Q. **Cost of Service Study (COSS) evidence - Exhibit JAB**

(1) Industrial revenues: Explain the basis for (a) the Industrial - Firm revenue credit of $40,326 in Schedule 1.2, line 4, column 4, and (b) the Industrial - Non Firm Revenues of $381,121 in Schedule 102, line 5, column 2. In each instance, indicate all billing determinants and rates assumed for these estimates.

(2) Industrial -Non Firm costs:

(a) Indicate any cost based rationale for the demand charge of $1.50 per kW proposed for non-firm sales to IC.

(b) Confirm that the COSS provides no analysis of any demand related costs for non-firm sales, and that the costs assigned to this service in the COSS are solely the firm energy cost of $.02311 per kWh. (Schedule 1.3, page 1)

(c) Provide a table setting out the assumed COSS generation (MWh) by source (hydraulic, No. 6 fuel, diesel fuel, gas turbine fuel, power purchases from NUGs, power purchases from non-NUGs) and month for the test year 2002 for the Island Interconnected System. Indicate the likely percent of load supplied by thermal during off-peak hours (low load evenings and weekend hours) during each month.

(d) Indicate annual functionalized cost of service for each of the above generation sources (in (c) above) and for transmission based on COSS for the Island Interconnected System, showing separately for each generation source and for transmission (where this is separate): fuel expenses, O&M, depreciation, expense credits, disposal gain/loss, return on debt and return on equity. Indicate classified generation and transmission costs (Production Demand, Production and Transmission Energy, Transmission Demand) separately for each fuel source and for transmission.

(e) Compare in detail the COSS firm energy cost of $.02311 per kWh and the non-firm energy charge rate as proposed in Schedule A of the Application (page 3), assuming the average cost of fuel assumed for the COSS; indicate how this charge could likely vary by month and time of day, based on the assumptions adopted for COSS as to expected fuel use. Explain how in practice it will be determined what fuel source is used to supply non-firm energy. What will happen if this energy is supplied in whole or in part from non-thermal sources?

(3) Holyrood average capacity factor: Provide, on the same basis as Schedule 4.3, the calculations to indicate the forecast net capacity factor for Holyrood for the year 2002. Explain the factors affecting variances in this capacity factor for the years 1997 through 2002. Assuming that the COSS for 2002 assumes No. 6 fuel consumption based on average hydraulic generation availability and forecasts loads, why would it not be more appropriate to use the net capacity factor consistent with these assumptions rather than one based on the prior 5-year actual average?

(4) Loads used for COSS: Provide a table or the Island Interconnected System test year 2002 setting out for each rate class the following projections: billing demands at customer meter; coincident peak loads at customer meter and at generator (after provision for losses); 2CP kW at customer meter and at generator (after provision for losses); sales at customer meter and generation energy requirements after losses; number of customers for COSS allocation purposes. Explain all assumptions used to derive these projections.

(5) Load Factor classification - generation costs: Review the rationale behind the Board’s 1993 Report recommendation for splitting hydraulic plant costs for the Island Interconnected System between energy and demand based on the system load factor. Indicate the change that this creates from the previous COSS adopted by Hydro for the last rate hearing. Indicate the rationale for also applying the load factor of each Isolated Diesel system group in order to split diesel plant costs between energy and demand.

(6) Generation cost allocation: As reviewed in the evidence of J. A. Brickhill (page 8), generation costs for the Island Interconnected System have been allocated among rate classes based on a 2CP allocator. Provide the loss of load hours (LOLH) study carried out by Hydro which supports use of a 2CP allocator because it indicates a greater risk of loss of load hours largely in two winter months. Provide the annual data supporting Schedule II of J. A Brickhill's evidence for each year indicated in this schedule (1994, 1996, 1997, 1998, 1999, 2000); provide the same information for 1995 (if available), projections for 2001, and the numbers supporting the projections for 2002. Indicate any other tests that could reasonably be considered when testing an allocation method in addition to the variation in results over time, and assess the 2CP method in light of each such test.

(7) Changes to rural deficit allocation: L. A Brickhill indicates at page 14 that the method of allocating the rural deficit between customers has changed to reflect the change in methodology from AED-based to CP-based. Indicate the difference in COSS results due to this one change in methodology, and the impact that this change has on allocation of the rural deficit for the 2002 test year.

