of gravel and highly variable flows

- remedial measures (to compensate for the increased tailrace flow variations) could include provision of minimum flows, and either on-site or off-site incubation.

- further observations should continue in 1981.

During the hearing there was considerable testimony with respect to the issues related to salmon, on the basis of which the Commission has concluded that:

- the 1980 studies were inconclusive;

- there may be a need to provide for significant flow releases. The present assumed release is equal to estimated leakage;
- greater plant discharge variations and frequent shutdowns will have a negative impact on the fish habitat;
- further study is required to prove any mitigative measures that may be required.

Accordingly, it is apparent to the Commission that the concerns expressed by the Department of Fisheries and Oceans (Exh. 25) have not been resolved.

In summary, the Commission concludes that the timing, extent and quality of the fish and wildlife studies undertaken by B.C. Hydro were less than satisfactory, and the results accordingly inconclusive. In particular, the conclusions with respect to salmon spawning activity, based on observations made under adverse conditions following a period of blasting and construction on the site, in the Commission's view remain unsupported. The Commission will therefore require that all future environmental studies by B.C. Hydro be completed before any actual construction of the approved facility begins and under conditions more likely to produce meaningful results.

In this instance, the Commission concludes that most of the environmental damage was done with the original development. The Commission is not prepared, however, to support the principle that mitigating measures or compensation after the fact for environmental damage, should justify start of construction before all the required environmental evidence is in. With respect to Falls River, while the proposed project would result in a maximum reservoir level no greater than levels experienced during the period 1971-77, drawdowns will be much more severe. More specifically, the proposed redevelopment project may affect salmon in the tailrace area, due both to wider variation in flow and velocity and to plant shutdowns. In this respect the Commission will expect B.C. Hydro to continue a monitoring program, in conjunction with the Department of Fisheries and Oceans, and will require B.C. Hydro to initiate remedial measures, if required, to at least maintain the present quality of fish habitat.

6. OTHER MATTERS

As indicated in the Introduction to this Decision, the Commission views the Falls River Application and Hearing as the first step in what must necessarily be a learning process for both B.C. Hydro and the Commission. For this reason the Commission finds it appropriate to comment on a number of issues arising from the hearing of this particular Application which will be pertinent to other future B.C. Hydro applications. Though the project itself may be small, the principles it demonstrates are of much broader importance.

6.1 Cost Estimating Methods and Procedures

All of the filed evidence on capital and operating costs was developed by the Applicant for use in applying B.C. Hydro's own internal tests for economic/engineering comparisons and justification. For regulatory purposes such costs require financial interpretation, to permit the required assessment of impacts on the Applicant's cost of service, rate base and rates to consumers.

Economic and financial costs have very different purposes and meaning. While economic costs involve long-term uninflated average costs and provide a basis on which different projects can be compared, financial costs involve the actual inflated costs of a given project for each year of its useful life, revealing the actual current impacts on cost of service, rate base and rates to consumers. Generally accepted and normal regulatory practice requires the Commission to consider the costs of a project in terms of financial cost.

Confusion in the matter of economic versus financial costs was very apparent at this hearing, aggravated by the use of such terms as "net interest rate" or interest rate net of inflation as compared to the actual financial or market rate, "interim replacements", "sinking fund" as compared to "depreciation". The Application appeared to the Commission to be lacking in input from the Finance staff in the preparation of the project estimates (Transcript page 59), as indicated by some misclassification between maintenance and capital items (Exh. 32 and 33). Moreover, the testimony of the Applicant's engineering and financial witnesses suggested the need for more effective communication and coordination between the engineering and financial departments in B.C. Hydro (Transcript pages 274, 309, 313 and 792) and inter-departmental feedback and cost control appear to need improvement.

The Commission therefore recommends that the Applicant undertake early efforts to improve its procedures and to expand the scope of its cost estimates for future project applications, and specifically to include estimated impact on consumers.

