Q. In reference to the evidence of Larry Brockman, page 12, lines 2 to 3 - "In Order No. P.U. 7 (1996-97), the Board ordered the Company to perform a review of its Curtailable Service Option. I was requested by the Company to conduct such a review." - Please provide the detailed review conducted by Mr. Brockman and any other documentation produced by Newfoundland Power with regard to this order from the Board.

A. The detailed review of Newfoundland Power's Curtailable Service Option conducted by Mr. Brockman in 1998 is provided as Attachment A. There has been no other documentation produced by Newfoundland Power with regard to the Board's Order to review the Curtailable Service Option.

A Review of the Curtailable Service Option

for

Newfoundland Power

A Review of the Curtailable Service Option

for

Newfoundland Power

July 29, 1998

Brockman Consulting

1.0 Background and Introduction

During the last Newfoundland Light & Power Co. Limited ("Newfoundland Power" or "the Company") rate hearing, the issue of how benefits associated with the curtailable rate option are determined and the difficulty of calculating the credit was discussed. In Order No. P.U. 7 (1996-97) the Board stated:

> *The Applicant shall investigate the benefits associated with curtailable rates, with a view to improving the reliability and accuracy of the credit value assigned to curtailable rate customers. The Board orders that the demand credit for curtailment continue at $29/kVA, on an interim basis, for a maximum of two winter seasons, until April 30, 1998. Beginning January 1, 1997 all future costs associated with curtailable rates shall be charged to the Applicant and not to the Rate Stabilization Account.*

The review ordered by the Board is the subject of this section of the report.

During the 1996 Newfoundland Power rate proceeding, both Newfoundland Power witnesses Brockman and Connors and the Board's consultant, Dr. Wilson, expressed concern over the current calculation of the benefits associated with the Newfoundland Power curtailable rate option. These concerns center around two primary problems.

The first problem is that the methodology that Newfoundland Power uses to calculate the curtailable credit is directly proportional to a loss of load probability ("LOLP") calculation provided by Hydro and that calculation has proven to be very unstable. In fact, in the 1996 Newfoundland Power hearing, the estimate of this number varied from a low of $12 per kVA to $67 per kVA during the course of several months. This prompted Newfoundland Power to change its recommendation for the curtailable credit from $14 per kVA per year to $29 per kVA per year, during the course of the hearing.

The other problem with the calculation of the credit is that it depends on a calculation of generation marginal costs by Newfoundland Power. There are two difficulties the Company has in calculating the generation marginal costs. First, Newfoundland Power does not have the proper data nor the proper computer programs to calculate marginal costs for Hydro's system. Second, since the island generation system is primarily based on hydraulic generation, what is known as a "firm energy criteria" is used in the generation planning process. This criteria is discussed further in Section 6.0. The firm energy criteria interacts in a complicated way with the marginal cost calculations, making it more difficult to calculate the long run marginal costs. Most North American utilities are no longer principally hydraulic generation based and therefore do not rely on firm energy criteria for system planning. In addition, most other North American utilities are not isolated systems, so even if they have mostly hydraulic generation, the energy criteria is not important.

2.0 Curtailable Rate Theory

The basic theory behind a curtailable rate is simply that the utility and its ratepayers receive a benefit when they can get customers to curtail load at the utility's request. The utility is willing to share that benefit with those customers willing to curtail by giving them a credit towards their demand charges. The theoretical benefits accrue from several sources. The utility can curtail customers at the time of system peaks and therefore does not have to build as much peaking capacity to serve them. There are also non-peak times when the system capacity is short for other reasons such as major generator or line outages. At those times the curtailable customers can be asked to drop off the system.

The benefits of not having to build or buy capacity to serve the curtailable customers are usually relatively easy to calculate for thermally based generating systems. It is simply a matter of determining what units will not be built or what purchased power cost savings there will be and calculating the respective revenue requirement savings. The costs of administering the program and the likelihood that customers will not curtail must also be considered in the calculation.

Once the marginal generation benefits are calculated the utility must decide whether to give all the benefits to the curtailable customers in the design of the curtailable credits or to share them with the other customers. Based on a survey of Canadian utilities discussed in the next section, it appears that most utilities seem to favor sharing the benefits between curtailable and non-curtailable customers.

