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August 17, 2001

G. Cheryl Blundon
Board Secretary
Board of Commissioners of Public Utilities
Suite E210, Prince Charles Building
120 Torbay Road
P.O. Box 21040
St. John's, NF
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Dear Ms. Blundon:

Re: Newfoundland & Labrador Hydro's 2001 General Rate Application

Please find enclosed the original plus seventeen (17) copies of Newfoundland and Labrador Hydro's responses to Newfoundland Power's Requests for Information for the following numbers:

NP-186, 187, 188, 189, 190, 191, 192, 193, 194, 195, 196, 197, 198, 199, 200, 201, 202, 203, 204 and 205.

Yours truly,

Newfoundland and Labrador Hydro

____

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Q. Further to NP-10, would Hydro allow the Board's financial consultants to review for reasonableness the labour escalation rate assumed for 2002 (subject to maintaining the confidentiality of the information)?

A. Yes.

Q. (a) Further to NP-11(a), provide details of inter-corporate transactions with affiliates or subsidiaries other than CF(L)Co for each year for the period 1992 to 2000 and forecast for 2001 and 2002 (JCR, Schedule I, lines 34 and 35); or confirm that there were no inter-corporate transactions with, or charges to Gull Island Power Company Limited, Lower Churchill Development Corporation and, Twin Falls Power Corporation Limited.

(b) Subject to the answer to NP-187(a) above, provide details on how Hydro allocates costs to its subsidiaries or affiliates (other than CF(L)Co), including costs of executives and other employees (JCR, Schedule I, lines 34 and 35).

A. (a) There are no charges by Hydro to Gull Island Power Company Limited, Lower Churchill Development Corporation Limited and Twin Falls Power Corporation Limited during the years 1992 to 2000 or forecast for 2001 and 2002.

(b) Please see response to (a) above.

Q. Further to NP-13, (JCR, Schedule I):

(a) provide details of advertising expense for the years 1992-2000;

(b) provide explanation of "Communications Plan" advertising;

(c) provide the justification for including a $60,000 contribution for Bay D'Espoir Street Lighting as part of regulated costs for 2002.

A. (a) Please see attached schedules which were inadvertently omitted from the response to NP-13(b).

(b) One of the issues that is being dealt with by Hydro's Management is that of internal and external communications. Good communication with internal and external stakeholders is essential in the conduct of business. Hydro is intent on ensuring that it has an effective communications program which supports and contributes to the overall success of its operations.

(c) In a January, 1978 Report to the Board, H.R. Doane and Company, the Board's auditors reviewed Hydro expenses and found that the grants to the Town of Bay D'Espoir to cover streetlighting were acceptable. Subsequently, the conclusion on page 54 of the Public Utilities Board (PUB) report containing the recommendations on the rates proposed by Newfoundland and Labrador Hydro in its March 6, 1989 referral states the following:

"The contribution towards street lighting in the Bay d'Espoir towns was accepted as an expense years ago, partly because of the employees of Hydro living in the area. It has been in place for a number of years and the Board will not recommend it be disturbed."

Further, on page 55 of the same report, the PUB goes on to state that "all… (charitable and other donations)… (with the exception of the street lighting grant now in place in the Bay D'Espoir Area) be removed from the cost of service…".

Historically, as outlined, the Bay d'Espoir street lighting contribution has been accepted as a legitimate cost of business.

Q. Further to NP-27, provide copies of any internal/external audit reports or reviews that discuss the Hydro customer service system (WEW, page 19, lines 17-20), or confirm that no reports prepared refer to the system.

A. There are no audit reports prepared that refer to the customer service system.

Q. (a) Further to NP-35(a), in its report to the Minister on July 29, 1996, the Board recommended that preferential rates be phased out and that the phase-out period should be five years. Why is Hydro not providing a schedule to eliminate the preferential rates in accordance with the Board's recommendation?

(a)*(sic)* Further to NP-35(b), in its report to the Minister on July 29, 1996, the Board recommended that the new rate for federal and provincial departments and agencies should be phased in over 5 years to recover full costs. Why is Hydro not providing a schedule to implement rates to recover full cost in accordance with the Board's recommendation?

A. (a) Please see response to NP-150 and NP-151. Hydro did not start the phase out of preferential rates since if preferential rates were phased out at this time the magnitude of the rate increase to Isolated Rural customers, including the general increase, is considered to be significant.

Also, it would not be prudent to start the complete phase out given the magnitude of the projected overall increases until the Board has given some direction on Rural rates arising from the current rate application.

