Q. (a) Provide the excerpts from the legislation to support, in Hydro's view, the statement "the legislative amendments indicate that, as a matter of public policy, Hydro is intended to operate as a fully regulated utility, more similar to that of an investor-owned utility" (WEW, page 6 lines 20-22).

(b) In addition to the legislation, what does Hydro view as the similarities between the way Hydro is intended to operate and the manner in which an investor-owned utility operates?

A. (a) Pursuant to Chapter 37 of the Statutes of Newfoundland 1995, there were a series of legislative amendments affecting Hydro. The effect of these amendments was to repeal certain provisions that had existed under the *Hydro Corporation Act*, Revised Statutes of Newfoundland, 1990, as amended to that time, and under various other statutes. Prior to the repealing of these provisions, a number of special legislative treatments usually associated with crown corporations and government agencies had applied to Hydro.

Section 5 of Chapter 37 reads as follows:

"5. Section 14 of the Act is repealed."

Section 14 of the *Hydro Corporation Act* provided Hydro with the exclusive franchise to develop all previously un-granted hydro-electric sites on the island portion of the province.

Section 6 of Chapter 37 reads as follows:

"6. Paragraph 16(1)(h) of the Act is repealed and the following substituted:

"(h) deposit money or securities with a bank, trustee, trust company, or other depository in Canada or outside Canada;"

Prior to this amendment, the prior approval of the Lieutenant-Governor in Council was required to deposit money or securities outside Canada.

Section 7 of Chapter 37 starts as follows:

"7. Sections 17, 18, 19, 20 and 21 of the Act are repealed . . . ."

Under section 17, Hydro had access to special powers of expropriation under the *Expropriation Act*. Section 19 provided Hydro with the ability to obtain rights to water powers and lands through an assurance of the Lieutenant-Governor in Council. Under sections 20 and 21, respectively, Hydro was exempt from the *Crown Lands Act* and the *Public Utilities Act*.

Section 8 of Chapter 37 reads as follows:

"8. Sections 22 and 23 of the Act are repealed."

Under section 22, Hydro was subject to the *Public Service Collective Bargaining Act.* Subsection 19(1) of the *Hydro Corporation Act* as amended by Chapter 37 reads as follows:

"19.(1) The *Labour Relations Act* applies to the corporation."

Section 10 of Chapter 37 reads as follows:

"10. Section 26 of the Act is repealed."

Section 26 of the *Hydro Corporation Act* provided Hydro with certain rights to obtain franchise rights to those hydro-electric sites in Labrador not subject to prior grants by the Crown.

Section 11 of Chapter 37 reads as follows:

"11. Subsection 40(2) of the Act is repealed."

Subsection 40(2) of the *Hydro Corporation Act* required Hydro to obtain the approval of the Lieutenant-Governor in Council for borrowing programs reflected in its budget.

Section 12 of Chapter 37 reads as follows:

"12. Subsection 41(3) of the Act is repealed and the following substituted:

"(3) The annual financial statement of the corporation shall be audited by a firm of auditors."

Prior to this amendment, the Act provided that the auditors be appointed by the Lieutenant-Governor in Council.

Section 13 of Chapter 37 reads as follows:

"13. Subsections 44(3), (4) and (6) and sections 45, 46, 47, 48, 49 and 50 of the Act are repealed."

Among other things, these provisions had provided Hydro and its directors special protections and limitation periods in litigation against them.

Section 20 of Chapter 37 reads as follows:

"20. Subsection 50(4) of the *Crown Lands Act* is repealed."

Section 21 of Chapter 37 reads as follows:

"21. The schedule to the *Freedom of Information Act* is amended by deleting the words "The Newfoundland and Labrador Hydro Corporation".

Section 23 of Chapter 37 reads as follows:

"23(1) Paragraph 2(b) of the *Public Tender Act* is amended by striking out the semicolon at the end of subparagraph (viii) and by substituting a comma and by adding immediately after subparagraph (viii) the following:

but does not include

(ix) Newfoundland and Labrador Hydro

(2) the Schedule to the Act is amended by deleting the words “Newfoundland and Labrador Hydro”.”

The *Electrical Power Control Act*, 1994 revised the power policies that had earlier been set out in the *Electrical Power Control Act*. The legislature removed from the 1994 statute the special treatment that had existed for Hydro as to the margin of profit. The provision that applies at present is the same for Hydro as it is for Newfoundland Power:

“3. It is declared to be the policy of the province that

(a) the rates to be charged, either generally or under specific contacts, for the supply of power within the province

(iii) should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the *Public Utilities Act* so that it is able to achieve and maintain a sound credit rating in the financial markets of the world . . .”

(b) Hydro views the following similarities between the way Hydro is intended to operate and the manner in which an investor-owned utility operates.

- Operate in an efficient and least cost basis
- Achieve an appropriate return on rate base
- Achieve an appropriate return on equity

- Achieve appropriate debt/equity ratios
- Provide an appropriate dividend payout

Q. What does Hydro view as the differences, if any, between the way Hydro is intended to operate and the manner in which an investor-owned utility operates (WEW, page 6, lines 20-22)?

A. Hydro views the following as the main differences between the way Hydro is intended to operate and the manner in which an investor-owned utility operates:

- As a Crown Corporation Hydro may receive directions from its shareholder, the Government of Newfoundland and Labrador, which reflects social or public policy considerations, not in conflict with legislation, which Hydro will implement.
- Hydro's ability to borrow and its borrowing program is influenced by the fact its debt is guaranteed by the Province. By having its debt guaranteed by the Province, Hydro is able to access capital markets under virtually all conditions and to borrow at a lower cost, which results in a lesser cost to customers.
- As a Crown Corporation, Hydro is not subject to corporate income taxes.

Q. Provide details of the calculation of the Debt Guarantee fee for each year from 1992 to 2000 and forecast for 2001 and 2002 (JCR, Schedule IX).

A. Please see attached schedule.

		1991	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
		$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Long-Term Debt		1,326,099	1,435,363	1,366,982	1,305,944	1,115,463	1,335,509	1,189,700	1,285,200	1,002,000	834,800	965,558
Unrealized Foreign Exchange Losses		-	-	-	-	-	(61,499)	-	-	-	-	-
Promissory Notes (adjusted for recall impact)		-	-	85,598	95,863	187,046	80,344	212,883	110,631	106,477	156,737	185,671
Curr Portion of Long-Term Debt		190,846	42,620	38,711	34,661	149,542	177,018	147,300	124,700	12,100	162,900	113,576
	Sub-Total	1,516,945	1,477,983	1,491,291	1,436,468	1,452,051	1,531,372	1,549,883	1,520,531	1,120,577	1,154,437	1,264,805
Less: Non Guaranteed Debt												
Churchill Falls (Labrador) Corporation		442,922	427,475	410,286	392,182	370,800	418,004	401,500	388,848	-	-	-
Swiss Franc Loan		28,286	-	-	-	-	-	-	-	-	-	-
Long Term Leases		6,839	6,631	6,398	6,138	5,848	5,524	6,386	6,984	6,000	5,300	3,712
	Sub-Total	478,047	434,106	416,684	398,320	376,648	423,528	407,886	395,832	6,000	5,300	3,712
Base amount of debt		1,038,898	1,043,877	1,074,607	1,038,148	1,075,403	1,107,844	1,141,997	1,124,699	1,114,577	1,149,137	1,261,093
Guarantee fee @ 1% (Payable in Following Year)		10,389	10,439	10,746	10,381	10,754	11,078	11,420	11,247	11,146	11,491	12,611
Less: CFLCo related share @ 1%		(365)	(305)	(455)	(398)	(365)	(326)	(272)	(151)	(45)	(268)	(275)
Net NLH Guarantee Fee		**10,024**	**10,134**	**10,291**	**9,983**	**10,389**	**10,752**	**11,148**	**11,096**	**11,101**	**11,223**	**12,336**

Notes:

1. The 2002 fee as filed was $11,993,000. This was in error. The correct amount as shown above is $12,336,000.
This error will be corrected in any final revisions to the Cost of Service filed in September.