(8) Changes in RSP allocation: L. A Brickhill indicates at page 15 that the RSP has historically been split between participating customer groups based on Hydro's COSS. Indicate what changes, if any, the current COS methodology makes with respect to such splits compared to the COSS methodology used previously and provide an assessment of the differences if any that result to the test year 2002 RSP allocation as provided for in schedule 1.2.1 of the COSS.

A. (1)(a) The Industrial - Firm revenue credit of $40,326 in Schedule 1.2, line 4, column 4, (Exhibit JAB-1, page 4) was allocated to customer classes based on revenue requirement. The $40,326 was therefore calculated as follows:

Industrial Firm Revenue Requirement Before Deficit and Revenue Credit	$ 50,005,883
Divided by:	
Total Island Interconnected Revenue Revenue Requirement (Excluding Non- Firm Revenue Requirement)	$277,812,814
Equals	18%
Multiplied By	
Total Island Interconnected Non-Firm Revenue Credit	$ 224,033
Equals	$ 40,326

(1)(b) The Industrial - Non Firm Revenues of $381,121 in Schedule 1.2, line 5, column 2 was calculated as shown on the attached Page 10 of 11.

(2) Industrial -Non Firm costs:

a) Please see response to NP-183.

b) The costs assigned to non-firm sales are as detailed in the Island Interconnected schedule showing the allocation of functionalized amounts to classes of service (Exhibit JAB-1, pages 39-40). The $157,088 is comprised of only energy cost allocations. The firm energy cost of $.02311 per kWh was derived from these allocated costs, rather than providing the basis for determining the costs.

c) The table below shows the assumed Cost of Service Generation by source for the test year 2002 for the Island Interconnected System.

Island Interconnected System
Assumed Cost of Service Generation by Source
(MWh)

Month	Hydraulic Plants	Holyrood (No.6 Fuel)	Diesel Plants	Gas Turbine Plants	Power PurchaseNUGs	Other Power Purchase
January	410,410	304,890	30	1,070	11,600	0
February	368,120	275,390	30	240	9,320	0
March	426,860	228,670	30	220	9,920	0
April	353,830	196,700	30	220	11,120	0
May	331,890	152,450	30	220	13,810	0
June	329,580	98,350	30	220	13,320	0
July	408,050	0	30	220	13,000	0
August	401,530	0	30	220	12,820	0
September	273,460	147,530	30	220	12,360	0
October	290,850	203,260	30	220	13,240	0
November	314,300	245,880	30	220	12,870	0
December	362,790	304,760	30	900	12,520	0
Total	4,271,670	2,157,880	360	4,190	145,900	0

While thermal generation is required to complement production from Hydro's hydraulic resources in order to meet the overall system load, its output is varied to maintain system security and for water management reasons.

Normally, thermal generation is base loaded at an efficient output level. Hydraulic generation is used to track the system load. Thermal output may be reduced for system security or for system loading reasons (ie. not enough load to share amongst required on-line generation). As well, thermal output may be increased from its base load to meet system peak requirements.

Each week, System Operations sets the thermal base load requirement to manage the water resource while respecting power system security. The likely percent of loading supplied by thermal generation during off peak hours varies as a result of the items previously mentioned, however, the likely percent of system load supplied by thermal generation in the off-peak hours is 2 to 5 percent higher than the percent of system load supplied by thermal generation in the on-peak hours.

d) This analysis is not currently available, but work is in progress.

e) The following table compares the industrial firm energy charge with the industrial non-firm energy charge by month for 2002. It uses the average cost of fuel used in the cost of service for each source.