Q. Further to the derivation of the $24,490,000 (*sic*) RSP transfer for 2002 provided in NP-43, reconcile:

(a) the $21.20 average COS fuel cost for 2002 provided in response to NP-43 with the $20 per barrel referred to by DWO line 18, page 3.

(b) the $28.43 average forecast fuel cost for 2002 provided in response to NP-43 with the $28 per barrel referred to by DWO line 25, page 3.

(c) The $28.43 average forecast fuel cost for 2002 provided in response to NP-43 with the $28.38 in RJH Schedule VIII.

A. (a) The $20 per barrel referred to in the evidence of D.W. Osmond on line 18, page 3 is the purchase price per barrel that is used in determining the cost of service fuel cost. For purposes of calculating the fuel variance portion of the RSP, the individual monthly costs are used as opposed to the twelve month average cost of $21.20 as shown in NP-43.

(b) The $28 per barrel referred to in the evidence of D.W. Osmond on line 25, page 3 is the projected purchase price per barrel of $28.38 expressed in whole dollars. For purposes of calculating the fuel variance portion of the RSP, the individual monthly costs are used as opposed to the twelve month average cost of $28.43 as shown in NP-43.

(c) The $28.38 per barrel shown in RJH Schedule VIII is the expected average purchase price per barrel for 2002. Please see answer to (b) above for the explanation of the $28.43 per barrel.

Q. Further to NP-56, provide details of the $2,731,000 decrease in depreciation expense from 2000 to 2001 (JCR, Schedule 1, Line 3) showing the calculation of depreciation expense for each year by class of property (e.g. distribution, transmission, general properties, etc.).

A. Details of the $2,731,000 decrease in depreciation expense from 2000 to 2001 are as follows:

	Depreciation Expense		
Asset Class	2000	2001	
Difference			
Hydraulic	$ 2,815,723	$ 2,865,242	$ 49,519
Thermal	8,450,994	5,129,042	(3,321,952)
Gas Turbines	2,107,551	1,800,606	(306,945)
Diesel Generation	2,144,808	2,265,999	121,191
Transmission Lines	3,208,419	3,734,253	525,834
Sub-Stations	3,716,423	3,736,949	20,526
Distribution	2,907,640	3,059,134	151,494
Telecontrol	1,774,581	1,837,219	62,638
General Plant	6,260,068	6,078,589	(181,479)
Computer Software	2,082,729	2,230,728	147,999
	35,468,936	32,737,761	(2,731,175)

Q. Further to NP-60, for the period 1995 to 1998, provide copies of any reports provided by Hydro to the Board reporting annual rates of depreciation applied to classes of property of Hydro as required by Section 68 of the *Public Utilities Act*.

A. Hydro has not filed any reports with the Board reporting annual rates of depreciation for the period 1995 to 1998.

Q. Further to the Debt Guarantee Fee calculation provided in NP-77, reconcile:

(a) the $10.6 million Debt Guarantee Fee for the year 2000 stated on page 36 of the 2000 Annual Report with the $11.1 million Debt Guarantee Fee for 2000 (based on 1999 debt) shown on NP-77; and

(b) The $1,261,093,000 base amount of debt for 2001 provided in NP-77 with the $1,225,076,000 amount for 2001 total debt provided in JCR, Schedule VIII.

A. (a) The $490 thousand difference is attributable to a $49 million adjustment to the closing debt balance at the end of 1999 relating to net income from the sale of recall energy to Hydro Quebec.

(b) Please see schedule below.

	(000's)
Base amount per NP-77	$1,261.0
CFLCo Share Purchase Debt	$ (27.5)
Unamortized Issue Expenses	$ (12.2)
Long Term Leases	$ 3.7
Base amount per JCR, Schedule VIII	$1,225.0

Q. Further to NP-82, provide details of the spread estimates on forecast long-term debt provided by “other members of the underwriting syndicate”. Identify the source of each estimate.

A. Estimates as provided by other members of the underwriting syndicate were received on March 28 relating to the benchmark 5.75% June 1, 2029 Canada, and were considered supportive of the Scotia Capital estimates. These were as follows:

RBC Dominion Securities	74
CIBC Wood Gundy	76
Nesbitt Burns	74
Merrill Lynch	75

Q. Further to NP-84(a) provide details of the CF(L)Co Share Purchase Debt (JCR Schedule VIII). Include the original amount of the loan, the date issued, the terms of repayment and the interest rate.