Q. Provide the details of:
(a) redemptions of long-term debt from 1992 to 2000; and
(b) anticipated future redemptions from 2001 to 2006 (JCR, Schedule X).

A. (a) Please see schedule below.
(b) Please see schedule below.

Issue Date	Coupon	Series	Original Par Value ($000)	Currency	Historical FX Rate	Canadian Equiv ($000)	Final Maturity Date
4/1/72	8.125%		15,000	Cdn	N/A	15,000	4/1/92
5/15/82	15.125%		100,000	US	1.24072	124,072	5/15/92
5/1/68	7.750%		25,000	US	1.07093	26,773	5/1/93
12/15/75	10.750%		25,000	Cdn	N/A	25,000	12/15/93
4/2/79	9.875%		50,000	US	1.15594	57,797	4/2/94
8/1/69	9.000%		15,000	US	1.07500	16,125	8/1/94
7/15/86	9.875%	S	100,000	Cdn	N/A	100,000	7/15/96
3/15/74	8.875%		20,000	Cdn	N/A	20,000	4/15/97
11/15/85	Various		7,000,000	Yen	0.00534	37,349	5/28/97
6/1/75	Various		75,000	SF	0.37715	28,286	6/16/97
9/28/77	10.000%	J	35,000	Cdn	N/A	35,000	9/28/97
12/15/87	10.500%	T	100,000	Cdn	N/A	100,000	12/15/97
12/15/79	11.250%	M	75,000	Cdn	N/A	75,000	12/15/97
11/15/85	11.250%		35,000	Cdn	N/A	35,000	12/15/97
6/27/78	10.000%	L	40,000	Cdn	N/A	40,000	6/27/98
8/2/88	9.875%	U	100,000	Cdn	N/A	100,000	8/2/98
10/15/76	10.250%		30,000	Cdn	N/A	30,000	10/15/98
3/1/78	10.250%	K	35,000	Cdn	N/A	35,000	10/15/98
1/30/81	13.375%	N	75,000	Cdn	N/A	75,000	1/30/99
5/9/77	10.000%		30,000	Cdn	N/A	30,000	5/9/99
(b) Anticipated future redemptions from 2001 to 2006:							
9/17/91	10.750%	W	150,000	Cdn	N/A	150,000	9/17/01
10/10/97	5.250%	Z	100,000	Cdn	N/A	100,000	10/10/02
9/1/01	5.300%		100,000	Cdn	N/A	100,000	9/1/06

Q. Provide details of the projected impact on revenue requirement of the realized foreign exchange loss for each year from 2002 to 2006. Identify the annual amortization portion separately from the return on rate base (JCR, page 8, line 25).

A. Assuming a weighted average cost of capital of 7.39% as per the 2002 test year, the return on ratebase below is the projected impact of the foreign exchange loss on revenue requirement.

			($thousands)		
	2002	2003	2004	2005	2006
Average Unamortized Foreign Exchange Loss	85,200	83,043	80,886	78,729	76,572
Revenue Requirement	6,304	6,144	5,985	5,825	5,666
Amortization	2,157	2,157	2,157	2,157	2,157

Q. Treat the debt guarantee fee as a component of return on equity rather than interest expense and recalculate return on equity as a percentage for each year from 1992 to 2000 and forecast for 2001 and 2002.

A. Attached is the calculation of Hydro's return on equity, treating the debt guarantee fee as a component of return rather than interest expense.

Q. Provide detailed calculations of the interest rate projections for 2001 and 2002 (JCR, page 6, line 27).

A. Please see schedule below.

Institution	Qtr 1 2001	Qtr 2 2001	Qtr 3 2001	Qtr 4 2001	Average	Selection Qtr 3	Qtr 4	
91-Day Treasury Bills	4.75%	4.24%	**4.15%**	**4.28%**	**4.35%**	**4.35%**	**4.48%**	**(includes 20 Basis Point Spread for NLH C**
CIBC/W.Gundy	4.49%	3.80%	3.35%	3.70%	3.84%			
Merrill Lynch	5.00%	4.60%	4.65%	4.75%	4.75%			
Nesbitt Burns	5.00%	4.35%	4.25%	4.20%	4.45%			
RBCDS	4.60%	4.50%	4.60%	4.60%	4.58%			
ScotiaMcleod	4.64%	3.95%	3.90%	4.15%	4.16%			
5 Year Canadas	5.10%	4.96%	4.99%	5.11%	**5.04%**	**5.33%**		**(includes 34 Basis Point Spread for NLH C Based on Planned Borrowing during Q3**
CIBC/W.Gundy (note)	0.00%	0.00%	0.00%	0.00%	0.00%			
Merrill Lynch	5.10%	5.00%	5.15%	5.35%	5.15%			
Nesbitt Burns	5.12%	4.75%	4.70%	4.65%	4.81%			
RBCDS	5.10%	5.40%	5.55%	5.65%	5.43%			
ScotiaMcleod	5.08%	4.70%	4.55%	4.80%	4.78%	N/A		
10 Year Canadas	5.34%	5.18%	5.19%	5.35%	**5.27%**			
CIBC/W.Gundy	5.22%	4.85%	4.80%	5.15%	5.01%			
Merrill Lynch	5.35%	5.25%	5.45%	5.65%	5.43%			
Nesbitt Burns	5.38%	5.15%	5.10%	5.05%	5.17%			
RBCDS	5.35%	5.60%	5.65%	5.75%	5.59%			
ScotiaMcleod	5.40%	5.05%	4.95%	5.15%	5.14%			
Long Canadas	5.67%	5.52%	5.56%	5.68%	**5.61%**	**6.26%**		**(includes 74 Basis Point Spread for NLH C Based on Planned Borrowing during Q2**
CIBC/W.Gundy	5.58%	5.25%	5.30%	5.50%	5.41%			
Merrill Lynch	5.65%	5.50%	5.70%	5.90%	5.69%			
Nesbitt Burns	5.67%	5.45%	5.37%	5.30%	5.45%			
RBCDS	5.65%	5.85%	6.00%	6.15%	5.91%			
ScotiaMcleod	5.78%	5.55%	5.45%	5.55%	5.58%			

Note: CIBC estimates were not available for 5 year term.

