Q. Provide the rural deficit (JAB-1, page 3 of 94) from 1992 to 2000 and forecast for 2001 and 2002 using the Cost of Service methodology approved in the Board's report in February 1993. Include a breakdown of the deficit generated by each of the following:

(a) Rural Interconnected System;
(b) Rural Isolated Island System;
(c) Rural Isolated Labrador System; and
(d) L'Anse Au Loup System.

A. The Rural Deficit is as follows:

Rural Deficit: 1993 Methodology	**1993**	**1994**	**1995**	**1999 (Rev.1)***	**2002**
Island Interconnected	7,731,075	8,909,084	10,155,536	14,276,491	14,939,871
Island Isolated				5,596,630	6,591,156
Labrador Isolated	24,035,096	24,492,706	24,921,964	9,683,365	13,122,291
L'Anse au Loup				1,062,096	1,365,687
Total	31,766,171	33,401,790	35,077,500	30,618,582	36,019,005

A Cost of Service Study with the methodology approved by the Board in 1993 was not produced for any year prior to 1993. For the years 1996-1998 and 2000-2001, please refer to the response to IC-1 for the explanation relating to Cost of Service availability.

* Refer to IC-1 for an explanation of revisions to the 1999 Cost of Service.

Q. For the L'Anse Au Loup system:

(a) Complete the following table showing the actual costs, revenues and recovery ratios by year from 1996 to 2000 and forecast for 2001 and 2002.

A.

Newfoundland & Labrador Hydro
L'Anse Au Loup
Comparisons of Revenue & Allocated Revenue Requirements
($ 000)

Year (1)	Revenues (2)	Cost of Service before Deficit & Revenue Credit Allocation (3)	Revenue Credits (4)	Deficit (5)	Revenue Requirement After Deficit & Revenue Credit Allocation (6)	Revenue to Cost Coverage (2 / 3)
1996						
1997						
1998						
1999	1,025	2,087	-	(1,062)	1,025	.49
2000						
2001						
2002	1,136	2,502	-	(1,366)	1,136	.45

The requested information for L'Anse Au Loup for 1996 – 1998 and for 2000 – 2001 is not currently available. As the data becomes available for additional years, the above table will be updated. Please refer to response to IC-1 for explanations related to of Cost of Service availability.

Q. For the L'Anse Au Loup system:

(b) Complete the following table showing the projections presented at the 1996 Hearing in L'Anse au Loup.

A.

Newfoundland & Labrador Hydro
L'Anse Au Loup
Comparisons of Revenu,e & Allocated Revenue Requirements
($ 000)

Year (1)	Revenues (2)	Cost of Service before Deficit & Revenue Credit Allocation (3)	Revenue Credits (4)	Deficit (5)	Revenue Requirement After Deficit & Revenue Credit Allocation (6)	Revenue to Cost Coverage (2 / 3)
1996	-	-	-	-	-	-
1997	962	1,613	-	(651)	962	.60
1998	1,043	1,764	-	(721)	1,043	.59
1999	1,119	1,863	-	(744)	1,119	.60
2000	1,189	1,880	-	(691)	1,189	.63
2001	1,253	1,929	-	(676)	1,253	.65
2002	1,318	2,027	-	(709)	1,318	.65

Note: Numbers reference PUB-40(ii), 1996, Page 2 of 3. Figures for 1996 were not used during the Hearing.

Q. For the budget item identified below, provide the following information:

Budget Item	**Amount**	**Description**
B-69	$8,942,000	Complete Microwave Radio System Interconnection

(a) Aliant Telecom has a looped digital fibre system in existence along the same path. Compare the cost and benefit of using the Aliant system with the proposed microwave system.

(b) Provide details on the projected annual cost of operating and maintaining this microwave system.

(c) Provide details on the reliability (availability in % per year) that Hydro has experienced on its existing microwave systems on the island.

