REPORT

Government of Newfoundland

Cost Effectiveness of Delivering Power From Churchill Falls To the Island of Newfoundland

Report SMR-18-81

November 1981

SHAWMONT NEWFOUNDLAND

TRANSMISSION PLANNING

REPORT

GOVERNMENT OF NEWFOUNDLAND

COST EFFECTIVENESS OF DELIVERING POWER FROM CHURCHILL FALLS TO THE ISLAND OF NEWFOUNDLAND

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LICENCE
TO PRACTICE

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S SUMMARY

S1 Objective and Findings

The objective of the study is to evaluate the cost-effectiveness of purchasing 800 MW of firm power at 90% capacity factor from Churchill Falls, Labrador, and transmitting the power to the Island of Newfoundland. The analysis shows that the project is cost effective relative to the power supply options considered and selected study parameters.

S2 The 800 MW Purchase Power Project

The project consists of:

- the purchase of 800 MW of firm power at 90% capacity factor at Churchill Falls on a "take or pay basis" at a fixed price of 4 mills per kwh.

- a $\pm$400 KV bipole transmission line between converter stations located at Churchill Falls in Labrador and Soldiers Pond on the Island.

- a crossing of the Strait of Belle Isle by submarine cable or tunnel.

S3 The Power Supply Options

The basic power supply options considered are:

- the 800 MW purchase project
- the Muskrat Falls project
- the Gull Island project
- "on Island" projects consisting of Cat Arm hydro and Island Pond hydro together with coal fired thermal plants.

The delivered power capability of the options is estimated to be:

Option	Delivered Capacity	Delivered Energy
800 MW Purchase	728 MW	5,783 GWh
Muskrat Falls	742 MW(1)	5,613 GWh(1)
Gull Island	1,705 MW(1)	11,713 GWh(1)
"On-Island"		
Cat Arm Hydro	127 MW	687 GWh
Island Pond Hydro	27 MW	187 GWh
150 MW Coal	138 MW	907 GWh
300 MW Coal	276 MW	1,813 GWh

(1) These figures include recall power

S4 Estimated Costs

The estimated capital costs of the projects in January 1980 dollars exclusive of escalation but including interest during construction at 6% per annum are as follows:

Option	Investment $\$10^6$	Unit Cost ($ per kW)
800 MW Purchase		
- Cable	1052.7	1,446(1)
- Tunnel	1170.4	1,608(1)
Muskrat Falls	1834.3	2,472
Gull Island	2952.5	1,732
"On Island"		
Cat Arm Hydro	187.1	1,473
Island Pond Hydro	54.6	2,022
150 MW Coal	110.5	737(2)
300 MW Coal	196.7	656(2)

(1) For comparison purposes, the cost of purchasing power has to be added.

(2) For comparison purposes, the cost of fuel has to be added.

S5 Comparison Procedures and Study Parameters

The procedure used was to compare alternative generation expansion plans to meet a given load with a given reliability. A system expansion was developed to include each of the basic options. The alternatives were compared in four (4) ways:

- the cumulative present worth of the incremental investment and operating costs required to meet the load.
- the comparative unit cost of the energy absorbed into the system from each project.
- the benefit/cost ratio for each project.
- the pay back period for each project, i.e. the period over which the investment is at risk.

The first method examines costs from a system basis. The other three examine the costs of the particular project including the effect of system utilization.

The basic comparison was made for the following study parameters:

- a load demand as estimated by Newfoundland and Labrador Hydro in February 1980.
- a price of 4 mills per kWh for purchased power declining at 10% per annum in real terms.

- capital cost estimates and fuel costs in effect in 1980.

- constant dollars; i.e. general inflation excluded.

- a decision discount rate of 6%.

S6 Results of Analysis

For the base scenario of NLH load growth, decision 1980 and a 6% discount rate, the projects rank as follows:

Cumulative Present Worth of Investment and Operating Costs ($\$ \times 10^6$)

Rank	Alternative	Declining Real Cost of Purchased Power	
		10%	5%
1	800 MW Purchase (cable)	2,822	2,866
2	800 MW Purchase (tunnel)	2,942	2,999
3	Gull Island (cable)	3,142	3,144
4	Muskrat Falls (cable)	3,409	3,418
5	On-Island	3,652	3,652

On the basis of Unit Cost of Energy
(Relative to a 300 MW Coal Fired Unit)

Rank	Alternative	10% Declining Real Cost of Purchased Power	
		Available	Absorbed
1	800 MW Purchase (cable)	0.48	0.53
2	800 MW Purchase (tunnel)	0.51	0.54
3	Gull Island (cable)		
	Stage 1	0.79	0.92
	Stage 2	0.69	0.87
	Stage 3	0.67	0.80
4	Muskrat Falls (cable)	0.77	0.85
5	300 MW Coal (on Island)	1.00	1.00

The relative unit costs for Gull Island reflect the staging of the project with no value attributed to surplus.

On the basis of Benefit/Cost Ratio (Relative to "On Island")

Rank	Alternative	Declining Real Cost of Purchased Power	
		10%	5%
1	800 MW Purchase (cable)	1.86	1.75
2	800 MW Purchase (tunnel)	1.77	1.67
3	Gull Island (cable)	1.24	1.24
4	Muskrat Falls (cable)	1.16	1.15

On the basis of Pay Back Period (Relative to "On Island")

Rank	Alternative	10% Declining Real Cost of Purchased Power
1	800 MW Purchase (cable)	6 years
2	800 MW Purchase (tunnel)	8 years
3	Gull Island (cable)	28 years
4	Muskrat Falls (cable)	26 years

S7 Sensitivity

The cost effectiveness of the project was tested for the following sensitivities:

- evaluation period of 30 years and 60 years
- load growth equal to 80% of the year by year NLH estimated load growth rate
- delay in the decision to proceed by 5 years
- differential escalation in coal prices of 1%
- declining real cost of purchased power of 10%, 5% and 0%
- increase in Labrador infeed costs of 15%

- a one year delay in "On Power" for the tunnel scheme and a 10% increase in costs

- sales of surplus energy from the Gull Project at a price of 10 mills per kWh.

For all sensitivities, the 800 MW Purchase Power Project (cable option) is the least cost except for the scenario considering the sales of surplus energy from the Gull Island Project. For this sensitivity scenario (Gull Island surplus sales at 10 mills per kWh), the cumulative present worth costs of the Gull Island generation alternative are the least; however, when one considers the benefit/cost ratio, the 800 MW Purchase Power Project (cable option) has the highest ratio. This indicates that the 800 MW Purchase Power Project (cable option) has a better internal rate of return and if the decision is to bring power to the Island from Labrador, the inference is that the 800 MW Purchase Power Project (cable option) should proceed first.

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1 AUTHORIZATION

In March 1981 the Government of Newfoundland retained ShawMont Newfoundland Limited (ShawMont) to study the cost effectiveness of delivering 800 MW of power from the Churchill Falls hydro-electric power plant located in Labrador to the Island of Newfoundland.

The study compares the cost of delivering 800 MW of power from Churchill Falls to the cost of delivering power from the Lower Churchill River and to the cost of 'on-island' generation. It relies on the results of previous studies recently undertaken by ShawMont; namely,

Report SMR-3-80 - On-Island Methods of Meeting the Projected Electrical Load Growth

Report SMR-12-80 - Cost Effectiveness of Delivering Power from the Lower Churchill River in Labrador to the Island of Newfoundland

Report SMR-33-80 - Cost Effectiveness of Delivering Power from the Lower Churchill River in Labrador to the Island of Newfoundland (Summary Report)

2 INTRODUCTION

The purpose of this study is to examine the cost effectiveness of delivering power to the Island of Newfoundland from the Churchill Falls power plant in Labrador based on two decision dates:

Decision 1980 assumes that the decision to proceed was taken in January 1980 with final release of the project in January 1981. This requires that all 'on-island' generation in advance of the infeed from Labrador recognize that the infeed would go 'on-power' in late 1985.

Decision 1985 assumes that the decision to proceed will be taken in January 1985 with project release in January 1986. Earliest 'on power' would be in 1990.

Both scenarios use the same load data, reliability studies, power studies, lead times and cost estimates.

The concept of bringing power from the Upper Churchill is compared to the following options:

(i) 'on-island' generation utilizing island hydro and coal fired plants;

(ii) the construction of the Muskrat Falls plant on the Lower Churchill and the delivery of power to the Island of Newfoundland;

(iii) the construction of the Gull Island plant on the Lower Churchill and the delivery of the power to the Island.

In this study the purchase power from the Upper Churchill has a constant price with other costs escalating.

3 SUMMARY OF BACKGROUND STUDIES

Report SM-1-76
Cost Effectiveness Analysis
of Single Line HVDC Scheme

In late 1975 and early 1976 ShawMont studied the possibility of purchasing power from Churchill Falls and transmitting the power to the Island of Newfoundland. The results are contained in the above draft report.

This study examined the breakeven price that Newfoundland and Labrador Hydro (NLH) could pay for power to make the total cost of the proposed infeed equivalent to the cost of 'on-island' generation from oil and nuclear. This study assumed that the sources of power would have been:

300 MW recall power
500 MW additional power

The price for the recall energy was estimated to be 3.7 mills/kWh at Churchill Falls. The break-even price for the additional power, based on an oil/nuclear development on the Island and a current discount rate of 11%, was estimated to be as follows:

Conditions	Break-Even Mill Rate
No escalation, fixed purchase price	
- NLH forecast of 6% growth per annum	5.5
- NLH forecast of 8% growth per annum	8.5
- NLH forecast of 10% growth per annum	7.7
6% escalation, fixed purchase price	
- NLH forecast of 6% growth per annum	7.3
- NLH forecast of 8% growth per annum	11.0
- NLH forecast of 10% growth per annum	10.2

Report SMR-3-80
On-Island Methods of Meeting the
Projected Electrical Load Growth

On November 24, 1978 the Government of Canada and the Government of Newfoundland agreed to establish the Lower Churchill Development Corporation (LCDC) to investigate the practicality of developing the untapped hydro-electric potential at Gull Island and at Muskrat Falls on the Churchill River in Labrador. One of the principal markets for any power developed would be to supply the needs of the Island portion of the Province of Newfoundland.

In December 1979, NLH commissioned ShawMont to study "on-island" methods of meeting the projected electrical load:

i) to assist it in appraising the benefits which might be derived from purchasing power from LCDC to serve the Island load;

ii) as an independent review of the power development alternatives which are practically available to serve anticipated future Island needs.

The results of the ShawMont study are contained in the above Report. This study demonstrated that the least cost on Island sources of energy would be coal-fired thermal with nuclear power as a possibility in later years. Based on the assumption that there would be no Labrador infeed it recommended that NLH seek sources of coal and establish firm prices with suppliers, establish likely sites for coal fired plant in the Avalon area and the western region and begin preliminary engineering on coal fired plant.

<u>SMR-12-80 and SMR-33-80</u>
Cost Effectiveness of Delivering
Power from the Lower Churchill River
in Labrador to the Island of Newfoundland

In April 1980, LCDC retained ShawMont to study the cost effectiveness of supplying the forecast electricity needs of the Island of Newfoundland utilizing hydro-electric power generated at the Muskrat Falls Site and/or the Gull Island site on the Lower Churchill River transmitted to the Island. The findings of the study are contained in Report SMR-12-80.

Subsequent to a review by the shareholders of LCDC, ShawMont was further requested to examine the cost effectiveness with changes in certain parameters. The results of these analyses are contained in Summary Report SMR-33-80 which was prepared following completion of the work.

This study essentially showed that either of the LCDC projects was cost effective with 'on-Island' generation at real discount rates up to 8-1/2% and that the LCDC project incorporating the Gull Island hydroelectric plant built first was more cost effective than a project with the Muskrat Falls plant built first. Sensitivity studies covered changes in load growth, timing of the projects, cost estimates of the LCDC projects and real escalation in the cost of coal.

4 THE 800 MW PURCHASE POWER PROJECT

The proposal is to purchase 800 MW of firm power at 90% capacity factor from CF(L)Co at Churchill Falls, Labrador and transmit the power to the Island of Newfoundland. The delivery point on the Island would be Soldiers Pond located southwest of St. John's.

The proposed transmission facilities comprise the following principal elements:

a) A ±400 kV bipole transmission line, 1278 km (794 mi) in length, between converter stations located at Churchill Falls in Labrador and Soldiers Pond on the Island.

b) Two alternatives are proposed for the crossing of the Strait of Belle Isle between Labrador and the Island: by submarine cables buried in trenches and by cables installed in a tunnel, approximately 18 km (11 mi) long, beneath the Strait. The submarine cable alternative is the lower cost and has the shorter construction period but has higher forced outage probabilities. Both crossing alternatives are included in the cost-effectiveness study.

5 THE ESTIMATED LOAD

5.1 Load Forecast

This study uses two load forecasts (Table 1):

- the NLH forecast
- a modified forecast.

The NLH Forecast was prepared by the utility in February of 1980 and the forecast is outlined in a report titled:

"Newfoundland and Labrador Hydro - Interim Load Forecast 1980-1998"

By: Newfoundland and Labrador Hydro, Feb. 1980

The modified load forecast was selected by ShawMont and is used to test the sensitivity of the cost effectiveness of the 800 MW purchase power project to a reduction in load forecast. The modified load assumes that the load growth rate each year is 80% of the load growth rate estimated by NLH.

Figure 1 plots the estimate of load prepared by NLH and relates it to the historic consumption going back to 1951.

The modified load forecast is also plotted on the same figure.

5.2 Load Shape

The shape of the load was estimated from an analysis of the hourly loads for the years 1976, 1977 and 1978. From this analysis the yearly peak load shape shown on Figure 2 was developed along with 13 interval load duration curves. Sample duration curves are given on Figure 2 for a typical winter interval, summer interval and the entire year.

6 SOURCES OF ENERGY

6.1 Purchased Power (Upper Churchill) (Figures 3, 4)

The installed generation at Churchill Falls is 11 units each at 475 MW = 5225 MW. The estimated energy capability is 34,500 GWh.

The Newfoundland Government has requested that CF(L)Co supply 800 MW at 90% capacity factor to NLH for use on the Island of Newfoundland. The power that can be obtained from this source is estimated at:

	Capacity	Energy
Available in Labrador	800 MW	6307 GWh
Received at Soldiers Pond	728 MW	5783 GWh

Table 6 shows the capacity capability available from purchased power interval by interval and Table 7 shows the energy available interval by interval.

6.2 The Lower Churchill Projects (Figures 5 and 6)

Two potential hydroelectric sites have been identified on the Lower Churchill: one at Muskrat Falls and the other 58 km (36 mi) further upstream at Gull Island. With the development of these two sites, the total hydroelectric potential of the Churchill River in Labrador will have been harnessed.

6.2.1 Muskrat Falls

At the Muskrat Falls site, the river drops 15 m (49 ft) in two sets of rapids. Upon completion of the project, the upstream water level will be raised to the tailwater level of Gull Island and develop a gross head of 37 m (121 ft).

The river valley between Gull Island and Muskrat Falls is narrow and cannot provide any significant storage; consequently, the development at Muskrat Falls will be a run-of-river hydroelectric plant.

The total installed capacity at Muskrat Falls will be 618 MW which will be provided by three 206 MW units. The average annual energy generated at the plant has been estimated at 4730 GWh.

6.2.2 Gull Island

Gull Island is located upstream of Gull Lake 225 km (140 mi) east of Churchill Falls. The project will utilize the 87 m (285 ft) head between the Churchill Falls tailrace and Gull Lake.

The total installed capacity for Gull Island is 1698 MW. For this capacity, the powerhouse would contain six units rated at 283 MW. The average annual energy generated at the plant has been estimated at 11,290 GWh.

6.2.3 Interconnection with Churchill Falls

Each of the Lower Churchill power developments will be interconnected to the Upper Churchill at Churchill Falls. For these developments, 200 MW of "recall" power remains available to CF(L)Co. In addition, for reliability studies, some 200 MW of backup power is considered to be available for emergencies. Planning of the developments on the Lower Churchill has been based on the assumption that the electrical interconnection permits maximum use of the river for power generation. This assumption results in 98% of the energy generated at Muskrat Falls and Gull Island to be regarded as prime energy.

6.2.4 Transmission System

The proposed transmission system to transmit the power from the LCDC projects in Labrador to the Island of Newfoundland has three components:

- an AC intertie between Churchill Falls and Gull Island converter station

- an AC intertie between Muskrat Falls and Gull Island converter station

- DC transmission line(s) between the Gull Island converter station and the Island of Newfoundland

The transmission intertie between Churchill Falls and Gull Island will be a single 735 kV circuit if Gull Island is built first. If Muskrat Falls is built first, the intertie will be a 345 kV circuit. Two 345 kV circuits will be built between Muskrat Falls and Gull Island. These interties provide sufficient intertie capacity to ensure effective water and energy management of the Churchill River.

The transmission line(s) from the Gull Island converter station to the Island will be ±400 kV HVDC and will cross the Strait of Belle Isle separating Newfoundland and Labrador via submarine cable(s) or via an undersea tunnel. In the case of Muskrat Falls, a single transmission line would be built. The line capability exceeds the capability of Muskrat Falls and additional capacity and energy would be drawn from Churchill Falls under the recall power entitlement. For Gull Island, two transmission lines would be built. As for Muskrat Falls, the energy transmission capability exceeds the capability of Gull Island and recall energy would be used.

6.2.5 Delivered Power

The available capacity and energy and the delivered capacity and energy from each of the LCDC schemes is as follows:

Muskrat Falls

	Capacity	Energy
Available in Labrador		
Muskrat Plant	618 MW	4730 GWh
'Recall' at Churchill Falls	200 MW	1380 GWh
Assumed Emergency Support at Churchill Falls	200 MW	
Total	1018 MW	6110 GWh
Sent Out	818 MW(1)	6110 GWh
Received at Soldiers Pond	742 MW(1)	5613 GWh

(1) The amounts shown are the limit of the contract supply. Through appropriate operating arrangements, the capacity suppply at the Labrador end of the HVDC line can reach 920 MW, the winter rating of a bipole, with a delivered capability at Soldiers Pond of 848 MW.

Gull Island

	Capacity	Energy
Available in Labrador		
Gull Island Hydro Plant	1698 MW	11290 GWh
'Recall' at Churchill Falls	200 MW	1380 GWh
Assumed Emergency Support at Churchill Falls	200 MW	
Total	2098 MW	12670 GWh
Sent Out	1840 MW(1)	12670 GWh
Received at:		
Soldiers Pond	848 MW	11713 GWh
Three Brooks	857 MW	
Total	1705 MW	11713 GWh

(1) The winter rating is 920 MW per bipole.

The amount of power available varies interval by interval because the effect of temperature on the transmission capability and the effect of planned outages for maintenance. Table 6 relates the capacity capability by interval for the various stages of transmission to the capability used for costing and for determining reliability. Table 7 relates the maximum energy capability for the transmission system interval by interval, with and without an allowance for planned outage, to the energy estimated to be available from Labrador.

6.3 On-Island Scenario

Report SMR-3-80 discusses the availability of energy for the Island, exclusive of hydro power in Labrador, in some detail. The identified power sources of significance are:

1) on-island hydro
2) coal
3) nuclear
4) wind

6.3.1 Hydro

Hydro on the Island which is environmentally acceptable is limited in quantity. The identified hydro sources are the Cat Arm project and the Island Pond project.

Cat Arm was identified as a possible project several years ago. Pre-feasibility studies, feasibility studies and environmental studies had been completed in early 1980 to the point where the project was ready for commitment. Because of the delay in the implementation of the LCDC project, NLH authorized the construction of Cat Arm early in 1981. As one of the scenarios in this study uses January 1980 as a possible decision date for the infeed from Labrador, the development sequences for the Decision 1980 scenario that utilize an infeed from Labrador do not show Cat Arm coming into service as presently planned but delayed until after power from the infeed is fully utilized.

Island Pond is a hydro project that was identified during the feasibility study on Upper Salmon. To date only desk studies have been undertaken. The project is small and it does not figure prominently in system planning.

6.3.2 Wind

Wind power is an old technology, but it is only recently that efforts have been made to develop the energy in quantity for a reasonable price. Its output varies with wind forces; therefore, it must operate in conjunction with other power sources where firm capacity can utilize the variable energy from wind to ensure that energy is always available.

Newfoundland, particularly the Avalon peninsula, is one of the areas of Canada where the wind energy potential is sizeable; consequently, such plants may prove useful as sources of energy for Newfoundland when commercially developed.

6.3.3 Fossil Fuels and Nuclear

Neither wind nor on-island hydro can meet more than a fraction of the forecast need. Aside from the hydro power from the Upper and Lower Churchill three possibilities exist for the supply of the forecast need:

Coal - Coal fired power generation is new to Newfoundland although the technology is conventional. The main uncertainties are source and price, but coal is available from sources such as Nova Scotia, Western Canada, the Eastern U.S.A., South Africa, Poland and Australia to mention a few. The price could rise in the long term. The future evolution of environmental standards may require increases in plant costs if additional flu gas treatment is required.

Nuclear - Nuclear is new to Newfoundland, but not to other areas of Canada. The CANDU technology is proven. The main uncertainty is related to the public acceptance of nuclear on the Island. Another disadvantage is size and lead time. Report SMR-3-80 concludes that coal is more cost effective than nuclear but that at a discount rate of 6%±, the difference is small. In this study it is not considered as a source of power.

Oil and/ or Gas - These fossil resources may be available from offshore deposits if proven commercial and developed. Because of the major uncertainty as to the potential oil and natural gas that could be delivered to the Island, its use has not been evaluated for power generation. It is, however, recommended that any new fossil fueled plants be sited and designed for the possible future use of gas firing.

- Imported oil has become non-competitive with alternative thermal energy sources, particularly coal, for firing thermal plants on a continuous basis.

6.3.4 Plant Size

For hydro, the unit size and energy output is established by the available water, head, reserve criteria and physical constraints. The identified hydro power sources are:

Site	Installation	Energy Firm	Energy Average
Cat Arm	2 x 63.5 MW = 127 MW	597 GWh	687 GWh
Island Pond	1 x 27 MW = 27 MW	156 GWh	187 GWh

For coal fired thermal plants, the unit size is established by load, reserve criteria and manufacturing standards. For this study the following thermal plant sizes have been used:

Nominal unit size	150 MW	300 MW
Sent out capacity	138 MW	276 MW
Sent out energy capability at 75% CF	907 GWh	1813 GWh

For nuclear plants, the unit size is established by Atomic Energy of Canada Limited (AECL). The present size of plant being built by AECL in Quebec, New Brunswick and overseas is:

Nominal unit size	600 MW
Sent out capacity	630 MW
Sent out capability at 80% CF	4415 GWh

7 COMPARISON PROCEDURE

7.1 System Expansion Procedure

The method used to examine the cost effectiveness of a generation expansion alternative is to compare, on a present worth basis, incremental investment and system operating costs for alternative system expansions. For a particular discount rate (i.e. value of money), the preferred alternative is the one with the lowest present worth cost. The sensitivity of the results to value of money is determined by varying the discount rate used in the present worth calculations.

The technique of comparing system expansion sequences permits an examination of the effect of a project, particularly of a large project such as the infeed of power from Labrador, on the plant that presently exists and plant that will likely follow (Figure 9). The effect of over supply is assessed and the system expansion technique can be used to test various staged development scenarios.

The procedure requires:

- The selection of a load growth. For this assignment, one possible load growth and one sensitivity load growth were examined (section 5).

- The selection of a time horizon or load horizon. For this assignment, the system expansions were extended far enough into the future to completely utilize the energy capability of both of the LCDC power projects. In other words, a load horizon was selected for comparing alternatives. This results in different simulation times for each load growth.

- The selection of a period of time over which to compare alternatives as to operating cost. A period of 60 years from 1981 was used. This is considered long enough to measure the difference between thermal plants, whose operating life is considered to be 30 years, and hydro plants, whose operating life is considered to exceed 60 years. As a sensitivity case, data was extracted for a 30 year evaluation period to demonstrate the effect of time on the results.

- The development of alternative generation expansion sequences to meet the load horizon. Figures 7 and 8 were used in the selection of the "on-Island" power generation sources. Equivalence in each scheme was achieved by:

  - adjusting each scheme at its termination to have equivalent energy capability. Part thermal plants were used.

  - adjusting the load carrying capability (LCC) of each scheme to give a loss of load probability (LOLP) of 0.2 days per year or better. Gas turbines were used to provide the necessary capacity capability.

- The present worthing of the cost streams for each alternative. Investment cash flows, operating costs and production costs were present worthed to the beginning of 1981. All production costing and cost computations were performed by Shawinigan's computer program SYPCO which uses deterministic procedures for loading hydro plants and probabilistic procedures for computing thermal production costs. Included in the production costing were allowances for forced outages unique to the Labrador infeeds and costs for preparing the thermal plant on the Island to act as standby.

All the studies assumed that energy not required to service the Newfoundland load would be spilled. In other words, it was assumed that there would be no revenue from sales of surplus.

7.2 Scheduling Criteria

Electrical load consists of two components - capacity and energy - and it is necessary to plan a system so that the production of both components have a given reliability. The criteria used are as follows:

Energy - This is the basic component used for scheduling. Plants have been scheduled based on the following:-

Labrador Infeed	-	as listed in Sections 6.1 and 6.2
hydro	-	firm, defined as the production under the lowest recorded flow
oil thermal	-	75% capacity factor of 95% of nameplate
coal thermal	-	75% capacity factor of 92% of nameplate

	nuclear	-	80% capacity factor of rated capability
	gas turbines	-	0% capacity factor
	reserve	-	equal to three months output of the largest thermal unit using average hydro energy in calculating capability. For the Labrador Infeeds, a unit was considered to be half of a bipole capability.
Capacity -	Labrador infeed	-	as listed in Sections 6.1 and 6.2
	hydro	-	based on nameplate adjusted for head if necessary
	oil	-	95% nameplate
	coal	-	92% nameplate
	nuclear	-	rated capability
	gas turbines	-	nameplate rating
	reserve	-	adequate capacity for the system to have a reliability index equal to a loss of load probability (LOLP) of 0.2 days per year.
	reliability	-	as defined in Table 4 (pages 3, 4 and 5).

For the "on-island" generation alternative, it is possible to locate generating units on both the Avalon Peninsula and the West Coast thus keeping internal transmission facilities to a minimum. For the Labrador infeed alternatives, the designed schemes call for the converter stations to be located at Soldiers Pond near St. John's for line 1 and at Three Brooks near Grand Falls for line 2. It is anticipated that the internal transmission for the Labrador infeed alternatives may be more costly than for the "on-island" alternative; however, experience in previous work has shown that internal transmission costs should not significantly affect the cost-effectiveness comparisons. A review of the transmission system planning that has been carried out indicated that the difference in transmission between an 'on-island' scheme and the Labrador infeed scheme would be minor.

7.3 Cost Factors

The factors tabulated in Table 4 were used for evaluating the alternatives. The basic cost parameters are:

Escalation - The study uses constant dollars with January 1980 as a base. This assumes that all costs will escalate at a uniform rate. It is standard procedure to examine the effect of this assumption on the comparison by using differential escalation on key variables. In this study, differential escalation on coal is tested. As it is anticipated that there will be general inflation and since the purchased power is at a fixed price, the cost of purchase power will decline in 'real' terms. As a base, this study assumes that purchase power will decline at a rate of 10% per annum in 'real' terms.

Discount rate - The analysis has been computed for a range of discount rates varying from 2 to 15%. A 6% rate is used to examine basic alternatives. The analysis has used 10%

for determining whether "overbuilding" is warranted to save oil because capital in excess of normal is required. Because of the use of constant dollars there is no need to include inflation in the discount rate. The discount rates used are effectively 'real' rates net of inflation.

'Real' Discount Rate =

$$R = \frac{1 + \text{Current Interest Rate}}{1 + \text{Inflation Rate}} - 1$$

Thus with a current interest rate of 16% and an inflation rate of 10%, the 'real' discount rate R would be:

$$R = \frac{1 + 0.16}{1 + 0.10} - 1 = 0.055 \text{ or } 5\text{-}1/2\%$$

Fuel costs - January 1980 World prices for fuel have been used rather than subsidized prices. These are:

No. 6 Oil : 0.95 x crude price, equal to $4.98/10^6$ BTU ($31.40/bbl).

No. 2 Diesel: 1.25 x crude price, equal to $7.12/10^6$ BTU ($41.30/bbl).

Coal : $55 per tonne which at 11,700 BTU/lb coal is equal to $2.14 per 10^6 BTU.

Purchase energy costs	- 4 mills per kWh for energy purchased at Churchill Falls. The terms are:

Purchase : 'take or pay' for 800 MW @ 90% capacity factor from the beginning of the purchase.

Recall : 'take or pay' once purchased.

8 COST OF ALTERNATIVES

8.1 Investment Costs

The estimated costs for the LCDC projects and for the Cat Arm hydro project are based on detailed engineering feasibility studies. The estimated cost for the transmission scheme required for the 800 MW purchase power project were developed from the LCDC investigations. The costs were supplied by LCDC.