Institution	Qtr 1 2002	Qtr 2 2002	Qtr 3 2002	Qtr 4 2002	Average	Selection	
91-Day Treasury Bills	4.59%	4.70%	4.87%	4.94%	**4.58%**	**avg +.20**	**(includes 20 Basis Point Spread for NLH C**
CIBC/W.Gundy	3.70%	3.45%	3.45%	3.40%	3.50%		
Merrill Lynch	5.05%	5.35%	5.65%	5.75%	5.45%		
Nesbitt Burns	4.15%	4.30%	4.40%	4.50%	4.34%		
RBCDS	4.75%	4.90%	5.25%	5.40%	5.08%		
ScotiaMcleod	4.30%	4.50%	4.60%	4.65%	4.51%		
5 Year Canadas	5.19%	5.30%	5.40%	5.41%	**5.33%**	**5.53%**	**(includes 34 Basis Point Spread for NLH C Based on Planned Borrowing during Q1**
CIBC/W.Gundy	0.00%	0.00%	0.00%	0.00%	0.00%		
Merrill Lynch	5.50%	5.65%	5.85%	5.80%	5.70%		
Nesbitt Burns	4.60%	4.70%	4.75%	4.80%	4.71%		
RBCDS	5.75%	5.90%	6.00%	6.00%	5.91%		
ScotiaMcleod	4.90%	4.95%	5.00%	5.05%	4.98%		
10 Year Canadas	5.41%	5.48%	5.51%	5.49%	**5.47%**	**6.14%**	**(includes 63 Basis Point Spread for NLH C Based on Planned Borrowing during Q3**
CIBC/W.Gundy	5.25%	5.25%	5.20%	5.20%	5.23%		
Merrill Lynch	5.75%	5.80%	6.00%	5.90%	5.86%		
Nesbitt Burns	4.90%	4.95%	5.00%	5.05%	4.98%		
RBCDS	5.90%	6.10%	6.05%	6.00%	6.01%		
ScotiaMcleod	5.25%	5.30%	5.30%	5.30%	5.29%		
Long Canadas	5.70%	5.73%	5.73%	5.69%	**5.71%**	**N/A**	
CIBC/W.Gundy	5.55%	5.55%	5.50%	5.50%	5.53%		
Merrill Lynch	6.00%	6.05%	6.15%	6.00%	6.05%		
Nesbitt Burns	5.10%	5.15%	5.20%	5.25%	5.18%		
RBCDS	6.25%	6.30%	6.20%	6.10%	6.21%		
ScotiaMcleod	5.60%	5.60%	5.60%	5.60%	5.60%		

Q. Provide details of all sources that were consulted in determining the applicable spreads on forecast long-term debt (JCR, page 7, line 1).

A. Spreads were selected for forecasting 2001 and 2002 interest rate projections (yields) as provided by Scotia Capital for the Newfoundland Government credit on April 9, 2001, for the 5, 10 and 30-year term and were as follows:

The 5-year maturity at plus 34 basis points over the Government of Canada Benchmark Bond 8.75% due December 2005.

The 10-year maturity at plus 63 basis points over the Government of Canada Benchmark Bond 6.00% due June 2011.

The 30-year maturity at plus 75 basis points over the Government of Canada Benchmark Bond 5.75% due June 2029.

These estimates were viewed in the context of similar estimates as provided by other members of the underwriting syndicate and were considered representative. Spread estimates from our advisors are based on actual market transactions, and do not normally vary by more than one or two basis points.

Q. Explain how the change from cost of debt to weighted average cost of capital impacts the forecast 2002 carrying charges for the RSP and CWIP. (JCR, page 8, line 8).

A. The embedded cost of debt, calculated on a consistent basis as prior years would have been 8%. As this is higher than the 7.4% weighted average cost of capital for 2002, the carrying charges for the RSP on CWIP are lower than they would otherwise have been.

	7.4%	8.0%	Difference
		($thousands)	
RSP	6,646	7,185	539
CWIP	8,504	9,190	686

Q. (a) Provide details of the CF(L)Co Share Purchased Debt (JCR, Schedule VIII). Include the derivation of the $25,609,000 for 2002.

(b) Provide the amortization and repayment schedule for (a).

A. (a) Please see schedule below

2002 Year

Description	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
WACC Monthly Rate	7.16%	7.16%	7.16%	7.16%	7.16%	7.16%	7.16%	7.16%	7.16%	7.16%	7.16%	7.16%	
Opening Balance	**27,546**	27,057	26,566	29,839	29,364	28,887	28,454	27,971	27,485	27,045	26,553	26,059	
Preferred Dividends	650	650	650	650	650	650	650	650	650	650	650	650	7,800
CFL Divs to Province	-	-	(4,644)	-	-	(1,200)	-	-	(1,200)	-	-	(1,200)	(8,244)
Guarantee fee	-	-	(275)	-	-	-	-	-	-	-	-	-	(275)
Common Dividends	-	-	1,152	-	-	1,152	-	-	1,152	-	-	1,152	4,607
Budget Interest	161	159	156	175	172	169	167	164	161	158	156	153	**1,951**
Closing Balance	27,057	26,566	29,839	29,364	28,887	28,454	27,971	27,485	27,045	26,553	26,059	**25,609**	

Average Balance Cflco Share Purchase Debt 27,248

This Dividend relates to 2001 results

Note: The monthly rate is applied to the opening monthly balance and is prorated based on days in the month to days in the year.
The rate is lower than the annual rate of 7.4% to reflect the impact of monthly compounding.

(b) As per a 1995 resolution of Hydro's Board of Directors, Hydro repays $1 million annually on the outstanding principal balance.

Q. Provide details of the calculation of the $1,951,000 cost of debt for 2002 on the CF(L)Co Share Purchase Debt (JCR, Schedule IX).

A. Please see attachment to NP-84.

Q. Provide details of the $94,151,000 Sinking Fund for 2002 (JCR, Schedule VIII).

A. Please see schedule below.

Sinking Fund	Bond Issue Par Value	Maturity	Estimated Opening Balance	Annual Contr.	Estimated Annual Earnings	Estimated Closing Balance
10.500%	125,000	6/15/14	44,527	1,875	3,566	49,968
10.250%	150,000	7/14/17	20,995	1,500	1,552	24,047
8.400%	300,000	2/27/26	15,053	2,400	1,125	18,578
6.250%	150,000	6/1/31	0	1,500	57	1,557
		Total	**80,575**	7,275	**6,301**	**94,151**

Q. Provide details of the calculation of the $101,662,000 Interest Expense for 2002 (JCR, Schedule IX) identifying long-term debt by issue and applicable short-term debt.

A. Please see attached document.

DESCRIPTION	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Canadian Bond Interest	7,052	7,052	7,052	7,510	7,510	7,510	7,510	7,510	8,527	8,235	8,090	8,090	91,650
Govt Of Canada Interest	168	168	168	133	133	133	133	133	133	133	133	133	1,702
Capital Leases	33	32	32	31	28	28	28	28	28	27	25	25	343
Short Term Interest	736	738	773	726	719	743	808	827	109	469	628	674	7,950
Rate Stabilization Exp	-	-	-	-	-	-	-	-	-	-	-	-	-
Fiduciary Fees	1	1	1	1	1	1	1	1	1	1	1	1	16
Total Interest Expense	**7,990**	**7,991**	**8,026**	**8,402**	**8,392**	**8,416**	**8,480**	**8,500**	**8,798**	**8,866**	**8,877**	**8,923**	**101,662**

CANADIAN BOND INTEREST

COUPON	MATURITY	PAR VALUE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
5.250%	10/10/02	100,000	438	438	438	438	438	438	438	438	438	146			4,083
5.300%	9/1/06	100,000	442	442	442	442	442	442	442	442	442	442	442	442	5,300
5.500%	3/31/07	100,000				458	458	458	458	458	458	458	458	458	4,125
5.500%	4/30/08	200,000	917	917	917	917	917	917	917	917	917	917	917	917	11,000
6.100%	9/1/12	200,000									1,017	1,017	1,017	1,017	4,067
10.500%	6/15/14	125,000	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094	13,125
10.250%	7/14/17	150,000	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	15,375
8.400%	2/27/26	300,000	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	25,200
6.250%	6/1/31	150,000	781	781	781	781	781	781	781	781	781	781	781	781	9,375
TOTAL			7,052	7,052	7,052	7,510	7,510	7,510	7,510	7,510	8,527	8,235	8,090	8,090	91,650

