Q. Provide a copy of Order No. P.U. 12 (1996-97) dated March 4, 1997 and a copy of all materials filed by Hydro in relation to that matter.

A. Order No. P.U. 12(1996-97) was filed in response to CA-3. Please see the attached Application dated February 20, 1997 that resulted in the Order.

Q. Provide a copy of Order No. P.U. 20 (1997-98) dated March 5, 1997 (sic) and a copy of all materials filed by Hydro in relation to that matter.

A. Order No. P.U. 20 (1997-98) dated March 5, 1998 was filed in response to CA-3. Please see the attached Application dated January 29, 1998 and related letter dated February 27, 1998.

Q. Provide a copy of Order No. P.U. 23 (1999-2000) and a copy of all materials filed by Hydro in relation to that matter.

A. Order No. P.U. 23 (1999-2000) was filed in response to CA-4. Please see the attached Application dated November 19, 1999, draft order dated November 23, 1999, Board's Information Requests, PUB 1 – PUB 5 dated November 29, 1999, Schedule "A" dated December 1, 1999, and the 1999 Cost of Service dated June 28, 2000.

Q. Provide a table showing (a) the total amount which would have been paid by the Industrial Customers in each of 1992, 1993, 1994, 1995, 1996, 1997, 1998 and 1999 in the absence of a contribution to the subsidy associated with serving Rural Customers, (b) the total amount paid by the Industrial Customers for electricity in each of those years and (c) the amount of the Industrial Customers' contribution to the Rural subsidy in each of those years.

A. See the table below. The Industrial Customers' contribution to the Rural Subsidy was estimated by applying the 10.74% reduction in Industrial rates as ordered by the Board in its Order No. P.U.23 (1999-2000).

Year	Industrial Revenue (excl. RSP)	Subsidy Portion	Industrial Revenue Net of Subsidy
1992	$46,380,228	$4,981,236	41,398,992
1993	46,158,300	4,957,401	41,200,899
1994	40,429,978	4,342,180	36,087,798
1995	44,467,369	4,758,008	39,691,574
1996	47,526,674	5,104,365	42,422,309
1997	47,689,883	5,121,893	42,567,990
1988	36,269,044	3,895,296	32,373,751
1999	43,453,323	4,666,887	38,786,435

Q. Provide a Table, which shows the following for each of the years 1992 - 2000, inclusive, where the vertical axis represents the years and the horizontal axis the following data:

1. the demand rate charged Industrial Customers for firm power and for each class of non-firm service;
2. the energy rate charged Industrial Customers for firm energy and for each class of non-firm service and wheeling;
3. the Specifically Assigned Charges charged to each Industrial Customers, and for all Industrial Customers;
4. the total dollar amount billed to the Industrial Customers in those years exclusive of sales tax, broken out for firm service, each class of non-firm service and wheeling;
5. the total number of kWh sold to the Industrial Customers for those years, broken out for firm service and each class of non-firm service; also the total number of kWh charged for wheeling;
6. the total billing demand charged to each Industrial Customer for those years for firm service, indicating separately each of the following:
   a. the contracted amount of power
   b. the maximum demand for each year
   c. billing demand (kW) charged before any provisions for reduced billing demand
   d. any provisions for reduced billing demand (kW) and the reasons for same
   e. actual billing demand (kW) charged.
7. the average cost per kilowatt hour billed to the Industrial Customer for those years.

A. See attached tables.

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 1	**Part 2**			
		Energy Rate			
			Bunker "C" Note (3)	Gas Turbine Note (4)	
Year	Demand Rate (Note 1)	Firm Note (2)	Low / High	Low / High	Wheeling
1992	$8.25	$0.02560	$0.02164 / $0.03671	$0.07868 / $0.10105	$0.00589
1993	$8.25	$0.02333	$0.02823 / $0.03319	$0.07442 / $0.09906	$0.00653
1994	$8.25	$0.02333	$0.02689 / $0.03264	$0.07440 / $0.08587	$0.00649
1995	$8.25	$0.02265	$0.03786 / $0.04247	$0.06845 / $0.09350	$0.00649
1996	$8.25	$0.02320	$0.04144 / $0.05066	$0.07506 / $0.08829	$0.00649
1997	$8.25	$0.02403	$0.04135 / $0.04849	$0.07567 / $0.09316	$0.00649
1998	$8.25	(Note 5)	$0.03357 / $0.04312	$0.07107 / $0.09426	$0.00649
1999	$8.25	$0.02654	$0.02855 / $0.05031	$0.06946 / $0.08661	$0.00649
2000	$7.36	$0.02284	$0.05285 / $0.07198	$0.08510 / $0.11618	$0.00649