ShawMont estimated the costs for the alternatives: oil fired thermal, coal fired thermal, gas turbines and nuclear. The estimates are based on its experience and knowledge related to these types of projects and its experience in Newfoundland.

8.2 Unit Investment Costs

The unit costs for the plants under study are as follows:

Plant	Capacity	Unit Cost ($ per kW) Exclusive of IDC and EDC	Unit Cost ($ per kW) With IDC at 6% but no EDC (1)
Purchase Power (1 Bipole HVDC line & Submarine Crossing)	728 MW (Delivered)	1304	1446
Purchase Power (1 Bipole HVDC line & Tunnel Crossing)	728 MW (Delivered)	1437	1608
Gull Island (incl. 2 Bipole HVDC lines & Submarine Crossing)	1705 MW (delivered incl. recall power)	1576	1732
Muskrat Falls (includ. 1 Bipole HVDC line & Submarine Crossing)	742 MW (delivered incl. recall power)	2210	2472
Cat Arm (including transmission)	127 MW	1361	1473
Island Pond (including transmission)	27 MW	1896	2022
150 MW Coal(2) (Average Unit)	150 MW	687	737
300 MW Coal(2) (Average Unit)	300 MW	596	656
630 MW CANDU (First Unit)	630 MW	1296	1471
Gas Turbines (Average Unit)	54 MW	261	268

(1) IDC - Interest During Construction
EDC - Escalation During Construction

(2) Coal plants are capable of using coal or oil as fuel.

8.3 Operating Costs

Operation and maintenance data was obtained from the following sources:

Labrador infeed projects	- a special study carried out by Shawinigan.
Hydro electric plants	- a review of the actual cost of operating Bay d'Espoir in 1979 and the estimates by ShawMont in its report on Cat Arm.
Oil fired thermal plants	- a review of the actual cost of operating Holyrood in 1979.
Coal fired thermal plants	- the cost of operating thermal plants in the Maritimes was adjusted to Newfoundland conditions using oil fired plants as a comparison base.
Nuclear plants	- operating costs were obtained from other studies carried out by Canatom and Shawinigan.
Gas turbines	- a review of the actual cost of operating gas turbines in Newfoundland in 1979.
Overhead	- from "Hydroelectric Power Evaluation" by the U.S. Department of Energy.

8.4 Discount Rate

All computations have been performed for discount rates covering the full range recommended by the Canadian Treasury Board. The cumulative present worth of investment plus operating costs were prepared for 6 discount rates: 2%, 5%, 6%, 7%, 10% and 15%.

The discount rate to be used in cost effective studies is properly selected by the agency for whom the study is prepared. Curves of present worth value vs discount rate have been prepared for selected power development scenarios so that the decision maker can evaluate the effect of discount rate. Figure 10 is an example.

ShawMont was instructed to use a discount rate of 6% as the basic discount rate. A 10% discount rate has been used for "overbuilding" to save oil.

8.5 Service Lives

Service lives are based on ShawMont's experience and generally follow the concept that hydro plants have lives that are about double that of thermal plants and the service lives for transmission lines are related to the energy source that they are servicing. The selected service lives are given on Table 4.

9 LEAD TIME

Virtually every new major generation and transmission project in Canada must now be approved through a public hearing. These approval hearings cover the subject of environmental impact, capital expenditure, use of resources, public concern, and special concerns; for example, nuclear safety. Table 5 gives the lead times selected for scheduling purposes.

The power infeeds from Labrador are controlled by the following lead times from date of final release:

HVDC from Labrador	- cable crossing	:	5 years
	- tunnel crossing	:	7 years

The Muskrat Falls hydro plant and the Gull Island hydro plant can be onstream within the construction period required by the HVDC transmission system.

10 STANDBY

The Labrador infeeds are large and will displace the use of present on-island thermal generation. System simulations show the oil fired units at Holyrood not being required for the following period:

800 MW Purchase	-	5 to 6 years
Muskrat Falls	-	3 to 4 years
Gull Island	-	16 to 17 years

Various methods were examined for maintaining Holyrood in a ready stand-by state. The method selected is that Holyrood could begin energy production within 24 hours of a system requirement. The estimated cost of preparing Holyrood for stand-by operation and maintaining 3 weeks of oil in reserve for 100% operation is:

Estimated cost of mothballing	=	$ 1,400,000
Cost of oil reserve 400,000 bbl @ $4.98/$10^6$ BTU	=	$12,450,000
Total	=	$13,850,000
Say		$15,000,000

In the cost effectiveness studies, each Labrador infeed scheme is charged with $15 Million the year that it comes into operation. It is assumed that some 400,000 bbl of oil over and above what is required for operation will be kept in reserve throughout the evaluation period.

11 RELIABILITY

Reliability studies carried out by Power Technologies Inc. (PTI) indicate that the forced outage rate for the cable crossing is higher than for the tunnel crossing (Table 4). The system simulations and cost studies include an investment allowance for reliability as the F.O.R.s provided by PTI were used for establishing the generation installation patterns. As shown in tables 8, 9, and 10, the cable alternative contains 3 more gas turbines than the tunnel alternative. In developing the system production costs, the Labrador infeeds have been treated as hydro plants and have thus been deterministically loaded. Due to the fact that infeed schemes operate at high capacity factors and the fact that outages, particularly with the cable schemes, could be prolonged, there could be energy losses. The cost of these probable energy losses are included in the present worth costs using the following computational technique:

(1) the operation of the system was simulated and costed with the infeed in operation;

(2) the operation of the system was simulated and costed with the infeed out of operation;

(3) the difference was multiplied by the estimated forced outage rate for the planned infeed and the result included in the cost of operating the Labrador infeed project under investigation.

12 ALTERNATIVES EXAMINED

The following alternatives were examined:

Scenario	Decision 1980		Decision 1985
Forecast	NLH	Modified	NLH
Alternatives			
800 MW purchase			
- Cable Option	X	X	X
- Tunnel Option	X	X	X
On Island	X	X	X
Muskrat Falls (Cable)	X	-	-
Gull Island (Cable)	X	X	X

Simulation of the system was developed up to the load required to absorb Muskrat Falls and Gull Island for the Decision 1980 Scenario. The same load horizon was used for developing system expansions for the Decision 1985 scenario.

The generation expansion scenarios containing the above alternatives are shown on the following tables:

Table 8 - Decision 1980, NLH Load Forecast
Table 9 - Decision 1980, Modified Load Forecast
Table 10 - Decision 1985, NLH Load Forecast

The basic generation expansion sequences may be described as follows:

800 MW Purchase - Cable Option

The purchase scheme is brought on stream as soon as possible and is followed by Cat Arm Hydro + Island Pond Hydro + 150 MW Coal units + 300 MW Coal units + Gas Turbines. The expansion plan for the base case alternative is shown in Table 8. Figure 18 shows the energy mix resulting from this sequence for the NLH load growth and decision 1980. The surplus energy that results in the early years has not been valued. Figure 22 shows the variation in energy production by different fuel types, during the course of a year. The figure demonstrates that it is necessary to utilize thermal generation in some years even though there is a surplus of hydro.

800 MW Purchase - Tunnel Option

The 800 MW purchase is brought on stream as quickly as possible but since the tunnel requires an additional 2 years construction period it is necessary to bring a 150 MW Coal unit on stream ahead of the purchase. The system additions are essentially the same as those for the cable option except for the variations required because of the extra construction period. The expansion plan for the base case alternative is shown in Table 8. Figure 19 shows the year by year energy production mix.

On-Island

This sequence consists of Cat Arm Hydro + Island Pond Hydro + 150 MW Coal units + 300 MW Coal units + Gas Turbines. The schedule dates for the base case alternative are shown in Table 8. Coal fired units have been advanced to restrict the production of Holyrood units to a capacity factor of 30% to 40% since at these capacity factors it is less costly to build and operate a coal fired unit compared to the fuel cost of operating Holyrood. Figures 17 and 22 plot the use of energy resulting from this sequence. The reduction in oil up until 1988 is due to the rapid build up of hydro and coal fired plants.

Muskrat Falls - Cable Option

The Muskrat Falls alternative is scheduled almost the same as the 800 MW purchase alternative. The Muskrat Falls hydro plant's planned installation is 618 MW. This alternative plans to utilize the Recall power available from Churchill Falls to better utilize the transmission facilities. Muskrat Falls is followed by Cat Arm Hydro + Island Pond Hydro + 150 MW Coal units + 300 MW Coal units + Gas Turbines (Table 8). Figure 20 shows the energy use. There is a surplus of hydro energy during the first 3 years of operation.

Gull Island - Cable Option

The Gull Island alternative provides a large surplus of energy. Table 8 shows the planned expansion sequence (base case) and Figure 21 shows the year by year energy production mix. It is noted that there are two energy surpluses, one on the island and one at Gull Island in Labrador. The reason is that the initial transmisson grid is constructed for about one half of the Gull Island capability. Gull Island is followed by Cat Arm Hydro + Island Pond Hydro + 300 MW Coal units + Gas Turbines. In the basic analysis no value was put on the surplus energy. The transmission from Gull Island to the Island of Newfoundland has been staged to suit the requirements of the load. Recall energy was purchased from Churchill Falls in the third stage of development.

Each of the Labrador infeed alternatives includes a power purchase component. The alternatives were costed on the basis that the purchase power costs would decline relative to other costs at a rate of 10% and 5% per annum.

The generation expansion sequences described above were tested for sensitivity to the following:

- the effect of the evaluation period;
- the effect of change in load growth;
- the effect of a delay in the decision to proceed;
- a differential escalation of 1% per annum in coal costs;
- the effect of a declining real cost for purchased power;

- an increase of 15% in Labrador infeed capital costs;

- the effect of a construction delay plus a 10% cost increase on the tunnel option;

- the effect of valuing surplus energy.

13 DISCUSSION OF RESULTS

This study uses four methods for comparing the alternatives for the NLH load growth, decision 1980 scenario:

- the cumulative present worth of incremental investment and operating costs;
- the comparative unit cost of energy absorbed into the system from a project;
- the benefit/cost ratio for each project;
- the payback period for each project; i.e. the period over which the investment is at risk.

13.1 Base Case Comparison

The basic comparison of the alternatives is based on NLH load growth, decision 1980, and purchase power declining at 10% in real terms. For each method of comparison mentioned above, tables 11, 17, 19 and figures 15 and 16 show that for the decision discount rate of 6%, that the least cost alternative method of supplying the electricity needs of the Island of Newfoundland is to purchase 800 MW of power from the Upper Churchill. The following sections comment on each method of comparison.

13.1.1 Present Worth Comparison

On a present worth basis, the alternatives compare as follows:

Cumulative Present Worth of Investment
and Operating Costs ($\$ \times 10^6$) @ 6% Discount Rate

NLH Load Growth, Decision 1980

Alternative	Declining 'Real' Cost of Purchase Power	
	10%	5%
800 MW Purchase (Cable)	2822	2866
800 MW Purchase (Tunnel)	2942	2999
Gull Island (Cable)	3142	3144
Muskrat Falls (Cable)	3409	3418
On-Island	3652	3652

The selection of a 6% discount rate has a bearing on the cost effectiveness of a project. The graphs in Figures 10 and 11 show how the discount rate affects the comparison. These graphs show that as the discount rate increases, high capital cost, low operating cost alternatives lose attractiveness. The following is observed.

Alternative	Range of discount rates the alternative is least cost	
	Declining Real Cost of Purchase Power	
	10%	5%
Gull Island	0.0% to 4.5%	0.0% to 4.8%
800 MW Purchase (Cable)	4.5% to 14.2%	4.8% to 14.1%
On-Island	14.2% and higher	14.1% and higher

13.1.2 Unit Cost of Energy Comparison

The unit costs of energy are shown on Table 17. The costs are in 1980 constant dollars for a discount rate of 6% and are shown in two ways:

- as a function of the energy available at 230 kV on the Island

- as a function of the energy absorbed on the Island at 230 kV.

The costs shown are based on the cost of purchase power declining at a real cost of 10% relative to other costs. The purchase power price is 4 mills per kWh on January 1, 1980.

The unit costs on Table 17 are comparative. They do not represent the cost once the project goes on power as the costs do not include E.D.C. or I.D.C. computed at current rates. The costs compared to energy from a 300 MW coal fired plant are as follows (coal fired = 1.00):

Comparative Unit Cost

	Energy Available	Energy Absorbed
800 MW Purchase (cable)	0.48	0.53
800 MW Purchase (tunnel)	0.51	0.54
Gull Island (cable)		
Stage 1 (800 MW)	0.79	0.92
Stage 2 (1200 MW)	0.69	0.87
Stage 3 (1600 MW)	0.67	0.80
Muskrat Falls (cable)	0.77	0.85
Cat Arm	0.63	0.63
Island Pond	0.68	0.68
300 MW Coal	1.00	1.00

The Gull Island costs shown for Stage 1 include the full power development and the transmission developed up to 800 MW. The costs shown for Stage 2 are the weighted costs for the power development and the transmission developed up to 1200 MW delivered to the Island. The costs shown for Stage 3 are the weighted costs for the full 1600 MW project including recall power. The unit costs for Gull Island reflect the staging of the project with no value attributed to surplus. If all the energy is useable from the on-power date of the Gull Island hydro-electric development, table 17 notes that the unit cost of power could be 1.74 cents per kWh. For such a condition, the comparative unit cost would be about 1.74 ÷ 2.93 = 0.59.

As shown above and on Table 17, the project with the lowest unit cost of energy is the 800 MW Purchase Power (cable) project.

13.1.3 Benefit/Cost Comparison

The projects can also be compared using benefit/cost ratios developed as follows:

$$\frac{\text{Benefit}}{\text{Cost}} = \frac{\text{Benefit due to project}}{\text{Cost of project}} =$$

$$\frac{(\text{PW Costs Alternat. B} - \text{PW Costs Alternat. A}) + \text{PW Cost Project A}}{\text{PW Cost Project A}}$$

Where:

PW Costs Alternative A = Cumulative present worth of investment and incremental operating costs for the alternative that includes Project A

PW Costs Alternative B = Cumulative present worth of investment and incremental operating costs for the alternative with which alternative A is being compared

PW Cost Project A = Cumulative present worth of the costs associated with the particular Project A; e.g., for the purchase alternative it includes: investment costs, operation costs and purchase power costs.

Table 19 gives the benefit/cost ratios relative to the on-island alternative. These ratios give the following comparisons:

Benefit/Cost Ratios for 6% Discount Rate

NLH Load Forecast, Decision 1980

Project	Declining Real Cost of Purchase Power	
	10%	5%
800 MW Purchase (Cable)	1.86	1.75
800 MW Purchase (Tunnel)	1.77	1.67
Gull Island (Cable)	1.24	1.24
Muskrat Falls (Cable)	1.16	1.15

The higher the benefit/cost ratio the more attractive is the project. The above benefit/cost ratios illustrate, as did the comparison of the cumulative present worths, that the 800 MW purchase option is more attractive than the other options at the 6% decision discount rate.

13.1.4 Payback Period Comparison

Figures 15 and 16 show the cumulative present worth of costs at 6% discount rate as a function of time. These graphs show that relative to the on-island alternative, that the Labrador infeeds will be equal to or less than the on-island alternative within the following period:

Period Capital is at Risk

	NLH Load Forecast Decision 1980
800 MW Purchase (Cable)	6 years
800 MW Purchase (Tunnel)	8 years
Muskrat Falls	26 years
Gull Island	28 years

13.2 Sensitivity Analysis

Figure 14 summarizes the sensitivity analyses that were carried out. The following sections discuss the individual tests.

13.2.1 Effect of Evaluation Period

The standard service life for a thermal plant is 25 to 30 years; for a hydro plant it is 50 to 75 years. In order to allow for the effect of the long service life of hydro plant the procedure used is to simulate expansion of the system for the period 1984-2015 and then to hold the load constant for a further 30 years,i.e. to 2045. Reinvestments were made for thermal plants at 30 years after their in-service dates. Thirty years after the in-service of the Labrador infeed schemes, a provision for replacement of cables and valve groups is included. The evaluation of the alternatives is made by comparing the cumulative present worths for the period 1984 to 2045. This period is referred to as the evaluation period. In order to evaluate the effect of a shorter evaluation period the comparison was also made of the cumulative present worth at the year 2015. Figure 14(a) shows the sensitivity of the comparisons to the evaluation period for the NLH Load Growth, Decision 1980 scenario.

The following conclusions were reached:

- The length of the evaluation period is not significant for high discount rates but is significant for low discount rates.

- The 800 MW purchase breaks even with the 'on-island' alternative at high discount rates so the evaluation period has little significance. In this case the breakeven discount rate changed by less than 0.5% from the basic 14.2%.

- The 800 MW purchase breaks even with the Gull Island alternative at low discount rates so the evaluation period is significant. In this case the breakeven discount rate changed by almost 2% from the basic 4.5%.

13.2.2 Effect of Load Growth

The effect of a reduced rate of growth on the cost effectiveness was analyzed by examining a load growth where the annual growth rate was equal to 80% of that in the NLH forecast. The generation expansion plans were developed to the same load horizon as that in the NLH forecast. Table 9 shows the revised alternative generation expansion plans. The basic assumption is that the projects (Labrador infeed) being evaluated are developed as soon as possible (i.e. the timing is the same as that in the NLH growth scenario, with an exception that Stages 2 and 3 for the Gull Island development are scheduled as required). The generation additions following these projects and for the 'on-island' alternative are scheduled as required by the reduced load. Since the load horizon is the same, the total amount of generation added is the same as that in the NLH growth scenario (See Tables 8 and 9). The results of the analysis are summarized in Tables 13 and 14, Figure 12 and Figure 14(b). The reduced load growth has the following effect on the cost effectiveness (for purchase power costs declining at 10% in real terms) of the 800 MW purchase (Cable) option:

- The breakeven discount rate with the 'on-island' scenario reduces from 14.2% to 12.3%.

- The breakeven discount rate with the Gull Island alternative reduces from 4.5% to 3.6%.

- The benefit/cost ratio of the 800 MW purchase option reduces from 1.86 to 1.70 at a decision discount rate of 6%.

13.2.3 Effect of Delay in the Decision to Proceed

An analysis was carried out to investigate the effect of a 5-year delay in the decision to proceed. The alternative generation plans for this assumption, referred to as Decision 1985, are shown in Table 10. In developing the expansion plans the assumption made is that all decisions made prior to 1985 will be common to all the alternatives i.e. the generation expansion plans will be similar. As a result, all generation plant committed up to 1988 will be the same for all the alternatives. The results of the analysis are summarized in Tables 15 and 16 and on Figure 13 and Figure 14(c). The 5-year delay in the decision to proceed has the following effect on the cost effectiveness (using a 10% differential escalation in purchase power costs) of the 800 MW purchase (Cable) option:

- There is an increase of about $148 Million in the cumulative present worth (at a 6% discount rate) of the 800 MW purchase alternative.

- There is little effect on the breakeven discount rate, with the 'on-island' scenario. The rate changes from 14.2% to 14.1%.

- The benefit/cost ratio for the 800 MW purchase goes from 1.86 to 1.95 at a decision discount rate of 6%.

13.2.4 Effect of a Differential Escalation in Coal Costs

A 1% differential escalation was applied to the coal fuel costs in all the alternatives. The results are summarized in Tables 11 to 16. The significant results are presented in Table 11 and Figure 14(d). For the NLH load forecast, a decision discount rate of 6%, Decision 1980, and with purchase power declining at a rate of 10% in 'real' terms the following conclusions can be drawn:

- The 800 MW purchase (Cable) option has the least cumulative present worth cost. The benefit/cost ratio relative to the base case increases from 1.86 to 2.20.

- Since the Gull Island alternative contains the least amount of coal generation, it is least affected by the differential escalation on coal. As a result, the cumulative present worth at which the 800 MW purchase alternative and the Gull Island alternative are equal moves closer to the selected discount rate of 6%.

13.2.5 Effect of a Declining 'Real' Cost for Purchase Power Costs

In the base case analysis it has been assumed that the 800 MW purchase power is at a fixed price. All other costs are assumed to increase in relative terms. The results of the analysis are summarized in Tables 11 to 16 and on Figure 14(e). As the rate of decline in the real cost of purchase power increases, the attractiveness of the Purchase Power option improves.

The effect of a changing 'real' cost for purchase power on the cost effectiveness of the 800 MW purchase (Cable) scheme can also be measured in terms of the benefit/cost ratio relative to the 'on-island' alternative. At a decision discount rate of 6% the benefit/cost ratios (Table 19) are:

- 1.86 for a 10% decline in 'real' cost of purchase power
- 1.75 for a 5% decline in 'real' cost of purchase power

Data is available for the situation where purchase power escalates at the same rate as all other costs. The break-even discount rate with 'On-Island' exceeds 12%. The benefit/cost ratio relative to 'On-Island' is 1.48.

13.2.6 Effect of an Increase in Labrador Infeed Capital Costs

The effect of a 15% increase in the total capital costs of the Labrador Infeed Schemes was examined. The results are summarized in Tables 11 to 16. Table 11, Table 19 and Figure 14(f) present the results for the base case scenario. The significant conclusions are that:

- at 6% discount rate, the 800 MW purchase (cable) option is the least cost scheme;
- the 800 MW purchase - tunnel scheme is the second least cost;
- the benefit/cost ratio for the 800 MW - cable option decreases from 1.86 to 1.65.

13.2.7 Effect of a Delay of One Year in 'On-Power' for the Tunnel Scheme and a 10% Increase in Costs

The effect of a one-year delay in the construction of the tunnel for the 800 MW power purchase was simulated by delaying the 'on-power' date by one year. In addition it was assumed that the construction delay resulted in a 10% increase in the capital cost of the project. Since the one-year delay in construction was not considered to be pre-planned no changes were made to the generation expansion sequence. The one-year delay forces more expensive generation to produce energy during that period and this results in an additional penalty of $76.7 Million in 1987/88. The results of the analysis (assuming a 10% decline in the 'real' cost of purchase power) are summarized below:

Alternative	Cumulative Present Worth to January 1981	
	Discount Rate 6%	Discount Rate 10%
1. On-Island	3652.0	1812.4
2. 800 MW Tunnel, no delay	2942.0	1663.9
3. 800 MW Tunnel, 1 year construction delay	3124.9	1802.0

It can be seen that the 800 MW purchase (tunnel) option with the one-year delay is still cost effective at 6%.

At 10% discount rate, the two alternatives (On-Island, and 800 MW purchase tunnel option) are equivalent.

13.2.8 Effect of Sales of Surplus Energy

The analysis has assumed that there would be no "sales of surplus". This assumption results in a considerable surplus of energy (particularly for the Gull Island alternative) for which no value has been assigned. To examine the effect of this assumption, the cost effectiveness was determined assuming that the surplus energy from the Gull Project, either available on the island or at the Gull site, could be sold for 10 mills per kWh. The results are:

	Cumulative Present Worth to Jan. 1981			
	Declining Real Cost of Purchase Power			
	10%		5%	
	Discount Rate		Discount Rate	
Alternative	6%	10%	6%	10%
1. 800 MW Purchase (Cable)	2821.7	1582.7	2886.3	1619.2
2. Gull Island (Cable) (No surplus sales)	3142.1	2235.1	3144.0	2235.6
3. Gull Island (Cable) (with surplus sales)	2753.2	1974.0	2755.1	1974.5

The above demonstrates that sales of surplus improves the competitiveness of the Gull Island project. With a revenue of 10 mills/kWh from surplus sales, the Gull Island project is the least cost alternative at a discount rate of 6%.

The benefit/cost ratios for the schemes are as follows:

Benefit/Cost Ratio (NLH Load Forecast)

Declining Real Cost of Purchase Power

Project	10% Discount Rate 6%	10% Discount Rate 10%	5% Discount Rate 6%	5% Discount Rate 10%
1. 800 MW Purchase (Cable)	1.86	1.29	1.75	1.23
2. Gull Island (Cable) (without surplus sales)	1.24	0.76	1.24	0.76
3. Gull Island (Cable) (with surplus sales)	1.42	0.91	1.42	0.91

From a benefit/cost point of view the 800 MW scheme has higher benefit/cost ratios even with revenues from sales of surplus included for the Gull Island project. This shows that from a project point of view that the 800 MW Purchase project is more attractive.

14 CONCLUSION

This study and previous studies carried out by ShawMont for LCDC (Section 3) show that relative to on-island generation, principally from coal, that an infeed from Labrador is cost effective. This present cost effectiveness study shows that for the selected study parameters and methods of comparison, that the least cost project under study is the 800 MW Purchase Power project (cable option).

One sensitivity study in which the surplus from the Gull Island development was valued at 10 mills, yielded the lowest present worth cost for the Gull Island project (cable option); however, from a benefit/cost analysis, the 800 MW Purchase Power project (cable option) ranked better. This indicates that the 800 MW Purchase Power project (cable option) has a higher internal rate of return. The inference is that if the decision is to bring power to the Island from Labrador, that the 800 MW Purchase Power project should proceed first.

Cost Effectiveness of Delivering Power From Labrador to the Island

List of Tables

List of Tables (Cont'd)

TOTAL ISLAND LOAD FORECAST

Year	NLH Load Forecast		Modified Load Forecast	
	Capacity MW	Energy GWh	Capacity MW	Energy GWh
1980	1188.0	5914.0	1188.0	5914.0
1981	1244.0	6574.0	1233.0	6442.0
1982	1312.0	6919.0	1287.0	6712.0
1983	1357.0	7108.0	1322.0	6859.0
1984	1427.0	7448.0	1377.0	7122.0
1985	1516.0	7908.0	1445.0	7473.0
1986	1591.0	8272.0	1502.0	7749.0
1987	1668.0	8634.0	1561.0	8020.0
1988	1751.0	9029.0	1623.0	8314.0
1989	1828.0	9395.0	1680.0	8583.0
1990	1898.0	9730.0	1731.0	8828.0
1991	1973.0	10078.0	1786.0	9081.0
1992	2048.0	10429.0	1840.0	9334.0
1993	2125.0	10789.0	1896.0	9591.0
1994	2204.0	11159.0	1952.0	9854.0
1995	2285.0	11536.0	2009.0	10121.0
1996	2370.0	11925.0	2069.0	10394.0
1997	2457.0	12330.0	2130.0	10676.0
1998	2548.0	12750.0	2193.0	10967.0
1999	2642.0	13182.0	2258.0	11264.0
2000	2739.0	13629.0	2324.0	11570.0
2001	2840.0	14091.0	2393.0	11884.0
2002	2945.0	14569.0	2464.0	12206.0
2003	3054.0	15063.0	2536.0	12537.0
2004	3166.0	15573.0	2611.0	12877.0
2005	3282.0	16100.0	2687.0	13226.0
2006	3402.0	16645.0	2766.0	13584.0

TOTAL ISLAND LOAD FORECAST

Year	NLH Load Forecast		Modified Load Forecast	
	Capacity MW	Energy GWh	Capacity MW	Energy GHh
2007	3526.0	17208.0	2847.0	13952.0
2008	3655.0	17791.0	2930.0	14330.0
2009	3789.0	18393.0	3016.0	14718.0
2010	3928.0	19016.0	3104.0	15116.0
2011	4071.0	19660.0	3195.0	15526.0
2012	4220.0	20323.0	3288.0	15945.0
2013	4374.0	21013.0	3384.0	16378.0
2014	4534.0	21724.0	3483.0	16821.0
2015	4700.0	22460.0	3585.0	17277.0
2016			3690.0	17745.0
2017			3798.0	18226.0
2018			3909.0	18720.0
2019			4024.0	19228.0
2020			4142.0	19749.0
2021			4263.0	20284.0
2022			4388.0	20833.0
2023			4516.0	21398.0
2024			4648.0	21978.0
2025			4700.0	22460.0

CAPITAL COST ESTIMATES - LABRADOR INFEED

CASH FLOW (JANUARY 1980 COSTS, MILLIONS OF DOLLARS)

Upper Churchill

A. 800 MW Purchase Cable Option

Year	Bipole Line	Cable Crossing Trenches	Total
1981	7	56	63
1982	111	75	186
1983	240	49	289
1984	262	18	280
1985	117	-	117
1986	14	-	14
Total	751	198	949

Replacement/Rebuild Facilities

Year	Total
2015	260

B. 800 MW Purchase Tunnel Option

Year	Bipole Line	Tunnel	Total
1981	-	33	33
1982	-	41	41
1983	7	41	48
1984	111	42	153
1985	240	53	293
1986	262	63	325
1987	117	22	139
1988	14	-	14
Total	751	295	1046

Replacement/Rebuild Facilities

Year	Total
2017	232

CAPITAL COST ESTIMATES - LABRADOR INFEED

CASH FLOW (JANUARY 1980 COSTS, MILLIONS OF DOLLARS)

Lower Churchill

A. Muskrat Falls Cable Option

Year	Muskrat	Trans. Line	Sub. Cable	Total
1981	130	7	56	193
1982	174	97	75	346
1983	179	208	49	436
1984	177	226	18	421
1985	114	100	-	214
1986	18	12	-	30
Total	792	650	198	1640

Replacement/Rebuild Facilities

Year	Total
2016	260

CAPITAL COST ESTIMATES - LABRADOR INFEED

CASH FLOW (JANUARY 1980 COSTS, MILLIONS OF DOLLARS)

Lower Churchill

B. Gull Island Cable Option

Stage 1

Year	Gull Island	1 line and 2 Trenches	Total
1981	110	63	173
1982	230	172	402
1983	255	257	512
1984	300	244	544
1985	270	100	370
1986	100	12	112
1987	7	-	7
Total	1272	848	2120

Stage 2

Year	2nd Line and 3rd Valve Group	3rd Trench	Total
1993	56	28	84
1994	131	38	169
1995	130	24	154
1996	59	9	68
Total	376	99	475

Stage 3

Year	4th Valve Group	Total
1999	12	12
2000	32	32
2001	33	33
2002	15	15
Total	92	92

Replacement/Rebuild Facilities

Year	Total
2017	260
2026	130
2032	92

CAPITAL COST ESTIMATES - ON ISLAND GENERATION

(January 1980 Prices, $ x 10^6, Excluding IDC & EDC)

Project	Cat Arm	Island Pond	150 MW Coal/Oil	300 MW Coal/Oil	54 MW GT
Total Capital Cost	172.9	51.2	103.0	178.8	14.1
Annual Cash Flow %:					
Year 1	10.5	6.0	10.3	5.8	40.0
2	35.0	22.0	25.2	15.6	60.0
3	30.5	43.0	36.5	30.3	-
4	24.0	29.0	28.0	28.5	-
5	-	-	-	19.8	-
6	-	-	-	-	-
7	-	-	-	-	-
8	-	-	-	-	-

Notes:

1. Plants generally go into service in the 10th interval of the last cash flow year, except GT's which are available at the beginning of that year.
2. Cost for Cat Arm and Island Pond includes transmission facilities.
3. Cost for coal/oil (dual-fired) units and gas turbines are for a typical unit, there are minor variations depending on specific site and unit number.
4. Costs are summarized from Report SMR-3-80 which gives more details.