GOVERNMENT OF CANADA INTEREST

Industry Canada	Maturity	Average Balance	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
5.250%	3/31/03	36	0	0	0	0	0	0	0	0	0	0	0	0	2
7.917%	3/31/03	4,964	51	51	51	27	27	27	27	27	27	27	27	27	393
5.250%	3/31/09	9,557	45	45	45	41	41	41	41	41	41	41	41	41	502
7.375%	3/31/09	183	1	1	1	1	1	1	1	1	1	1	1	1	14
5.875%	3/31/12	5,944	31	31	31	28	28	28	28	28	28	28	28	28	349
7.605%	3/31/14	5,536	37	37	37	35	35	35	35	35	35	35	35	35	421
			166	166	166	131	131	131	131	131	131	131	131	131	1,680
Municipal Development Loan Board															
5.250%	9/1/06	57	0	0	0	0	0	0	0	0	0	0	0	0	3
5.375%	9/1/06	234	1	1	1	1	1	1	1	1	1	1	1	1	13
5.625%	9/1/06	111	1	1	1	1	1	1	1	1	0	0	0	0	6
			2	2	2	2	2	2	2	2	2	2	2	2	22
Total Government of Canada Interest			**168**	**168**	**168**	**133**	**133**	**133**	**133**	**133**	**133**	**133**	**133**	**133**	**1,702**
CAPITAL LEASES															
Energy Management System															
11.314%	10/31/05	2,850	29	29	29	29	26	26	26	26	26	26	24	24	323
IBM															
7.620%			1	1	1	0									3
2.170%			0	0	0	0									0
6.500%			0	0	0	0									0
6.500%			1	1	1	1	1	1	1	1	1	1	1	1	13
9.620%			0	0	0	0									0
6.500%			0	0	0	0	0	0	0	0	0	0	0	0	3
			3	3	3	2	2	2	1	1	1	1	1	1	21
Total Capital Leases Interest			**33**	**32**	**32**	**31**	**28**	**28**	**28**	**28**	**28**	**27**	**25**	**25**	**343**
SHORT TERM INTEREST															
Promissory Notes															
Opening Balance			185,671	187,936	202,308	179,817	183,253	173,762	191,753	199,404	214,017	29,557	144,545	151,014	
Closing Balance			187,936	202,308	179,817	183,253	173,762	191,753	199,404	214,017	29,557	144,545	151,014	161,489	
Average Balance			193,055	193,635	202,921	186,015	184,256	190,495	199,824	204,627	26,923	114,295	153,191	164,425	
Average Rate			4.573%	4.573%	4.573%	4.682%	4.682%	4.682%	4.850%	4.850%	4.850%	4.920%	4.920%	4.920%	
Total Short Term Interest			**736**	**738**	**773**	**726**	**719**	**743**	**808**	**827**	**109**	**469**	**628**	**674**	**7,950**

FIDUCIARY FEES

			JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
5.250%	10/10/02		0	0	0	0	0	0	0	0	0	0	0	0	1
5.300%	9/1/06		0	0	0	0	0	0	0	0	0	0	0	0	1
5.500%	3/31/07		0	0	0	0	0	0	0	0	0	0	0	0	1
5.500%	4/30/08		0	0	0	0	0	0	0	0	0	0	0	0	1
6.100%	9/1/12		0	0	0	0	0	0	0	0	0	0	0	0	1
10.500%	6/15/14		0	0	0	0	0	0	0	0	0	0	0	0	4
10.250%	7/14/17		0	0	0	0	0	0	0	0	0	0	0	0	1
8.400%	2/27/26		0	0	0	0	0	0	0	0	0	0	0	0	1
6.250%	6/1/31		0	0	0	0	0	0	0	0	0	0	0	0	1
EMS Lease			1	1	1	1	1	1	1	1	1	1	1	1	8
Total Fiduciary Fees			**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**16**

Q. Provide details of the calculation of the $1,175,000 Amortization of Debt Discount and Issue Expense for 2002 (JCR, Schedule IX).

A. Please see schedule below.

Coupon	Maturity Date	Par Value	Proceeds	Total Discount	Total Amortization Period (Mths)	Monthly Amortization	2002 Amortization
10.500%	6/15/14	125,000	123,847	1,153	300	4	46
10.250%	7/14/17	150,000	148,565	1,435	300	5	57
8.400%	2/27/26	300,000	291,338	8,662	360	24	289
5.250%	10/10/02	100,000	98,924	1,076	60	18	215
5.500%	4/30/08	200,000	197,281	2,719	120	23	272
5.30%	9/1/06	100,000	99,470	530	60	9	106
6.25%	6/1/31	150,000	148,748	1,253	360	3	42
EMS LEASE	10/31/05	-					2
5.50%	3/31/07	100,000	99,470	530	60	9	80
6.10%	9/1/12	200,000	198,008	1,992	120	17	66
							1,175

Note: All figures in $000's.

Q. Provide details of the calculation of the $6,301,000 Interest on Sinking Fund Assets for 2002 (JCR, Schedule IX).

A. Please see attachment to NP-86.

Q. Reconcile the $108,735,000 cost of debt forecast for 2002 (JCR, Schedule IX) with the $93,584,000 interest expense (JCR, Schedule I, line 40).

A.

Net Interest, JCR, Schedule IX	$	108,735,000
Less: Interest earned, RSP		6,646,000
Interest capitalized		8,504,000
Rounding		1,000
Interest expense, JCR, Schedule I, line 40	$	93,584,000

Q. Provide summaries, both actual and prospective, of the terms of the sinking fund arrangements for each debt issue identified (JCR, Schedule X).

A. Please see schedule below.

Series	Interest Rate	Year of Issue	Year of Maturity	(000's) 2001	(000's) 2002	
Z	5.25%	1997	2002	100,000	-	No Sinking Fund arrangement for this issue.
AA	5.50%	1998	2008	200,000	200,000	No Sinking Fund arrangement for this issue.
V	10.50%	1989	2014	125,000	125,000	1.50 % of Par Value ($1,875,000) contributed each year
X	10.25%	1992	2017	150,000	150,000	1.00 % of Par Value ($1,500,000) contributed each year
Y	8.40%	1996	2026	300,000	300,000	0.80 % of Par Value ($2,400,000) contributed each year
	5.30%	2001	2006	100,000	100,000	No Sinking Fund arrangement for this issue.
	6.25%	2001	2031	150,000	150,000	1.00 % of Par Value ($1,500,000) to be contributed each year
	5.50%	2002	2007	-	100,000	No Sinking Fund arrangement for this issue.
	6.10%	2002	2012	-	200,000	No Sinking Fund arrangement for this issue.

Q. Provide an explanation of why the 2002 borrowings are proposed as different maturities (JCR, Schedule X).

A. The determination of appropriate debt term is a question that is viewed in the context of our total debt portfolio. Key factors which we consider are market receptivity, the current debt maturity profile, and the impact on the weighted average term to maturity of our debt portfolio.

Market Receptivity

We rely on our advisors to provide us with an indication of expected market receptivity for various debt terms.

Our Current Debt Maturity Profile

Consideration must be given to the expected maturity dates of current debt issues. It is important to ensure, to the extent possible, a manageable financing burden in future years.

Impact on Weighted Average Term to Maturity

Hydro annually benchmarks this measure with similar utilities and certain government entities, in an effort to determine our relative and desired positioning.

Q. Provide reports on the cost benefit analysis justifying the interconnection of the former diesel areas of Westport, Mud Lake and LaPoile (DWR, page 13, lines 14-19).

A. Copies of the reports/analysis for the former diesel areas of Westport, Mud Lake and LaPoile are attached.

Q. Provide details of the $107,453,000 capital expenditures for 2002 (JCR, Schedule VI). Reconcile this amount with the $119,469,000 net additions to capital assets (JCR, Schedule XIII).