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 3								
	Specifically Assigned Charges								
Year	Corner Brook Pulp & Paper	Deer Lake Power	Albright & Wilson	API - Stephenville	API - Grand Falls	North Atlantic Refining	Royal Oak Mines	Hope Brook Gold	Total
1992	$9,108	$3,671	$431,811	$120,095	$8,650	$343,417	$170,277	$70,095	$1,157,124
1993	$8,690	$3,671	$359,143	$127,827	$4,999	$332,188	$262,933	N/A	$1,099,451
1994	$8,162	$3,671	$343,798	$127,792	$5,075	$323,444	$244,651	N/A	$1,056,593
1995	$8,162	$3,671	$343,798	$127,792	$5,075	$323,444	$244,651	N/A	$1,056,593
1996	$8,162	$3,671	$343,798	$127,792	$5,075	$323,444	$244,651	N/A	$1,056,593
1997	$8,162	$3,671	$329,473	$127,792	$5,075	$323,444	$244,651	N/A	$1,042,268
1998	$8,162	$3,671	N/A	$127,792	$5,075	$323,444	N/A	N/A	$468,144
1999	$11,833	N/A	N/A	$127,792	$5,075	$323,444	N/A	N/A	$468,144
2000	$10,562	N/A	N/A	$114,067	$4,530	$288,706	N/A	N/A	$417,865

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 4					
	Total Amount Billed Exclusive of Sales Tax (Note 12)					
Year	Firm	Interruptible	Exceptional	Emergency	Wheeled	Total
1992	$45,776,674	$323,220	$13,663	$92,057	$174,614	$46,380,228
1993	$44,142,228	$572,652	$96,977	$1,244,346	$102,097	$46,158,300
1994	$39,320,862	$881,043	$32,407	$94,462	$101,204	$40,429,978
1995	$43,658,532	$542,666	$50,121	$126,060	$89,990	$44,467,369
1996	$45,232,744	$500,644	$52,724	$1,534,423	$206,139	$47,526,674
1997	$46,731,607	$350,894	$202,736	$171,826	$232,820	$47,689,883
1998	$35,850,623	$174,663	$68,345	$38,173	$137,243	$36,269,047
1999	$42,994,857	$82,246	$130,140	$16,067	$230,012	$43,453,322
2000	$39,565,833	$266,921	$191,254	$66,212	$185,367	$40,275,587

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 5					
	kWhs Sold					
Year	Firm	Interruptible	Exceptional	Emergency	Wheeled	Total
1992	1,150,306,632	2,896,746	51,417	2,937,518	29,645,791	1,185,838,104
1993	1,194,300,551	5,580,007	1,674,355	40,839,278	15,635,098	1,258,029,289
1994	1,048,227,983	10,989,245	134,332	3,195,004	15,593,780	1,078,140,344
1995	1,192,524,551	3,301,662	741,495	3,088,407	13,866,004	1,213,522,119
1996	1,222,558,101	8,651,765	317,776	32,757,458	31,353,104	1,295,638,204
1997	1,258,387,918	1,815,891	1,627,498	3,649,480	35,873,648	1,301,354,435
1998	963,942,230	516,260	583,382	975,731	21,146,721	987,164,324
1999	1,170,542,532	126,874	1,260,054	407,207	35,441,079	1,207,777,746
2000	1,241,636,729	3,520,721	1,463,623	1,096,248	28,562,015	1,276,279,336