Comparison of Industrial Firm Rates and Non-Firm Energy Rates

Month	Firm Energy Rate	Holyrood Non-Firm Energy Rate	Variance from Firm	Gas Turbine Non-Firm Energy Rate	Variance from Firm	Diesel Non-Firm Energy Rate	Variance from Firm
January	$0.02311	$0.04387	$0.02076	$0.10401	$0.08090	$0.10743	$0.08432
February	$0.02311	$0.03914	$0.01603	$0.10278	$0.07967	$0.10743	$0.08432
March	$0.02311	$0.03914	$0.01603	$0.10367	$0.08056	$0.10743	$0.08432
April	$0.02311	$0.03745	$0.01434	$0.10360	$0.08049	$0.10743	$0.08432
May	$0.02311	$0.03745	$0.01434	$0.10354	$0.08043	$0.10743	$0.08432
June	$0.02311	$0.03686	$0.01375	$0.10524	$0.08213	$0.10743	$0.08432
July	$0.02311	$0.03686	$0.01375	$0.10518	$0.08207	$0.10743	$0.08432
August	$0.02311	$0.03686	$0.01375	$0.10514	$0.08203	$0.10743	$0.08432
September	$0.02311	$0.03657	$0.01346	$0.10686	$0.08375	$0.10743	$0.08432
October	$0.02311	$0.03639	$0.01328	$0.10686	$0.08375	$0.10743	$0.08432
November	$0.02311	$0.03620	$0.01309	$0.10683	$0.08372	$0.10743	$0.08432
December	$0.02311	$0.03613	$0.01302	$0.10814	$0.08503	$0.10743	$0.08432

The non-firm energy charge will be at the Holyrood non-firm rate for all periods including the periods when no thermal source is operating, except when either or both of the diesel plants and the gas turbine plants are operated or their output must be increased to meet the non-firm load. Typically the diesel plants or gas turbine plants would be required to meet non-firm energy requirements during peak load periods or when there are transmission restrictions to the area of the grid where the customer is located. Although the higher non-firm rates could apply during any hour of the year due to transmission or generation problems, the probability is higher in the winter period (December to March) and during the peak hours of 0800 to 2000 hours each day.

The decision to use a higher cost source is made by the power system operator when he determines there is insufficient power or energy available from other sources, either hydroelectric or Holyrood to meet the load demanded on the system, or there is insufficient transmission capacity to an area where the non-firm load is being demanded.

(3) The Holyrood net capacity factor for the year 2002 based on the forecast energy production is as follows:

$$\frac{2{,}157{,}880{,}000}{466{,}000 \times 8{,}760} = 52.86\%$$

The capacity factors from 1997 to 2000 are based on the thermal production required in those years. Both hydraulic generation and system load affect the Holyrood net production requirement. In all of these years the hydraulic generation was above average resulting in reduced Holyrood requirements. In addition, in 1998 and 1999 net production at Holyrood was reduced further due to the lower load caused by extended labour disputes in the pulp and paper industry. The capacity factors for 2001 and 2002 are based on forecast net production at Holyrood, which is based on the load forecast for those years with average hydraulic production.

(4) The table requested is shown on the attached page 11 of 11.

(5) At the last rate hearing, hydraulic plant costs for the Island Interconnected System were split on a 50% demand/50% energy basis in the 1992 COS Study.

Diesel plants in the Isolated Systems are operated as base load plants similar to the Holyrood Thermal plant. For this application, Hydro has proposed using the system load factor for the Labrador and Island Isolated Systems as a proxy for capacity factor as used for Holyrood for consistency.

(6) See response to NP-135 for copy of 2CP allocator report. See response to IC-137 regarding data supporting Schedule II of J.A. Brickhill. Other tests which could be reasonably considered are Bonbright's fair-cost-apportionment objective and the consumer rationing objective. The 2CP method meets both. It fairly distributes the generation demand requirement among the Island Interconnected System customers as it reflects cost causality. It promotes the use of economically justified service because it allocates costs to those who cause the incurrence of the costs.

(7) The 1992 test year Cost of Service (COS) methodology used Average and Excess Demand (AED) kW to allocate production and transmission demand costs to rate classes. The proposed methodology uses Coincident Peak (CP) to perform these allocations. The Cost of Service, revised to reflect the AED methodology, is attached.