3.0 Survey of Canadian Practices on Curtailable Rates

In order to help assess Newfoundland Power's practices on curtailable rates, a confidential survey was conducted with 12 Canadian utilities. The following questions were asked:

1. Do utilities in your province offer curtailable rates?
2. Is the credit in the rate design based on embedded or marginal costs?
3. How is the credit in the rate designed?
4. To what classes does the curtailable rate apply?

5. What is the amount of the credit for each class?
6. Are there minimum and maximum loads to which the rate applies? What are they?
7. What are the perceived benefits of the curtailable rate? Is the curtailable load counted for demand planning?
8. What are the minimum notice provisions that apply to the customer wanting to get off the rate?
9. How much time is the customer given to drop load when called upon under this rate?
10. What are the penalties for a customer who does not curtail load when requested to do so?
11. How often are customers curtailed in a typical year under this rate?
12. How do you think retail competition will change the curtailable rate designs?

The detailed results are contained in Appendix A. Eight of the 12 Canadian utilities surveyed offered curtailable rates; however, two of those said the rates were being closed due to either the credit being higher than the savings or because deregulation of the generation sector is expected in the near future.

All but one Canadian utility that had curtailable rates and responded to the question based the rates on marginal costs with expected avoided generation as a benefit. The Canadian credits ranged from less than $1.00 per kW per month to $4.80 per kW per month, with most between $1.00 per kW per month and $3.75 per kW per month.

The length of time given to the Canadian customer to curtail varied from five minutes to 18 hours but most were less than one hour. The time required to notify the utility if a customer wants to get off the curtailable rate without penalty varied between one and five years.

The most relevant observations from the survey are that most Canadian utilities offer curtailable rates and most base the calculation of benefits on marginal costs. Most of them expect benefits to accrue from avoided generation. The range of curtailable credits is between less than $1.00 kW per month to $4.80 per kW per month, but most were between $1.00 per kW per month and $3.75 per kW per month.

4.0 The Newfoundland Power Curtailable Rate Option

Newfoundland Power currently has nine customers on its curtailable rate option. The curtailable rate option is available only to those customers on Rates 2.3 and 2.4 who can curtail a minimum of 300 kW. There are two options available for calculating the credit available to the customers on this rate but both are based on a $29 per kVA credit per year. The curtailments are limited to 100 hours total duration during the year and no more than six hours at a time. The customers are given a one hour notice to curtail. Newfoundland Power requires a six month notice before a customer can leave the rate. The one hour provision is within the mainstream of the rest of North America. The six month notice provision to get off the rate would not allow sufficient time to build replacement capacity but, as is discussed later, it is not clear the rate is resulting in any generation being deferred.

According to the *1998 Curtailable Service Option Report* filed with the Board and attached as Appendix B, the total cost of administering the option was $122,737 from April 1997 to March 1998. Four requests for curtailment totaling 6.75 hours were made and 89 per cent of the curtailment requests were met. The option provides between five and six MW of curtailable peak load.

5.0 Derivation of the Newfoundland Power Credit

The $29 per kVA credit was derived in 1996 by using a *National Economic Research Associates* ("NERA") method for calculating the short run marginal capacity cost. This methodology depends on the assumption that some sort of peaking unit (or other way of meeting reserve requirements) could be deferred by reducing peak load. A detailed explanation of how the credit was calculated is contained in Company witness Mr. Tom Connors' evidence from the 1996 Rate Hearing and is attached to this report as Appendix C.

The shortage cost in each year is defined as:

$$\text{Shortage Cost} = \frac{\text{Annual Cost/kW of reserves}}{\text{(1- Expected Forced Outage Rate)}} \times \frac{\text{LOLP in Year}}{\text{Target LOLP}}$$

As the equation shows, the shortage value is directly proportional to the LOLP in a given year. To derive the curtailable credit, Newfoundland Power has taken a number of years of future shortage costs and levelized the value. The LOLP value was shown to be highly volatile in the last rate case. Therefore Newfoundland Power recommended not using it to change the credit until further investigation could be done. The shortage cost estimate also depends on

Newfoundland Power's assumed annual cost of reserves. In the 1996 Newfoundland Power rate hearings it was assumed that the savings would be based on a deferred combustion turbine.