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 6									
	Firm Billing Demand (kWs) (Note 6)									
	Corner Brook Pulp & Paper					Deer Lake Power				
Year	Contracted	Maximum	Before Reduction	Reduction	Billed	Contracted	Maximum	Before Reduction	Reduction	Billed
1992	38,000	38,000	456,000	0	456,000	2,000	2,000	24,000	0	24,000
1993	38,000	38,000	456,000	0	456,000	2,000	2,000	24,000	0	24,000
1994	38,000	38,000	456,000	0	456,000	2,000	2,000	24,000	0	24,000
1995	38,000	38,000	456,000	0	456,000	2,000	2,000	24,000	0	24,000
1996	46,000	46,000	517,000	0	517,000	2,000	2,000	24,000	0	24,000
1997	46,000	46,000	552,000	0	552,000	2,000	2,000	24,000	0	24,000
1998	54,000	54,000	640,000	0	640,000	2,000	2,000	24,000	0	24,000
1999	51,000	51,000	612,000	0	612,000	N/A	N/A	N/A	N/A	N/A
2000	51,000	51,000	612,000	0	612,000	N/A	N/A	N/A	N/A	N/A

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 6 (Cont'd)									
	Firm Billing Demand (kWs) (Note 6)									
	Albright & Wilson (Note 7)					API - Stephenville (Note 13)				
Year	Contracted	Maximum	Before Reduction	Reduction	Billed	Contracted	Maximum	Before Reduction	Reduction (Note 10)	Billed
1992	Maximum	1,447	14,275	0	14,275	66,192	66,192	793,800	0	793,800
1993	Maximum	1,577	14,968	0	14,968	66,192	66,192	794,304	0	794,304
1994	Maximum	1,534	15,077	0	15,077	66,192	66,192	794,304	0	794,304
1995	Maximum	583	5,302	0	5,302	70,000	70,000	840,000	0	840,000
1996	Maximum	583	5,085	0	5,085	70,000	70,000	840,000	0	840,000
1997	Maximum	550	4,689	0	4,689	70,000	70,000	840,000	0	840,000
1998	N/A	N/A	N/A	N/A	N/A	70,000	70,000	840,000	326,826	513,174
1999	N/A	N/A	N/A	N/A	N/A	70,000	70,000	840,000	0	840,000
2000	N/A	N/A	N/A	N/A	N/A	68,000	70,000	818,000	0	818,000

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 6 (Cont'd)									
	Firm Billing Demand (kWs) (Note 6)									
	API - Grand Falls					Newfoundland Processing / North Atlantic Refining (Note 8)				
Year	Contracted	Maximum	Before Reduction	Reduction (Note 10)	Billed	Contracted	Maximum	Before Reduction	Reduction (Note 11)	Billed
1992	28,000	28,000	336,000	0	336,000	12 Month Peak	32,403	343,877	0	343,877
1993	25,000	25,000	300,000	0	300,000	12 Month Peak	29,091	348,001	0	348,001
1994	22,000	22,000	264,000	0	264,000	12 Month Peak	29,091	330,482	132,402	198,080
1995	22,000	22,000	264,000	0	264,000	12 Month Peak	29,010	341,791	0	341,791
1996	22,000	22,000	264,000	0	264,000	12 Month Peak	30,966	369,904	0	369,904
1997	24,000	24,000	288,000	0	288,000	12 Month Peak	30,966	371,792	0	371,792
1998	22,000	22,000	264,000	99,958	164,042	12 Month Peak	31,329	375,948	0	375,948
1999	22,000	22,000	264,000	0	264,000	12 Month Peak	30,764	364,128	0	364,128
2000	22,000	22,000	264,000	0	264,000	12 Month Peak	30,260	362,347	0	362,347

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 6 (Cont'd)									
	Firm Billing Demand (kWs) (Note 6)									
	Royal Oak Mines (Note 9)					Hope Brook Gold				
Year	Contracted	Maximum	Before Reduction	Reduction	Billed	Contracted	Maximum	Before Reduction	Reduction	Billed
1992	12 Month Peak	9,636	59,112	0	59,112	12 Month Peak	10,492	36,527	0	36,527
1993	12 Month Peak	10,736	127,120	0	127,120	N/A	N/A	N/A	N/A	N/A
1994	12 Month Peak	10,764	112,331	0	112,331	N/A	N/A	N/A	N/A	N/A
1995	9,000	9,000	108,000	0	108,000	N/A	N/A	N/A	N/A	N/A
1996	9,000	9,000	108,000	0	108,000	N/A	N/A	N/A	N/A	N/A
1997	9,000	9,000	108,000	0	108,000	N/A	N/A	N/A	N/A	N/A
1998	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1999	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Newfoundland and Labrador Hydro
Island Industrial Customers