COST FACTORS AND OPERATION DATA FOR ECONOMIC COMPARISON

Real Discount Rates: 2%, 5%, 6%, 7%, 10%, 15%

Service Lives for New Plant	Years
Hydro	60
Thermal and Gas Turbines	30
Nuclear	30
Transmission Associated with Hydro	60

Period of Comparison

NLH Load Forecast	
Simulation Period	32 (1984-2015)
Evaluation Period	62 (1984-2045)
Modified Load Growth	
Simulation Period	42 (1984-2025)
Evaluation Period	62 (1984-2045)

Insurance

Hydro (on-island)	0.10% of investment
Thermal	0.25% of investment
Gas Turbines	0.25% of investment

Operation and Maintenance	Fixed ($/kW/yr)	Variable (mills/kWh)
Existing Hydro	none	none
Future Hydro - Cat Arm	5.00	none
- Island Pond	6.50	none
Existing Thermal - NLH	none	0.260
- others	none	0.518
Future Thermal- 150 MW - oil fired	4.52	0.260
- 150 MW - coal fired	5.88	0.339
- 300 MW - oil fired	3.83	0.220
- 300 MW - coal fired	4.79	0.288
Gas Turbines (existing and future)	none	7.400

COST FACTORS AND OPERATION DATA

FOR ECONOMIC COMPARISON

Operation and Maintenance (Cont'd)

Upper Churchill

800 MW Purchase Cable Option (incl. transmission)	\$ 9.5 million/year (all incl. cost)
800 MW Purchase Tunnel Option (incl. transmission)	\$ 8.8 million/year (all incl. cost)

Lower Churchill

Muskrat Falls Cable Option (incl. transmission)	\$11.5 million/year (all incl. cost)
Gull Island Cable Option (incl. transmission)	
Stage 1 (2 Trenches)	\$13 million/year (all incl. cost)
Stage 2 (3 Trenches)	\$15 million/year (all incl. cost)
Stage 3 (3 Trenches)	\$15.4 million/year (all incl. cost)

Overhead

Generation	35% of Fixed and Variable Costs

Fuel Costs

Oil	498 cents/106 BTU
Coal	214 cents/106 BTU
Diesel	712 cents/106 BTU
Recall Energy from Churchill Falls	4.0 mills/kWh at the plant, equivalent to the following delivered costs. Purchase:4.29 mills/kWh Muskrat :4.35 mills/kWh Gull :4.35 mills/kWh

OPERATING DATA: NON-HYDRO EXISTING UNITS (ISLAND OF NEWFOUNDLAND)

Plant Name	Owner	Type of Plant	No. of Units	Gross Capacity (MW)	Net Capacity (MW)	Firm Energy (gWh)	F.O.R.(1) %	Heat Rate BTU/kWh	O + M + A Fixed $/kW	O + M + A Variable mills/kWh
Holyrood	NLH	OF	2	150	142.5	935	7	10,500		.351
Holyrood	NLH	OF	1	150	142.5	935	7 (2)	10,500		.351
St. John's	NLPC	OF	1		20.0	66.7	7	13,700		.700
St. John's	NLPC	OF	1		10.0	133.3	7	13,700		.700
Corner Brook	BWP	OF	1		6.0	42.0	1	4,600		.700
Grand Falls	Price	OF	1		5.0	37.4	7	4,600		.700
Holyrood	NLH	GT	1		14.15	-	15	13,400		10.0
Stephenville	NLH	GT	1		54.0	-	15	13,400		10.0
Other(St.John's)	NLH	GT	1		41.35	-	15	13,400		10.0
Greenhill	NLPC	GT	1		25.0	-	15	13,400		10.0
Salt Pond	NLPC	GT	1		13.0	-	15	13,400		10.0

OPERATING DATA: NON-HYDRO NEW UNITS

Type of Plant	Gross Capacity (MW)	Net Capacity (MW)	Firm Energy (gWh)	F.O.R.(1) %	Heat Rate BTU/kWh	O + M + A Fixed $/kW	O + M + A Variable mills/kWh
Coal Fired	150	138.0	907	7	9,400	7.9	.457
Coal Fired	300	276.0	1,814	7	9,200	6.5	.389
Gas Turbine		54.0	-	15	13,400	-	10.0

Note:

(1) Immature F.O.R.

	Oil Fired	Coal Fired	Nuclear
Year 1	12	12	23
2	10	10	18
3	9	9	14
4	8	8	13
5	7	7	13

(2) In-Service in 1980

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OPERATING DATA: EXISTING HYDRO (ON THE ISLAND OF NEWFOUNDLAND)

Name of Plant	Owner	No. of Ident. Units	Capacity (MW) Firm	Capacity (MW) Average	Energy (gWh) Firm	Energy (gWh) Average	F.O.R.
Bay D'Espoir 1	NLH	6	72.0	72.0	2250	2544	.20
Bay D'Espoir 2	NLH	1	148.0	148.0			.20
Cape Broyle	NLPC	1	6.0	6.0			1.28
Heart's Content	NLPC	1	2.4	2.4			1.72
Horse Chops	NLPC	1	7.7	7.7			1.28
Lockstone	NLPC	2	1.5	1.5			1.72
Lookout Brook 1	NLPC	2	1.4	1.4			1.72
Lookout Brook 2	NLPC	1	2.4	2.4			1.72
Mobile	NLPC	1	9.4	9.4			1.28
New Chelsea	NLPC	1	4.0	4.0			1.72
Petty Harbour	NLPC	3	1.6	1.6	285	375	1.72
Pierre's Brook	NLPC	1	3.2	3.2			1.72
Rattling Brook	NLPC	2	6.4	6.4			1.28
Rocky Pond	NLPC	1	3.2	3.2			1.72
Sandy Brook	NLPC	1	6.0	6.0			1.28
Seal Cove 1	NLPC	1	1.2	1.2			1.72
Seal Cove 2	NLPC	1	2.4	2.4			1.72
Tors Cove	NLPC	3	2.0	2.0			1.72
Others	NLPC	1	4.7	4.7			1.72
Deerlake 1	BWH	6	9.9	12.0			.68
Deerlake 2	BWH	2	19.7	24.0	714	824	.68
Watson's Brook	BWH	2	3.6	4.5			1.28
Bishop's Falls 1	Price	2	1.5	1.5			1.72
Bishop's Falls 2	Price	7	2.0	2.0			1.72
Grand Falls 1	Price	3	1.5	1.5	360	418	1.72
Grand Falls 2	Price	1	22.0	22.0			.68
Others	Price	2	5.7	5.7			1.28
PDD	PDD	1	1.0	1.0	6	6	1.72

Committed Hydro (on the Island of Newfoundland)

Name of Plant	No. of Units	Capacity (MW)	Energy (gWh) Firm	Energy (gWh) Average	F.O.R.	Year of Commissioning	Fixed Costs $/kW	Remarks
Hinds Lake	1	75.0	297	319	.2	1981	-	See Note 1
Upper Salmon	1	84.0	415	497	.2	1983		See Note 1

Planned & Probable Hydro (on the Island of Newfoundland)

Name of Plant	No. of Units	Capacity (MW)	Energy (gWh) Firm	Energy (gWh) Average	F.O.R.	Year of Commissioning	Fixed Costs $/kW	Remarks
Cat Arm	2	63.5	597	687	1.0	1985	6.75	See Note 2
Island Pond	1	27.0	156	187	1.0	1985 or 1987	8.80	See Note 2

Note: (1) Immature Forced Outage Rates: 5.14% (first year), 2.57 (2nd to 5th Year)
(2) Immature Forced Outage Rates: 5% (first year), 3% (2nd year)
Fixed costs include administration.

LABRADOR INFEED SCHEMES
OPERATING DATA

	Sending End Capacity MW	Sending End Average Energy GWh	Receiving End Capacity MW	Receiving End Average Energy GWh	Reliability Equivalent Capacity MW	F.O.R. %	O + M + A $ 10⁶
Upper Churchill							
A. 800 MW Purchase - Cable Option (2 Trenches)							
1 Bipole	800	6307	728	5783	726	0.96	9.5
B. 800 MW Purchase - Tunnel Option							
1 Bipole	800	6307	728	5783	726	0.18	8.8
Lower Churchill (Cable Option)							
C. Muskrat Falls (2 Trenches)							
Muskrat	618	4730		4345			
Recall	200	1380		1268			
Reserve	200						
Total	1018	6110	848	5613			
1 Bipole	920	6110	848	5613	805	0.893	11.5
D. Gull Island							
Stage 1 (2 Trenches)							
Gull	1698	11290					
Reserve	200	-					
Total	1898	11290					
1 Bipole	920	7483*	848	6929**	845	0.890	13.0
Stage 2 (3 Trenches)							
Gull	1698	11290					
Reserve	200						
Total	1898	11290					
1½ Bipoles	1380	11241*	1276	10409**	848 428	2.4 4.5	15.0
Stage 3 (3 Trenches)							
Gull	1698	11290					
Recall	200	1380					
Reserve	200	-					
Total	2098	12670					
2 Bipoles	1840	12670	1705	11713	1683	0.11	15.4

Notes: * Received energy x 1.08

** Limited by transmission

Lead Times to Bring Power Sources "On Power"

Project	Approval Time	Construction Time	Earliest On Power	Remarks
Cat Arm Hydro	½ year	4 years	end of 84	Feasibility study complete Environmental studies underway
Island Pond Hydro	2½ years	4 years	end of 86	Desk study only
Holyrood # 4 (oil fired)	½ year	3½ years	end of 83	Site developed
Coal fired	1½ years	4 years	end of 85	Site to be selected
Nuclear	4-5 years	7 years	end of 91	Site to be selected

LABRADOR INFEED SCHEMES

DELIVERED CAPACITY (MW)

	BIPOLE CAPABILITY				800 MW Purchase Cable or Tunnel	Muskrat Falls + Recall	Gull Island + Recall		
	Soldiers Pond	Three Brooks	1-1/2 Bipole	2 Bipoles			Stage 1	Stage 2	Stage 3
Interval					LOLP & Production	LOLP & Production	LOLP & Production	LOLP & Production	LOLP & Production
1	848	857	1276	1705	726	805	845	848+428	1683
2	848	857	1276	1705	726	805	845	848+428	1683
3	800	800	1200	1600	726	800	800	800+400	1600
4	800	800	1200	1600	726	800	800	800+400	1600
5	800	800	1200	1600	726	800	800	800+400	1600
6	742	751	1117	1493	726	742	742	742+375	1493
7	742	751	1117	1493	726	742	742	742+375	1493
8	742	751	1117	1493	726	742	742	742+375	1493
9	800	800	1200	1600	726	800	800	800+400	1600
10	800	800	1200	1600	726	800	800	800+400	1600
11	800	800	1200	1600	726	800	800	800+400	1600
12	848	857	1276	1705	726	805	845	848+428	1683
13	848	857	1276	1705	726	805	845	848+428	1683

Note: The capacities indicated for the Labrador Infeed schemes are the equivalent units determined in the reliability studies.

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Table 6

LABRADOR INFEED SCHEMES

DELIVERED ENERGY (GWh)

	BIPOLE CAPABILITY								PRODUCTION CAPABILITY								
	Soldiers Pond		Three Brooks		1-1/2 Bipole		2 Bipoles		800 MW Purchase Cable or Tunnel	Muskrat + Recall Cable Option			Gull Island + Recall Cable Option				
													Stage 1	Stage 2	Stage 3		
Interval	No MTCE	With MTCE(1)	No MTCE	With MTCE(1)	No MTCE	With MTCE(1)	No MTCE	With MTCE(1)		Muskrat	Recall	Total	Gull	Gull	Gull	Recall	Total
1	571	544	577	550	860	832	1149	1120	445	347	98	445	571	860	935		935
2	571	544	577	550	860	832	1149	1120	445	395	98	493	571	860	1064		1064
3	540	514	540	514	810	784	1078	1057	445	382	98	480	540	810	1029		1029
4	540	514	540	514	810	784	1078	1057	445	260	97	357	540	810	701		701
5	540	514	540	514	810	784	1078	1057	445	139	97	236	540	810	427(2)		427
6	500	477	506	481	753	728	1006	981	445	260	97	3 ~~257~~	477(1)	728(1)	753(2)	CAPACITY NOT REQUIRED, THEREFORE ENERGY CONSIDERED AS PART OF GULL CAPABILITY	753
7	500	477	506	481	753	728	1006	981	444	373	97	4 ~~370~~	477(1)	728(1)	953(2)		953
8	500	477	506	481	753	728	1006	981	444	373	97	4 ~~370~~	477(1)	705(2)	953(2)		953
9	540	514	540	514	810	784	1078	1057	445	382	97	479	514(1)	758(2)	1028		1028
10	540	514	540	514	810	784	1078	1057	445	399	98	497	540	810	1071		1071
11	540	514	540	514	810	784	1078	1057	445	408	98	506	540	810	1071		1071
12	571	544	577	550	860	832	1149	1120	445	325	98	423	571	860	909		909
13	571	544	577	550	860	832	1149	1120	445	303	98	401	571	860	819		819
Total									5783	4345	1268	5613	6929	10409	11713		11713

5314

(1) 1 valve group out of service for 5 days.

(2) 2 valve groups out of service for 5 days.

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Table 7

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1980, NLH LOAD FORECAST

Year	On Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
1984	2 x 63.5 MW Cat Arm (10)	2 x 54 MW GT (1)	2 x 54 MW GT(1)	2 x 54 MW GT (1)	2 x 54 MW GT (1)
1985	150 MW Coal (10)	728 MW Churchill (10)	150 MW Coal(10)	848 MW Muskrat (10)	-
1986	150 MW Coal (10) 27 MW Island Pond (10)	-	54 MW GT(1)	-	848 MW Gull (1)
1987	150 MW Coal (10)	-	728 MW Churchill (10)	-	-
1988	150 MW Coal (10)	54 MW GT (1)	-	-	-
1989	-	54 MW GT (1)	-	2 x 54 MW GT (1) Recall *	2 x 54 MW GT (1)
1990	150 MW Coal (10)	2 x 54 MW GT (1)	-	54 MW GT (1)	54 MW GT (1)
1991	-	54 MW GT (1)	-	2 x 54 MW GT (1)	2 x 54 MW GT (1)
1992	-	2 x 54 MW GT (1)	-	54 MW GT (1)	54 MW GT (1)
1993	150 MW Coal (10)	54 MW GT (1)	-	2 x 63.5 MW Cat Arm (10) 27 MW Island Pond (10)	2 x 54 MW GT (1)
1994	-	2 x 63.5 MW Cat Arm (10) 27 MW Island Pond (10)	54 MW GT (1)	-	2 x 54 MW GT (1)
1995	150 MW Coal (10)	-	54 MW GT (1)	2 x 54 MW GT (1)	54 MW GT (1)
1996	54 MW GT (1)	150 MW Coal (10)	2 x 63.5 MW Cat Arm(10) 27 MW Island Pond(10)	150 MW Coal (10)	428 MW Gull (10)
1997	150 MW Coal (10)	54 MW GT (1)	-	54 MW GT (1)	-
1998	2 x 54 MW GT (1)	150 MW Coal (10)	150 MW Coal (10)	150 MW Coal (10)	-
1999	150 MW Coal (10)	54 MW GT (1)	54 MW GT (1)	54 MW GT (1)	2 x 54 MW GT (1)
2000	54 MW GT (1)	150 MW Coal (10)	150 MW Coal(10)	150 MW Coal (10)	2 x 54 MW GT (1)
2001	2 x 54 MW GT (1)	54 MW GT (1)	2 x 54 MW GT(1)	54 MW GT (1)	2 x 54 MW GT (1)

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1980, NLH LOAD FORECAST

Year	On Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
2002	300 MW Coal (10)	2 x 54 MW GT (1)	2 x 54 MW GT(1)	300 MW Coal (10)	429 MW Gull (10) + Recall*
2003	54 MW GT (1)	300 MW Coal (10)	300 MW Coal(10)	-	-
2004	2 x 54 MW GT (1)	-	-	54 MW GT (1)	-
2005	300 MW Coal (10)	2 x 24 MW GT (1)	3 x 54 MW GT (1)	300 MW Coal (10)	2 x 63.5 MW Cat Arm (10) 27 MW Island Pond (10)
2006	54 MW GT (1)	2 x 54 MW GT (1)	2 x 54 MW GT (1)	-	-
2007	2 x 54 MW GT (1)	300 MW Coal (10)	300 MW Coal (10)	2 x 54 MW GT (1)	300 MW Coal (10)
2008	300 MW Coal (10)	-	54 MW GT (1)	3 x 54 MW GT (1)	-
2009	54 MW GT (1)	3 x 54 MW GT (1)	3 x 54 MW GT(1)	300 MW Coal (10)	300 MW Coal (10)
2010	3 x 54 MW GT (1)	300 MW Coal (10)	300 MW Coal(10)		-
2011	300 MW Coal (10)	54 MW GT (1)	54 MW GT(1)	300 MW Coal (10)	-
2012	54 MW GT (1)	300 MW Coal (10)	300 MW Coal(10)	54 MW GT (1)	2 x 54 MW GT (1)
2013	300 MW Coal (10)	54 MW GT (1)	2 x 54 MW GT(1)	3 x 54 MW GT (1)	300 MW Coal (10)
2014	54 MW GT (1) 56.6 MW Coal (10)	300 MW Coal (10)	300 MW Coal(10)	300 MW Coal (10)	69.3 MW Coal (10)
2015	3 x 54 MW GT (1)	2 x 54 MW GT (1)	54 MW GT(1)	54 MW GT 28.3 MW coal (10)	2 x 54 MW GT (1)

Notes 1: (1), (10) - in service interval.
2: MW shown are gross capacity - Labrador schemes show receiving end production capability.
*: Recall energy purchased as required.

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1980, NLH LOAD FORECAST

Year	On Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
AVERAGE ENERGY ADDED: 1984 to 2015					
Oil	-	-	-	-	-
Coal	17571 GWh	11786 GWh	11786 GWh	11956 GWh	5857 GWh
GT's	-	-	-	-	-
Hydro	874 GWh	874 GWh	874 GWh	874 GWh	874 GWh
Labrador	-	5783 GWh	5783 GWh	5613 GWh	11713 GWh
	18445 GWh	18443 GWh	18443 GWh	18443 GWh	18444 GWh
TOTAL CAPACITY ADDED: 1984 to 2015					
Oil	-	-	-	-	
Coal	2907 MW	1950 MW	1950 MW	1978 MW	969 MW
GT's	1134 MW	1404 MW	1242 MW	1296 MW	1242 MW
Hydro	154 MW	154 MW	154 MW	154 MW	154 MW
Labrador	-	728 MW	728 MW	848 MW	1705 MW
	4195 MW	4236 MW	4074 MW	4276 MW	4070 MW
LOSS OF LOAD PROBABILITY FOR SELECTED YEARS IN DAYS PER YEAR					
1985	.031	.091	.138	.116	.179
1990	.010	.126	.028	.195	.188
1995	.123	.178	.197	.155	.181
2000	.152	.116	.184	.116	.158
2005	.085	.169	.149	.083	.190
2010	.157	.097	.098	.181	.188
2015	.195	.152	.197	.173	.195

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1980, MODIFIED LOAD GROWTH FORECAST

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
1984	2 x 63.5 MW Cat Arm (10)	54 MW GT (1)	54 MW GT (1)		54 MW GT (1)
1985	150 MW Coal (10)	728 MW Churchill (10)	150 MW Coal(10)		-
1986	27 MW Island Pond (10) 150 MW Coal (10)	-	-		844 MW Gull (1)
1987	150 MW Coal (10)	-	728 MW Churchill (10)		-
1988	-	-	-		-
1989	-	-	-		-
1990	150 MW Coal (10)	54 MW GT (1)	-		54 MW GT (1)
1991	-	54 MW GT (1)	-		54 MW GT (1)
1992	-	54 MW GT (1)	-		54 MW GT (1)
1993	-	2 x 54 MW GT (1)	-		54 MW GT (1)
1994	150 MW Coal (10)	54 MW GT (1)	-		54 MW GT (1)
1995	-	54 MW GT (1)	-		2 x 54 MW GT (1)
1996	-	54 MW GT (1)	-		54 MW GT (1)
1997	150 MW Coal (10)	54 MW GT (1)	54 MW GT (1)		54 MW GT (1)
1998	-	2 x 54 MW GT (1)	2 x 54 MW GT (1)		54 MW GT (1)
1999	54 MW GT (1)	2x63.5 MW Cat Arm (10) 27 MW Island Pond (10)	54 MW GT (1)		2 x 54 MW GT (1)
2000	150 MW Coal (10)	-	54 MW GT (1)		54 MW GT (1)
2001	54 MW GT (1)	150 MW Coal (10)	2x63.5 MW Cat Arm (10) 27 MW Island Pond (10)		54 MW GT (1)
2002	54 MW GT (1)	-	-		428 MW Gull (10)
2003	150 MW Coal (10)	54 MW GT (1)	54 MW GT (1)		-
2004	54 MW GT (1)	150 MW Coal (10)	150 MW Coal (10)		-

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1980, MODIFIED LOAD GROWTH FORECAST

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
2005	150 MW Coal (10)	-	-		54 MW GT (1)
2006	54 MW GT (1)	54 MW GT (1)	2 x 54 MW GT (1)		54 MW GT (1)
2007	54 MW GT (1)	150 MW Coal (10)	150 MW Coal (10)		2 x 54 MW GT (1)
2008	300 MW Coal (10)	54 MW GT (1)	-		429 MW Gull (10) + Recall*
2009	-	300 MW Coal (10)	300 MW Coal (10)		-
2010	2 x 54 MW GT (1)	-	-		-
2011	2 x 54 MW GT (1)	-	2 x 54 MW GT (1)		-
2012	300 MW Coal (10)	2 x 54 MW GT (1)	2 x 54 MW GT (1)		54 MW GT (1)
2013	-	2 x 54 MW (1)	2 x 54 MW GT(1)		2x63.5MW Cat Arm (10) 27 MW Island Pond(10)
2014	54 MW GT (1)	300 MW Coal (10)	300 MW Coal(10)		-
2015	2 x 54 MW GT (1)	-	-		54 MW GT (1)
2016	2 x 54 MW GT (1)	54 MW GT (1)	2 x 54 MW GT (1)		300 MW Coal (10)
2017	300 MW Coal (10)	300 MW Coal (10)	300 MW Coal (10)		-
2018	54 MW GT (1)	-	-		-
2019	300 MW Coal (10)	2 x 54 MW GT (1)	2 x 54 MW GT (1)		2 x 54 MW GT (1)
2020	-	300 MW Coal (10)	300 MW Coal (10)		300 MW Coal (10)
2021	2 x 54 MW GT (1)	-	-		-
2022	300 MW Coal (10)	2 x 54 MW GT (1)	3 x 54 MW GT (1)		300 MW Coal (10)
2023	54 MW GT (1)	2 x 54 MW GT (1)	54 MW GT (1)		-
2024	56.6 MW Coal (10) 54 MW GT (1)	300 MW Coal (10)	300 MW Coal (10)		69.3 MW Coal (10)
2025	54 MW GT (1)	-	-		-

Notes 1: (1), (10) - in service interval.
2: MW shown are gross capacity - Labrador schemes show receiving end production capability.
* Recall energy purchased as required.

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1980, MODIFIED LOAD GROWTH FORECAST

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
AVERAGE ENERGY ADDED: 1984 to 2025					
Oil	-	-	-		-
Coal	17571 GWh	11786 GWh	11786 GWh		5857 GWh
GT's	-	-	-		-
Hydro	874 GWh	874 GWh	874 GWh		874 GWh
Labrador	-	5783 GWh	5783 GWh		11713 GWh
	18445 GWh	18443 GWh	18443 GWh		18444 GWh
TOTAL CAPACITY ADDED: 1984 to 2025					
Oil	-	-	-		-
Coal	2907 MW	1950 MW	1950 MW		969 MW
GT's	1134 MW	1404 MW	1242 MW		1242 MW
Hydro	154 MW	154 MW	154 MW		154 MW
Labrador	-	728 MW	728 MW		1705 MW
	4195 MW	4236 MW	4074 MW		4070 MW
LOSS OF LOAD PROBABILITY FOR SELECTED YEARS IN DAYS PER YEAR					
1985	0.012	0.062	0.082		0.113
1990	0.003	0.163	0.012		0.151
1995	0.050	0.149	0.152		0.134
2000	0.107	0.099	0.187		0.169
2005	0.090	0.160	0.194		0.155
2010	0.137	0.099	0.170		0.164
2015	0.175	0.126	0.140		0.199
2020	0.070	0.079	0.087		0.198
2025	0.184	0.108	0.130		0.194

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1985, NLH LOAD FORECAST

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
1984	2 x 63.5 MW Cat Arm (10)	2 x 63.5 MW Cat Arm (10)	2 x 63.5 MW Cat Arm (10)		2x63.5 MW Cat Arm(10)
1985	150 MW Coal (10)	150 MW Coal (10)	150 MW Coal (10)		150 MW Coal (10)
1986	27 MW Island Pond (10) 150 MW Coal (10)	27 MW Island Pond (10) 150 MW Coal (10)	27 MW Island Pond (10) 150 MW Coal (10)		27 MW Island Pond(10) 150 MW Coal (10)
1987	150 MW Coal (10)	150 MW Coal (10)	150 MW Coal (10)		150 MW Coal (10)
1988	-	-	-		-
1989	150 MW Coal (10)	-	-		-
1990	150 MW Coal (10)	728 MW Churchill (10)	54 MW GT (1)		-
1991	-	-	2 x 54 MW GT (1)		848 MW Gull (1)
1992	-	-	728 MW Churchill (10)		-
1993	150 MW Coal (10)	-	-		-
1994	-	-	-		-
1995	150 MW Coal (10)	54 MW GT (1)	-		54 MW GT (1)
1996	54 MW GT (1)	2 x 54 MW GT (1)	-		2 x 54 MW GT (1)
1997	150 MW Coal (10)	2 x 54 MW GT (1)	-		2 x 54 MW GT (1)
1998	2 x 54 MW GT (1)	2 x 54 MW GT (1)	-		2 x 54 MW GT (1)
1999	150 MW Coal (10)	2 x 54 MW GT (1)	-		2 x 54 MW GT (1)
2000	54 MW GT (1)	2 x 54 MW GT (1)	2 x 54 MW GT (1)		2 x 54 MW GT (1)
2001	2 x 54 MW GT (1)	2 x 54 MW GT (1)	3 x 54 MW GT (1)		428 MW Gull (10)

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1985, NLH LOAD FORECAST

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
2002	300 MW Coal (10)	2 x 54 MW GT (1)	2 x 54 MW GT (1)		-
2003	54 MW GT (1)	300 MW Coal (10)	300 MW Coal (10)		54 MW GT (1)
2004	2 x 54 MW GT (1)	-	-		2 x 54 MW GT (1)
2005	300 MW Coal (10)	2 x 54 MW GT (1)	3 x 54 MW GT (1)		2 x 54 MW GT (1)
2006	54 MW GT (1)	2 x 54 MW GT (1)	2 x 54 MW GT (1)		428 MW Gull (10) + Recall*
2007	2 x 54 MW GT (1)	300 MW Coal (10)	300 MW Coal (10)		-
2008	300 MW Coal (10)	54 MW GT (1)	54 MW GT (1)		-
2009	54 MW GT (1)	3 x 54 MW GT (1)	3 x 54 MW GT (1)		-
2010	3 x 54 MW GT (1)	300 MW Coal (10)	300 MW Coal (10)		2 x 54 MW GT (1)
2011	300 MW Coal (10)	54 MW GT (1)	54 MW GT (1)		3 x 54 MW GT (1)
2012	54 MW GT (1)	300 MW Coal (10)	300 MW Coal (10)		300 MW Coal (10) 54 MW GT (1)
2013	300 MW Coal (10)	54 MW GT (1)	2 x 54 MW GT (1)		-
2014	54 MW GT (1) 56.6 MW Coal (10)	300 MW Coal (10)	300 MW Coal (10)		219 MW Coal (10)
2015	3 x 54 MW GT (1)	2 x 54 MW GT (1)	54 MW GT (1)		54 MW GT (1)

Note: (1), (10) in service interval.
* Recall energy purchased as required.