As we describe later, since Newfoundland & Labrador Hydro ("Hydro") uses a firm energy generation planning criteria, it is difficult for Newfoundland Power to know exactly how Hydro's plans might change with different levels of peak load. In order to accurately calculate the marginal costs and the corresponding level of curtailable benefits, it would be necessary for Hydro to participate in an estimation of marginal generation costs. A discussion of the value of curtailable load in light of Hydro's planning criteria is provided in the next section.

6.0 The Value of Curtailable Load in Hydro's Planning Scheme

In order to understand the benefits of curtailable load on Hydro's system, one must understand the planning process used. Hydro uses two primary criteria in its generation planning in addition to a least cost criteria. These criteria are a reliability based criteria of one day in five years (0.20) LOLP and a firm energy criteria that the island must be able to supply all required electrical energy in firm water years. Falling short on either criteria may result in Hydro being forced to add generation. The effect was illustrated by Mr. David Mercer, a Hydro witness, in the 1981 Hydro Rate Hearing. His testimony contained the following table of estimated future LOLPs and energy balances.

Year	Coincident Peak Demand (MW)	Installed System Capability (MW)	LOLP Index[1]	System Energy Required (GWH)	Firm Energy Capability (GWH)	Energy Balance (GWH)
1981	1234	1510	0.11	6396	6988	592
1982	1309	1594	0.06	6764	6911	147
1983	1362	1594	0.15	7059	7455	396
1984	1423	1600	0.45	7391	7490	99
1985	1487	1600	1.37	7745	7490	(255)
1986	1548	1600	3.58	8046	7490	(556)
1987	1674	1602	-	8822	7503	(1319)

Note: (1) Each LOLP index is derived by analyzing the reliability records of generating equipment similar to that which provides the Island's supply, in relation to peak load and expresses the expectation that the installed capacity will not be able to satisfy the forecast load. An index less than 0.2 indicates that the integrated Island System has enough reserve capacity to meet Hydro's LOLP target of "one day in five years". An index greater than 0.2 means that the criterion is not being met.

Mr. Mercer expressed the opinion that the system would be capacity deficient in 1984 because the LOLP is above 0.20 and energy deficient in 1985 because the energy balance is negative. He also explained that the failure to meet Hydro's LOLP criteria in 1984 was not considered a critical deficiency that would justify a major new plant; however, the energy deficit in 1985 would justify adding a major new source of generation. In order to satisfy both the reliability and energy criteria, Hydro was evaluating a new 127 MW Hydro source at Cat Arm and another 150 MW unit at Holyrood. The Cat Arm unit was capable of supplying 597 GWh of firm energy a year and the Holyrood unit could supply 935 GWh. Either one of these units could satisfy both the reliability and firm energy criteria and were considered viable candidates for adding to the system.

Hydro does not consider combustion turbines as sources of firm energy and curtailable load can only be called upon a few hours during the year. Neither would have significant impact on the need for firm energy during a year. Therefore, adding additional combustion turbines or additional curtailable load would not reduce the energy need in 1985 and a baseload plant would still be needed. It made little sense to add additional curtailable load or a combustion turbine in 1984 under those circumstances because the baseload source added for firm energy in 1985 would eliminate the LOLP deficiency by 1985. It made more sense to add a unit like Cat Arm or Holyrood which could satisfy both requirements.

It is clear from this example that baseload additions built to satisfy firm energy criteria will not be deferred solely by reducing peak loads. In fact, nothing would have been deferred by shaving peak loads since the reliability criteria violated in 1984 was not severe enough to make Hydro add a combustion turbine.

For the current forecast (March 1998), Hydro has supplied the new table shown on the next page. The reliability target is now expressed as hours per year and should not exceed 2.8 hours per year. From the table we see that the island will be both energy and capacity deficient in 2002, without additional generation, or the addition of a Labrador infeed. Reducing peak loads will not reduce energy requirements. It therefore does not appear that reducing peak loads will defer anything, since the energy criteria in 2002 and beyond will still not be met without either new sources of generation or reductions in energy usage.