(8) The 1992 test year Cost of Service (COS) methodology used Average and Excess Demand (AED) kW to allocate production and transmission demand costs to rate classes. The proposed methodology uses Coincident Peak (CP) to perform these allocations. This change in methodology impacts the RSP customer splits, as revised actual energy amounts, using AED methodology, also affected demand costs, and revised demands were therefore also required for the RSP split between customer groups. Schedule 1.2.1 (exhibit JAB-1, pages 9-10) is impacted in that CP kW are also used to determine the unit costs of the deficit. It is important to note that cost allocation also would change if AED were used. This analysis does not

consider those impacts. The effects of allocating the rural deficit (Schedule 1.2.1) using AED on the 2002 forecast annual RSP activity are:

	Proposed	Revised	Difference
Newfoundland Power	$19,380,610	$19,375,272	$(5,338)
Island Industrial	5,909,874	5,909,874	-
Labrador interconnected	199,739	205,077	5,338
	$25,490,223	$25,490,223	-

Interruptible 'A' Rates (Industrial):

	January	February	March	April	May	June	July	August	September	October	November	December	Total
A. Bunker 'C' Consumption ($/Bbl.)	28.5734	28.4562	28.4562	28.4144	28.4144	28.3998	28.3998	28.3998	28.3925	28.3879	28.3833	28.3816	
B. Efficiency (kWh/Bbl.)	610	610	610	610	610	610	610	610	610	610	610	610	
C. Mill Rate before Administration- (A / B * 1000)	46.84	46.65	46.65	46.58	46.58	46.56	46.56	46.56	46.55	46.54	46.53	46.53	
D. Administration	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
E. Mill Rate (C * (1 + D))	51.52	51.32	51.32	51.24	51.24	51.22	51.22	51.22	51.21	51.19	51.18	51.18	
F. Demand ($ per kW)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
G. Forecast Energy	88,000	82,000	91,000	88,000	85,000	88,000	91,000	91,000	3,237,000	2,681,000	88,000	88,000	
H. Energy Revenue	4,534	4,208	4,670	4,509	4,355	4,507	4,661	4,661	165,767	137,240	4,504	4,504	348,121
I. Forecast Demand	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	6,000	6,000	1,000	1,000	
J. Demand Revenue	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	9,000	9,000	1,500	1,500	33,000
Total Revenue	6,034	5,708	6,170	6,009	5,855	6,007	6,161	6,161	174,767	146,240	6,004	6,004	381,121

Newfoundland and Labrador Hydro
2002 Test Year Projections
Island Interconnected

		Billing Demands (kW)	CP at Customer Meter (kW)	CP at Generator (kW)	2 CP at Customer Meter (kW)	2 CP at Generation (kW)	Sales at Customer Meter (MWh)	Energy at Generator (MWh)	Number of Customers
1	Newfoundland Power	-	1,026,791	989,280	2,053,582	1,978,568	4,454,800	4,602,195	1
2	Industrial - Firm	2,244,000	172,601	179,125	345,202	358,251	1,464,970	1,513,441	4
3	Industrial - Non-Firm	22,000	-				6,798	7,023	2
	Rural								
4	1.1 Domestic	-	24,142	27,814		54,650	107,264	119,486	12,256
5	1.12 Domestic All Electric	-	30,640	35,301		69,359	109,736	122,240	6,783
6	1.3 Special	-	51	59		115	220	245	2
7	2.1 GS 0-10 kW	-	3,223	3,713		7,044	15,763	17,559	1,931
8	2.2 GS 10-100 kW	188,235	9,250	10,657		21,869	54,336	60,527	830
9	2.3 GS 110-1,000 kVa	165,655	5,507	6,308		10,994	39,444	43,802	70
10	2.4 GS Over 1,000 kVa	91,946	5,510	6,256		11,363	31,237	34,524	8
11	4.1 Street and Area Lighting	-	714	823		1,616	3,000	3,342	974
12	**Subtotal Rural**	445,836	79,037	90,931	-	177,010	361,000	401,725	22,854

Assumptions:

CP at Customer Meter
NP and Industrial CP based on the load forecast January peaks, to which the following Coincidence Factors have been applied:

Newfoundland Power	1.00
Industrial - Firm	0.92

Rural CP based on load research applied to load forecast.

CP at Generator
Common transmission losses allocated to all rate classes based on transmission level CP.
Distribution losses allocated to rural rate classes only.
Newfoundland Power's CP includes it's own generation, less generation demand credit.

2 CP at Customer Meter
CP at meter for the two peak months of January and December calculated and summed.
Data not available for rural rate classes.

2 CP at Generator
CP at generator for the two peak months of January and December calculated and summed.

Billing Demands, Sales at Customer Meter
Based on load forecast.

Energy at Generator
Common transmission losses allocated to all rate classes based on transmission level energy.
Distribution losses allocated to rural rate classes only.