A.

Net additions to capital assets, JCR, Schedule XIII	$	119,469,000
Classification error		(376,000)
Adjusted net additions to capital assets, JCR Schedule XIII		119,093,000
less: Capitalized salaries, overhead		5,723,000
Interest capitalized		5,529,000
Capital leases		388,000
Capital expenses on which HST is payable JCR, Schedule VI	$	107,453,000

The $119 million is comprised of the 2002 Capital Budget of $48 million, plus additional capital expenditures of $71 million which are exempted from the Board's jurisdiction.

Q. (a) Provide details of all capital and operating leases entered into by Hydro for the period 1992 to 2000 and forecast for 2001 and 2002 for which Board approval is required pursuant to Section 41 of the *Public Utilities Act*.

(b) How does Hydro determine whether to buy or lease capital assets?

A. (a) Attached are the capital and operating leases entered into by Hydro. 1997 was the first year that the Board approval was required pursuant to Section 41 of the Public Utilities Act.

(b) Where a leasing option is presented by a potential supplier, or requested by the Hydro Group, the requestor submits all necessary data regarding the leasing option to the Treasury Department. The Treasurer then performs lease versus purchase analysis to determine the most economic method of acquisition. There may be instances, when other considerations may factor into a lease or buy decision. For example, in cases of products experiencing rapid technological change, leasing may be advantageous to ensure Hydro retains the flexibility to upgrade to the most current technology.

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

Budget Item	***Amount***	***Description***
B-36	$1,330,000	Upgrade Distribution Systems – Central, Northern and Labrador

(a) Provide the details of the unit capital expenditure costs per customer by region for the period 1996 to 2000 and forecast for 2001 and 2002.

(b) Provide details of the budgeted amount including material and labour costs.

A. (a) The following table shows the capital cost per customer for the period 1996 – 2002.

DISTRIBUTION UPGRADING SYSTEM - CENTRAL, NORTHERN & LABRADOR				
Cost Per Customer By Region				
		Capital		**Unit Cost per**
Region	**Year**	**Expenditures**	**Customers**	**Customer**
Central	1996	$596,000	13,611	$43.79
	1997	566,000	13,628	41.53
	1998	378,000	13,683	27.63
	1999	666,000	13,731	48.50
	2000	583,000	13,758	42.38
	2001	541,000	13,729	39.41
	2002	551,000	13,755	40.07
Northern	1996	739,000	11,958	61.80
	1997	799,000	11,917	67.05
	1998	586,000	11,826	49.55
	1999	301,000	11,913	25.27
	2000	754,000	11,940	63.15
	2001	602,000	11,984	50.23
	2002	614,000	12,017	51.12

Labrador	1996	152,000	9,765	15.57
	1997	138,000	9,994	13.81
	1998	139,000	10,241	13.57
	1999	380,000	10,404	36.52
	2000	416,000	10,547	39.44
	2001	162,000	10,597	15.29
	2002	165,000	10,689	15.44

(b) The following table shows the 2002 budget amounts for material and labour.

DISTRIBUTION UPGRADING SYSTEM CENTRAL, NORTHERN & LABRADOR			
2002 Capital Expenditures			
Region	**Materials**	**Labour**	**Total Budget**
Central	286,520	264,480	551,000
Northern	319,280	294,720	614,000
Labrador	85,800	79,200	165,000
Total	691,600	638,400	1,330,000

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

Item	***Amount***	***Description***
B-38	$669,000	Replace Insulators – English Harbour West
B-39	$317,000	Replace Insulators – South Brook Distribution System

(a) Provide details of the estimated costs of insulator replacements.

(b) Provide an explanation of the difference in the unit costs of insulator replacements in item B-38 with B-39.

A. (a) Specific costs budgeted for purchasing and installing the replacement insulators are as follows:

<u>English Harbour West</u>	
Material Supply	$160,000
Labour	265,000
Engineering	22,000
Project Management	16,000
Inspection & Commissioning	57,000
Corporate O/H, IDC, Esc., Contingency	148,000

<u>South Brook</u>	
Material Supply	$72,000
Labour	110,000
Engineering	17,000
Project Management	8,000
Inspection & Commissioning	38,000
Corporate O/H, IDC, Esc., Contingency	71,700

A. (b) The budget proposal for insulator replacements on the South Brook distribution system actually covers 1420 units. The figure of 850 units quoted in Hydro’s 2002 Capital Budget submission is incorrect. This results in per unit costs of insulator replacements, based on material and labour, for English Harbour West and South Brook of $125.00 and $128.00 respectively.

Q. Provide an electronic copy of the cost of service study (Exhibit JAB-1 with formulas included and user documentation).

A. The electronic copy of the cost of service study, Exhibit JAB-1, is provided on the enclosed diskette in the file labeled NP120.COS2002P.zip. The user documentation is also included on the diskette in the file labeled NP-120 COS User Guide.doc.

A hard copy of the user documentation is also attached.

NEWFOUNDLAND AND LABRADOR HYDRO
Cost of Service (COS) Model – User Documentation

The COS Model is comprised of four files as follows:

1. COS.xls (Main model)
2. Load2002Proposed.xls (Load data, along with rural revenue data)
3. Oam2002Proposed.xls (Revenue requirement components)
4. Plant2002Proposed.xls (Plant Original Cost, Net Book Value and Depreciation data)

The COS.xls file contains the calculations relevant to the production of the COS schedules filed in this proceeding. The remaining files contain the requisite input data.

General Flow of the COS Model

Newfoundland and Labrador Hydro maintains its accounting data by business unit, or cost center. Plant data are, for the most part, identified by system and function. At the point the accounting and plant data enter the COS model they have been compiled and identified, to the extent possible, by appropriate system, function and sub-function. If the system and/or function are not readily identifiable, the cost of service model allocates the appropriate amounts. Load allocation data are provided for each rate class.

Cost of Service amounts are compiled by system, and identified in the model as such. Costs by system are functionalized and classified within the system sheets, into demand, energy, and customer amounts, for the production, transmission and distribution functions.

The revenue requirement, before return on rate base, is then calculated for each system. Return on rate base is comprised of both a return on equity and a return on debt. Rural rate base is excluded from the calculation of the return on equity component. Return on debt is calculated on total rate base. Total revenue requirement, after return on rate base, is then allocated to classes of customers in the following manner:

System	**Allocation Basis**
Island Interconnected	
Production Demand	Coincident Peak (2CP)
Production Energy	MWh at production
Transmission Demand	Coincident Peak (1CP)
Rural Transmission Demand	Coincident Peak (1CP)
Distribution Demand	Coincident Peak (1CP)
Distribution Customers	Customers, weighted customers

Other Systems

Production Demand	Coincident Peak (1CP)
Production Energy	MWh at production
Transmission Demand	Coincident Peak (1CP)
Distribution Demand	Coincident Peak (1CP)
Distribution Customers	Customers, weighted customers

Following the allocation of total revenue requirement to rate classes, the total demand, energy and customer costs for each rate class are determined. Unit costs are then calculated as follows:

Demand costs - Demand	$ per kW
Demand costs - Non-demand	$ per kWh
Energy costs	$ per kWh
Non-demand Demand and Energy	$ per kWh
Customer costs	$ per bill

The rural deficit is allocated to the following customers:

Newfoundland Power
Rural Labrador Interconnected
CFB – Goose Bay

After the Rural deficit allocation, the amounts of the Island Industrial Non-firm Revenue Credit and the CFB-Goose Base Secondary Revenue Credit are calculated and allocated to firm customers within each applicable system.