A. (a) Refer to response to NP-180, letter to Mr. Geoff Emberley dated March 07, 2001.

Generating and transmission utilities like NLH have traditionally, and still continue to, utilize privately owned telecommunication facilities that are essential to maintaining the appropriate level of security and reliability of mission critical services.

Therefore the outsourcing of mission critical teleprotection services was not considered by Hydro and as such an evaluation of the Aliant infrastructure was not undertaken.

In 2000, Hydro undertook a survey of the major generating and transmission utilities in Canada to obtain information and trends on the technologies used to support mission critical applications. The second component was to determine if there was a trend by the major utilities to move towards a leased or out-sourced telecom service rather than the traditional owned telecom solution.

The results of the survey concluded:

1. Technologies used to support teleprotection and SCADA applications are primarily utility owned fibre optic cable and microwave radio.
2. All utilities have plans to install new privately owned infrastructure to support teleprotection and SCADA circuits.
3. Utilities surveyed do not use leased telecom facilities to support critical teleprotection or SCADA circuits.

Hydro is a member of the Canadian Electricity Association (CEA) Telecom Task Group and the consensus of this group favors an owned rather than leased philosophy as well.

(b) The estimated annual operating expense would be approximately $60,000 per year. This covers diesel fuel and nitrogen, road maintenance and electricity.

(c) Hydro has experienced extremely high availability on its existing microwave radio system. End to end circuit availability was designed and has been consistently measured to be better than 99.9999%. This high degree of availability is an absolute requirement for teleprotection of transmission lines and is consistent with utility design practices.

Q. For the budget item identified below, provide the following information:

Budget Item	Amount	Description
B-72	$171,000	Install Interactive Voice Response System – Hydro Place

Provide a cost benefit analysis to support the purchase of this system.

A. A formal cost benefit analysis has not been performed for this purchase. An IVR was identified as a desirable application in order to provide improved customer service. It is anticipated that an additional benefit would be to increase effectiveness of the customer services personnel due to faster response time for customer queries by customer service representatives, and the offloading of routine query response to an automated system.

Q. Hydro's 2000 Annual Report, page 10 indicates that the "digital radio technology will provide opportunities for the generation of non-traditional revenue for the company with the sale of any excess bandwidth to outside parties":

a) Identify the other parties that are anticipated to use the system.

b) How much revenue has been provided in the test year from this source?

c) How have the rates charged been established?

d) How has the cost of service been determined and has such been allocated to non-regulated operations?

e) Have the costs and revenues been included in the revenue requirement calculation in JCR Schedule 1? If so, provide details in the form of JCR Schedule 1.

f) What percentage of the capacity of the system is used by Hydro?

g) What percentage of the capacity of the system is used by other parties?

h) What percentage of the capacity of the system is spare (i.e. not currently used by Hydro or other parties)?

i) What percentage of the capacity of the system is anticipated to be used by other parties in the future?

j) Provide any other instances where Hydro is generating non-traditional revenue and how the revenue and associated expenses are treated for regulatory purposes.

A. a) Several local telco and cable companies as well as NP have expressed interest in using any excess bandwidth available. No firm commitments have been made, as the East Coast Microwave infrastructure will not be completed until December 2001.

b) No revenue has been provided in the test year from this source.

c) No rates have been established.

d) Not applicable based on response to parts (a), (b) and (c).

e) The operating costs have been included in JCR schedule 1 (refer to NP-118 p. (b).

f) Hydro will initially use 33% of the capacity of the main transport backbone infrastructure and 50% of the capacity on the low capacity drops to terminal/generating stations and area offices. As Hydro's requirements increase, Hydro's use of the capacity will increase.

g) No capacity will be used by other parties when the system goes into service in December 2001.

h) Sixty-six percent (66%) of the capacity will be spare when the system goes into service in December 2001. Of the main transport backbones infrastructure and 50% of the capacity and low capacity drops to terminal/generating stations and area offices.

i) The percentage of the capacity of the system that is anticipated to be used by others in the future is estimated at this time, to be 33%. It should be noted that the capacity and the infrastructure to support the capacity are not directly related. The same infrastructure is required whether Hydro uses 33% or 100% of the capacity of the system, as the additional multiplexing equipment which is required to add additional capacity is not a large component of the overall cost.

j) Hydro generates revenue from the joint-use and/or rental of excess capacity of poles, microwave and VHF systems, and buildings. Such revenues are treated as expense credits and reduce the revenue requirement from ratepayers.