6.2 Falls River Cost Estimates

(a) Capital Costs

The Commission examined the capital costs as estimated by B.C. Hydro and concludes that they are reasonable. These estimates, however, had been revised several times prior to the hearing, to reflect different cost base years and to up-date for later information. The substantial variation in these estimates is displayed in Appendix C. As can be seen, cost estimate revisions have produced increases of 62% for the proposed Redevelopment and 112% for the Rehabilitation alternative over the original costs as estimated by the Applicant.

Despite the Applicant's testimony as to its record of insignificant cost overruns in similar projects (Transcript page 1080) the Commission does not find the Falls River estimates reassuring as to probable final in-service cost.

(b) Overhead Allocation

The principles and method of allocation of overhead employed by B.C. Hydro represent a large subject more properly dealt with at the Applicant's forthcoming Rate Application Hearing. The Commission believes, however, that the practice of charging overhead on a percentage of direct capital cost basis, and at higher rates on the smaller capital projects, could bias the total unit cost of energy produced in favour of the larger projects (Exh. 34). Moreover, since B.C. Hydro has not reviewed its overhead allocation formula since its adoption eight years ago (Transcript page 808), in the Commission's opinion it is doubtful if the allocation so derived is representative of the costs fairly attributable to each capital project. Indeed, total overhead including direct or field engineering and engineering administration costs appear to the Commission to be significantly higher than levels generally encountered in comparable contracts in the private sector.

(c) Interest During Construction (IDC)

B.C. Hydro's application of IDC to overhead is unusual and not normal utility practice (Exh. 15, Table 2-3 and Exh. 11, Table 7-3). IDC is allocated to project estimates on an annual basis in the engineering/economic analysis whereas the Applicant's accounting department charges IDC on a monthly basis (Transcript 799). The Commission concludes that this results in under-estimation of IDC in the project estimating phase and leads to distortion of the evidence on which the choice between competing projects is made.

(d) Interest Rate Employed in Project Estimates

The Applicant favours the use of a 3% net interest or discount rate, on the basis that this rate represents B.C. Hydro's historic and current experience with respect to the real cost of funds (Exh. 15, page 5-2). It represents the difference between the actual rates prevailing in the money markets and the prevailing rates of inflation.

The Environmental Land Use Committee (ELUC) guidelines, however, recommends use of a rate representing the opportunity cost of capital (in the order of 10%)(Exh. 15, page 5-7). This has the effect of loading higher annual cost on the more capital intensive projects in the early years of the project. The ELUC Secretariat has adopted the principle that "Acceptable investment criteria must reflect all benefits and costs attributable to the investment of these benefits and costs, since those which occur earliest are more significant than those which occur later" (ELUC Secretariat, page 73). B.C. Hydro, however, maintains that "If B.C. Hydro were to use such a high discount rate for project evaluation, it would not be possible to justify investments [in hydro-electric projects] ... which minimize the long-term cost to B.C. Hydro customers" (Exh. 15, page 5-7).

The Commission recognizes that the matter of the appropriate discount rate for project evaluation will be an issue of fundamental importance in all major energy project reviews. The Commission, however, concludes that this issue was not adequately explored in the Falls River proceedings and accordingly does not have the basis for a firm conclusion or decision in the matter. This important issue will be further assessed in the forthcoming B.C. Hydro Site C and Rate Application hearings.

Financial Impact on Consumers

The Applicant's pre-hearing submission, incorporating its internal engineering/economic evaluation methods and procedures failed to demonstrate the relative impact on B.C. Hydro's customers, in terms of the delivered cost of energy (and hence rates) of the Rehabilitation and Redevelopment alternatives. Accordingly, during the course of the proceedings the Applicant was asked, with reference to Exh. 49, to produce Exh. 32B reflecting the impact on the delivered cost of energy (in mills per kwh), of various interest and inflation rates and the 1.3 to 1 interest coverage required by B.C. Hydro Special Direction No. 1.