ALTERNATIVE GENERATION EXPANSION PROGRAM

DECISION 1985, NLH LOAD FORECAST

AVERAGE ENERGY ADDED: 1984 to 2025

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
Oil	-	-	-		-
Coal	17571 GWh	11786 GWh	11786 GWh		5857 GWh
GT's	-	-	-		-
Hydro	874 GWh	874 GWh	874 GWh		874 GWh
Labrador	-	5783 GWh	5783 GWh		11713 GWh
	18445 GWh	18443 GWh	18443 GWh		18444 GWh

TOTAL CAPACITY ADDED: 1984 to 2015

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
Oil	-	-	-		-
Coal	2907 MW	1950 MW	1950 MW		969 MW
GT's	1134 MW	1404 MW	1242 MW		1242 MW
Hydro	154 MW	154 MW	154 MW		154 MW
Labrador	-	728 MW	728 MW		1705 MW
	4195 MW	4236 MW	4074 MW		4070 MW

LOSS OF LOAD PROBABILITY FOR SELECTED YEARS IN DAYS PER YEAR

Year	On-Island Alternative	Upper Churchill 800 MW Purchase Cable Option	Upper Churchill 800 MW Purchase Tunnel Option	Lower Churchill Muskrat Falls Cable Option	Lower Churchill Gull Island Cable Option
1985	0.031	0.050	0.031		0.057
1990	0.010	0.021	0.136		0.079
1995	0.123	0.199	0.017		0.196
2000	0.152	0.162	0.201		0.154
2005	0.085	0.163	0.149		0.191
2010	0.157	0.094	0.098		0.200
2015	0.195	0.199	0.197		0.186

COMPARISON OF ALTERNATIVES

NLH LOAD FORECAST

DECISION 1980

PRICE OF POWER AT CHURCHILL FALLS = 4.0 MILLS PER KWh
DECLINING AT 10% PER ANNUM IN REAL TERMS

Cumulative Present Worth to January 1981 of Investment and Incremental Operating Costs (1984-2045) ($\$x\ 10^6$)

Discount Rate	Sensitivity	On-Island	Upper Churchill: 800 MW Purchase Cable Option	Upper Churchill: 800 MW Purchase Tunnel Option	Lower Churchill: Muskrat + Coal Cable Option	Lower Churchill: Gull + Coal Cable Option
2%	All costs as estimated	10583.3	7564.2	7668.5	8250.4	$\boxed{6036.8}$
	Infeed and LCDC @ 1.15 estimate	10583.3	7716.9	7826.8	8500.8	$\boxed{6423.4}$
	Coal escalating @ 1% per year	13545.5	9258.0	9367.2	9987.5	$\boxed{6666.5}$
5%	All costs as estimated	4579.3	$\boxed{3450.4}$	3576.6	4056.6	3553.6
	Infeed and LCDC @ 1.15 estimate	4579.3	$\boxed{3578.8}$	3704.6	4275.0	3872.1
	Coal escalating @ 1% per year	5492.2	3923.6	4054.4	4544.3	$\boxed{3716.4}$
6%	All costs as estimated	3652.0	$\boxed{2821.7}$	2942.0	3409.1	3142.1
	Infeed and LCDC @ 1.15 estimate	3652.0	$\boxed{2944.5}$	3062.6	3619.5	3435.2
	Coal escalating @ 1% per year	4295.2	$\boxed{3141.1}$	3265.5	3738.0	3248.4
7%	All costs as estimated	2979.7	$\boxed{2367.8}$	2479.7	2938.0	2830.7
	Infeed and LCDC @ 1.15 estimate	2979.7	$\boxed{2485.8}$	2593.8	3141.2	3118.3
	Coal escalating @ 1% per year	3442.2	$\boxed{2586.6}$	2702.2	3164.1	2900.9
10%	All costs as estimated	1812.4	$\boxed{1582.7}$	1663.9	2108.1	2235.1
	Infeed and LCDC @ 1.15 estimate	1812.4	$\boxed{1689.0}$	1762.0	2293.3	2487.9
	Coal escalating @ 1% per year	2005.0	$\boxed{1659.1}$	1743.3	2187.6	2256.8
15%	All costs as estimated	$\boxed{1023.1}$	1044.9	1077.7	1509.2	1723.8
	Infeed and LCDC @ 1.15 estimate	$\boxed{1023.1}$	1136.6	1156.2	1670.9	1935.0
	Coal escalating @ 1% per year	1084.4	$\boxed{1061.7}$	1096.5	1526.8	1727.5

$\boxed{\quad}$ Least Cost

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Table 11

COMPARISON OF ALTERNATIVES

NLH LOAD FORECAST

DECISION 1980

PRICE OF POWER AT CHURCHILL FALLS = 4.0 MILLS PER KWh
DECLINING AT 5% PER ANNUM IN REAL TERMS

Discount Rate	Sensitivity	Cumulative Present Worth to January 1981 of Investment and Incremental Operating Costs (1984-2045) ($x 10^6)				
			Upper Churchill		Lower Churchill	
		On-Island	800 MW Purchase Cable Option	800 MW Purchase Tunnel Option	Muskrat + Coal Cable Option	Gull + Coal Cable Option
2%	All costs as estimated	10583.8	7701.8	7796.2	8272.8	$\boxed{6045.2}$
	Infeed and LCDC @ 1.15 estimate	10583.8	7854.5	7954.5	8523.2	$\boxed{6431.8}$
	Coal escalating @ 1% per year	13545.5	9395.6	9494.8	10009.9	$\boxed{6674.9}$
5%	All costs as estimated	4579.3	$\boxed{3526.7}$	3644.7	4067.4	3556.3
	Infeed and LCDC @ 1.15 estimate	4579.3	$\boxed{3655.1}$	3772.6	4286.1	3874.7
	Coal escalating @ 1% per year	5492.2	3999.9	4122.5	4555.1	$\boxed{3719.0}$
6%	All costs as estimated	3652.0	$\boxed{2886.3}$	2998.8	3417.8	3144.0
	Infeed and LCDC @ 1.15 estimate	3652.0	$\boxed{3009.1}$	3119.4	3628.2	3446.0
	Coal escalating @ 1% per year	4295.2	$\boxed{3205.7}$	3322.3	3747.4	3250.2
7%	All costs as estimated	2979.7	$\boxed{2423.1}$	2527.6	2945.0	2831.9
	Infeed and LCDC @ 1.15 estimate	2979.7	$\boxed{2541.0}$	2641.7	3148.3	3119.6
	Coal escalating @ 1% per year	3442.2	$\boxed{2641.8}$	2750.1	3171.2	2902.2
10%	All costs as estimated	1812.4	$\boxed{1619.2}$	1694.1	2112.1	2235.6
	Infeed and LCDC @ 1.15 estimate	1812.4	$\boxed{1725.4}$	1792.3	2297.3	2488.4
	Coal escalating @ 1% per year	2005.0	$\boxed{1695.6}$	1773.5	2191.6	2257.2
15%	All costs as estimated	$\boxed{1023.1}$	1065.5	1093.6	1511.0	1723.9
	Infeed and LCDC @ 1.15 estimate	$\boxed{1023.1}$	1157.2	1172.1	1672.7	1935.1
	Coal escalating @ 1% per year	1084.4	$\boxed{1082.2}$	1112.4	1528.6	1727.6

$\boxed{}$ Least Cost

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Table 12

COMPARISON OF ALTERNATIVES

MODIFIED LOAD FORECAST

DECISION 1980

PRICE OF POWER AT CHURCHILL FALLS = 4.0 MILLS PER KWh
DECLINING AT 10% PER ANNUM IN REAL TERMS

		Cumulative Present Worth to January 1981 of Investment and Incremental Operating Costs (1984-2045) ($x 10^6)				
			Upper Churchill		Lower Churchill	
Discount Rate	Sensitivity	On-Island	800 MW Purchase Cable Option	800 MW Purchase Tunnel Option	Muskrat + Coal Cable Option	Gull + Coal Cable Option
2%	All costs as estimated	8959.8	6203.8	6290.4		$\boxed{5274.3}$
	Infeed and LCDC @ 1.15 estimate	8959.8	6356.4	6448.7		
	Coal escalating @ 1% per year	11575.1	7586.4	7681.7		
5%	All costs as estimated	3712.2	$\boxed{2755.5}$	2853.8		3132.1
	Infeed and LCDC @ 1.15 estimate	3712.2	2883.9	2981.8		
	Coal escalating @ 1% per year	4478.2	3104.6	3208.8		
6%	All costs as estimated	2932.4	$\boxed{2254.9}$	2347.8		2787.3
	Infeed and LCDC @ 1.15 estimate	2932.4	$\boxed{2377.7}$	2468.5		
	Coal escalating @ 1% per year	3463.2	$\boxed{2481.7}$	2579.6		
7%	All costs as estimated	2376.1	$\boxed{1900.9}$	1986.5		2528.6
	Infeed and LCDC @ 1.15 estimate	2376.1	$\boxed{2018.8}$	2100.7		
	Coal escalating @ 1% per year	2751.8	$\boxed{2050.0}$	2140.2		
10%	All costs as estimated	1435.2	$\boxed{1306.5}$	1366.3		2037.9
	Infeed and LCDC @ 1.15 estimate	1435.2	$\boxed{1412.7}$	1464.5		
	Coal escalating @ 1% per year	1585.8	$\boxed{1352.3}$	1415.2		
15%	All costs as estimated	$\boxed{821.6}$	909.1	926.7		1611.8
	Infeed and LCDC @ 1.15 estimate	$\boxed{821.6}$	1000.8	1005.2		
	Coal escalating @ 1% per year	$\boxed{868.1}$	917.0	936.5		

$\boxed{\quad}$ Least Cost

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Table 13

COMPARISON OF ALTERNATIVES

MODIFIED LOAD FORECAST

DECISION 1980

PRICE OF POWER AT CHURCHILL FALLS = 4.0 MILLS PER KWh
DECLINING AT 5% PER ANNUM IN REAL TERMS

		Cumulative Present Worth to January 1981 of Investment and Incremental Operating Costs (1984-2045) ($x 10^6)				
			Upper Churchill		Lower Churchill	
Discount Rate	Sensitivity	On-Island	800 MW Purchase Cable Option	800 MW Purchase Tunnel Option	Muskrat + Coal Cable Option	Gull + Coal Cable Option
2%	All costs as estimated	8959.8	6341.4	6418.1		$\boxed{5279.2}$
	Infeed and LCDC @ 1.15 estimate	8959.8	6494.0	6576.4		
	Coal escalating @ 1% per year	11575.1	7724.0	7809.4		
5%	All costs as estimated	3712.2	$\boxed{2831.9}$	2921.9		3133.5
	Infeed and LCDC @ 1.15 estimate	3712.2	2960.2	3049.8		
	Coal escalating @ 1% per year	4478.2	3181.0	3276.8		
6%	All costs as estimated	2932.4	$\boxed{2319.5}$	2404.6		2788.1
	Infeed and LCDC @ 1.15 estimate	2932.4	$\boxed{2442.3}$	2525.3		
	Coal escalating @ 1% per year	3463.2	$\boxed{2546.3}$	2636.4		
7%	All costs as estimated	2376.1	$\boxed{1956.1}$	2034.4		2529.2
	Infeed and LCDC @ 1.15 estimate	2376.1	$\boxed{2074.1}$	2148.6		
	Coal escalating @ 1% per year	2751.8	$\boxed{2105.2}$	2188.1		
10%	All costs as estimated	1435.2	$\boxed{1343.0}$	1396.6		2038.1
	Infeed and LCDC @ 1.15 estimate	$\boxed{1435.2}$	1449.2	1494.8		
	Coal escalating @ 1% per year	1585.8	$\boxed{1388.8}$	1445.5		
15%	All costs as estimated	$\boxed{821.6}$	929.7	942.6		1611.8
	Infeed and LCDC @ 1.15 estimate	$\boxed{821.6}$	1021.4	1021.0		
	Coal escalating @ 1% per year	$\boxed{868.1}$	937.6	952.4		

$\boxed{\quad}$ Least Cost

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Table 14

COMPARISON OF ALTERNATIVES

NLH LOAD FORECAST

DECISION 1985

PRICE OF POWER AT CHURCHILL FALLS = 4.0 MILLS PER KWh
DECLINING AT 10% PER ANNUM IN REAL TERMS

Cumulative Present Worth to January 1981 of Investment and Incremental Operating Costs (1984-2045) ($x 10^6)

Discount Rate	Sensitivity	On-Island	Upper Churchill		Lower Churchill	
			800 MW Purchase Cable Option	800 MW Purchase Tunnel Option	Muskrat + Coal Cable Option	Gull + Coal Cable Option
2%	All costs as estimated	10594.1	7817.4	7885.1		$\boxed{6482.8}$
	Infeed and LCDC @ 1.15 estimate	10594.1	7955.6	8028.5		
	Coal escalating @ 1% per year	13554.9	9534.3	9611.3		
5%	All costs as estimated	4585.0	$\boxed{3622.0}$	3695.2		3680.1
	Infeed and LCDC @ 1.15 estimate	4585.0	3722.5	3795.5		
	Coal escalating @ 1% per year	5497.2	4112.2	4192.9		
6%	All costs as estimated	3656.7	$\boxed{2969.6}$	3035.0		3189.1
	Infeed and LCDC @ 1.15 estimate	3656.7	$\boxed{3061.4}$	3125.1		
	Coal escalating @ 1% per year	4299.2	$\boxed{3304.4}$	3376.7		
7%	All costs as estimated	2983.4	$\boxed{2493.5}$	2550.0		2808.3
	Infeed and LCDC @ 1.15 estimate	2983.4	$\boxed{2577.6}$	2631.4		
	Coal escalating @ 1% per year	3445.3	$\boxed{2726.3}$	2789.1		
10%	All costs as estimated	1813.9	$\boxed{1650.3}$	1680.5		2052.1
	Infeed and LCDC @ 1.15 estimate	1813.9	$\boxed{1716.3}$	1741.5		
	Coal escalating @ 1% per year	2006.1	$\boxed{1737.5}$	1772.2		
15%	All costs as estimated	$\boxed{1022.3}$	1039.2	1039.5		1380.0
	Infeed and LCDC @ 1.15 estimate	$\boxed{1022.3}$	1084.8	1078.5		
	Coal escalating @ 1% per year	1083.3	$\boxed{1063.1}$	1066.3		

$\boxed{}$ Least Cost

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Table 15

COMPARISON OF ALTERNATIVES

NLH LOAD FORECAST

DECISION 1985

PRICE OF POWER AT CHURCHILL FALLS = 4.0 MILLS PER KWh
DECLINING AT 5% PER ANNUM IN REAL TERMS

Cumulative Present Worth to January 1981 of Investment and Incremental Operating Costs (1984-2045) ($x 10^6)

			Upper Churchill		Lower Churchill	
Discount Rate	Sensitivity	On-Island	800 MW Purchase Cable Option	800 MW Purchase Tunnel Option	Muskrat + Coal Cable Option	Gull + Coal Cable Option
2%	All costs as estimated	10594.1	7929.4	7986.7		$\boxed{6491.2}$
	Infeed and LCDC @ 1.15 estimate	10594.1	8067.6	8130.0		
	Coal escalating @ 1% per year	13554.9	9646.2	9712.8		
5%	All costs as estimated	4585.0	$\boxed{3677.8}$	3743.5		3682.7
	Infeed and LCDC @ 1.15 estimate	4585.0	3778.4	3843.8		
	Coal escalating @ 1% per year	5497.2	4168.1	4241.2		
6%	All costs as estimated	3656.7	$\boxed{3015.1}$	3073.7		3189.9
	Infeed and LCDC @ 1.15 estimate	3656.7	$\boxed{3106.9}$	3163.9		
	Coal escalating @ 1% per year	4299.2	$\boxed{3349.9}$	3415.4		
7%	All costs as estimated	2983.4	$\boxed{2531.1}$	2581.4		2809.6
	Infeed and LCDC @ 1.15 estimate	2983.3	$\boxed{2615.2}$	2662.8		
	Coal escalating @ 1% per year	3445.3	$\boxed{2763.8}$	2820.5		
10%	All costs as estimated	1813.9	$\boxed{1672.4}$	1698.1		2052.6
	Infeed and LCDC @ 1.15 estimate	1813.9	$\boxed{1738.4}$	1759.1		
	Coal escalating @ 1% per year	2006.1	$\boxed{1759.6}$	1789.9		
15%	All costs as estimated	$\boxed{1022.3}$	1049.5	1047.1		1380.1
	Infeed and LCDC @ 1.15 estimate	$\boxed{1022.3}$	1095.1	1086.1		
	Coal escalating @ 1% per year	1083.3	$\boxed{1073.4}$	1073.8		

$\boxed{}$ Least Cost

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Table 16

COMPARATIVE UNIT ENERGY COSTS

Discount Rate = 6%,

10% Declining 'Real' Cost of Purchase Power

Description	Cat Arm	Island Pond	150 MW Coal Fired	300 MW Coal Fired	Upper Churchill		Lower Churchill			
					800 MW Purchase Cable Option	800 MW Purchase Tunnel Option	Muskrat (Cable Option)	Gull (Cable Option)		
								Stage 1	Stage 2	Stage 3
1. Nominal Capacity (MW)	127	27	150	3000	800	800	800	800	1200	1600
2. Maximum Annual Energy (GWh)	687	187	907	1814	5783	5783	5613	6929	10409	11713
3. Unit Energy Cost (cents/kWh, available)	1.85	1.99	3.11	2.93	1.40	1.49	2.26	2.31	2.04	1.96
4. Unit Energy Cost (cents/kWh, absorbed)	1.85	1.99	3.11	2.93	1.56	1.59	2.50	2.70	2.56	2.36

Notes: The unit costs for Gull Island reflect the staging of the project with no value attributed to surplus. If all the energy is useable from the on-power date of the hydro-electric development, the comparative unit costs are 1.74 cents/kWh.

The above unit costs are comparative. They do not represent the cost once the project goes on power as the costs do not include EDC and IDC computed at current rates.

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Table 17

LCDC PROJECT

GULL ISLAND ALTERNATIVE

Energy Available for Surplus Sales

Year	Capability of Gull at source	Gull Absorbed	Surplus at source	Revenue at 10 mills/kWh	Present Worth to January 81 at 6%	Present Worth to January 81 at 10%
	GWh	GWh	GWh	$ x 10^6	$ x 10^6	$ x 10^6
1986	9152	3085	5820	58.20	41.04	32.85
1987	11290	3656	7342	73.42	48.83	37.67
1988	11290	4015	6915	69.15	43.39	32.26
1989	11290	4417	6520	65.20	38.59	27.65
1990	11290	4751	6159	61.59	34.39	23.74
1991	11290	5098	5784	57.84	30.47	20.27
1992	11290	5445	5410	54.10	26.89	17.24
1993	11290	5794	5033	50.33	23.59	14.58
1994	11290	6122	4678	46.78	20.69	12.32
1995	11290	6394	4384	43.84	18.29	10.50
1996	11290	6766	3982	39.82	15.68	8.67
1997	11290	7348	3354	33.54	12.46	6.64
1998	11290	7761	2908	29.08	10.19	5.23
1999	11290	8181	2455	24.55	8.11	4.01
2000	11290	8605	1997	19.97	6.23	2.97
2001	11290	9011	1558	15.58	4.58	2.10
2002	11290	9527	1022	10.22	2.84	1.26
2003	11290	9800	706	7.06	1.85	0.79
2004	11290	10188	287	2.87	0.71	0.29
2005	11290	10353	109	1.09	0.25	0.10
2006	11290	10408	50	0.50	0.11	0.04
2007	11290	10707				
2008	11290	10974				
2009	11290	11217				
2010	11290	11447				
2011	11290	11592				
2012	11290	11640				
2013	11290	11686				
2014	11290	11704				
2015	11290	11706				
Total					388.94	261.11

COMPARISON OF ALTERNATIVES
BENEFIT/COST RATIOS

Description	Benefit/Cost Ratio Relative to 'On-Island' Purchase Cost Declining in Real Terms			
	@ 10%		@ 5%	
	Discount Rate 6%	10%	Discount Rate 6%	10%
A. Decision 1980, NLH Load Forecast				
1. 800 MW Purchase (Cable)	1.86	1.29	1.75	1.23
2. 800 MW Purchase (Tunnel)	1.77	1.21	1.67	1.16
3. Gull Island (Cable)	1.24	0.76	1.24	0.76
4. Muskrat Falls (Cable)	1.16	0.77	1.15	0.77
B. Sensitivity (800 MW Purchase, Cable)				
1. Modified Load Forecast, Decision 1980	1.70	1.16	1.60	1.11
2. 5-Year Delay in Decision, Decision 1985, NLH Load Forecast	1.95	1.33	1.84	1.27
3. Differential Escalation in Coal 1%, Decision 1980, NLH Load Forecast	2.20	1.43	2.06	1.37
4. 15% Increase in Infeed Costs, Decision 1980, NLH Load Forecast	1.65	1.14	1.56	1.09
C. Other Sensitivities				
1. One-year Delay and 10% Cost Increase in 800 MW Purchase, Tunnel Option	1.55	1.01	1.46	0.97
2. Gull Island with Revenue of 10 Mills/kWh from Surplus Sales.	1.42	0.91	1.42	0.91

Cost Effectiveness of Delivering Power From Labrador to the Island

List of Figures

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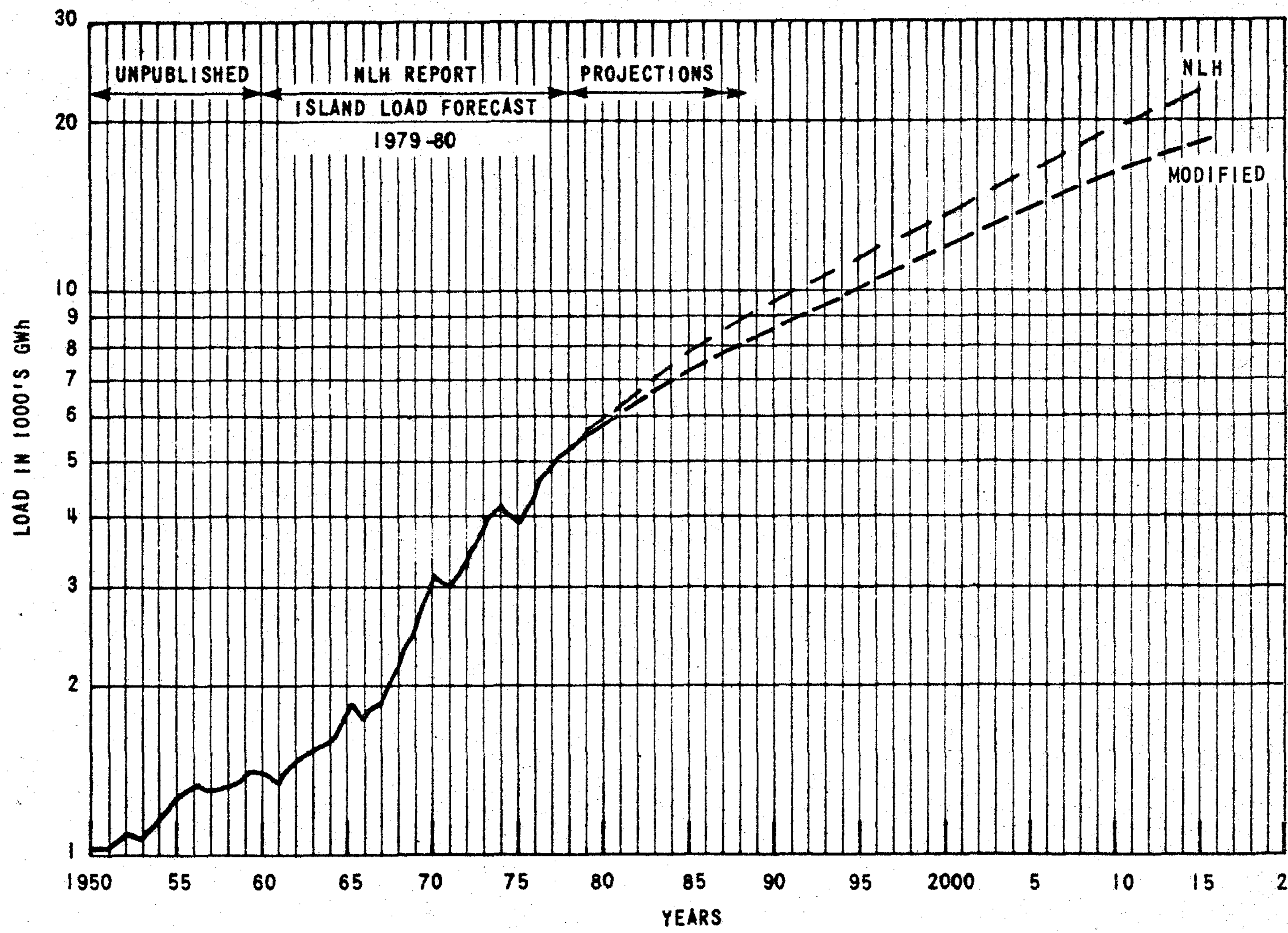
FIGURE 1



ENERGY CONSUMPTION
HISTORIC & PROJECTED
ISLAND OF NEWFOUNDLAND

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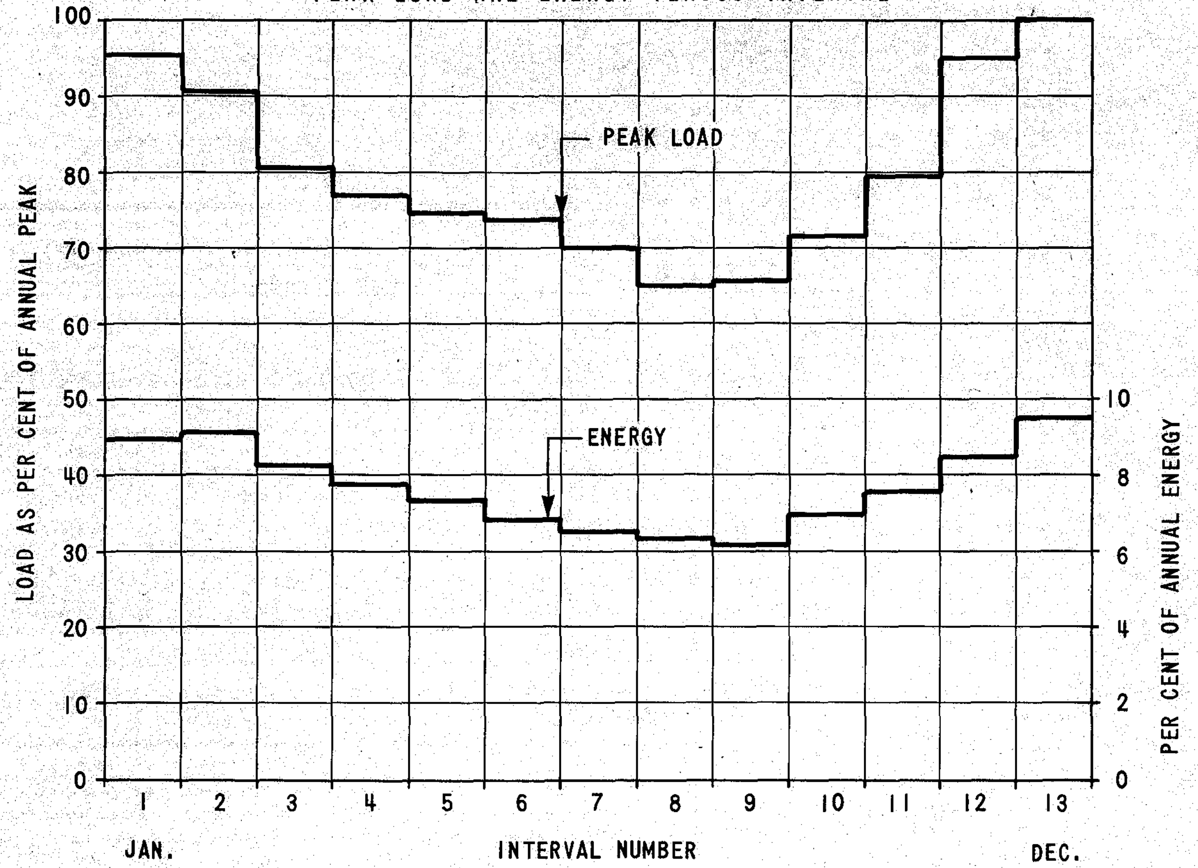
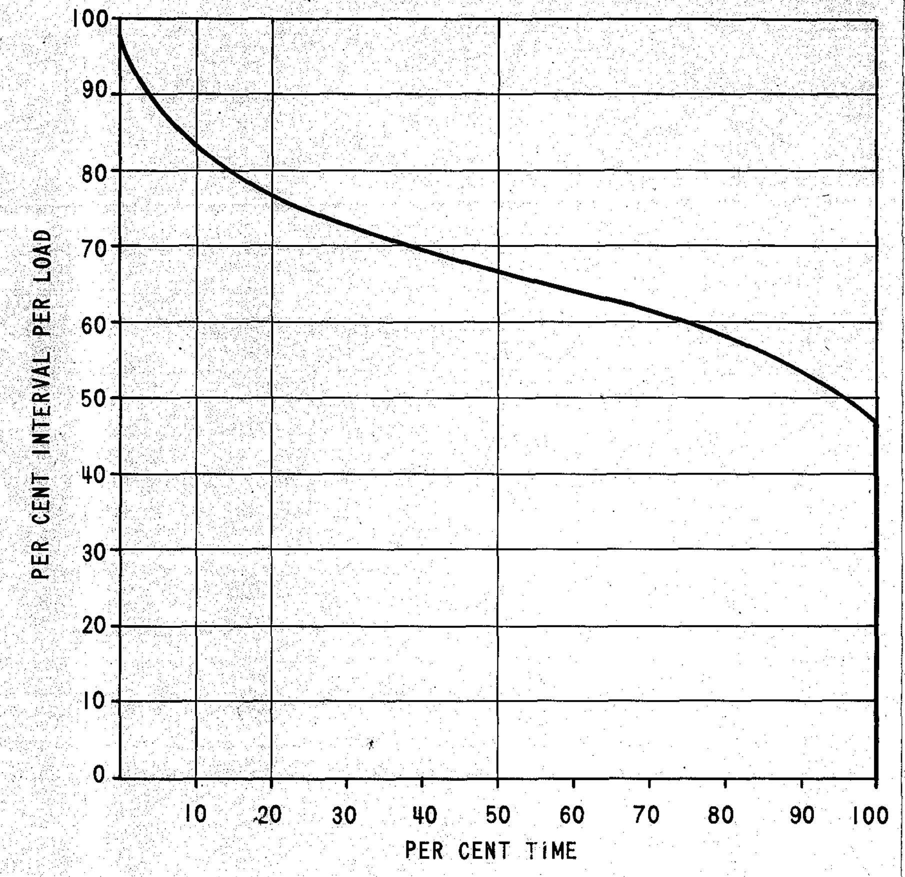
FIGURE 2