Q. The Board recommended in its July 29, 1996 *'Referral by the Lieutenant Governor in Council Concerning Rural Electrical Service'*:

(i) "that Hydro prepare a detailed calculation of long run marginal costs. In the event that a detail estimate of long run marginal cost confirms it to be significantly below the current energy rate, the Board recommends that consideration be given to reducing the energy rate to a level closer to long run marginal cost"; (page 31)

(ii) "that Hydro be directed to provide a cost benefit analysis of a rate structure for general service customers which provide for a demand charge. The energy and demand charge in such a rate structure should recover long run marginal cost"; (page 32)

(iii) "that Hydro provide, as part of future cost of service reports, the specific policies as well as an allocation schedule related to operation and maintenance overheads"; (page 37)

(iv) "Design criteria for plant and auxiliary equipment should be re-examined, with a view to ensuring reliability requirements are not unduly stringent, particularly in communities operating close to capacity limits; (page 37) and,

(v) "Conservation programs for isolated areas should be designed to defer expansion of capacity and to target for subsidy reduction rather than lower energy use. Demand side management should be directed toward those systems which will soon require capacity expansion." (page 37)

(a) Provide the detailed calculation of long run marginal cost as recommended by the Board. If the calculation was not completed, please explain why not.

(b) Provide the cost benefit analysis of a demand/energy rate structure for general service rates in isolated areas as recommended by the Board. If the analysis was not completed, please explain why not.

(c) Provide the specific policies and allocation schedule related to operation and maintenance overheads.

(d) Provide details of, or any reports prepared on, the re-examination of design criteria for plant and auxiliary equipment.

(e) Provide details of any conservation or demand side management programs designed to defer expansion of capacity and to target for subsidy reduction rather than lower energy use.

A. (a) Please see attached report entitled “An Estimate of Long Run Marginal Costs in Newfoundland and Labrador Hydro’s Isolated Rural Areas”, July 2001.

(b) Please see attached report entitled “Cost Benefit Analysis of Implementing Demand Charges in the General Service Rate Structure in Isolated Areas”.

(c) Please see response to NP-132.

(d) Hydro has carried out a review of the planning criteria used for the isolated systems. The review was based on a survey of the planning practices of other Canadian utilities which have significant isolated/diesel operations. Please see attached report "Isolated Systems Generation Planning Practices; A Survey of Canadian Utilities", 2001. After reviewing the results of the survey it was concluded that Hydro's planning criteria is consistent with the practices of other utilities.

(e) Since 1996 Hydro has generally not encountered circumstances where it was practical or feasible to defer capacity expansion where called for on the diesel systems (as per evidence of H.G. Budgell, pages 12-13). Significant power requirements for seafood processing operations have been the key underlying factor in the case of St. Lewis, Makkovik, and Charlottetown. Expanded generating capacity was required in Davis Inlet due to a rapid increase in peak demand attributed to new community infrastructure and loads. Diesel unit replacement in Hopedale and Postville led to an increase in installed capability. There is some on-going work and analysis aimed at deferring capacity expansion for Norman Bay. An analysis was prepared in December 2000 on the potential for demand side management for this system and some fieldwork was carried out in 2001. Some additional work on load controllers and operational matters remains to be done before an impact evaluation can be carried out.