COS.xls

Worksheet Contents

Several of the worksheets, e.g. Revisions, Balance and Index, are designed to check the results of the calculations or aid the user. This document describes those sheets relevant to the production of the filed COS schedules only.

1. Run Options

   This worksheet identifies the input files linked to the model (automated by the print macro) and permits the user to set certain run options. Specifically, there are three calculation switches defined on this worksheet:

   a) Test Year Switch: This switch provides the capability to run the model on a test year basis, or on a fallout year basis. When the value of the switch changes, the calculations are automated with a macro. The model differences between a test year and a fallout year are as follows:

Test Year (Value of 1): Return on equity is an input percentage. The return on equity for Hydro's non-regulated industrial customer (IOCC) is derived from this percentage, and is used to calculate IOCC's revenue requirement.

Fallout Year (Value of 0): Return on equity is a calculated value derived from regulated revenues minus expenses minus return on debt. The portion of regulated revenues related to IOCC is determined through an iteration process which matches the calculated return on equity percent with the return on equity percent used for IOCC's revenue requirement.

b) Rural Island Interconnected Margin Switch: Determines whether or not the return on equity is applicable to the entire Island Interconnected rate base or just a portion thereof.

c) Labrador Interconnected / Isolated System CP/AED Switch: Allows the user to determine whether production demand costs are allocated to customers in all systems other than Island Interconnected by CP or AED.

This worksheet also allows the user to enter a name for the particular COS version being worked on. This name appears as part of the title of each schedule.

2. Summaries: The worksheets in this section of the model present summary COS results.

a) Revenue Requirement: This worksheet contains Schedule 1.1, page 1, Total System Revenue Requirement. It presents the detailed revenue requirement for each of the 5 systems being analyzed as well as the system as a whole.

b) Rate Base: This worksheet contains Schedule 1.1, page 2, Total Rate Base by System.

c) Revenue to Cost: Schedule 1.2, Comparison of Revenue and Allocated Revenue Requirement compares revenue and allocated revenue requirement by rate class for the total system as well as each of the 5 systems being analyzed.

Schedule 1.2.1, Rural Deficit Allocation, details the rural deficit allocation.

NEWFOUNDLAND AND LABRADOR HYDRO
Cost of Service (COS) Model – User Documentation

d) Unit Costs

Schedule 1.3, Unit Demand, Energy and Customer Amounts, presents the unit demand, energy and customer amounts by rate class for each of the 5 systems. The results are presented both before and after the deficit allocation.

Schedule 1.3.1, Total Demand, Energy and Customer Amounts, presents the total demand, energy and customer amounts by rate class for each of the 5 systems. As with Schedule 1.3, the results are presented both before and after the deficit allocation.

Schedule 1.3.2, Demands, Sales and Number of Bills, shows billing demands, sales and number of bills by rate class for each of the 5 systems.

Schedule 1.4 is the Calculation of Firming Up Charge for the Island Interconnected System.

Schedule 1.5 is the Calculation of Transmission Wheeling Charge for the Island Interconnected System.

3. Functional Classification and Allocation Schedules: There is a separate worksheet for each system containing the functionalization, classification and allocation schedules as follows:

Schedule 2.1 – Functional Classification of Revenue Requirement
Schedule 2.2 – Functional Classification of Plant in Service for the Allocation of O&M Expense
Schedule 2.3 – Functional Classification of Net Book Value
Schedule 2.4 – Functional Classification of Operating & Maintenance Expense
Schedule 2.5 – Functional Classification of Depreciation Expense
Schedule 2.6 – Functional Classification of Rate Base
Schedule 3.1 – Basis of Allocation to Classes of Service
Schedule 3.2 – Allocation of Functionalized Amounts to Classes of Service
Schedule 3.3 – Allocation of Specifically Assigned Amounts to Classes of Service (Island Interconnected only)

Schedules 2.1, 2.2, 2.4 and 2.6 have a corresponding documentation schedule detailing the basis of the functional classification. The documentation schedules are located to the right of the main schedule.

4. Other Schedules: This group of worksheets contain additional COS calculations.

a) Schedule 4.1: This worksheet contains Schedule 4.1, Functionalization and Classification Ratios.

b) Schedule 4.2,4.3,4.4: Three schedules are presented on this worksheet. They are Schedule 4.2, System Load Factors, Schedule 4.3, Holyrood Capacity Factor and Schedule 4.4, Total System Power Purchases.

5. Backup Schedules: The worksheets in this section of the model contain supporting calculations, but the schedules are not part of the published COS.

a) AED: Two schedules, Calculation of the Generation AED Factors, and Calculation of Transmission AED Factors, are presented for each of the five systems. These calculations are retained to support the Run Option to switch production demand allocators for systems other than Island Interconnected.

b) AllocPlt, AllocNBV, AllocDEP and AllocMisc: These worksheets contain additional allocation factors, derived from data on other COS worksheets, to allocate O&M data.

In addition, the AllocNBV sheet includes the calculation of allocated interest and margin.

c) Average Costs: Average costs per kWh are shown for the total system as well as for each of the 5 systems.

d) Coverage: This worksheet calculates regulated gross interest coverage.

e) Customers: This worksheet contains calculations for weighted customers.

f) DistnDetails: This worksheet calculates the functionalization ratios for distribution plant by system.

g) O&M Summary: The final allocations of the O&M data are made on this worksheet prior to inclusion in the COS system schedules, e.g. IslIntCos.

h) SPLT Details, SNBV Details and SDEP Details: These worksheets are used to functionalize some items of the plant data prior to use on the COS sheets, e.g. IslIntCos.

i) SpecAssFuel: This worksheet details the amount of specifically assigned fuel for Island Interconnected. For the test year, this schedule is not used.

j) SystemizedPlant: Two schedules are presented containing supplemental plant allocations for meters and computer software.

Printing the COS Schedules

A print routine is included on the COS.xls file. The schedules may be printed from any location in the workbook by pressing CTRL-T. A print menu allows the user to choose from the following options:

(1) Print the full cost of service, or
(2) Print one or more of the following:
- (i) Summaries
- (ii) Island Interconnected
- (iii) Island Isolated
- (iv) Labrador Isolated
- (v) L'Anse au Loup
- (vi) Labrador Interconnected
- (vii) Other
- (viii) Backup Schedules

Each printed sheet includes the date and number of pages. An optional run label can be entered by the user and appears in the lower right-hand corner of each output sheet.

Q. (a) Provide the capacity factors for each year for the time period 1992 to 2000 and forecasts for 2001 and 2002 on each of Hydro's hydraulic and thermal plants (including gas turbines and diesels) on the Island (in the format of Exhibit JAB-1, page 93 of 94, Schedule 4.3).

(b) Provide the island interconnected system capacity factor for each of these years.

A. (a) The net capacity factors for all Island Interconnected System generating plants are provided on the attached sheets. Data from a plant for the year it was connected to the system was excluded from the total.

(b) The Island Interconnected System capacity factors are in the following table. Data from a plant for the year it was connected to the system was excluded from the total.