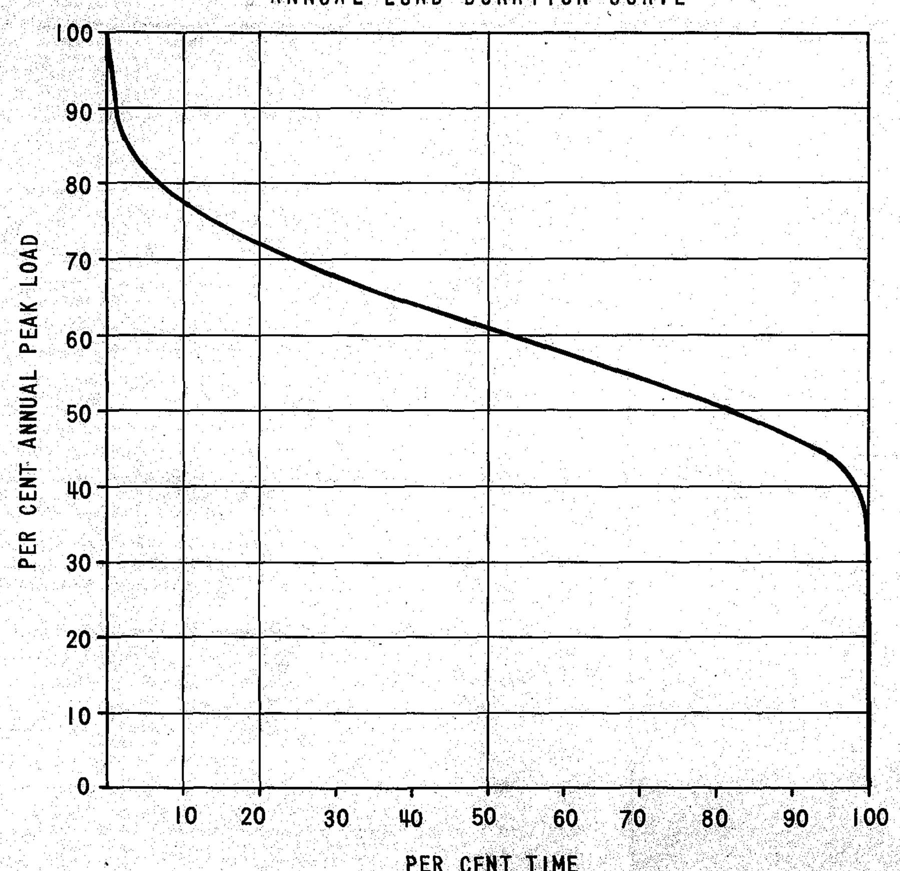
PEAK LOAD AND ENERGY VERSUS INTERVAL



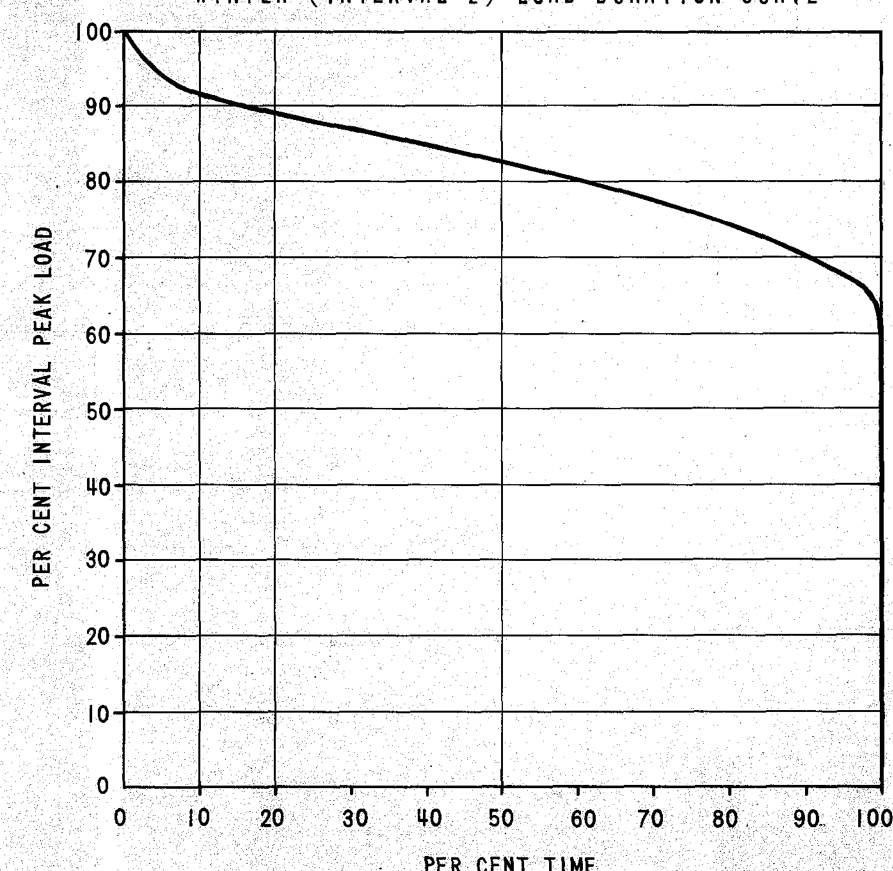
SUMMER (INTERVAL 7) LOAD DURATION CURVE



ANNUAL LOAD DURATION CURVE



WINTER (INTERVAL 2) LOAD DURATION CURVE



LOAD SHAPE
- PEAK BY INTERVAL
- ENERGY BY INTERVAL
- TYPICAL LOAD DURATION CURVES

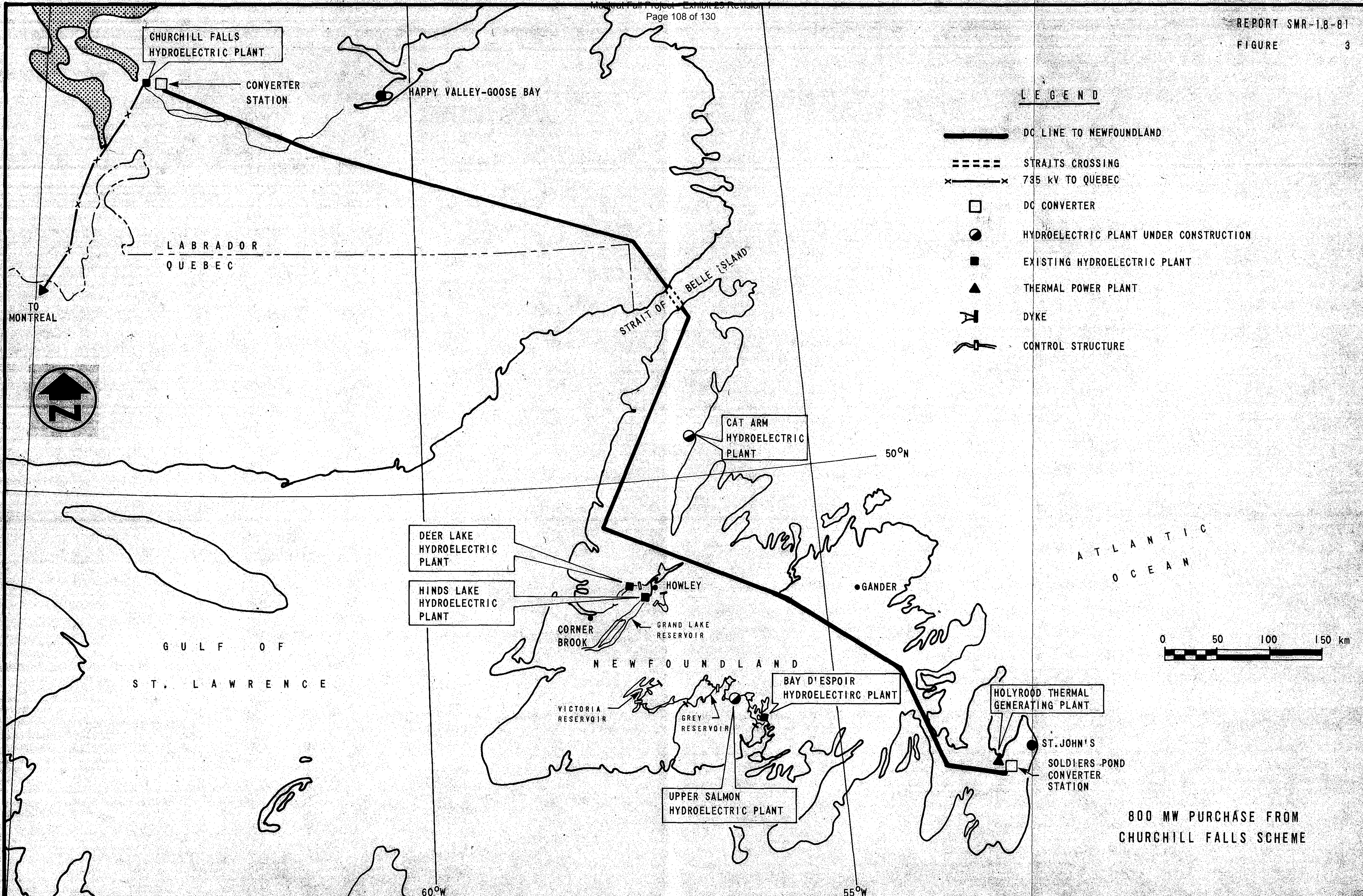

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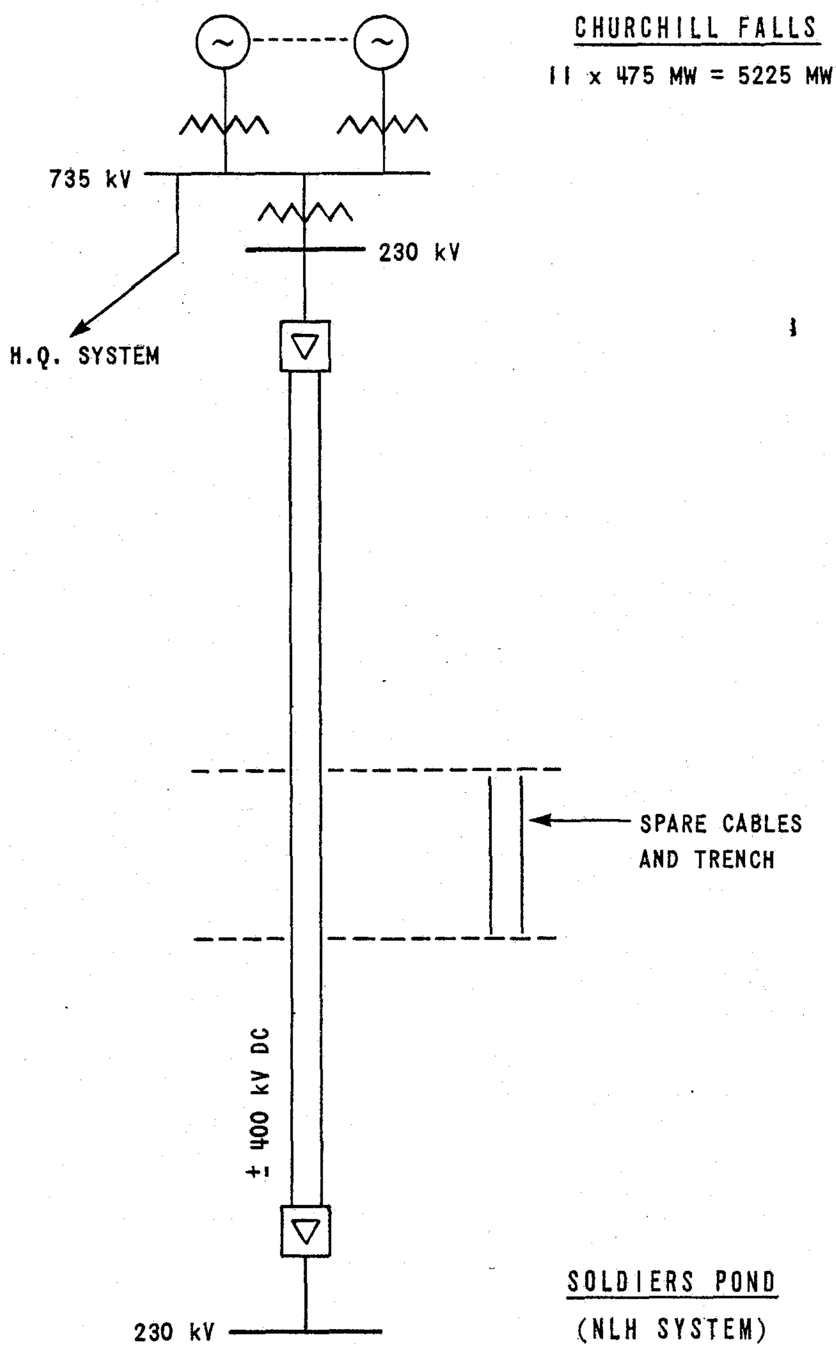
FIGURE 3
LEGEND
DC LINE TO NEWFOUNDLAND
STRAITS CROSSING
735 kV TO QUEBEC
DC CONVERTER
HYDROELECTRIC PLANT UNDER CONSTRUCTION
EXISTING HYDROELECTRIC PLANT
THERMAL POWER PLANT
DYKE
CONTROL STRUCTURE
CHURCHILL FALLS HYDROELECTRIC PLANT
CONVERTER STATION
HAPPY VALLEY-GOOSE BAY
LABRADOR
QUEBEC
TO MONTREAL
STRAIT OF BELLE ISLAND
CAT ARM HYDROELECTRIC PLANT
50°N
DEER LAKE HYDROELECTRIC PLANT
HINDS LAKE HYDROELECTRIC PLANT
HOWLEY
CORNER BROOK
GRAND LAKE RESERVOIR
GANDER
ATLANTIC OCEAN
GULF OF ST. LAWRENCE
NEWFOUNDLAND
VICTORIA RESERVOIR
GREY RESERVOIR
BAY D'ESPOIR HYDROELECTIRC PLANT
UPPER SALMON HYDROELECTRIC PLANT
HOLYROOD THERMAL GENERATING PLANT
ST.JOHN'S
SOLDIERS POND CONVERTER STATION
0 50 100 150 km
60°W
55°W
800 MW PURCHASE FROM CHURCHILL FALLS SCHEME



800 MW PURCHASE ALTERNATIVE
SINGLE LINE DIAGRAM

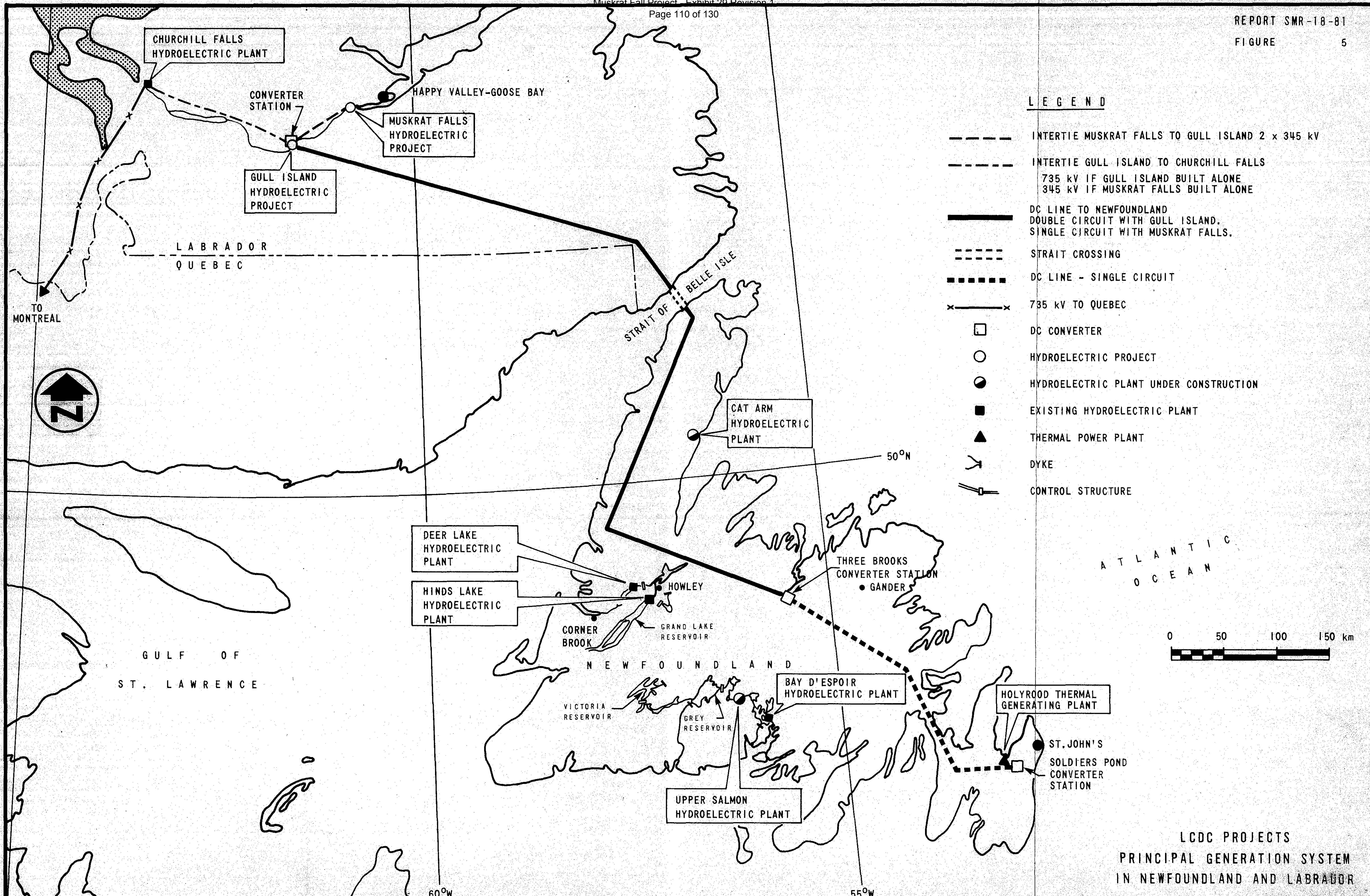

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FIGURE 5
LEGEND
INTERTIE MUSKRAT FALLS TO GULL ISLAND 2 x 345 kV
INTERTIE GULL ISLAND TO CHURCHILL FALLS
735 kV IF GULL ISLAND BUILT ALONE
345 kV IF MUSKRAT FALLS BUILT ALONE
DC LINE TO NEWFOUNDLAND
DOUBLE CIRCUIT WITH GULL ISLAND.
SINGLE CIRCUIT WITH MUSKRAT FALLS.
STRAIT CROSSING
DC LINE - SINGLE CIRCUIT
735 kV TO QUEBEC
DC CONVERTER
HYDROELECTRIC PROJECT
HYDROELECTRIC PLANT UNDER CONSTRUCTION
EXISTING HYDROELECTRIC PLANT
THERMAL POWER PLANT
DYKE
CONTROL STRUCTURE
CHURCHILL FALLS HYDROELECTRIC PLANT
CONVERTER STATION
HAPPY VALLEY-GOOSE BAY
MUSKRAT FALLS HYDROELECTRIC PROJECT
GULL ISLAND HYDROELECTRIC PROJECT
LABRADOR
QUEBEC
TO MONTREAL
STRAIT OF BELLE ISLE
CAT ARM HYDROELECTRIC PLANT
50°N
ATLANTIC OCEAN
DEER LAKE HYDROELECTRIC PLANT
HINDS LAKE HYDROELECTRIC PLANT
HOWLEY
THREE BROOKS CONVERTER STATION
GANDER
CORNER BROOK
GRAND LAKE RESERVOIR
0 50 100 150 km
GULF OF ST. LAWRENCE
NEWFOUNDLAND
BAY D'ESPOIR HYDROELECTRIC PLANT
VICTORIA RESERVOIR
GREY RESERVOIR
HOLYROOD THERMAL GENERATING PLANT
ST. JOHN'S
SOLDIERS POND CONVERTER STATION
UPPER SALMON HYDROELECTRIC PLANT
60°W
55°W
LCDC PROJECTS
PRINCIPAL GENERATION SYSTEM
IN NEWFOUNDLAND AND LABRADOR

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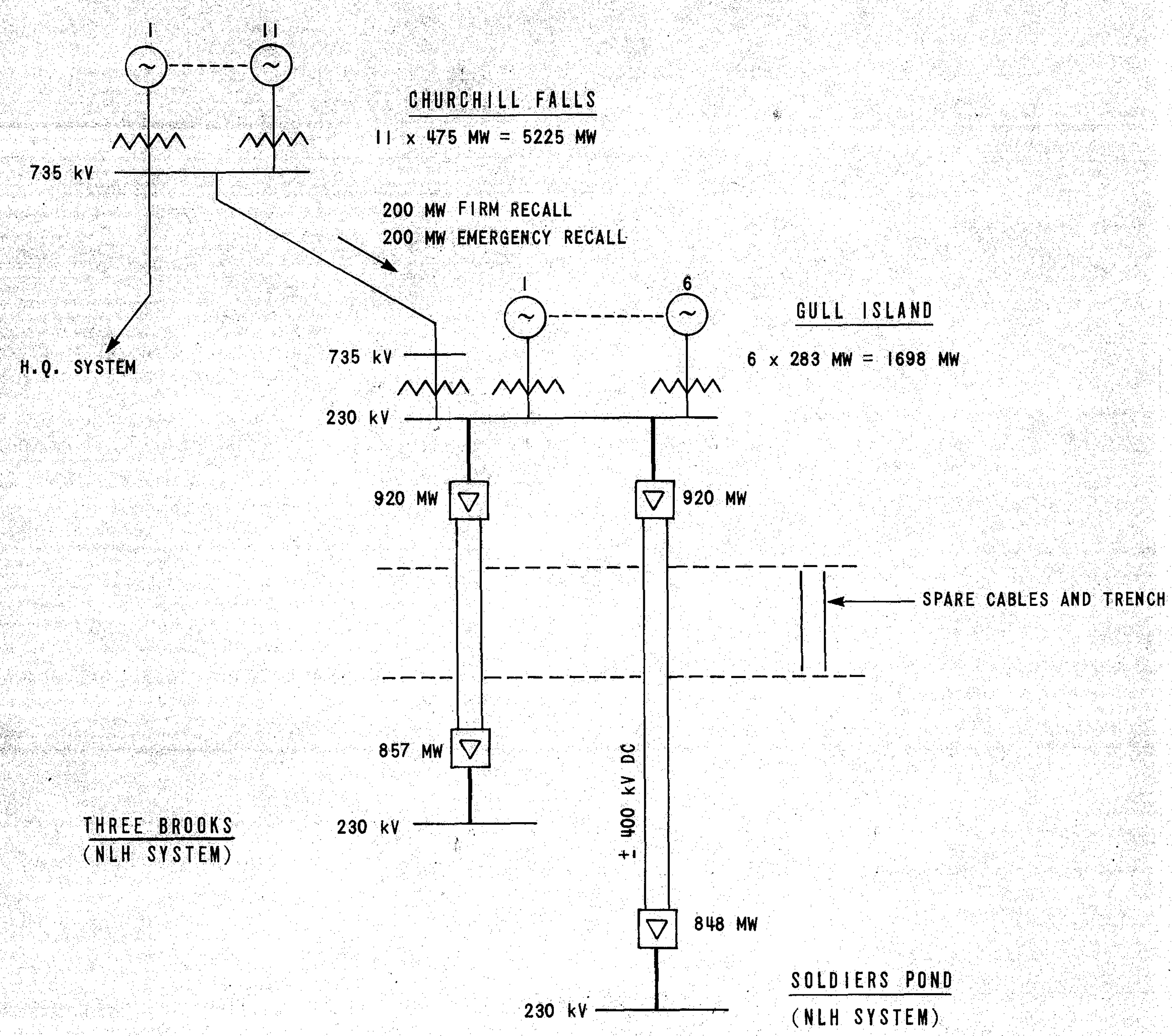
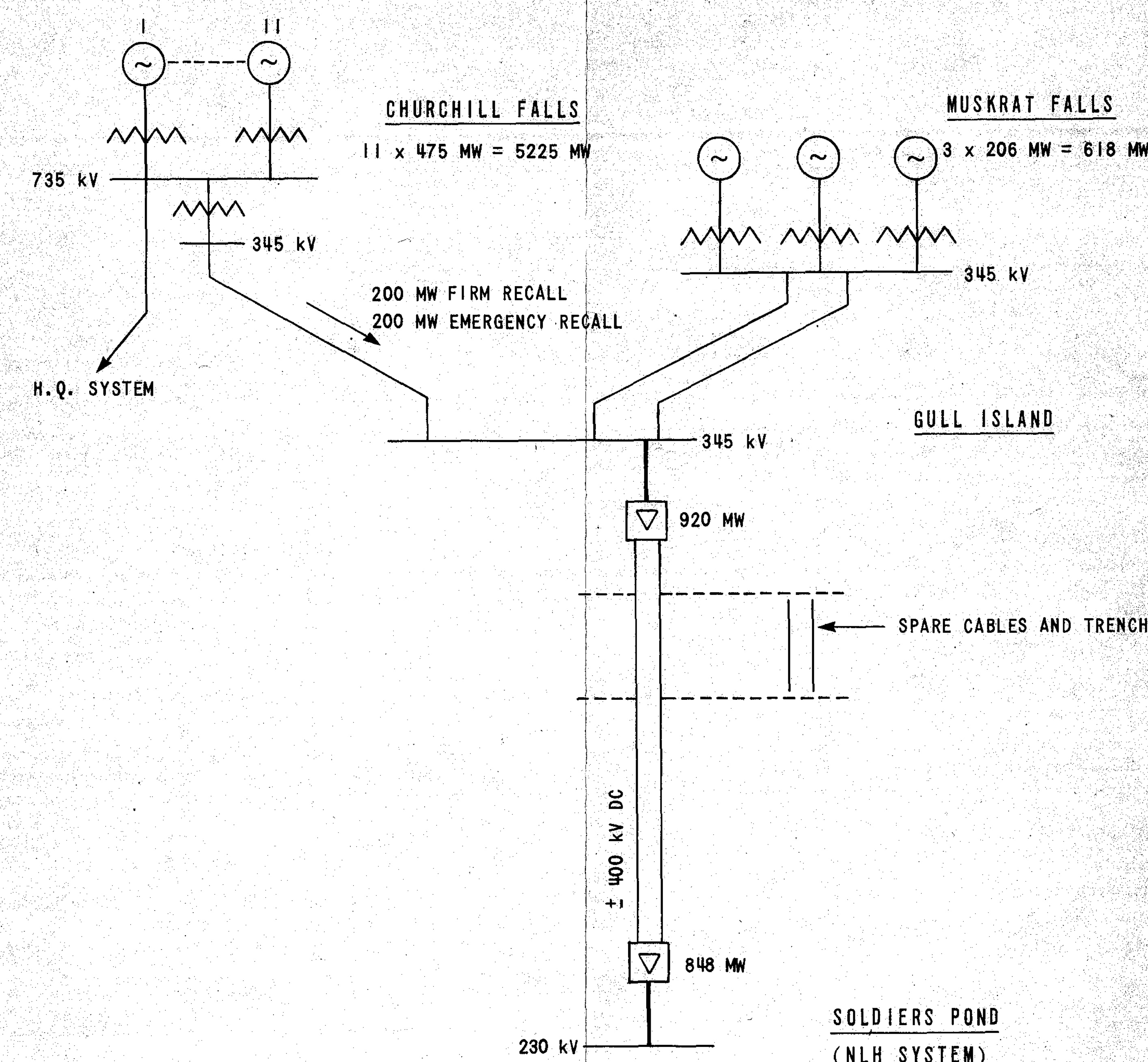
FIGURE 6