A. Please see schedule below. Also please refer to NP-84b for further details on loan amortization. From 1975 to 1992, interest on CF(L)Co related debt on Hydro's books was calculated at each month end using a weighted average rate of Hydro's most recent debt sufficient to cover the outstanding CF(L)Co debt. Since 1993, Hydro's average embedded cost of total debt at each year end has been applied to the CF(L)Co debt balance for the entire ensuing year.

Year	Opening Balance ($000)	Common Dividends Received ($000)	Preferred Dividends Received ($000)	Rentals & Royalties Received ($000)	Dividends Paid to Province ($000)	Interest & Guarantee Fee ($000)	Closing Balance ($000)	Interest Rate
1975	144,751	-	-	-	-	14,860	159,611	N/A
1976	159,611	4,901	-	-	-	13,134	167,844	N/A
1977	167,844	9,801	-	-	-	16,922	174,965	N/A
1978	174,965	19,314	-	5,780	-	19,340	169,211	N/A
1979	169,211	19,371	2,638	5,509	-	21,800	163,493	N/A
1980	163,493	15,682	3,218	6,068	-	23,365	161,890	11.00%
1981	161,890	20,237	4,564	5,874	-	26,592	157,807	13.44%
1982	157,807	17,815	3,487	5,300	-	24,340	155,545	15.34%
1983	155,545	12,741	2,668	4,899	-	22,985	158,222	14.63%
1984	158,222	14,990	4,846	8,535	-	23,482	153,333	13.47%
1985	153,333	18,219	5,007	5,377	-	16,363	141,093	11.60%
1986	141,093	16,893	5,715	5,107	-	13,302	126,680	9.73%
1987	126,680	15,740	5,327	5,002	-	11,244	111,855	9.30%
1988	111,855	15,970	5,969	4,851	-	9,872	94,937	9.41%
1989	94,937	12,972	5,250	3,086	-	8,687	82,316	11.07%
1990	82,316	2,883	1,347	3,787	-	9,988	84,287	12.75%
1991	84,287	20,063	6,698	3,751	-	7,624	61,399	9.96%
1992	61,399	11,242	5,770	(3,751)	-	5,986	54,124	7.46%
1993	54,124	10,897	3,898	-	-	5,500	44,829	10.90%
1994	44,829	6,399	4,045	-	-	4,805	39,190	10.30%
1995	39,190	7,841	4,952	-	5,000	4,640	36,037	10.70%
1996	36,037	6,342	5,183	-	3,221	4,494	32,227	9.70%
1997	32,227	10,493	5,883	-	8,563	2,760	27,174	9.60%
1998	27,174	12,626	6,160	-	4,800	1,896	15,084	8.95%
1999	15,084	8,360	8,371	-	5,000	1,109	4,462	8.80%
2000	4,462	5,246	7,575	-	33,300	1,842	26,783	8.55%
2001	26,783	4,607	7,430	-	10,000	2,537	27,283	8.40%
2002	27,283	4,607	7,800	-	8,507	2,219	25,602	7.40%

Rates for the years 1975 to 1979 were not available.

Note: Response to NP-84a will be revised prior to commencement of Hearing to be in agreement with details contained in the above schedule.

Q. Further to NP-127, provide details of specifically assigned amounts to Newfoundland Power and the Industrial customers (in the format provided in NP-127 but identifying each transmission line or terminal station separately).

A. Details of specifically assigned amounts are attached.

Note: These calculations have been slightly revised from the specifically assigned charges calculated in JAB-1 due to the inadvertent omission of approximately $25,000 of plant from the customer plant ratios on JAB-1, p41.

Q. Further to NP-131, does the 66 kV plant feeding 400L at Bottom Brook Terminal Station, that has been proposed by Hydro to be treated as specifically assigned to Newfoundland Power, provide any benefit to customers other than Newfoundland Power?

A. The 66 kV plant feeding 400L at Bottom Brook Terminal Station does not provide any benefit to customers other than Newfoundland Power.

Q. Further to NP-134, would surplus earnings exist for the Wabush area if the Wabush cost of service methodology included estimates of overhead cost allocation, margin allocation, and rural deficit allocation (consistent with the Board's recommendations from the 1993 Report on Cost of Service)?

A. As outlined in NP-134, over the past number of years costs for Wabush have been compiled based on the accounting records and these costs do not include any overhead cost allocation, margin allocation or rural deficit allocation. Since a separate cost of service study for Wabush has not been completed, or required, using the 1993 cost of service methodology, there cannot be a proper estimate of these allocations.