Year	1998 Load Forecast (MW)	1998 Load Forecast (GWh)	System Firm Capability (GWh)	LOLH (hours) (Target 2.8)	Energy Balance (GWh)
1998	1549	7982	8141	2.129	159
1999	1568	8081	8232	1.430	151
2000	1580	8163	8259	1.671	96
2001	1594	8203	8286	2.373	83
2002	1618	8303	8286	3.177	(17)
2003	1643	8400	8286	4.556	(114)
2004	1664	8505	8286	5.599	(219)
2005	1679	8549	8286	8.225	(263)
2006	1698	8630	8286	10.341	(344)
2007	1719	8711	8286	13.288	(425)
AAGR	1.16%	0.98%			

If nothing is deferred by curtailable loads then curtailable loads have little marginal value. It is also true that peak load pricing and seasonal rates can have only minor time of day or seasonal differentials since most of the marginal energy comes from Holyrood. This is one of the reasons that Newfoundland Power has not strongly supported seasonal and time-of-use rates in the past.

The situation is further complicated by the possibility of a direct current ("DC") link to Labrador, recently given new life by government. The capability of such a line is estimated to be about 800 MW. This project is influenced by many factors. The minor reductions in peak load that would occur from curtailable rates, other forms of peak load or seasonal pricing will have no effect on whether the project goes ahead. The DC link to Labrador will have a dramatic impact on the marginal costs of the Island for many years into the future. Shawinigan Consulting performed a marginal time of use cost study for Hydro in 1984 in which the effects of a Labrador infeed were examined. That study found that long run marginal winter on-peak costs would be 11.1¢ per kWh and summer off-peak marginal costs would be 6.5¢ per kWh without the Labrador infeed. When the infeed was assumed to be built the marginal on-peak costs dropped to 5.8¢ per kWh and off-peak marginal costs dropped to 0.4¢ per kWh. The fuel, load growth and capital cost assumptions in the 1984 report are undoubtedly out of date but the study still indicates the dramatic impact a Labrador infeed will have on marginal costs.

7.0 Alternative Methods for Dealing with the Value of Curtailable Loads on the Island

There are several alternatives to the method used by Newfoundland Power to calculate the rate credit to be paid to curtailable customers. Some utilities base their interruptible and curtailable credits on embedded cost. That is, they simply take a portion of the embedded demand charge and forgive it for interruptible or curtailable customers. This has the advantage of not requiring a precise calculation of marginal costs and it treats all customers in the same manner with respect to demand related costs. These utilities forgive only a portion (say 50 per cent) of the demand charge as a way to make sure that curtailable customers still pay some of the fixed costs of baseload units and as a way to share perceived benefits with other customers.

In an effort to see if other hydraulic systems might be of help, we considered the way B.C. Hydro calculates its marginal costs. Mr. D.J. Druce, a resource planner for B.C. Hydro, presented a paper at a 1993 Canadian Electricity Association workshop on *Planning with Energy Uncertainty* where he described the problems of calculating marginal costs for B.C. Hydro. Mr. Druce states that "by design, B.C. Hydro generally has more energy that it needs to meet the domestic demand, plus any other firm obligations, except under prolonged low water conditions." This is the same situation in which Hydro finds itself. The solution that B.C. Hydro came up with for calculating marginal costs was to use the value of exports to predominately thermal systems to the south. Clearly this method of estimating marginal costs will not work for an isolated system.

It might also be possible for Newfoundland Power to improve its modeling of Hydro's generation expansion planning. Models could be built that take into account the firm energy criteria and they could be used to simulate the expansion plans under peak load shaving conditions. However, these models still require that Newfoundland Power have good estimates of the costs and characteristics of Hydro's future generation options and will not eliminate the problems of the dramatic changes in marginal costs the Labrador infeed will have. This option would duplicate the efforts of Hydro. A much better method would be to have Hydro participate with Newfoundland Power to calculate the marginal costs and effects of peak load reductions on the future generation system.

A second option for Newfoundland Power to consider would be to close the curtailable option to new load or freeze the rate until such time as a proper estimate of the value of such load can be obtained. Once a good estimate of the marginal benefits is obtained, we would recommend that Newfoundland Power use a simple method such as giving the curtailable customers a demand reduction equal to 50 per cent of the marginal benefits per year.