6 a) GULL ISLAND ALTERNATIVE



6 b) MUSKRAT FALLS ALTERNATIVE

LCDC PROJECTS
SINGLE LINE DIAGRAMS

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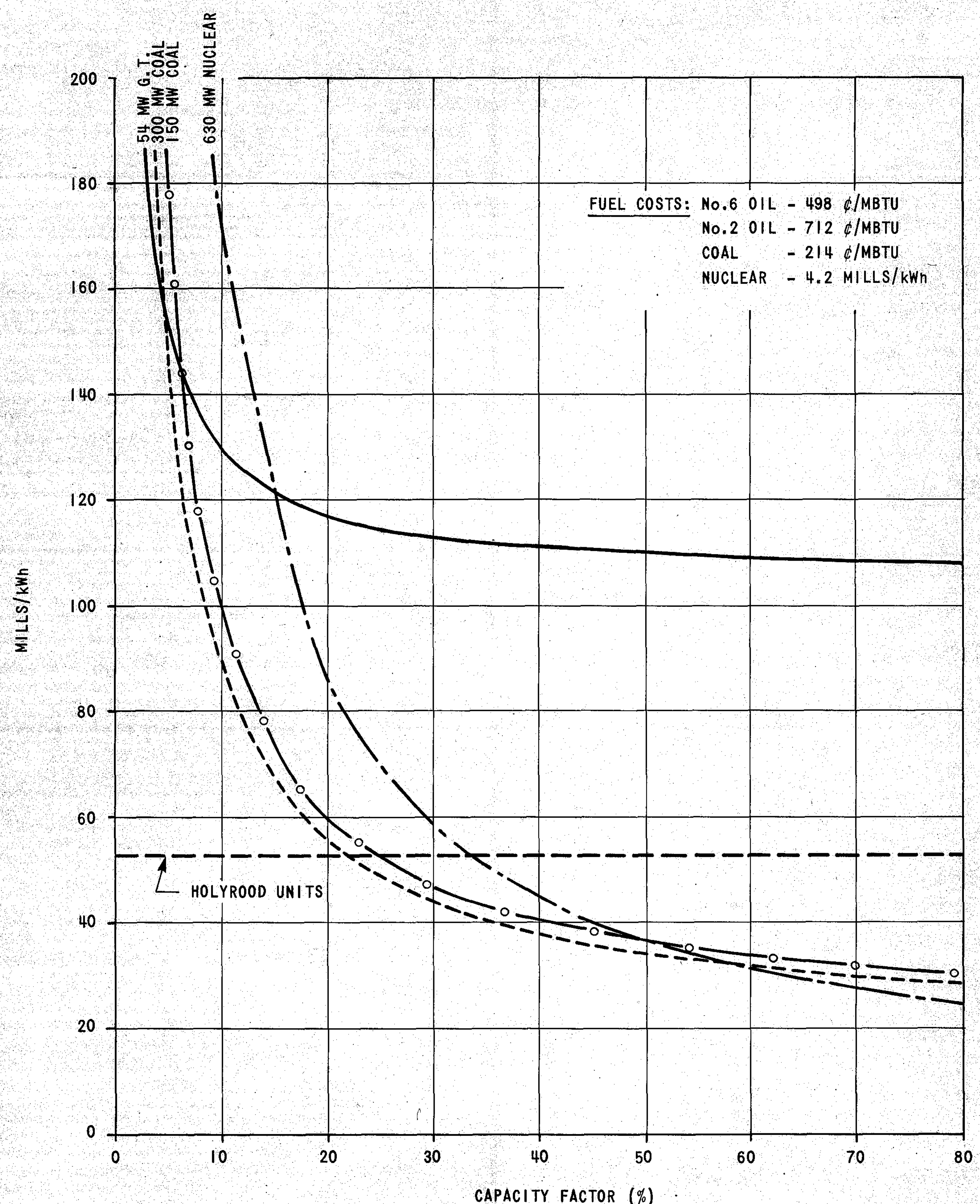
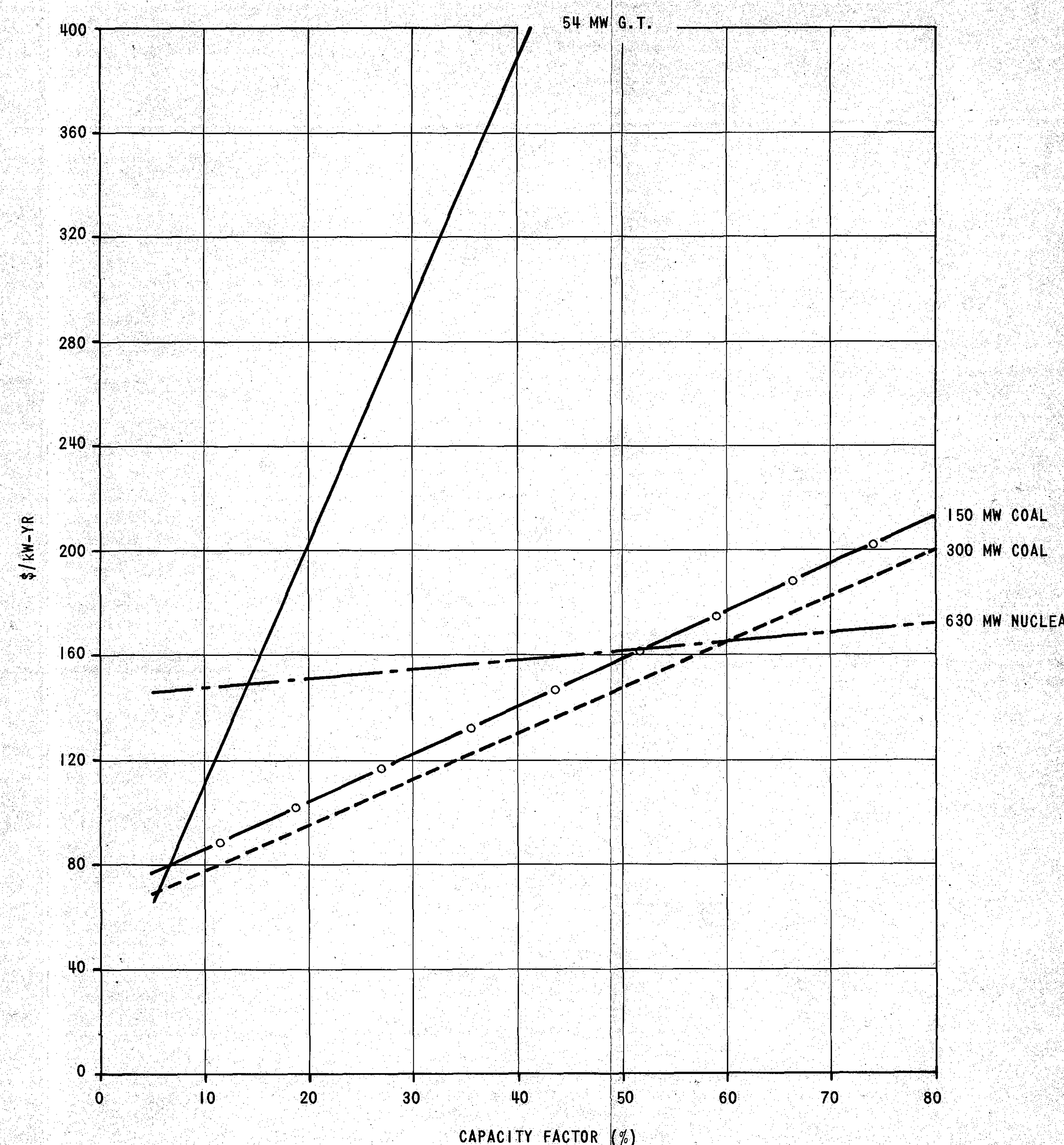
FIGURE 7





SCREENING CURVES
DISCOUNT RATE = 6%

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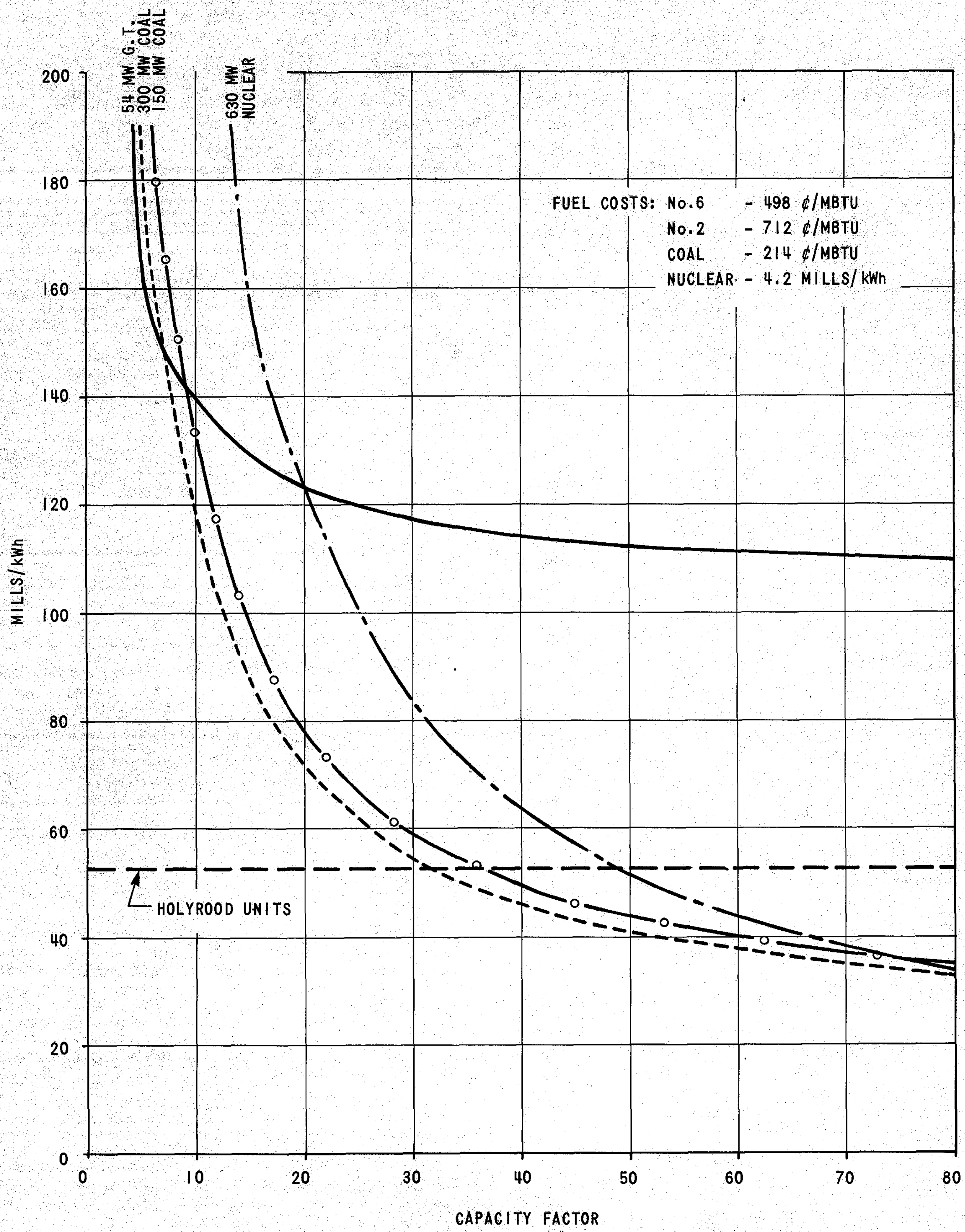
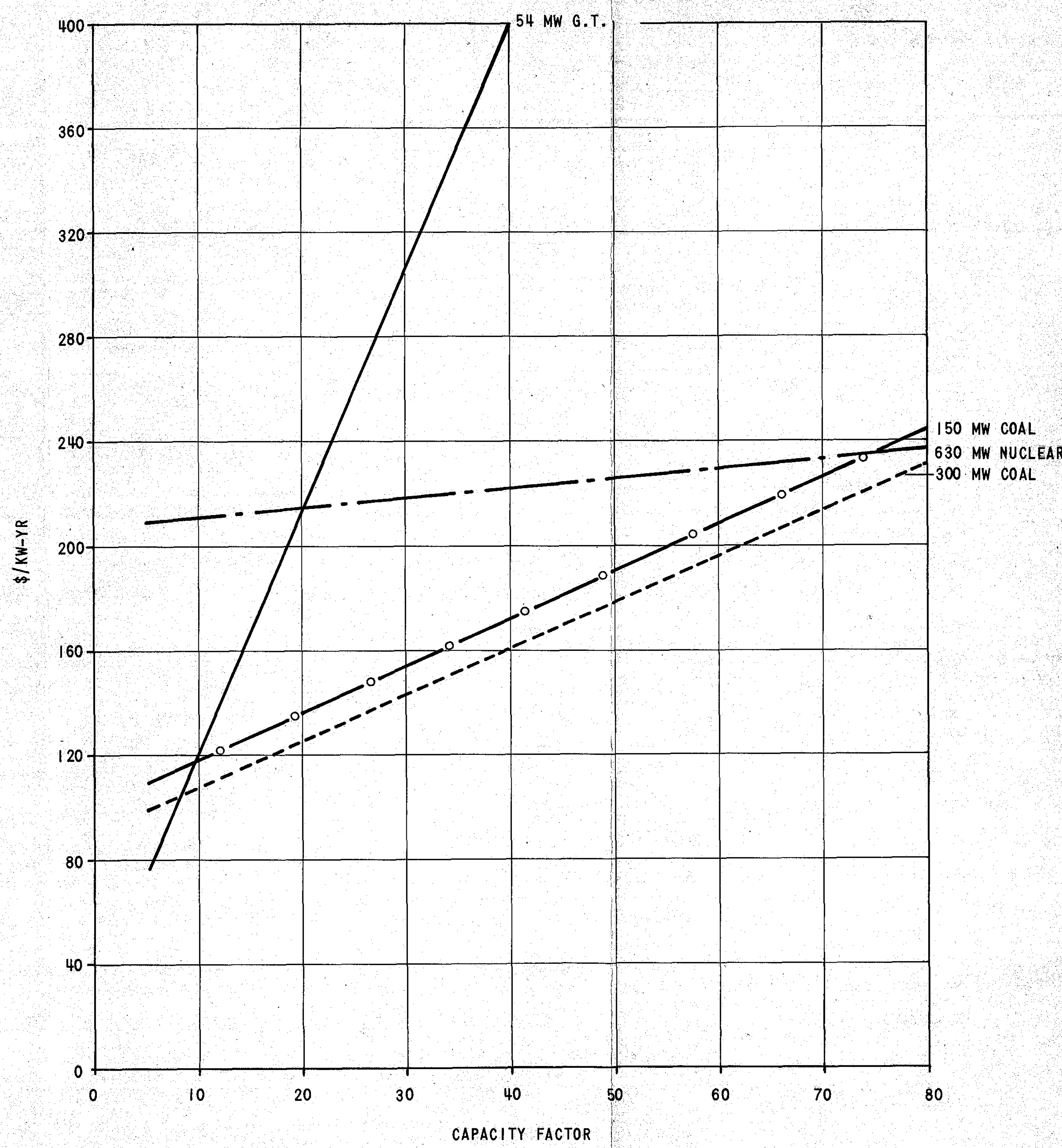
FIGURE 8





SCREENING CURVES
DISCOUNT RATE = 10%

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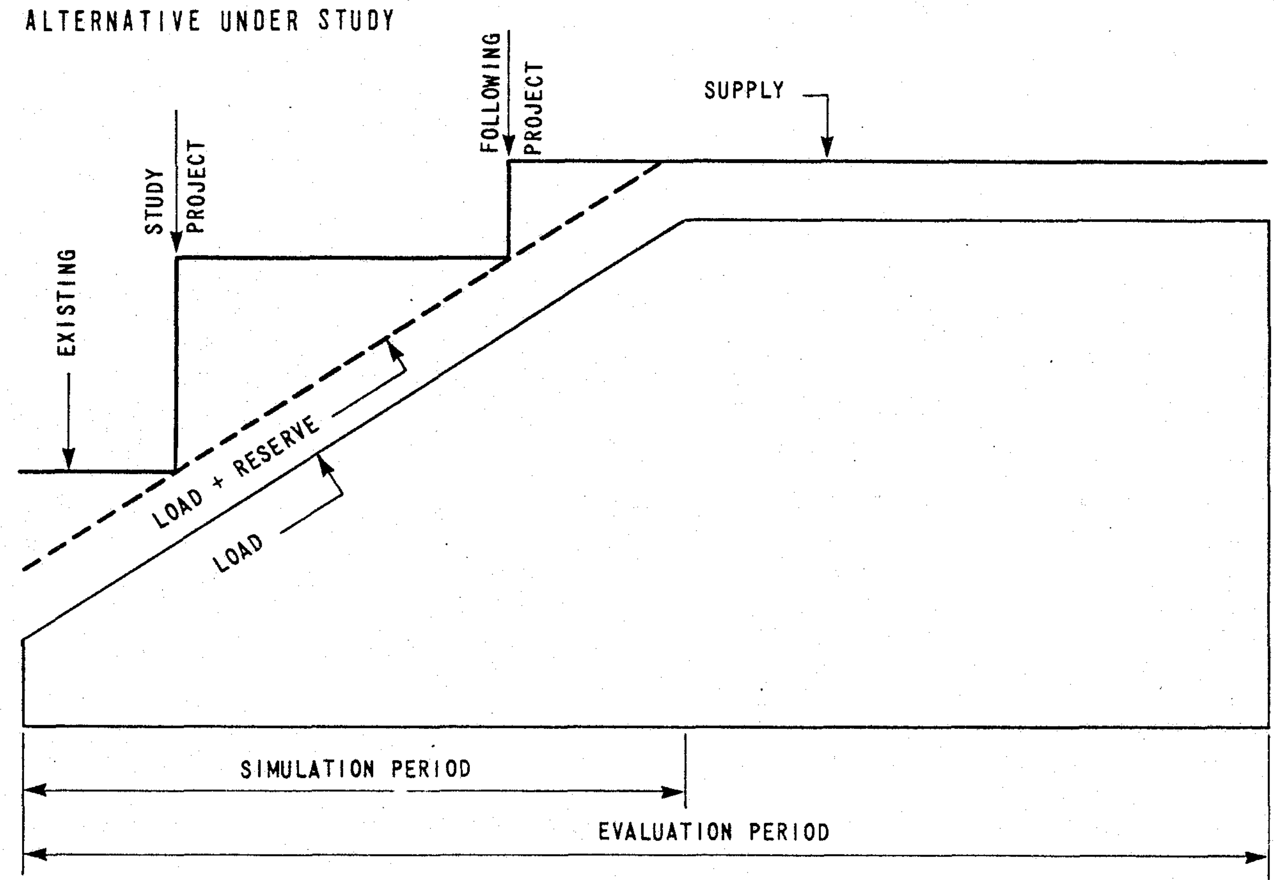
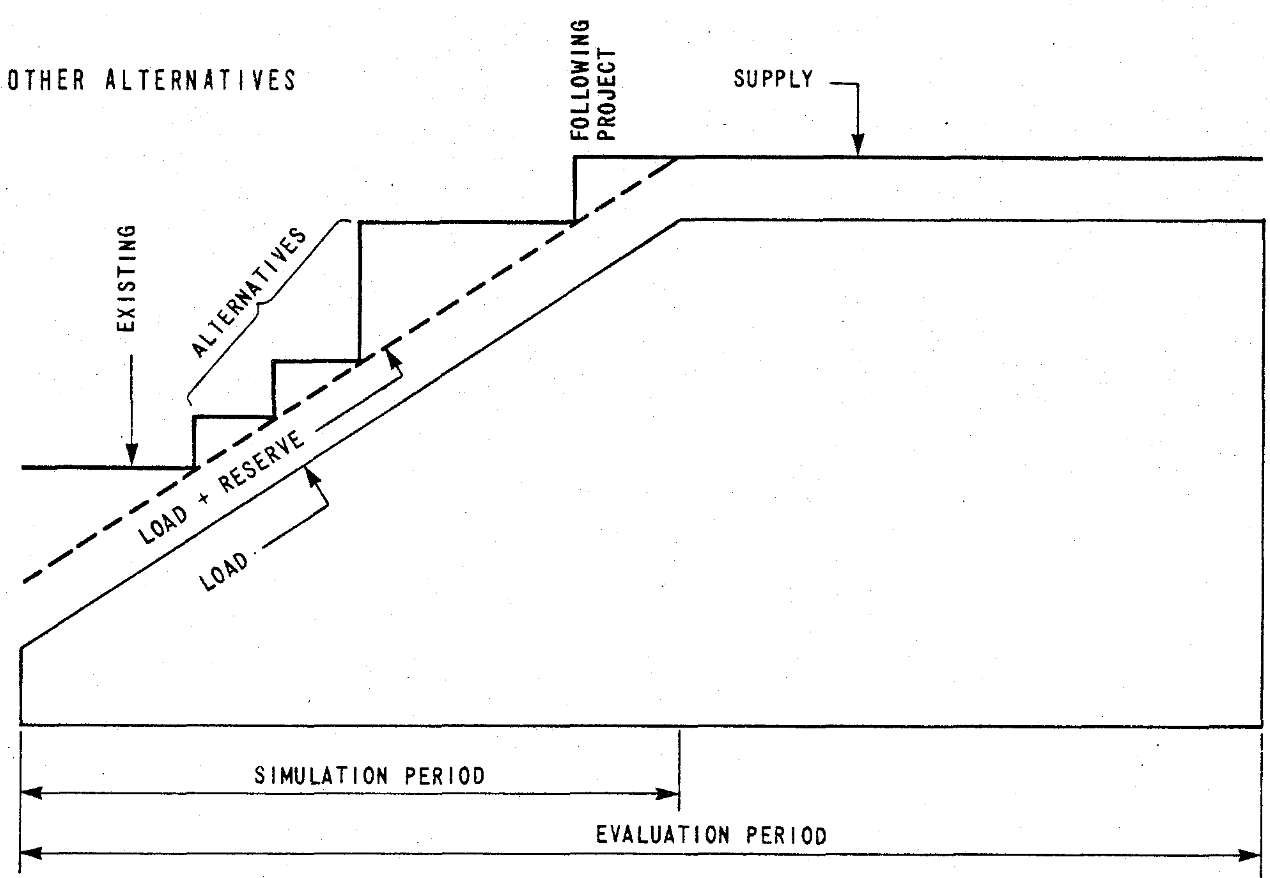
FIGURE 9





COMPARISON METHOD

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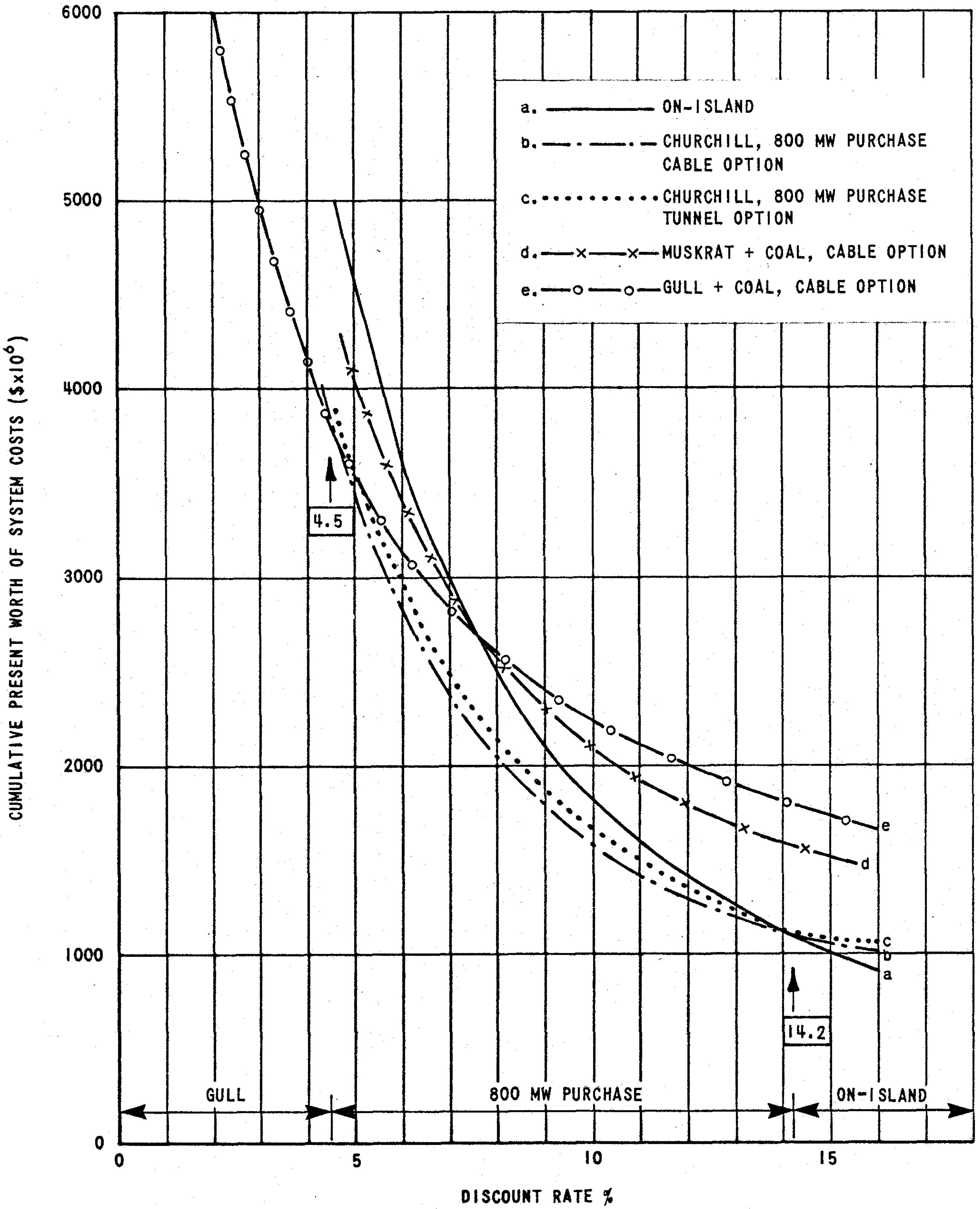
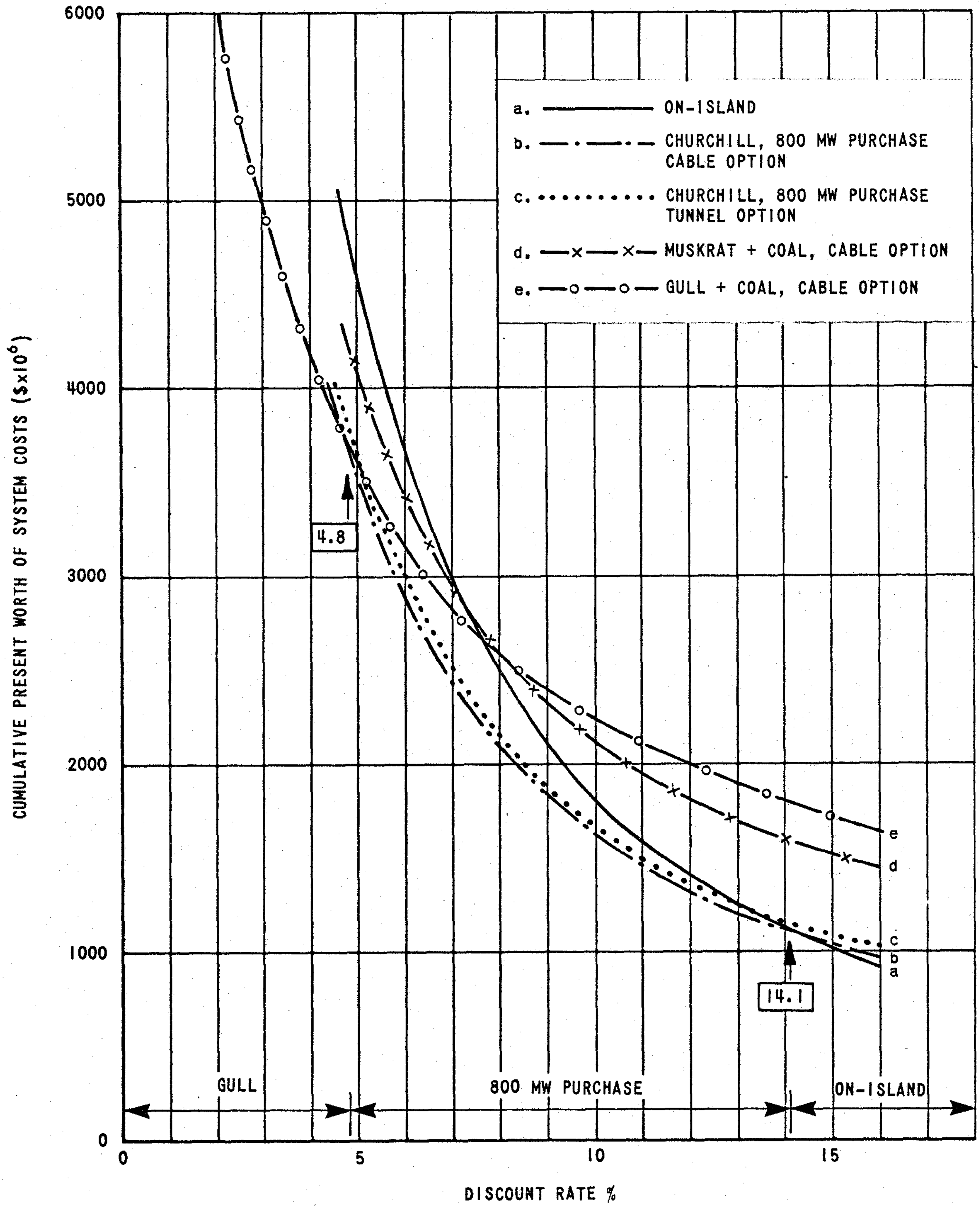
FIGURE 10