However, based on 1999 accounting data Hydro has available and upon reviewing the Actual 1999 Cost of Service Study (Revised) it is unlikely that a surplus would exist for that year, or any year 1989 to 2000, if estimates of overhead cost allocation, margin allocation, and rural deficit allocation were included consistent with the Board's recommendations from the 1993 Report on Cost of Service.

Q. Further to NP-142 (d), provide the rationale for earning margin on the mid-year balances in RSP and CWIP.

A. The mid-year balance of RSP and CWIP represents the average amount outstanding during the year. The RSP and CWIP are not financed by debt alone, rather, they are financed by the same proportions of capital as the rate base assets. Therefore, the weighted average cost of capital rather than the embedded cost of debt is the appropriate rate to apply to both the RSP and the CWIP. Please refer to the evidence of K.C. McShane, pages 10 - 11, and the responses to PUB-65 and PUB-66.

Q. Reconcile the $322,300,000 2002 forecast revenue requirement (JCR, Schedule I) with the $315,795,747 total revenue from rates (PRH, Table 2, page 9).

A.

Forecast Revenue Requirement, JCR Schedule 1	$322,300,000
Less Miscellaneous Revenue reclassified in the Cost of Service as Expense Credits	(1,051,216)
Less IOCC revenues	(5,459,471)
Plus wheeling revenue included as revenue from rates in Table 2, but included in revenue requirement as Cost reduction	6,950
Less other rounding difference	(516)
Forecast Revenue, PRH, Table 2	315,795,747

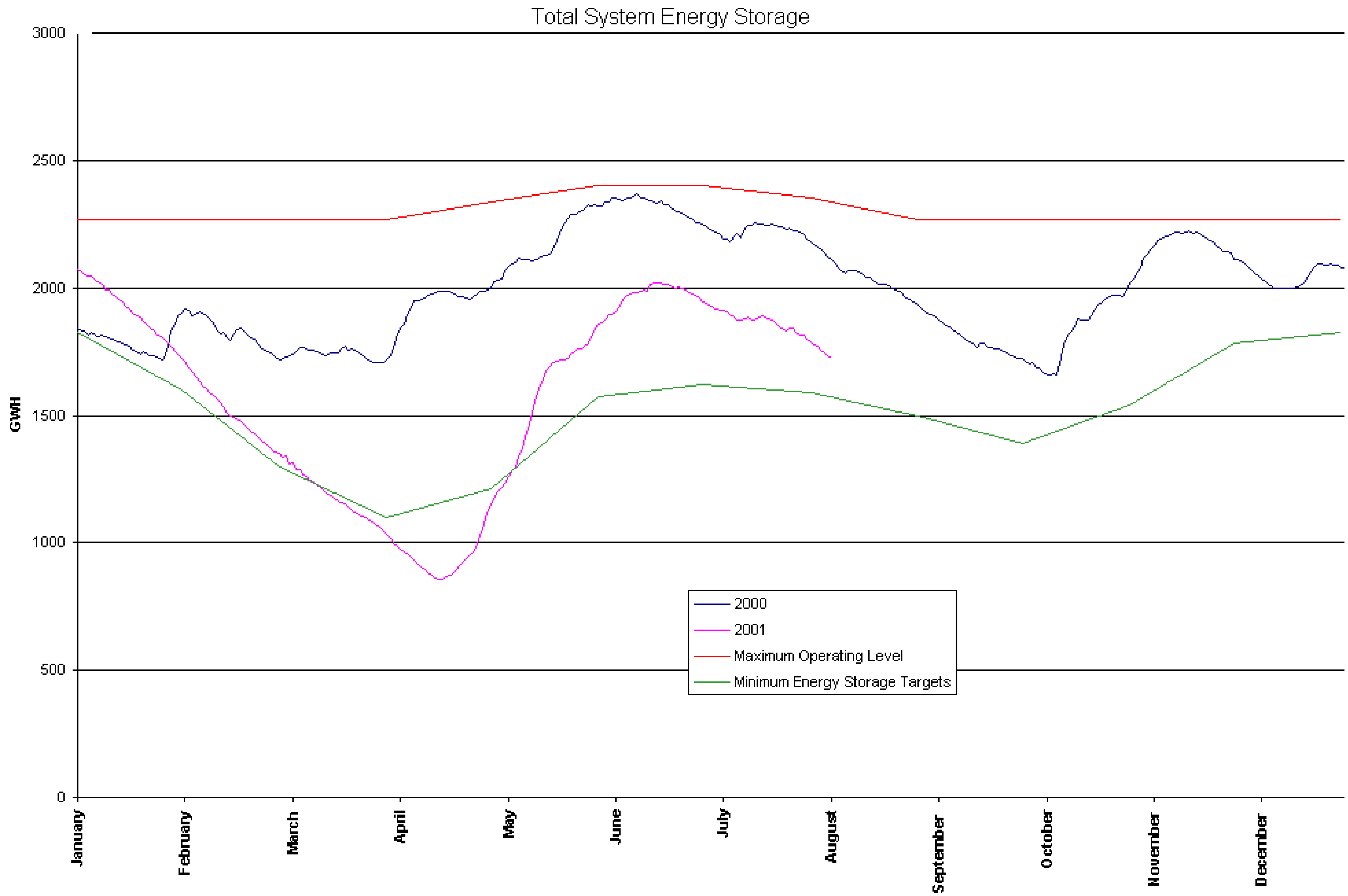
Q. Further to the proposed changes in the RSP detailed in IC-120, provide a recalculated RSP report for December 2000 utilizing the method proposed. Also provide the detailed calculation of the RSP splits by Customer Plan and the detailed rate calculation using the method proposed in IC-120.