As a result of this additional evidence, as indicated heretofore the Commission is satisfied that the cost of energy to consumers will be less on average over the longer term (70 years) for the Redevelopment as proposed, and less over the medium term (20 years) for the Rehabilitation alternative (Exh. 32 and Exh. 32B).

In future applications by B.C. Hydro, the Commission will require the Application itself, whatever measures are used for internal evaluation by B.C. Hydro, to contain evidence demonstrating the impact on consumers in real-life financial terms.

6.3 Existing Reservoir Conditions

The condition of the reservoir and the Falls River above the dam, as viewed by the Commission during its visit on May 6, 1981, was not satisfactory in terms of reasonable environmental treatment. The Commission finds it rather surprising that the Applicant's witnesses on environmental matters chose to virtually disregard environmental impacts upstream of the dam, when it was known to be a trout fishery of interest to local sports fishermen.

The Commission was not impressed by the Applicant's testimony that the unsightly forest of dead and dying trees protruding from the reservoir provides a positive element in the fish habitat, by providing a home for the insects on which the fish feed. Those same trees ultimately wind up as debris requiring removal from the stoplogs or upstream face of the dam.

In the meantime, the condition of the reservoir does not reflect well on B.C. Hydro's concern for the environment, and the fact that it is in a remote and rarely frequented location is not viewed by the Commission as an extenuating factor. Accordingly, the Commission will require as part of the Redevelopment project, that the Applicant clear the reservoir of dead and dying trees. To minimize the cost this should be undertaken over a reasonable period of time, (perhaps 1 or 2 years) making maximum use of local labour and local skills. The need for special equipment could perhaps be avoided by confining clearing operations to periods of low reservoir levels or during winter freeze up.

6.4 B.C. Hydro - Special Direction No. 1

In final argument at the hearing the Applicant, through counsel, took the position "that no constraint is put upon B.C. Hydro by the provincial directive" (Transcript page 1140). The implications of this Special Direction No. 1, requiring the Applicant to achieve and maintain an interest coverage ratio of 1.3 to 1 by fiscal year 1983-84, and to ultimately achieve and maintain a debt/equity ratio of 80/20, are very significant to the Applicant's project planning process and to regulation of B.C. Hydro by this Commission. While the issue was not extensively explored at the Falls River hearing, it clearly does impose significant constraints on both the Applicant and the Commission, and will be the subject of further and more conclusive consideration at the Applicant's Rate Hearing in January 1982.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of September, 1981.

J.D.V. Newlands, Division Chairman

D.B. Kilpatrick

D.B. Kilpatrick, Commissioner

B.M. Sullivan, Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER C-3-81

PROVINCE OF BRITISH COLUMBIA

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the Utilities Commission Act, SBC 1980, c. 60

and

IN THE MATTER OF an Application of the British Columbia Hydro and Power Authority for a Certificate of Public Convenience and Necessity

BEFORE:	J.D.V. Newlands, Division Chairman; D.B. Kilpatrick, Commissioner; and B.M. Sullivan, Commissioner	July 30, 1981

CERTIFICATE OF PUBLIC
CONVENIENCE AND NECESSITY

WHEREAS by Application dated December 22, 1980 the British Columbia Hydro and Power Authority ("B.C. Hydro") applied for a Certificate of Public Convenience and Necessity to permit the redevelopment of the Falls River hydro-electric plant located approximately 35 miles southeast of Prince Rupert, British Columbia; and

WHEREAS a public hearing was held in Prince Rupert, British Columbia from May 5 to 8, 1981 and in Vancouver, British Columbia from May 27 to 29, 1981; and

WHEREAS certain additional material resulting from the hearing was received on June 9, 1981; and

WHEREAS the planning and detailed engineering studies and significant capital expenditures had been incurred prior to the regulation of B.C. Hydro; and

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER C-3-81

WHEREAS the redevelopment will permit the greater utilization of an existing natural resource; and

WHEREAS the Commission has determined that the redevelopment and operation of the Falls River project is necessary for the public convenience and properly conserves the public interest.