COMPARISON OF ALTERNATIVES, DECISION 1980,
NLH LOAD FORECAST,
PRICE OF PURCHASE POWER AT CHURCHILL FALLS = 4.0 MILLS/kWh
DECLINING AT 10% PER ANNUM IN REAL TERMS



COMPARISON OF ALTERNATIVES, DECISION 1980,
NLH LOAD FORECAST,
PRICE OF PURCHASE POWER AT CHURCHILL FALLS = 4.0 MILLS/kWh
DECLINING AT 5% PER ANNUM REAL TERMS

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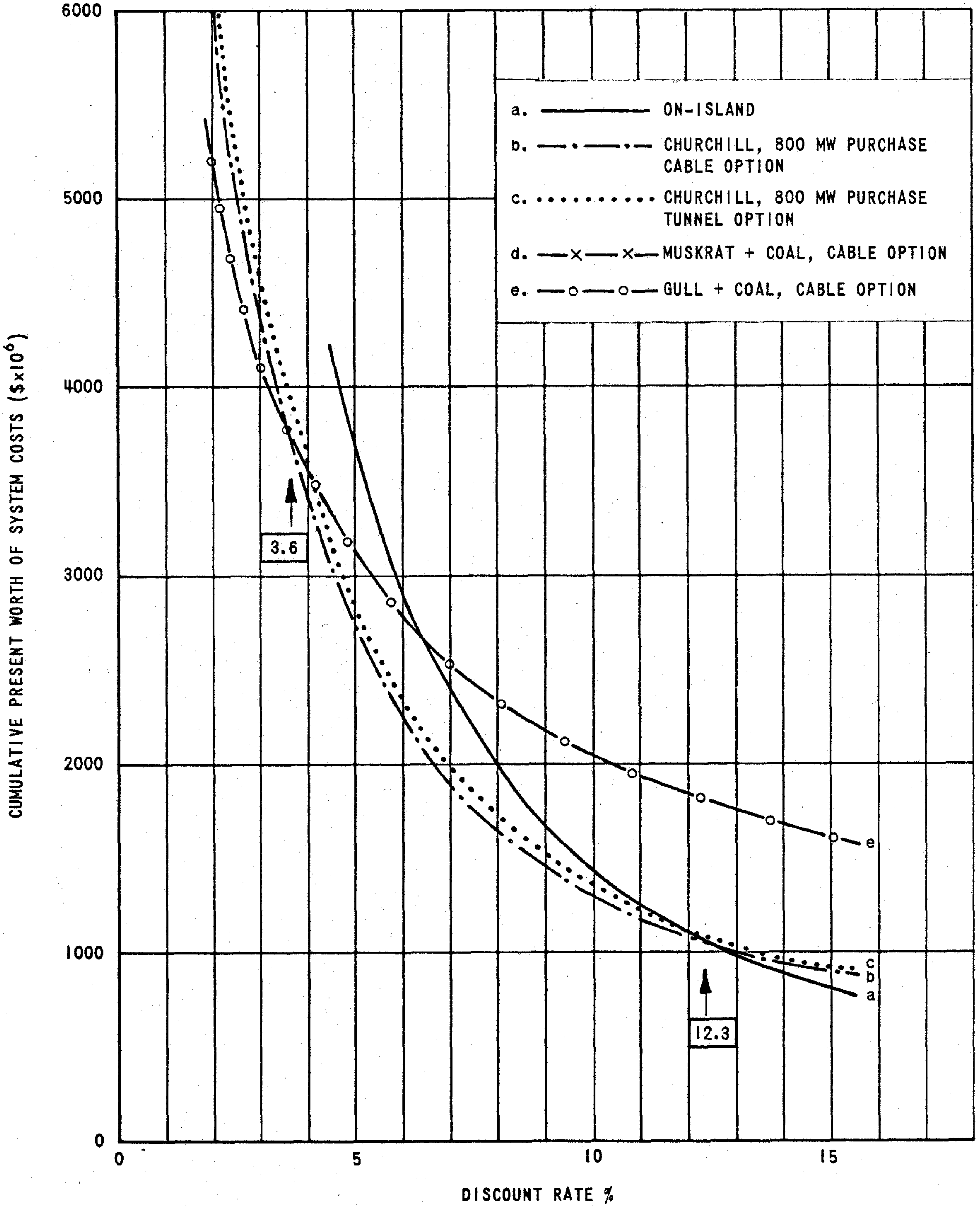
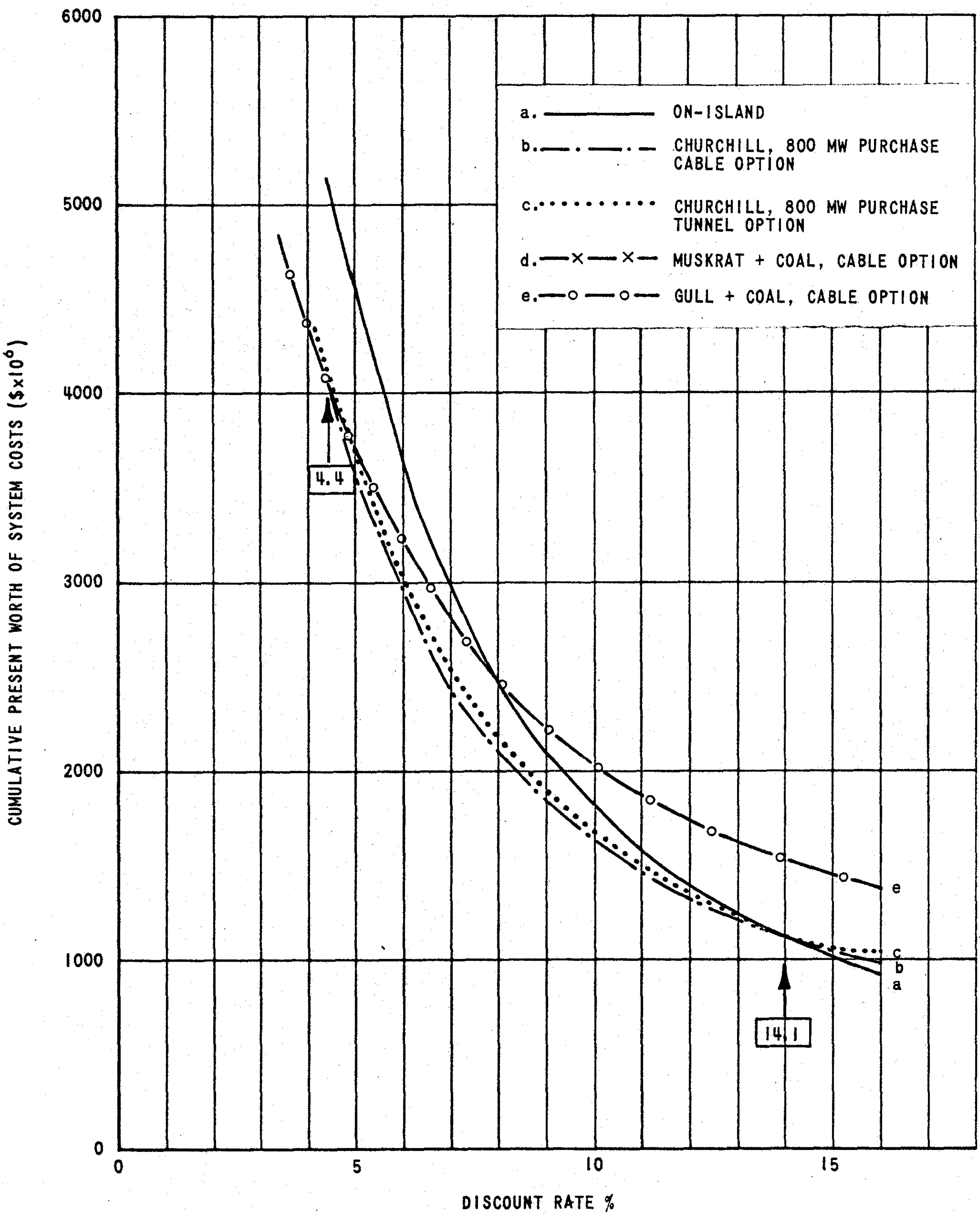
FIGURE 12



COMPARISON OF ALTERNATIVES, DECISION 1980,
MODIFIED LOAD FORECAST
PRICE OF PURCHASE POWER AT CHURCHILL FALLS = 4.0 MILLS/kWh
DECLINING AT 10% PER ANNUM IN REAL TERMS



COMPARISON OF ALTERNATIVES,
DECISION 1985, NLH LOAD FORECAST

PRICE OF PURCHASE POWER AT CHURCHILL FALLS = 4.0 MILLS/kWh
DECLINING AT 10% PER ANNUM IN REAL TERMS

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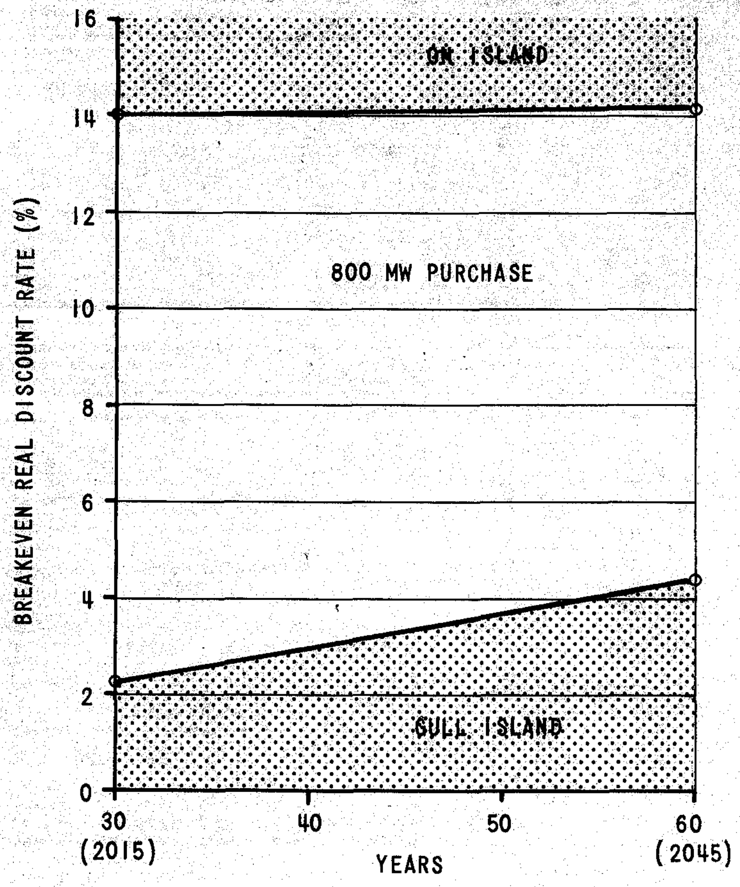
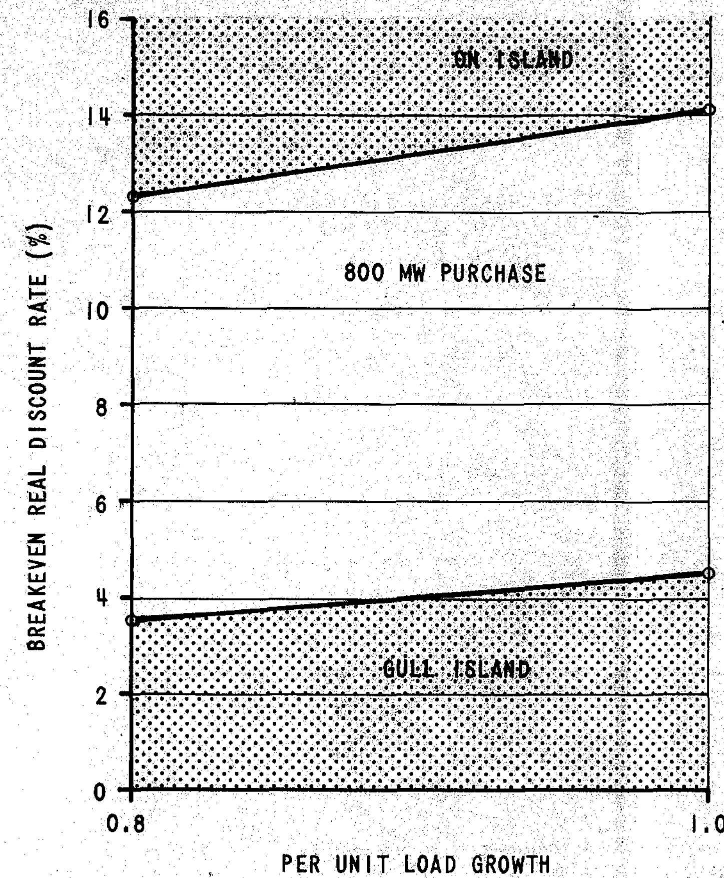
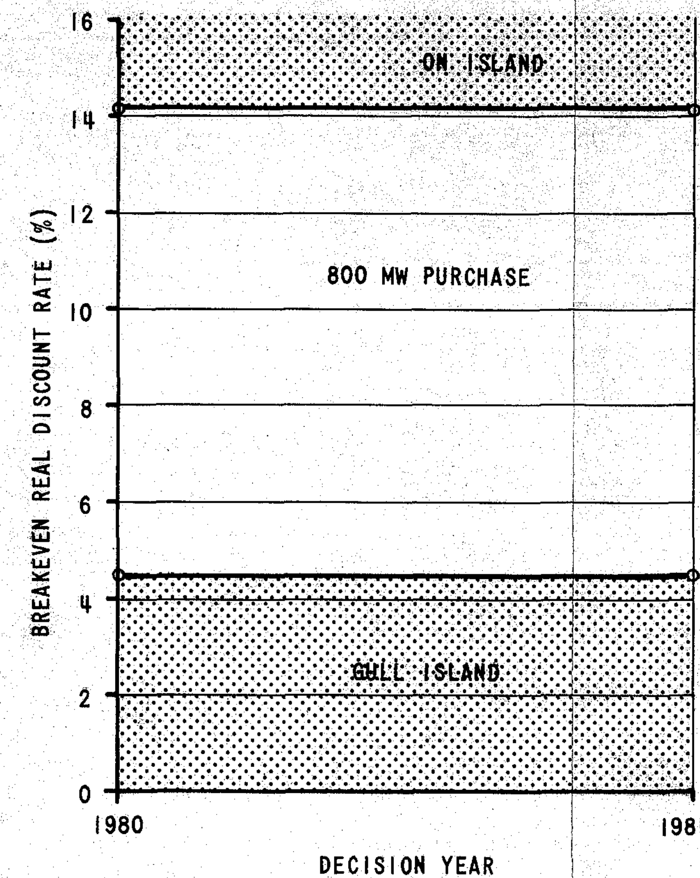
FIGURE 14



a) EFFECT OF EVALUATION PERIOD

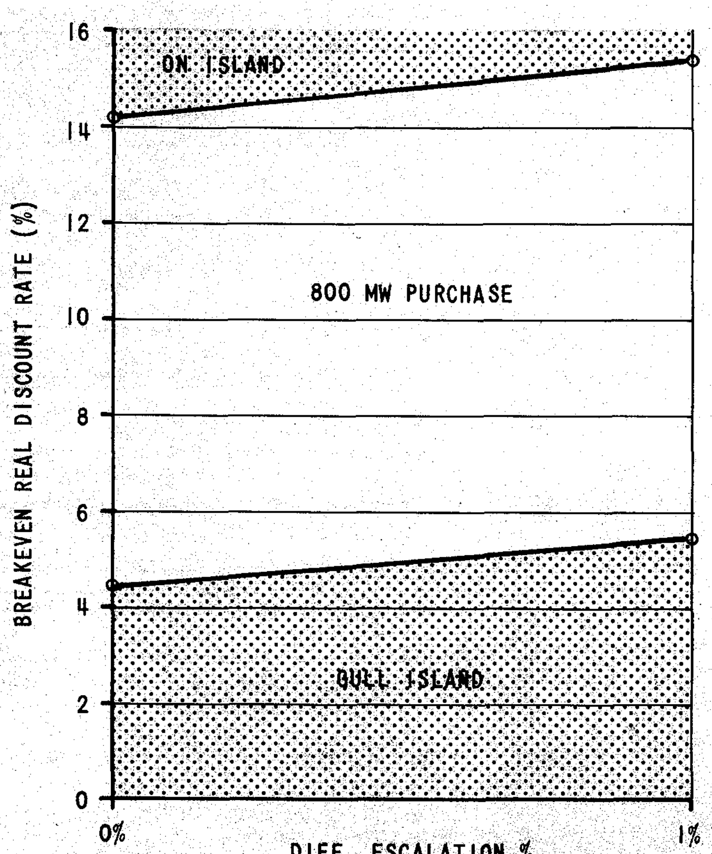


b) EFFECT OF LOAD GROWTH

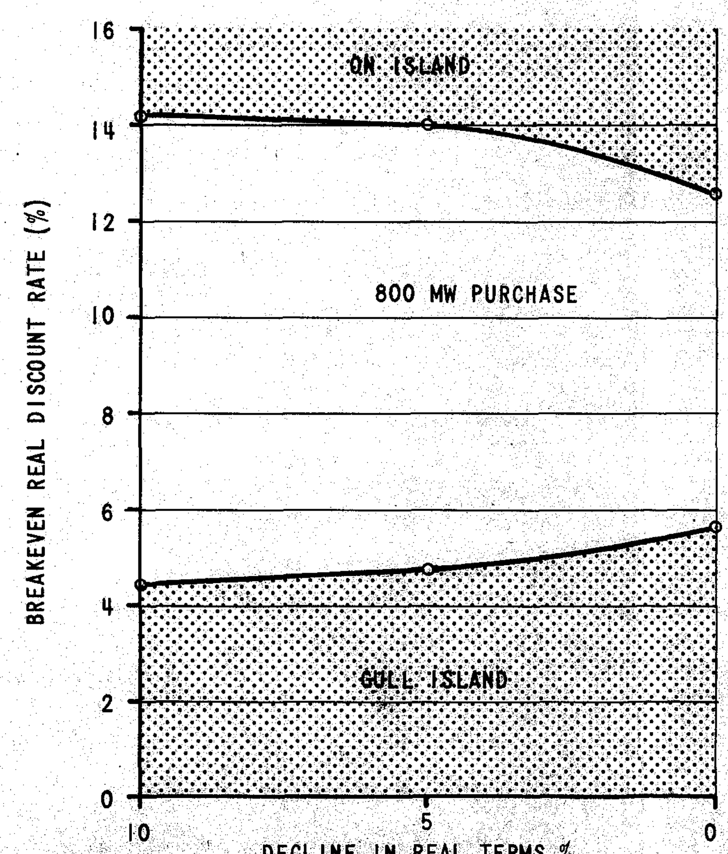


c) EFFECT OF DELAY IN DECISION TO PROCEED

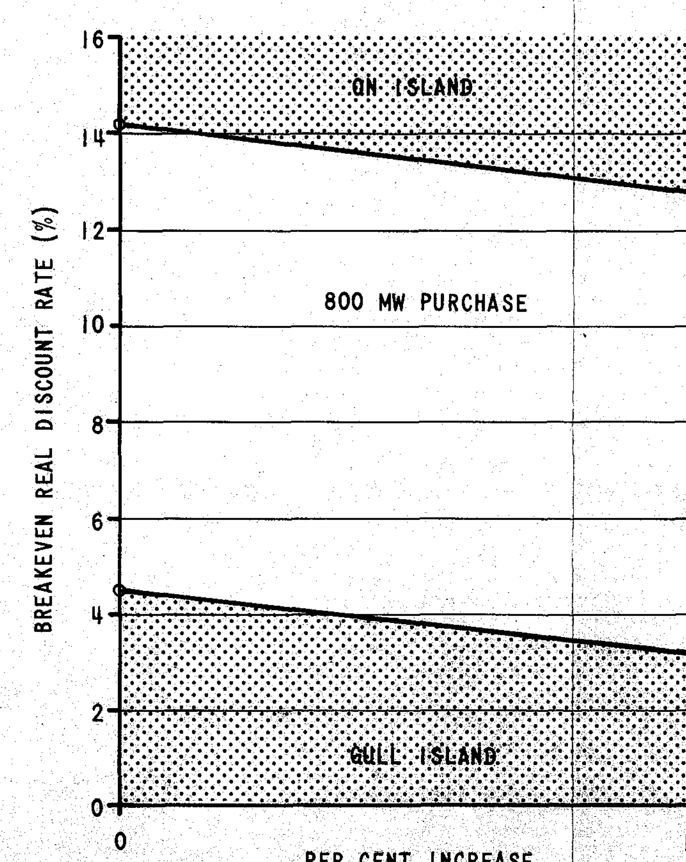
NOTE: FIGURES 14a,b,c,d AND f ARE BASED ON PURCHASE POWER COST DECLINING AT 10% IN REAL TERMS