8.0 Conclusions and Recommendations

Conclusions:

1. Newfoundland Power currently uses a method for calculating the curtailable rate option credit that is unstable and is not likely to accurately capture the benefits of the curtailable load.
2. Newfoundland Power does not currently have the proper data or programs to accurately calculate the benefits of reducing peak load.
3. The use of a firm energy criteria in generation planning by Hydro makes the value of curtailable load more difficult and may even mean that it has little value.
4. Minor reductions in peak load from curtailable rates or other forms of peak load or seasonal pricing will probably have no impact on the proposed Labrador infeed, making the estimation marginal benefits of curtailable load very problematic.
5. It is difficult at the present time to see any substantial benefit from having curtailable loads on the system. At the same time, it will be difficult to recruit more curtailable load in the future when needed if it is abandoned now.

Recommendations:

1. Newfoundland Power should consider adopting a simple method (such as simply reducing the embedded demand charge by 50 per cent); freezing the current credit and not allowing any new entrants to go on the rate until the benefits can be properly calculated; or as a minimum, freeze the current credit and inform customers that the rate may be subject to significant changes.
2. Hydro should be asked to participate with Newfoundland Power to calculate the marginal cost of electricity on the island and the value of reducing peak load. At such time as a reliable estimate of marginal costs and peak load reduction benefits can be obtained, we recommend that Newfoundland Power use a simple method such as giving the curtailable customers a demand reduction equal to 50 per cent of the marginal benefits per year.

APPENDIX A

A Survey of Curtailable Rate Options

To assist in assessing Newfoundland Power's relative position with respect to the curtailable service option a survey of Canadian Utilities was performed. The following utilities were contacted:

Nova Scotia Power
Maritime Electric
Manitoba Hydro
Alberta Power
West Kootenay Power
Newfoundland and Labrador Hydro
New Brunswick Power
Ontario Hydro
Saskatchewan Power
TransAlta Power
B.C. Hydro
Hydro Quebec

Not all utilities answered all questions.

1. Do the utilities in your Province offer curtailable rates?

Yes	8
No	4

Comments:

2 of the existing rates will terminate in 2000 because the credit exceeds the benefits.

1 of the existing rates is experimental

2 utilities don't have a specific rate but can contract with individual customers.

2. Is the credit in the rate design based on embedded or marginal costs?

Embedded	1
Marginal	8
Don't know or no response	3

Comments:

3. How is the credit in the rate designed?

Peaker deferral	1
Unspecified unit deferral	8
Comments: One utility based the credit on a percentage of the embedded demand costs.	

4. To what classes does the curtailable rate apply?

All classes	1
General Service	2 greater than or equal to 1 MW
Industrial	6 greater than or equal to 5MW
Comments:	

5. What is the amount of the credit for each class?

Less than $1/kW per month	1
$1 to $3.75/kW per month	5
$3.75 to $4.80/ kW per month	1

6. Are there minimum and maximum loads to which the rates apply? What are they?

No	3
Yes, 1 MW minimum	1
Yes, 2.5 MW minimum	1
Yes, 3 MW minimum	1
Yes, 5 MW minimum	2
Comments: None of the utilities had maximum loads for curtailable loads.	

7. What are the perceived benefits of the curtailable rate? Is the curtailable load counted for demand planning?

Generation Deferral Benefits	7
Curtailable Load Factored into Planning	7
Comments: One utility based benefits on the on-peak pool pricing.	

8. What are the minimum notice provisions that apply to the customer wanting to get off the rate?

2 years	1
3 years	3
4 year	1
5 years	3
Don't know or no response	4
Comments: Two of the responses said the rate was experimental and might end in 6 months.	

9. How much time is the customer given to drop load when called upon under this rate?

Comments:

One respondent gave five minutes to 48 hours (depending on option selected).
Three respondents gave 10 minutes.
One respondent gave 10 minutes to one hour (depending on option selected).
One respondent gave 10 minutes to four hours (depending on option selected).
One respondent gave one hour.
One respondent gave 18 hours.

10. What are the penalties for a customer who does not curtail load when requested to do so?

Comments: Penalties varied considerably.

Two respondents charge twice the regular demand charge as a penalty.
One respondent charges $3/kW per month.
One respondent charges half the demand charge as a penalty.
Several respondents take the credit back the first time and excessive failure to curtail will result in being put off the rate.