Island Interconnected System NET

Year	Net Production (kWh)	Net Capacity (MW)	Net Production Hours	Net Capacity Factor
1992	5,926,373,147	1,464	8,784	46.09%
1993	5,998,219,216	1,466	8,760	46.71%
1994	5,821,774,061	1,470	8,760	45.21%
1995	5,926,288,933	1,474	8,760	45.90%
1996	5,977,960,323	1,476	8,784	46.11%
1997	6,160,353,193	1,491	8,760	47.17%
1998	5,525,111,462	1,491	8,760	42.30%
1999	5,721,707,245	1,491	8,760	43.81%
2000	5,985,452,087	1,486	8,784	45.85%
2001 Forecast	6,246,218,812	1,491	8,760	47.84%
2002 Forecast	6,434,088,000	1,486	8,760	49.43%
Average	5,974,867,862	1,480	8,767	46.04%

Newfoundland & Labrador Hydro
Capacity Factors

Line No.	1 Year	2 Net Production (kWh)	3 Net Capacity (MW)	4 Net Production Hours	5 Net Capacity Factor
	Bay Despoir NET				
1	1992	2,613,023,747	580	8,784	51.29%
2	1993	2,814,689,877	582	8,760	55.21%
3	1994	3,282,273,338	586	8,760	63.94%
4	1995	2,587,721,679	590	8,760	50.07%
5	1996	2,785,871,835	592	8,784	53.57%
6	1997	2,845,782,777	592	8,760	54.88%
7	1998	2,609,236,542	592	8,760	50.31%
8	1999	3,088,238,874	592	8,760	59.55%
9	2000	3,115,048,699	592	8,784	59.90%
10	2001 Forecast	2,598,000,000	592	8,760	50.10%
11	2002 Forecast	2,598,000,000	592	8,760	50.10%
12	Average	2,812,535,215	589	8,767	54.44%
	Hinds Lake NET				
13	1992	308,069,400	75	8,784	46.76%
14	1993	354,162,600	75	8,760	53.91%
15	1994	459,039,460	75	8,760	69.87%
16	1995	402,552,500	75	8,760	61.27%
17	1996	352,272,400	75	8,784	53.47%
18	1997	407,475,600	75	8,760	62.02%
19	1998	408,690,300	75	8,760	62.21%
20	1999	345,717,400	75	8,760	52.62%
21	2000	387,975,200	75	8,784	58.89%
22	2001 Forecast	340,000,000	75	8,760	51.75%
23	2002 Forecast	340,000,000	75	8,760	51.75%
24	Average	373,268,624	75	8,767	56.77%
	Upper Salmon NET				
25	1992	558,649,600	84	8,784	75.71%
26	1993	551,711,100	84	8,760	74.98%
27	1994	658,440,200	84	8,760	89.48%
28	1995	552,100,600	84	8,760	75.03%
29	1996	597,657,300	84	8,784	81.00%
30	1997	599,077,900	84	8,760	81.41%
31	1998	553,898,400	84	8,760	75.27%
32	1999	649,086,200	84	8,760	88.21%
33	2000	636,938,500	84	8,784	86.32%
34	2001 Forecast	552,000,000	84	8,760	75.02%
35	2002 Forecast	552,000,000	84	8,760	75.02%
36	Average	587,414,527	84	8,767	79.77%

Newfoundland & Labrador Hydro
Capacity Factors

	Cat Arm NET				
37	1992	704,510,400	127	8,784	63.15%
38	1993	666,888,200	127	8,760	59.94%
39	1994	602,861,400	127	8,760	54.19%
40	1995	808,451,400	127	8,760	72.67%
41	1996	793,196,800	127	8,784	71.10%
42	1997	734,915,200	127	8,760	66.06%
43	1998	650,412,900	127	8,760	58.46%
44	1999	674,854,100	127	8,760	60.66%
45	2000	836,766,400	127	8,784	75.01%
46	2001 Forecast	735,000,000	127	8,760	66.07%
47	2002 Forecast	735,000,000	127	8,760	66.07%
48	Average	722,077,891	127	8,767	64.86%
	Paradise River NET				
49	1992	30,637,520	8	8,784	43.60%
50	1993	45,086,890	8	8,760	64.34%
51	1994	34,388,570	8	8,760	49.07%
52	1995	35,452,810	8	8,760	50.59%
53	1996	36,885,220	8	8,784	52.49%
54	1997	34,758,580	8	8,760	49.60%
55	1998	32,005,510	8	8,760	45.67%
56	1999	37,971,130	8	8,760	54.18%
57	2000	36,441,220	8	8,784	51.86%
58	2001 Forecast	39,370,000	8	8,760	56.18%
59	2002 Forecast	39,370,000	8	8,760	56.18%
60	Average	36,578,859	8	8,767	52.16%
	Snook's Arm				
61	1992	3,865,320	0.56	8,784	78.58%
62	1993	3,571,290	0.56	8,760	72.80%
63	1994	4,016,700	0.56	8,760	81.88%
64	1995	3,567,690	0.56	8,760	72.73%
65	1996	4,394,160	0.56	8,784	89.33%
66	1997	3,868,290	0.56	8,760	78.85%
67	1998	4,033,170	0.56	8,760	82.22%
68	1999	2,981,640	0.56	8,760	60.78%
69	2000	1,661,760	0.56	8,784	33.78%
70	2001 Forecast	3,675,000	0.56	8,760	74.91%
71	2002 Forecast	3,675,000	0.56	8,760	74.91%
72	Average	3,573,638	0.56	8,767	72.79%

Newfoundland & Labrador Hydro
Capacity Factors

Venam's Bight

73	1992	2,827,140	0.36	8,784	89.40%
74	1993	2,921,520	0.36	8,760	92.64%
75	1994	2,564,340	0.36	8,760	81.31%
76	1995	2,571,420	0.36	8,760	81.54%
77	1996	2,921,400	0.36	8,784	92.38%
78	1997	2,816,580	0.36	8,760	89.31%
79	1998	2,900,520	0.36	8,760	91.97%
80	1999	2,592,900	0.36	8,760	82.22%
81	2000	1,151,040	0.36	8,784	36.40%
82	2001 Forecast	2,575,000	0.36	8,760	81.65%
83	2002 Forecast	2,575,000	0.36	8,760	81.65%
84	Average	2,583,351	0.36	8,767	81.86%

Roddickton Mini Hydro NET

85	1992	0			
86	1993	0			
87	1994	0			
88	1995	0			
89	1996	377,490	0.40	2,928	32.23%
90	1997	804,048	0.40	8,760	22.95%
91	1998	1,348,514	0.40	8,760	38.48%
92	1999	1,111,690	0.40	8,760	31.73%
93	2000	731,940	0.40	8,784	20.83%
94	2001 Forecast	1,050,000	0.40	8,760	29.97%
95	2002 Forecast	1,050,000	0.40	8,760	29.97%
96	Average	1,016,032	0.40	8,764	28.98%

THERMAL Holyrood NET

97	1992	1,706,212,840	466	8,784	41.68%
98	1993	1,558,883,340	466	8,760	38.19%
99	1994	776,894,400	466	8,760	19.03%
100	1995	1,533,078,080	466	8,760	37.56%
101	1996	1,403,596,120	466	8,784	34.29%
102	1997	1,531,300,920	466	8,760	37.51%
103	1998	1,263,264,060	466	8,760	30.95%
104	1999	919,801,520	466	8,760	22.53%
105	2000	970,283,280	466	8,784	23.70%
106	2001 Forecast	1,971,340,000	466	8,760	48.29%
107	2002 Forecast	2,157,880,000	466	8,760	52.86%
108	Average	1,435,684,960	466.00	8,767	35.14%

Newfoundland & Labrador Hydro
Capacity Factors

Hardwoods GAS TURBINE NET

109	1992	(1,353,360)	54	8,784	-0.29%
110	1993	(347,061)	54	8,760	-0.07%
111	1994	920,893	54	8,760	0.19%
112	1995	245,812	54	8,760	0.05%
113	1996	286,028	54	8,784	0.06%
114	1997	(44,408)	54	8,760	-0.01%
115	1998	(204,270)	54	8,760	-0.04%
116	1999	(214,544)	54	8,760	-0.05%
117	2000	(662,432)	54	8,784	-0.14%
118	2001 Forecast	1,590,000	54	8,760	0.34%
119	2002 Forecast	2,240,000	54	8,760	0.47%
120	Average	223,333	54.00	8,767	0.05%