NOW THEREFORE the Commission hereby orders as follows:

(1) Construction commence immediately as set forth in the Application as amended, with completion before 1985.

(2) The cost of the project is not to materialy exceed approximately $40 million without a further Order of the Commission.

(3) B.C. Hydro will comply with the directives set forth in the Reasons for Decision which will be issued as soon as possible.

DATED at the City of Vancouver, in the Province of British Columbia, this 30 day of July, 1981.

BY ORDER

J.D.V. Newlands
Division Chairman

BRITISH COLUMBIA

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APPROVED AND ORDERED MAR. 19.1981

Lieutenant-Governor

EXECUTIVE COUNCIL CHAMBERS, VICTORIA MAR. 19.1981

On the recommendation of the undersigned, the Lieutenant-Governor, by and with the advice and consent of the Executive Council, orders that the British Columbia Utilities Commission (the "commission") comply with the following Special Direction No. 1.

SPECIAL DIRECTION
B.C. Hydro NO. 1

Application

1. This special direction applies with respect to the exercise of the commission's powers and functions in connection with the British Columbia Hydro and Power Authority (the "authority").

Debt Support

2. The authority should generate adequate funds from the efficient operation and conduct of its business to support all of its activities and debt.

Economic Borrowing

3. The authority should achieve a financial position that allows it to borrow funds on the most economic terms available.

Financial Standards

4. The financial standards to be observed by the authority should include interest coverage ratio and debt/equity ratio.

Minimum Standards

5. The authority should achieve by the 1983-84 fiscal year an interest coverage ratio of 1.3:1 and should maintain that ratio thereafter so as to achieve and ultimately maintain a debt/equity ratio of 80:20.

Minister of Energy, Mines and Petroleum Resources

W. R. Bennett

Presiding Member of the Executive Council

(This part is for administrative purposes and is not part of the Order.)

Authority under which Order is made:

Act and section: Utilities Commission Act, section 3

Other (specify):

Statutory authority checked by: GEORGE B. MACAULAY
(Signature and typed or printed name of Legal Officer)

March 18, 1981.

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FALLS RIVER - COMPARATIVE COST ESTIMATES

	UNINFLATED					INFLATED			
	Oct/79 (1)	Feb/80 (2)	Jul/80 (3)	Aug/80 (4)	Jan/81 (5)	May/81 (6)	System Plan (7)	System Plan(Rev) (8)	Jun/81 (9)
Cost Base	Oct/79	Oct/79	Apr/80	Apr/80	Apr/81	Jul/83	Jul/83	Jul/84	Jul/84
Redevelopment ($million)									
Direct cost	15.34	16.15	19.55	20.19	24.79	-	24.422	26.257	29.072
Overhead	-	-	3.15	3.23	4.38	-	3.997	4.777	5.158
IDC	-	-	0.91	.93	1.35	-	5.501	4.673	5.469
Total Capital Cost	-	-	23.61	24.35	30.52	32.78	33,920	35.707	39.699
Rehabilitation ($million)									(10)
Direct cost	4.20	-	4.41	5.79	8.903	-	-	-	9.6
Overhead	-	-	1.15	1.45	-	-	-	-	2.0
IDC	-	-	.18	.13	-	-	-	-	1.1
Value of energy lost	-	-	-	.17	-	-	-	-	-
Total Capital Cost	-	-	5.74	7.54	-	10.15	-	-	12.7

Reference:
1. Exhibit 14, Evidence of Mr. G.M. Salmon, Page 10
2. Exhibit 11, Page 7-2
3. Exhibit 1, Tables C-1 and C-2
4. Redevelopment - Exhibit 11, Table 7-3; Rehabilitation Exhibit 15, Table 2-3
5. Exhibit 32B
6. Exhibit 35
7. Exhibit 50 and Transcript Page 1082
8. Transcript Page 1088
9. Exhibit 32B
10. Cost base November, 1982

APPENDIX "C"