A. Please see attached. The restated RSP was calculated using the following assumptions:

- Test Year 1992 - unchanged
- Mini Hydro included in Hydraulic variation
- Holyrood conversion factor changed from 605 kWh/bbl to 610 kWh/bbl.
- Interruptible energy no longer included in the plan.
- RSP customer split based on 12 months to date energy
- RSP adjustment rate established on the same basis as split (12 months to date)
- Finance charge is Hydro’s 2002 Test Year weighted average cost of capital

Q. Provide an update of RJH, Schedule 3 reflecting June and July storage levels.

A. See attached schedule.


Total System Energy Storage
GWH
3000
2500
2000
1500
1000
500
0
January
February
March
April
May
June
July
August
September
October
November
December
2000
2001
Maximum Operating Level
Minimum Energy Storage Targets

1

Q. Further to distribution of inflows provided in IC-195, provide:

(a) the data used to determine the distribution of inflows in electronic form;

(b) The mean, mode and median of the 50 years of system energy inflow data.

A. (a) The electronic copy of the annual distribution of inflows is provided on the enclosed diskette in the file NP_204.xls.

(b) The mean of the 50 years of system energy inflow data is 4,294 GWh and the median is 4,331 GWh. As no two years have the same energy inflows, there is no mode for this data.

COMBINED RESERVOIR
"ENERGY INFLOWS"
(Bay D'Espoir + Cat Arm + Hinds Lake)
MONTHLY INFLOWS (GWh)

YEAR	TOTAL
1950	3,392
1951	4,263
1952	4,431
1953	3,993
1954	4,564
1955	3,594
1956	4,285
1957	3,871
1958	4,205
1959	3,417
1960	3,158
1961	3,068
1962	4,732
1963	4,797
1964	4,331
1965	3,985
1966	3,536
1967	4,149
1968	4,287
1969	5,052
1970	3,571
1971	4,878
1972	4,873
1973	4,500
1974	4,020
1975	3,824
1976	4,771
1977	5,499
1978	3,694
1979	4,195
1980	4,718
1981	5,252
1982	4,339
1983	4,919
1984	4,701
1985	3,306
1986	3,742
1987	3,717
1988	4,388
1989	3,389
1990	4,440
1991	4,066
1992	4,201

1993	5,367
1994	4,654
1995	4,679
1996	4,548
1997	4,419
1998	4,728
1999	5,214
2000	5,255

Q. Further to NP-72 (c):

(a) Confirm the month in which the dividend is assumed to be paid;

(b) provide the details behind the $1.7 million estimate;

(c) provide the estimated impact on 2003 revenue requirement.

A. (a) $68 million of the dividend is assumed to be paid at the end of March 2002, with smaller payments of $680 thousand being paid at the end of each succeeding quarter.

(b) Please see schedule below.

($ thousands)

		As Filed			Without $70m dividend		
Component	2002	WACD	WACC	Return	WACD	WACC	Return
Rural	134,308	6.941		9,322	6.757		9,075
Other	1,236,163		7.399	91,464		7.284	90,042
Total	1,370,471			100,786			99,117

(c) The estimated impact on the 2003 revenue requirement is $2.4 million.