Stephenville GAS TURBINE Net

121	1992	(476,460)	54	8,784	-0.10%
122	1993	327,360	54	8,760	0.07%
123	1994	(211,440)	54	8,760	-0.04%
124	1995	(177,058)	54	8,760	-0.04%
125	1996	24,060	54	8,784	0.01%
126	1997	(510,480)	54	8,760	-0.11%
127	1998	(598,860)	54	8,760	-0.13%
128	1999	(253,200)	54	8,760	-0.05%
129	2000	(553,460)	54	8,784	-0.12%
130	2001 Forecast	1,200,000	54	8,760	0.25%
131	2002 Forecast	1,200,000	54	8,760	0.25%
132	Average	(2,685)	54.00	8,767	0.00%

Holyrood GAS TURBINE

133	1992	215,000	10	8,784	0.24%
134	1993	156,100	10	8,760	0.18%
135	1994	471,000	10	8,760	0.54%
136	1995	124,000	10	8,760	0.14%
137	1996	255,000	10	8,784	0.29%
138	1997	189,000	10	8,760	0.22%
139	1998	248,000	10	8,760	0.28%
140	1999	296,000	10	8,760	0.34%
141	2000	124,000	10	8,784	0.14%
142	2001 Forecast	440,000	10	8,760	0.50%
143	2002 Forecast	750,000	10	8,760	0.86%
144	Average	297,100	10.00	8,767	0.34%

Newfoundland & Labrador Hydro
Capacity Factors

	St. Anthony Diesel NET				
145	1992	0			
146	1993	0			
147	1994	0			
148	1995	0			
149	1996	969,500	8.00	2,928	4.14%
150	1997	(202,202)	8.00	8,760	-0.29%
151	1998	(11,200)	8.00	8,760	-0.02%
152	1999	(180,000)	8.00	8,760	-0.26%
153	2000	(227,600)	8.00	8,784	-0.32%
154	2001 Forecast	204,000	8.00	8,760	0.29%
155	2002 Forecast	204,000	8.00	8,760	0.29%
156	Average	(35,500)	8.00	8,764	-0.05%
	Hawkes Bay Diesel NET				
157	1992	192,000	5	8,784	0.44%
158	1993	168,000	5	8,760	0.38%
159	1994	115,200	5	8,760	0.26%
160	1995	600,000	5	8,760	1.37%
161	1996	600,000	5	8,784	1.37%
162	1997	129,600	5	8,760	0.30%
163	1998	115,888	5	8,760	0.26%
164	1999	170,056	5	8,760	0.39%
165	2000	(148,860)	5	8,784	-0.34%
166	2001 Forecast	120,000	5	8,760	0.27%
167	2002 Forecast	120,000	5	8,760	0.27%
168	Average	198,353	5.00	8,767	0.45%
	Roddickton Diesel NET				
169	1992	0			
170	1993	0			
171	1994	0			
172	1995	0			
173	1996	129,780	2.00	2,928	2.22%
174	1997	429,020	2.00	8,760	2.45%
175	1998	31,840	2.00	8,760	0.18%
176	1999	(56,040)	2.00	8,760	-0.32%
177	2000	(77,600)	1.70	8,784	-0.52%
178	2001 Forecast	24,000	1.70	8,760	0.16%
179	2002 Forecast	24,000	1.70	8,760	0.16%
180	Average	62,537	1.85	8,764	0.39%

Newfoundland & Labrador Hydro
Capacity Factors

Roddickton Woodchip NET

181	1992	0			
182	1993	0			
183	1994	0			
184	1995	0			
185	1996	631,860	4.60	2,928	4.69%
186	1997	(437,232)	4.60	8,760	-1.09%
187	1998	(259,852)	4.60	8,760	-0.64%
188	1999	(410,481)	4.60	8,760	-1.02%
189	2000				
190	Average	(369,188)	4.60	8,760	-0.92%

Island Interconnected NET

191	1992	5,926,373,147	1,464	8,784	46.09%
192	1993	5,998,219,216	1,466	8,760	46.71%
193	1994	5,821,774,061	1,470	8,760	45.21%
194	1995	5,926,288,933	1,474	8,760	45.90%
195	1996	5,977,960,323	1,476	8,784	46.11%
196	1997	6,160,353,193	1,491	8,760	47.17%
197	1998	5,525,111,462	1,491	8,760	42.30%
198	1999	5,721,707,245	1,491	8,760	43.81%
199	2000	5,985,452,087	1,486	8,784	45.85%
200	2001 Forecast	6,246,218,812	1,486	8,760	47.98%
201	2002 Forecast	6,434,088,000	1,486	8,760	49.43%
202	Average	5,974,867,862	1,480	8,767	46.05%

Q. Provide the report on the study completed on attributing system losses to rate classes on a time-differentiated basis (JAB, page 9, lines 8-20).

A. See attached reports.

Q. Reconcile the 1026.8 MW peak forecasted for 2002 (HGB, Schedule V) and the 2 CP production demand data (JAB-1, page 38).

A. See table below.

Reconcilation of Newfoundland Power Demand Forecast Versus 2CP (KW)			
	January	December	2CP - Total
NP as per JAB-1, page 38	989,280	989,288	1,978,568
Demand as per Forecast	1,026,791	1,026,791	
Adjustment to include load supplied by NP	46,960	46,960	
Generation Credit	(120,500)	(120,500)	
Allocated Losses to Transmission side of Generation	36,029	36,037	
Generation CP	989,280	989,288	1,978,568

Q. Provide details of specifically assigned amounts to Newfoundland Power and the Industrial customers (JAB-1, page 41).

A. See attached.

Specifically Assigned Charges	Total	NF Power	Industrial Customers	Basis for amount	Schedule Reference
Transmission Lines	5,701	-	5,701	Transmission Lines O&M total expenses allocated based on plant	Exhibit JAB-1, Page 33
Transmission Terminal Station	211,168	123,365	87,803	Terminal Station O&M total expenses allocated based on plant	Exhibit JAB-1, Page 33
Administrative & General	169,725	98,281	71,444	Overhead allocations based on plant and total direct O&M expenses	Exhibit JAB-1, Page 33
Depreciation Transmission Lines	42,698	41,510	1,188	Depreciation on Specifically assigned plant	Exhibit JAB-1, Page 35
Depreciation Transmission Terminal Stations	333,789	264,588	69,201	Depreciation on Specifically assigned plant	Exhibit JAB-1, Page 35
Depreciation General Plant	171,828	139,703	32,125	General Plant depreciation allocation based on specifically assigned plant	Exhibit JAB-1, Page 35
Rental Income	(130)	(76)	(54)	Expense Credit allocation based on total plant	Exhibit JAB-1, Page 28
Other Expense Credits	(2,165)	(1,254)	(911)	Expense Credit allocation based on total O&M expenses	Exhibit JAB-1, Page 28
Gain or Loss on Disposal of Fixed Assets	5,803	4,548	1,255	Expense allocation based on total plant	Exhibit JAB-1, Page 28
Return on Debt	656,397	514,402	141,995	Expense allocation based on total plant	Exhibit JAB-1, Page 36
Return on Equity	43,319	33,948	9,371	Expense allocation based on total plant	Exhibit JAB-1, Page 36
		1,219,015	419,118		