11. How often are customers curtailed in a typical year under this rate?

Never curtailed (last few years)	4
1-5 times a year	1
5-10 times a year	1
More than 10 times a year	2
Don't know or no response	4

12. How do you think competition will change the curtailable rate designs?

Comments:

One respondent thinks competition will make the rate inappropriate.
Most respondents said the rate will change but don't know how.

APPENDIX B

1998 CURTAILABLE SERVICE OPTION REPORT

Newfoundland Power
April 22, 1998

1. Purpose of Report

This report summarizes the annual costs of maintaining the curtailable service option ("the Option"). The Option statistics for the 1997-98 winter season and the impact of the Option on the energy requirements of Newfoundland Light & Power Company Limited ("Newfoundland Power" or "the Company") during peak load conditions.

This report is submitted in response to Order No. P.U. 7 (1996-97) which states:

"*The Applicant shall follow the directions given in Items (4) and (5) of Order No. P.U. 4 (1994-95) and provide the updated statistics, thirty days after each "winter season" for the Board's information and evaluation.*."

Items (4) and (5) of Order No. P.U. 4 (1994-95) are as follows:

(4) "Accounts will be established to accumulate all costs associated with the curtailable service option for purpose of evaluation at the next rate hearing."
(5) "Statistics are to be compiled for the purpose of determining the impact on peak load conditions during the period in which curtailment occurred."

2. Costs of the Curtailable Service Option

Operating Costs

There are three types of operating costs incurred through the offering of the Option: the Company's labour cost, the cost of telephone line rental and the cost of the curtailment credits. The costs associated with each for the period April 1997 to March 1998 are shown below.

Labour	$ 7,386
Telephone Line Rentals	4,903
Curtailment Credits	110,448
Total Operating Costs	$122,737

Capital Costs

No specialized metering equipment was purchased to serve customers on the Option during 1997. The load recorders and pulse meters required on services that avail of the Option were purchased as part of the load research program during the late 1980's and early 1990's.

3. Curtailable Service Option Statistics

The curtailment statistics for the nine services on the Option during the 1997-98 winter season are shown in the table below.

	December	January	Total
Number of Requests	1	3	4
Requested Hours of Curtailment	1 ½	5 ¼	6 ¾
Curtailment Failures	1	3	4
% of Successful Curtailments	89%	89%	89%

The percentage of successful curtailments is determined by dividing the number of successful curtailments by the number of total curtailment requests. For example, in January nine services were requested to curtail three times each. This totals 27 curtailment requests, of which 24 were successful curtailments and three were curtailment failures (24/27 = 89 per cent). Three of the four curtailment failures were the result of generator problems on the part of customers.