As recognized by the PUB in its 1996 recommendation noted above, utility sponsored programs that aim to reduce electricity use on isolated systems can lead to an increase in cross subsidy requirements, and therefore should not be undertaken by Hydro. However, there are a few diesel systems where the short run marginal cost exceeds marginal revenue to the point where lower energy use may reduce subsidy requirements (e.g. Norman Bay, Paradise River, Francois, Williams Harbour), assuming no negative impacts on diesel system operations. Due to the isolation of these systems, DSM programs costs can be high and pure subsidy reduction conservation initiatives generally need to be co-ordinated with other utility system visits to minimize delivery costs. Achievable savings are limited and typically restricted to the application of compact fluorescent lighting, and to a lesser extent electric hot water heaters. Hydro is currently making arrangements to deliver compact fluorescent lighting to the isolated systems noted above following on its review in 2000 of isolated short run marginal costs and marginal revenues.

Cost Benefit Analysis of Implementing Demand Charges in the General Service Rate Structure in Isolated Areas

Introduction

The PUB expressed the view in its report dated July 29, 1996 concerning rural electrical service that general service customers in isolated systems should have demand charges to encourage reduced levels of demand. Further on page 32 of that report the Board stated:

> *"The Board recommends that Hydro be directed to provide a cost benefit analysis of a rate structure for general service customers which provides for a demand charge. The energy and demand charge in such a rate structure should recover long run marginal cost."*

This following analysis has been conducted to meet this request.

Costs

The additional costs associated with implementing demand charges relate primarily to the additional costs of demand meters versus energy only meters, additional billing costs and additional enquiry costs.

Demand meters cost approximately $175 - $250 for self-contained units and $425 for cabinet units plus installation labour compared with $40 for energy only meters. There are approximately 200 general service customers in isolated areas with demands greater than 10 kW. Over 75% of these customers currently have demand meters installed therefore the additional cost to install the remaining units will be small when spread over the life of the meter.

Billing on demand energy rates requires capturing, processing and retaining demand data resulting in additional data gathering and processing time. The level of increased costs however will be negligible as existing staff and billing systems can handle these items.

Customer enquiries are more difficult to deal with due to the increased complexity of the rate structure. Many customers will never understand or accept the concept of demand charges. The increased time required will however be provided by existing staff resulting in no overall increase in costs but potentially an increase in allocated costs.

The level of costs associated with implementing demand charges will therefore be negligible and not an impediment to proceeding. There will also be a cost to provide communication material to the affected customers and possibly personal explanations of the change. No attempt has been made to estimate the cost of implementing a communication plan as such a plan has not been developed.

Benefits

The benefits associated with implementing demand charges relate to sound rate design principles, consistency with Interconnected Systems rate structures and promote improved customer load factors.

It is a generally accepted principle of rate design that rate structures and the respective component levels should reflect the nature of the costs as accurately as possible in order to minimize the level of intra-rate class subsidization. As costs are generally capacity, energy and customer related¸ rate structures with these components will better reflect the costs associated with the level of service provided. Care must be taken to not make the rate too complicated however.

Moving to a rate structure with a demand component will be consistent with the rate structure currently used for the interconnected systems.

Having a rate structure with a flat energy charge results in higher load factor customers subsidizing lower load factor customers. Moving to a demand energy rate structure will therefore improve financial viability of high load factor customers in isolated system areas.

Conclusion

The cost of implementing demand charges in general service rates in isolated areas is not significant. Such a change in rate structure will have varying effects on customer’s individual bills. Generally lower load factor customers tend to receive increases while higher load factor customers will receive decreases assuming the rate is designed to recover the same revenue. Customers that will receive higher bills are likely to complain about such a change. Customers’ bills will however, better reflect their respective costs and provides them with an opportunity to reduce their bills through managing the level of demand they place on the system. Therefore Hydro should implement demand charges in the general service rates charged in isolated areas.

The timing of the implementation should reflect the other rate issues to be addressed in the isolated areas. However in preparation for the eventual implementation, demand meters should be installed on all appropriate customers in the near future.