d) EFFECT OF DIFF. ESCALATION IN COAL COSTS

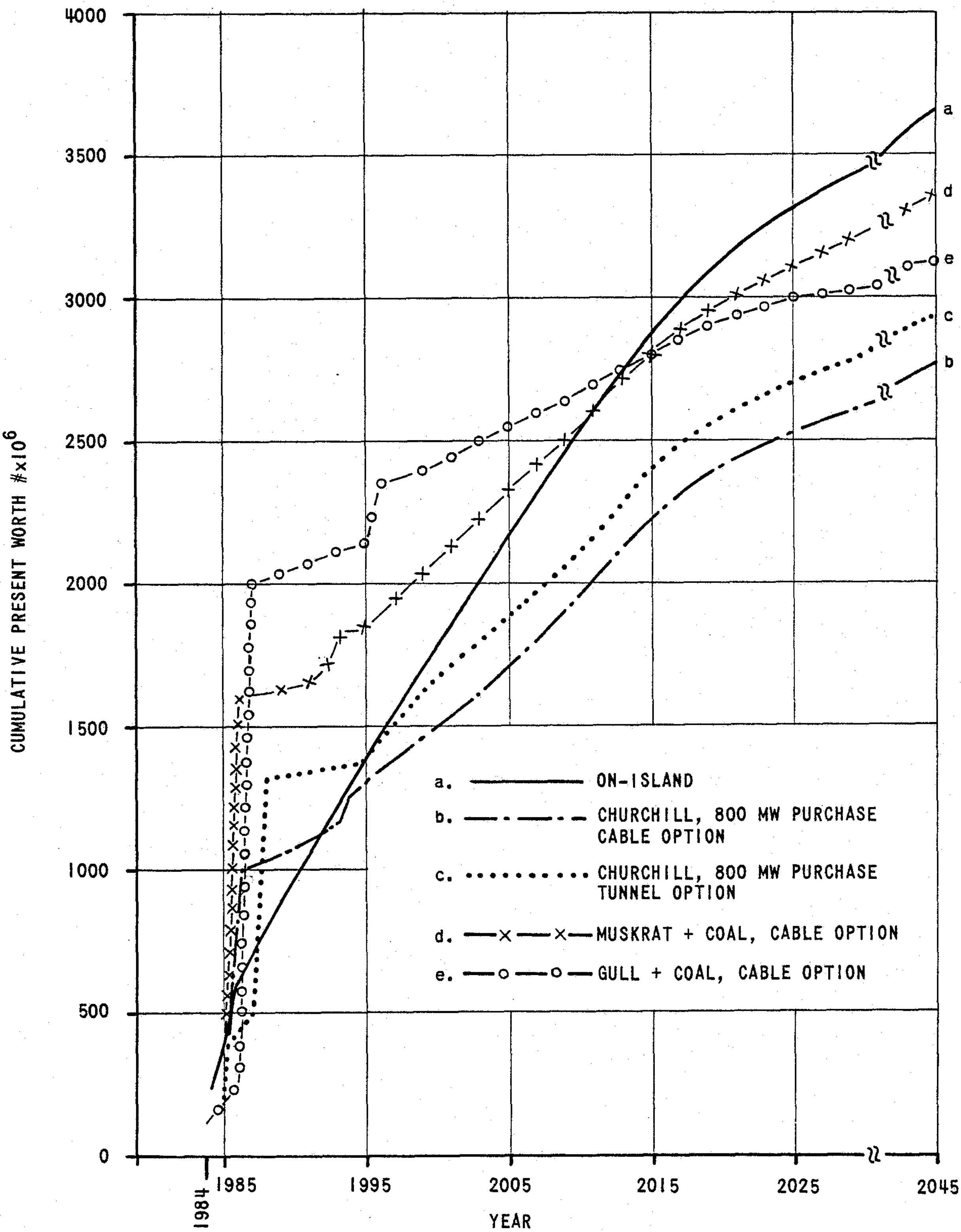


e) EFFECT OF PURCHASE POWER COSTS DECLINING IN REAL TERMS

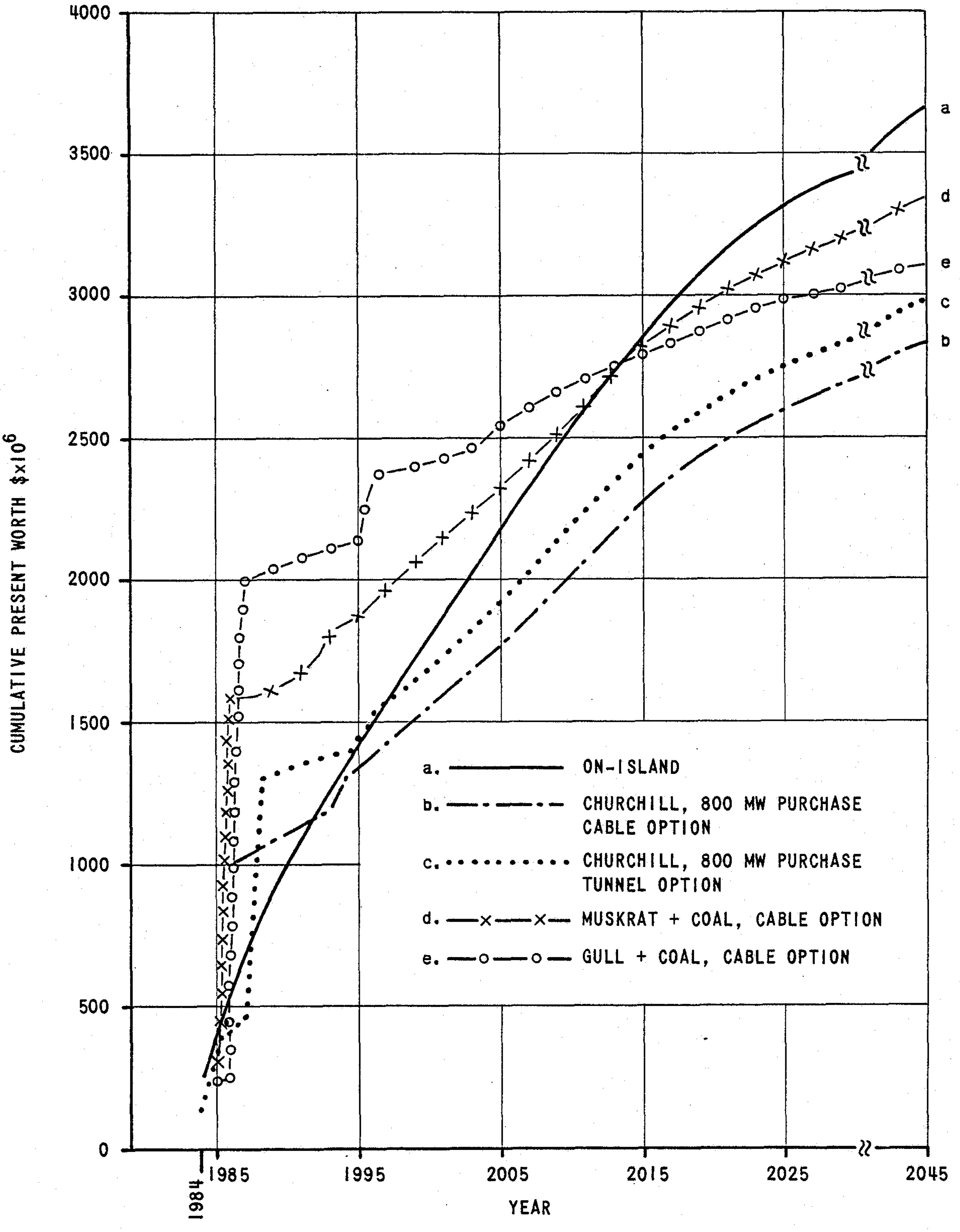


f) EFFECT OF INCREASE IN LABRADOR CAPITAL COSTS

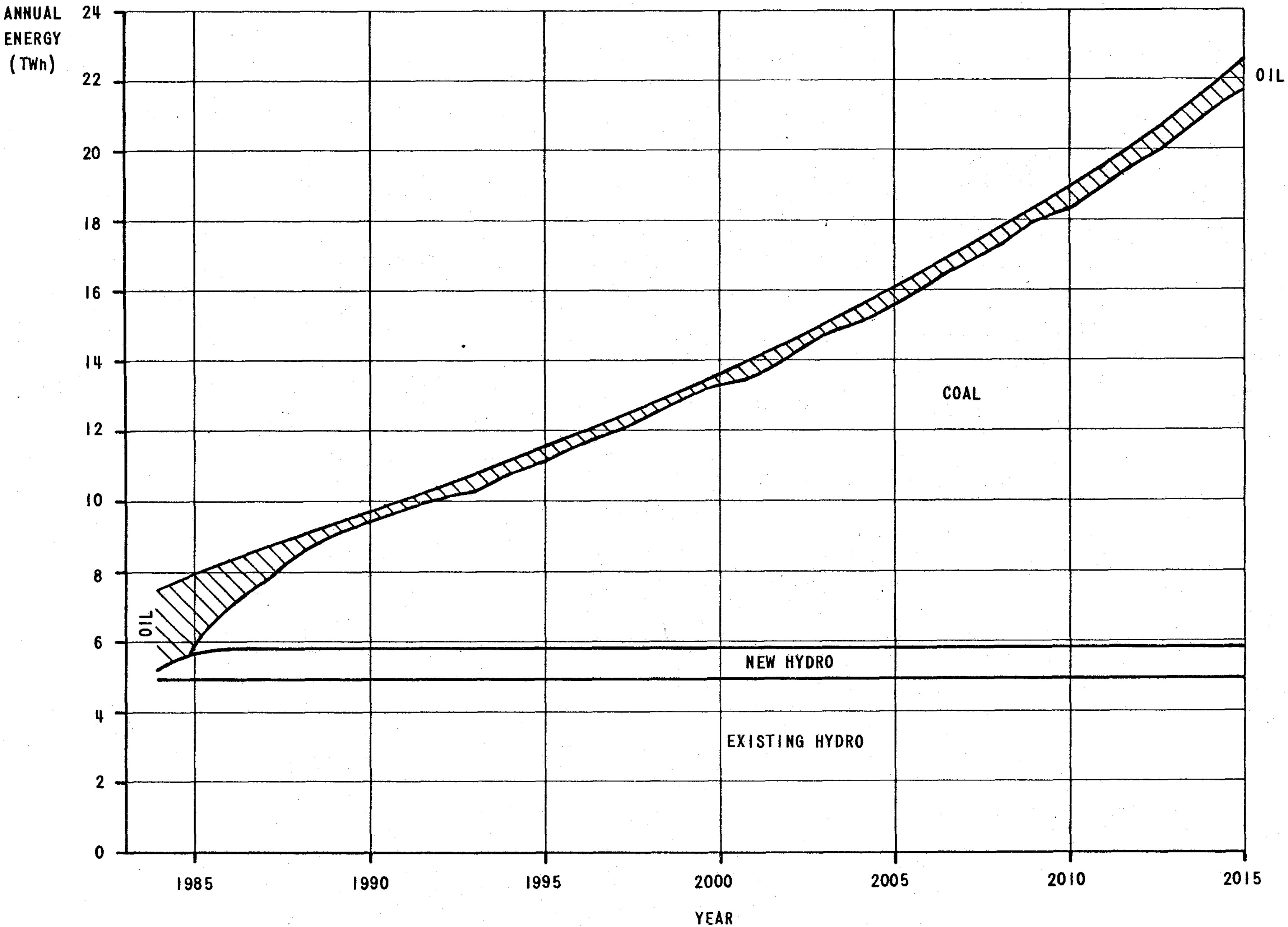
COMPARISON OF ALTERNATIVES
SENSITIVITY TO
VARIOUS PARAMETERS



COMPARISON OF CUMULATIVE PRESENT WORTH
OF SYSTEM COSTS OVER TIME AT 6% REAL DISCOUNT RATE
DECISION 1980, NLH FORECAST
PRICE OF PURCHASE POWER AT CHURCHILL FALLS = 4.0 MILLS/kWh
DECLINING AT 10% PER ANNUM IN REAL TERMS



COMPARISON OF CUMULATIVE PRESENT WORTH
OF SYSTEM COSTS OVER TIME AT 6% REAL DISCOUNT RATE
DECISION 1980, NLH FORECAST
PRICE OF PURCHASE POWER AT CHURCHILL FALLS = 4.0 MILLS/kWh
DECLINING AT 5% PER ANNUM IN REAL TERMS



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SYSTEM ENERGY USE - DECISION 1980, NLH LOAD FORECAST
ON ISLAND ALTERNATIVE

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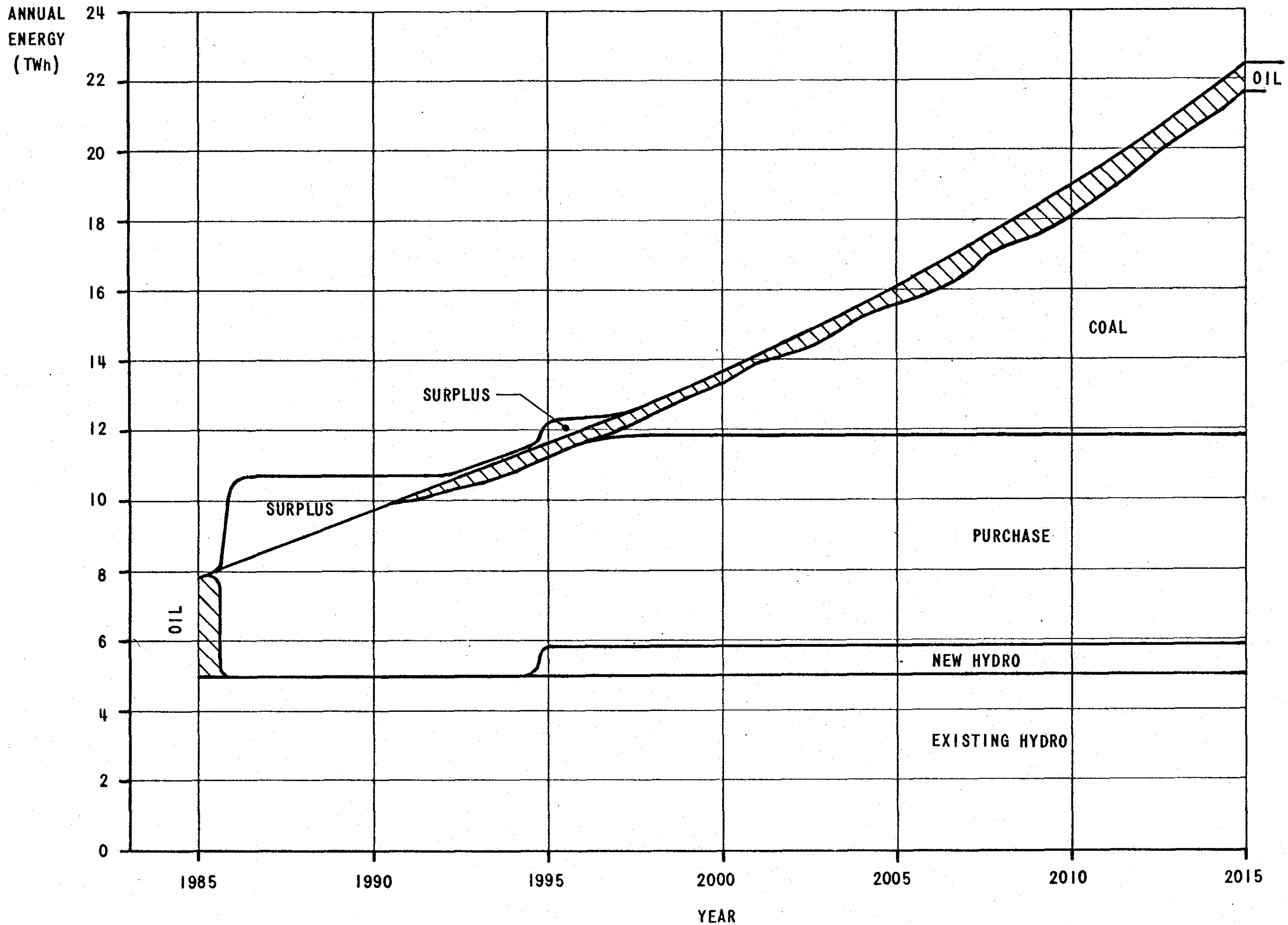
FIGURE 17



SYSTEM ENERGY USE - DECISION 1980, NLH LOAD FORECAST
800 MW PURCHASE - CABLE OPTION

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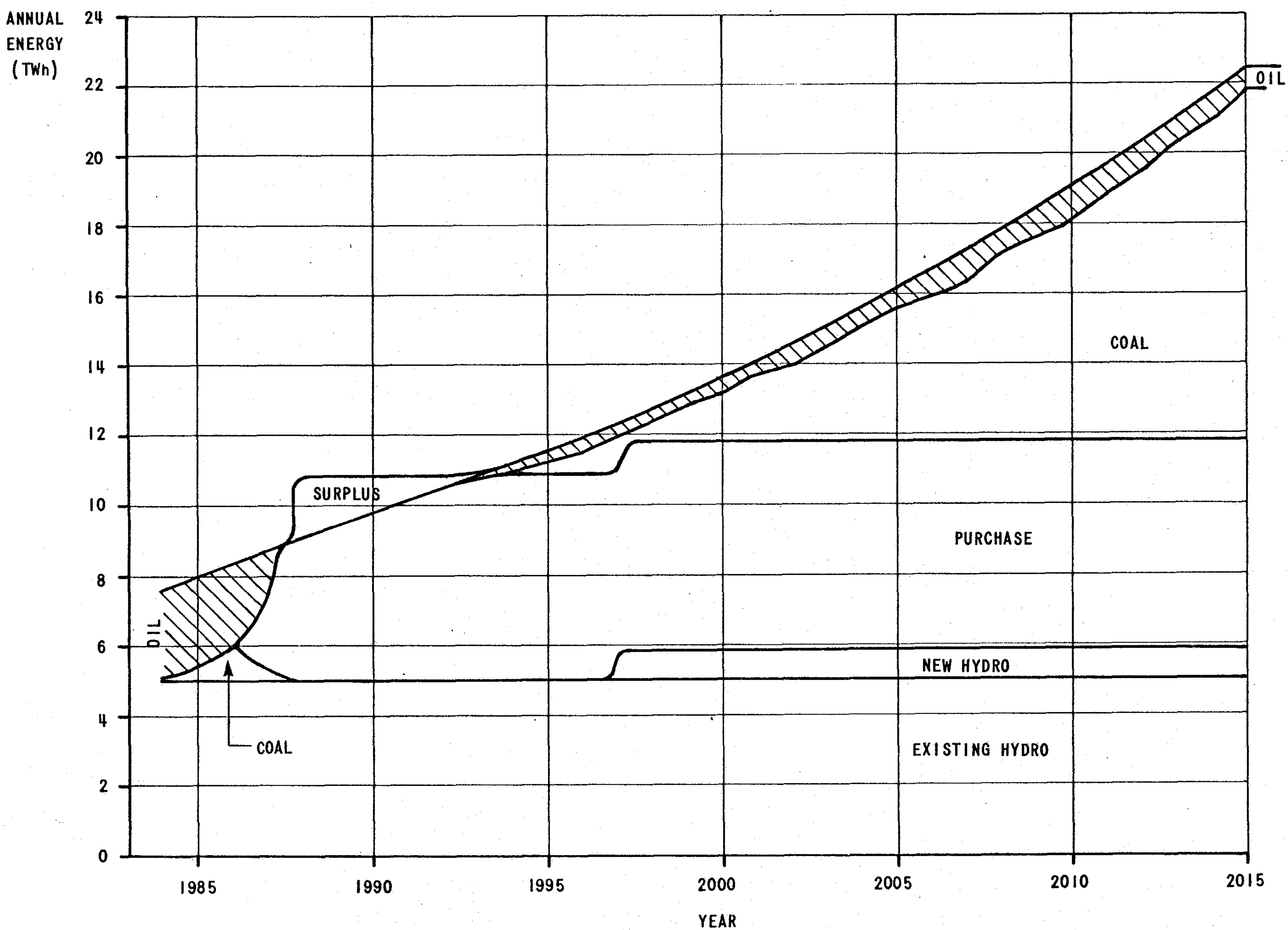
FIGURE 18



SYSTEM ENERGY USE - DECISION 1980, NLH LOAD FORECAST
800 MW PURCHASE - TUNNEL OPTION

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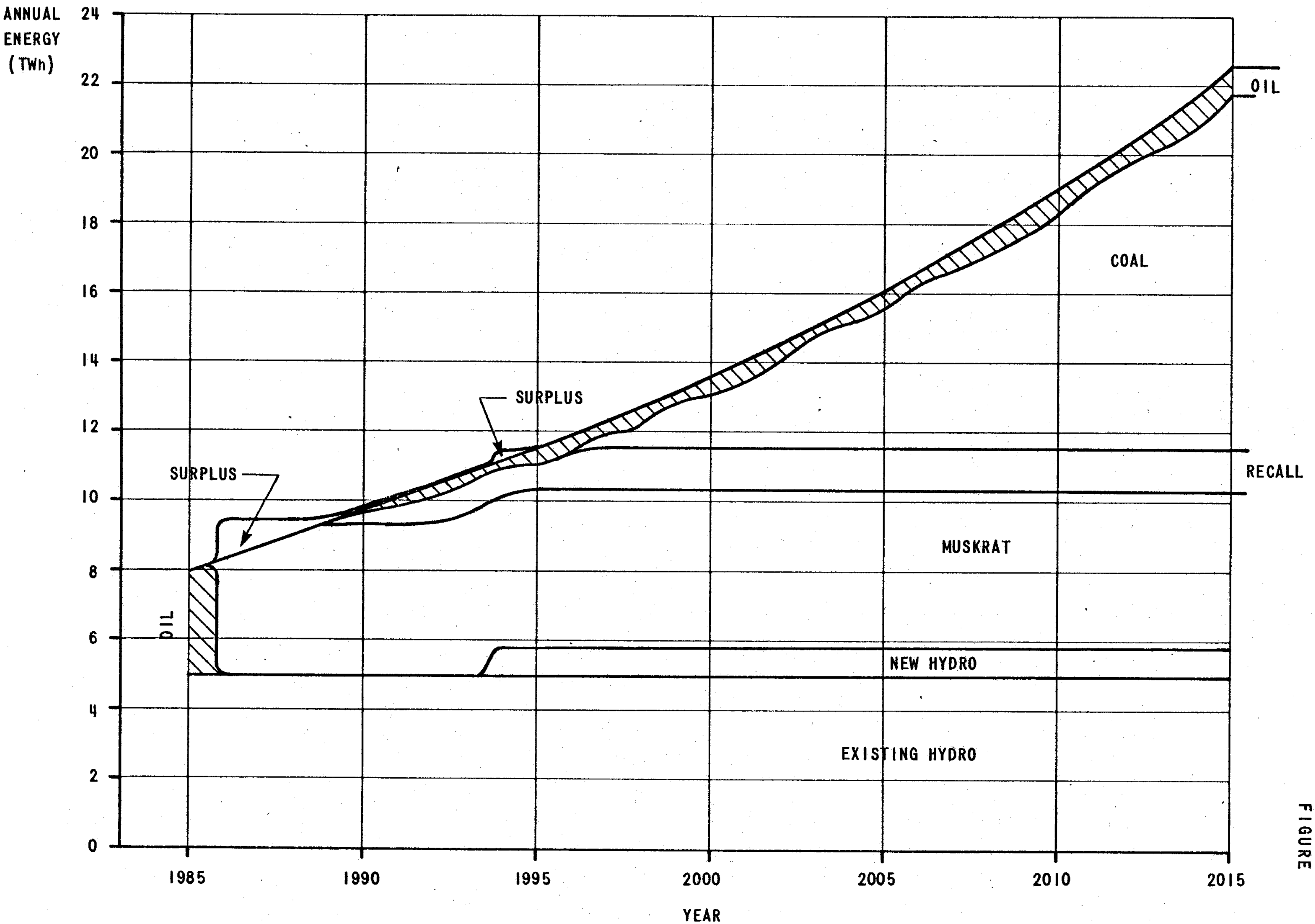
FIGURE 19



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SYSTEM ENERGY USE - DECISION 1980, NLH LOAD FORECAST
MUSKRAT FALLS & COAL

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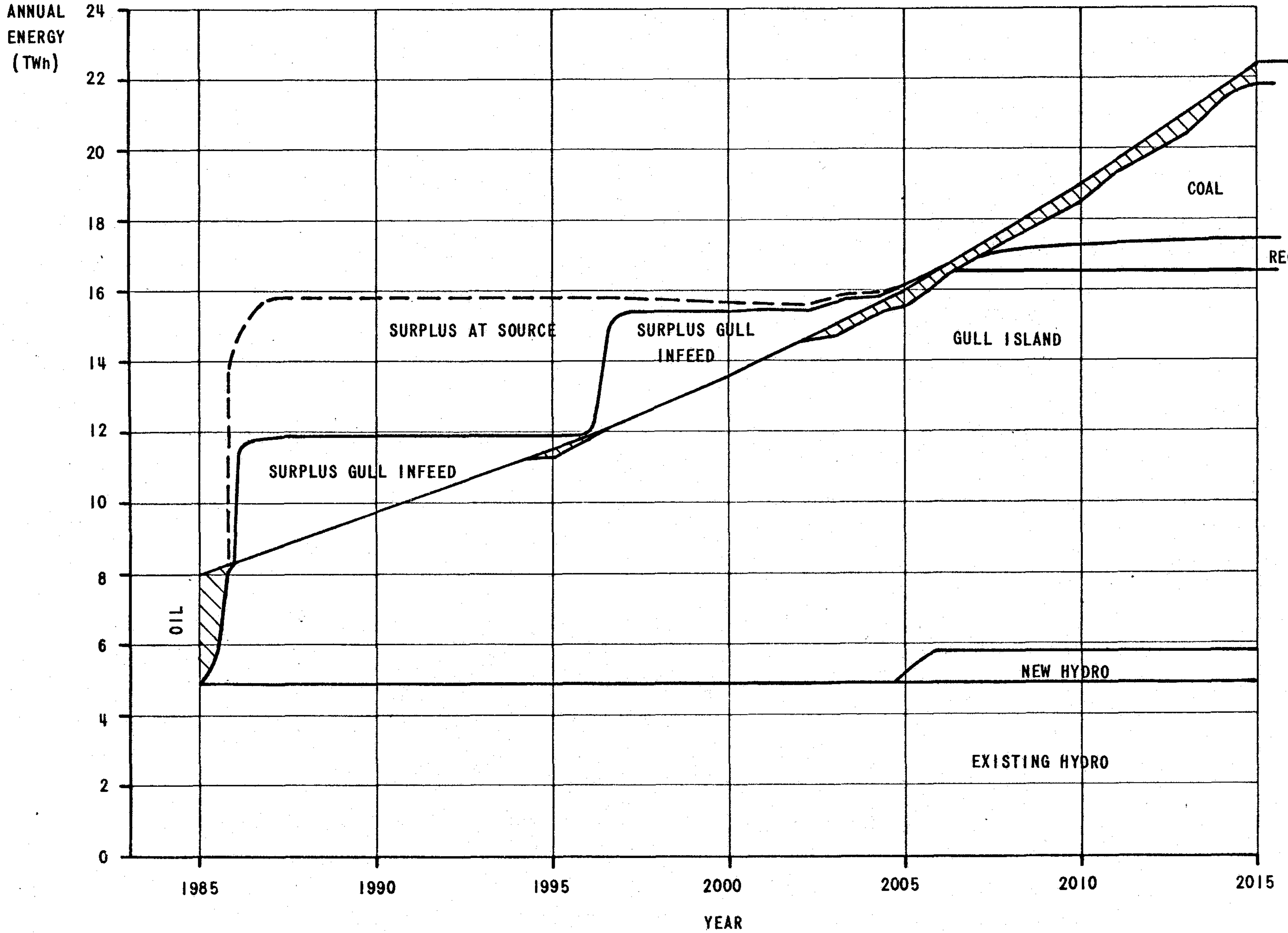
FIGURE 20



SYSTEM ENERGY USE - DECISION 1980, NLH LOAD FORECAST
GULL ISLAND & COAL

SHAWMONT NEWFOUNLAND LIMITED

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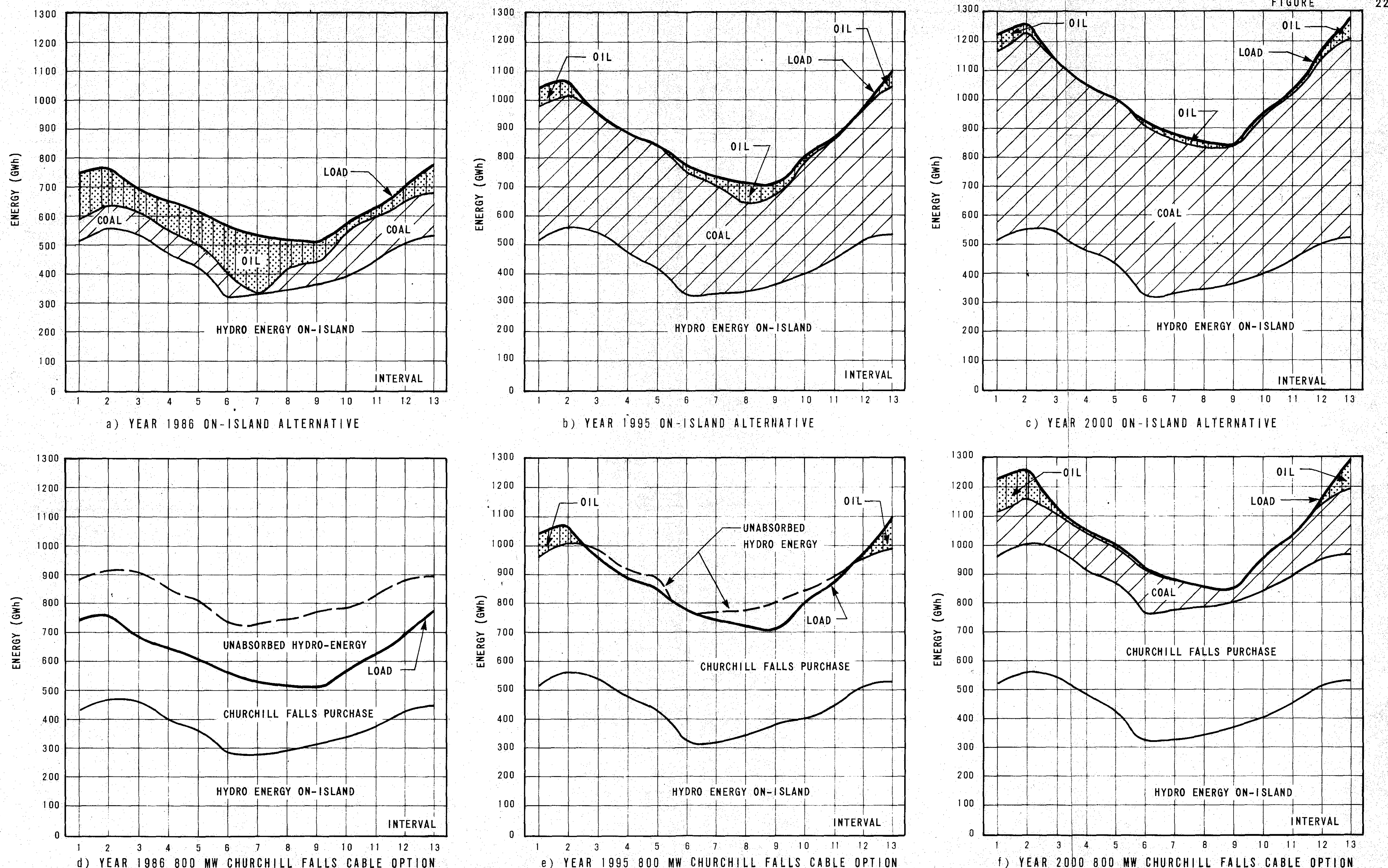
FIGURE 21

FIGURE 22



ENERGY PRODUCTION BY FUEL TYPE - VARIATION DURING A YEAR

APPENDIX

GLOSSARY OF TERMS

'Economic'

Cost effectiveness analysis

- A means of evaluating the cost and effectiveness of various methods of achieving a common objective.

Benefit/cost analysis

- A method of evaluating the relative merits of alternative investment projects in order to achieve the efficient allocation of resources. It assesses the benefits and costs of a project and reduces them to a common denominator. In this particular study the benefits do not include socio-economic type benefits.

Discount Rate

- An interest rate that is used to convert both benefits and costs which occur in the future into present values and thus weight the differences in the timing of cash flows.

Real Discount Rate

- A discount rate where prices (benefits and costs) are held constant; i.e., inflation is excluded.

Current or nominal discount rate

- A discount rate that includes expectations regarding future price (benefits and costs) changes; i.e., inflation is included.

Constant Dollars

- Costs relative to a reference date. Expectations of future price (cost) changes are not included.

EDC and IDC

- Escalation during construction (EDC)

- Interest during construction (IDC)

- Costs are usually given effective for a reference date. To determine the actual 'in-service' cost of a project it is necessary to add escalation beginning with the reference date until the estimated cost is incurred. It is also necessary to add interest incurred while building the project to determine the 'in-service' cost. In constant dollar analysis EDC is excluded and IDC is calculated using the real discount rate.

<u>'Power'</u>

Energy

- The amount of power delivered or received over an interval of time. It is normally expressed in kilowatt-hours (kWh).

Capacity

- The rate at which power is or can be delivered or received. It is normally expressed in terms of kilowatts or megawatts.

Firm Energy

- Energy that is available to serve a load with a stated reliability.

Secondary Energy

- Energy in a hydro system that does not meet a stated reliability of occurrence.

Average Energy

- In a hydro system it is the total of firm and the average secondary energy.

Surplus Energy

- Energy in a system that is surplus to firm requirements.

Load Duration Curve

- The arrangement of the loads occuring in a given period in a sequence of descending magnitude. The ordinate is load and the abscissa is "percent time equalled or exceeded". The lowest measured load is equalled or exceeded 100% of the time. The highest load is equalled or exceeded 0% of the time.

Capacity Factor for a given period

$$CF = \frac{\text{Energy capability or energy produced}}{\text{Capacity capability of the facility}}$$

Load Factor for a given period

$$LF = \frac{\text{Energy used (during the period)}}{\text{Peak load (during the period)} \times \text{number of hours (in the period)}}$$

'Methods of Determining Unit Energy Production'

Deterministic

- The stacking of hydro units under the load duration curve takes into account the unit forced outages in a pre-determined manner. The level at which the hydro units are stacked is determined in such a way that all their available energy is utilized, if possible.

Probabilistic

- The stacking of thermal units under the load duration curve takes into account the random nature of the forced outages of the units.