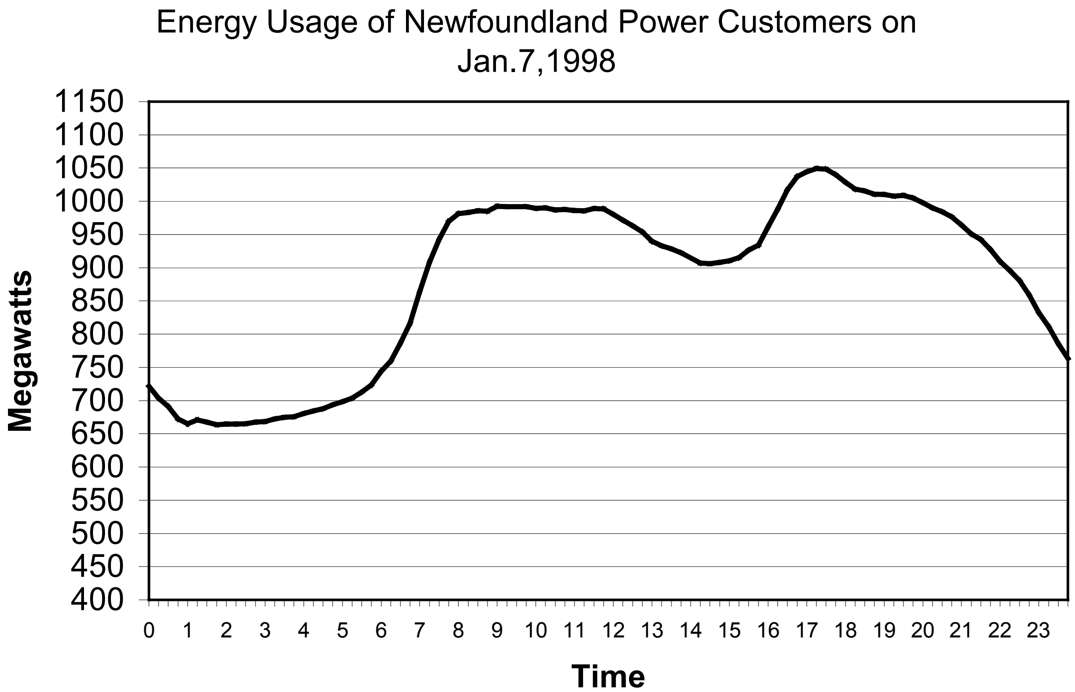
4. **Impact on Peak Load**

The Option provides between five and six MWs of curtailable load to the Company. This is approximately one MW more than last year which is the net effect of one large service with approximately two MW of load joining the rate option and two services with smaller loads no longer participating.

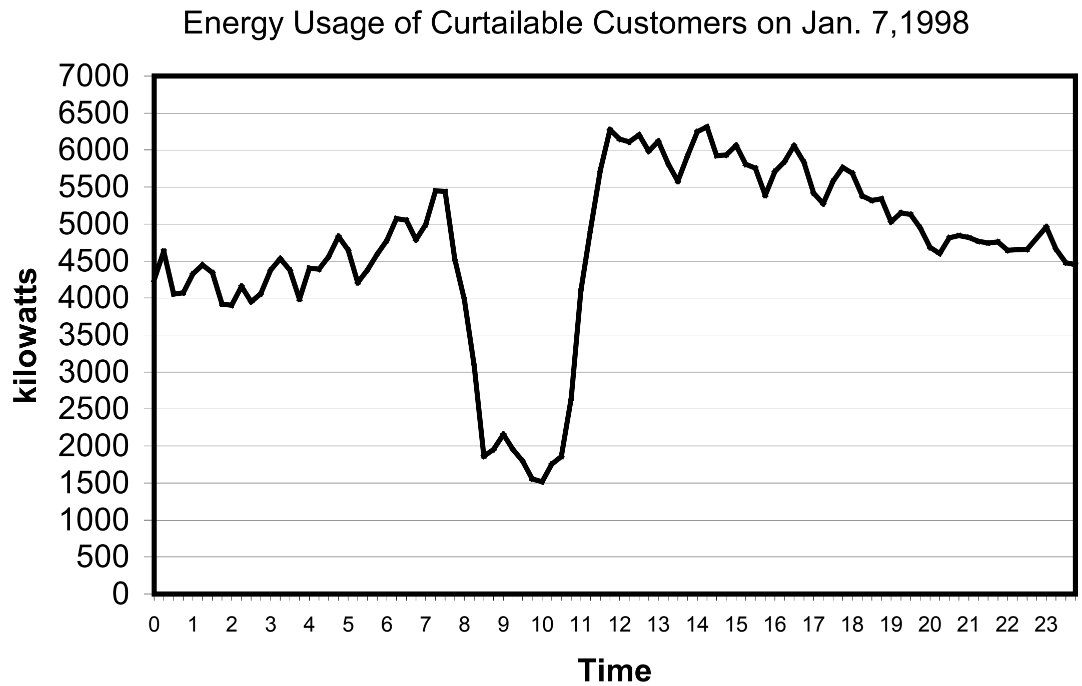
The actual level of curtailable load depends on both the number of successful curtailments for each request and the coincidence of curtailable customers' peak energy usage with the Company's peak energy usage. The curtailable load is approximately 0.5 per cent of the historical maximum peak load for Newfoundland Power (1,120 MW).

On days when the Company's load requirements reach approximately 1,000 MW or greater, there is a high probability that Newfoundland & Labrador Hydro (Hydro) will be near peak load conditions. It is on these days that the Company requests curtailments.

As an example, the graph that follows shows the energy usage pattern of the customers of Newfoundland Power on January 7, 1998 (the winter season peak day). On this day, the maximum demand requirement of the customers was approximately 1,050 MW. This load was within 70 MW of the historical maximum demand requirement.



Customers were requested to curtail once on January 7, 1998. The curtailment request was for one hour and 45 minutes from 8:45 a.m. to 10:30 a.m. The impact of the curtailment on the usage of customers on the Option is shown in the graph on the following page.



The customers on the Option were not requested to curtail on the afternoon of January 7, 1998 because the system load unexpectedly climbed higher than anticipated. This occurrence combined with the minimum one hour curtailment notice prevented the Company from having customers curtailed for the afternoon peak.

5. Summary

The cost of offering the Option for the period April 1997 to March 1998 was $122,737 of which $110,448 was paid in credits. The balance represents the cost to administer the Option.

During the 1997-98 winter season there were nine services on the Option. There were four curtailment requests requiring approximately seven hours of curtailments.

The Option provides between five and six MWs of curtailable load to the Company. The curtailable load is approximately 0.5 per cent of the historical maximum peak load for Newfoundland Power (1,120 MW).

APPENDIX C

Derivation Of Curtailable Demand Credit

The curtailable rate credit was derived in two stages. First, short run marginal capacity costs by year were estimated. Second, the resulting time series of marginal costs were levelized to determine a curtailment credit.

Short Run Marginal Capacity Costs

To develop short run marginal capacity costs, the National Economic Research Associates ("NERA") methodology was used. A summary of the NERA methodology is provided in Appendix C of the NARUC publication *Aligning Rate Design Policies With Integrated Resource Planning*, January 1994. The NERA method appears to be the dominant method of marginal cost computation in use today.

The NERA methodology is based on the premise that in the short run, when capacity cannot be expanded, system load growth increases the probability of electricity outages to customers. The NERA methodology uses this increase in outage probability as the basis for determining short run marginal capacity costs. The cost to customers of decreasing reliability is referred to as marginal "shortage" costs.

Loss of load probability ("LOLP") is a measure of the probability that load will exceed available capacity. The higher the LOLP, the lower the reliability of the electrical system. LOLP is usually referred to in unit hours per year. Hydro uses LOLP in unit days per year. Hydro currently plans to add capacity when the LOLP of the interconnected system exceeds 0.2 days per year (i.e., target LOLP).

Applying the NERA method to Hydro's data gives the following formula for use in deriving the short run marginal costs on the island interconnected system:

$$\text{Short Run Marginal Costs} = \frac{\text{Annual Cost/kW of reserves}}{1 - \text{Expected Forced Outage Rate}} \times \frac{\text{LOLP in Year}}{\text{Target LOLP}}$$

The expected forced outage rate used in the above calculation is the probability of forced or unplanned outages for the generation source used as reserve capacity.

The NERA methodology, rather than specifically measuring the long run marginal cost, examines the short run marginal costs in successive years. The resulting capacity costs are actually customer shortage costs not the costs of adding capacity. The end result is a stream of short run marginal capacity costs which differ by year as shown in Table 1.

The annual cost per kW of reserve capacity divided by one minus the expected forced outage rate as shown in the previous formula is referred to as the marginal capacity cost. This is based on summary of which is provided in NARUC's *Electric Utility Cost Allocation Manual 1992* (pp.120-123). Reference is also made in the NARUC manual to the NERA method of adjusting long run marginal costs developed from a peaker deferral method to reflect short run marginal costs (p. 122).

Curtailable Rate Credit

Rather than having the curtailable credit change from year to year as the marginal costs change, we decided to levelize the rate over a three year period to reflect regulatory lag. That is, if we assume that the credit will change at the next rate application then it makes sense to levelize the rate over this period. We have assumed three years for this purpose. Based on the three-year levelization period, the curtailable credit will be $13.70 per kW ($12/kVA).

The reason for the reduction in the credit is twofold. First, we used a 10 year levelization period for the interim rate. The second and primary reason is that the demand forecast has dropped significantly from the 1994 demand forecast.

Table 1
NEWFOUNDLAND LIGHT & POWER CO. LIMITED
PROJECTION OF SHORT RUN MARGINAL CAPACITY COSTS

Year	Marginal Capacity Cost ($/kW)	Loss of Load Probability (Days/Yr)	Target Loss of Load Probability (Days/Yr)	Short-run Marginal Capacity Cost ($/kW)
1996	101	0.0364	0.20	18.4
1997	103	0.0242	0.20	12.5
1998	104	0.0184	0.20	9.5
1999	104	0.0247	0.20	12.8
2000	103	0.0438	0.20	22.5