	Part 7
Year	Average Cost per kWh
1992	$0.03911
1993	$0.03669
1994	$0.03750
1995	$0.03664
1996	$0.03668
1997	$0.03665
1998	$0.03674
1999	$0.03598
2000	$0.03156

Newfoundland and Labrador Hydro
Island Industrial Customers

Notes:
(1) - Applies to Firm, Interruptible, and Exceptional classes of power.

(2) - Rate includes RSP. Some Interruptible energy may be billed at Firm rates.

(3) - Some Emergency and Exceptional energy may be billed at Bunker "C" rates.

(4) - Some Interruptible, Emergency, and Exceptional energy may be billed at Gas Turbine rates.

(5) - $0.02511 for Jan - Mar ; $0.02482 for Apr - Dec. ($0.00315 is the RSP portion for the full year.)

(6) - Contracted and Maximum are monthly. Before Reduction, Reduction, and Billed are annual.

(7) - Firm Power on Order not to exceed 5,000 kW.

(8) - Firm Power on Order not to exceed 35,000 kW.

(9) - Beginning in 1994 Firm Power on Order is not to be less than 5,000 kW and not more than 15,000 kW.

(10) - A strike at the premises caused in a reduction in Billing demand as per the Power contract.

(11) - A fire at the premises caused in a reduction in Billing demand as per the Power contract.

(12) - Excludes RSP and Interest on Overdue amounts.

(13) - Contracted firm demand changed from 70,000 to 68,000 kW beginning in February, 2000.

Q. Provide the same information as requested in 16 above for 2001 based on your most recent forecasts for 2001.

A. See attached tables.

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Part 1	**Part 2**			
	Energy Rate			
		Bunker "C" (Note 3)	Gas Turbine (Note 4)	
Demand Rate (Note 1)	Firm (Note 2)	Low / High	Low / High	Wheeling
$7.36	$0.02214	(Note 7)	(Note 7)	$0.00649

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Part 3				
Specifically Assigned Charges				
Corner Brook Pulp & Paper	API - Stephenville	API - Grand Falls	North Atlantic Refining	Total
$10,562	$114,067	$4,530	$288,706	$417,865

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Part 4					
Total Amount Billed Exclusive of Sales Tax (Note 8)					
Firm	Interruptible	Exceptional	Emergency	Wheeled	Total
$41,446,836	$418,489	$0	$0	$6,490	$41,871,815

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Part 5					
kWhs Sold					
Firm	Interruptible	Exceptional	Emergency	Wheeled	Total
1,335,006,000	11,744,000	0	0	1,000,000	1,347,750,000

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Part 6									
Firm Billing Demand (kWs) (Note 5)									
Corner Brook Pulp & Paper					API - Stephenville				
Contracted	Maximum	Before Reduction	Reduction	Billed	Contracted	Maximum	Before Reduction	Reduction	Billed
51,000	51,000	612,000	0	612,000	69,000	69,000	828,000	0	828,000

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Part 6 (Cont'd)									
Firm Billing Demand (kWs) (Note 5)									
API - Grand Falls					Newfoundland Processing / North Atlantic Refining (Note 6)				
Contracted	Maximum	Before Reduction	Reduction	Billed	Contracted	Maximum	Before Reduction	Reduction	Billed
22,000	22,000	264,000	0	264,000	12 Month Peak	30,257	362,570	0	362,570

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Part 7
Average Cost per kWh
$0.03107

Newfoundland and Labrador Hydro
Island Industrial Customers
2001 Forecast

Notes:

(1) - Applies to Firm, Interruptible, and Exceptional classes of power.

(2) - Rate includes RSP. Some Interruptible energy may be billed at Firm rates.

(3) - Some Emergency and Exceptional energy may be billed at Bunker "C" rates.

(4) - Some Interruptible, Emergency, and Exceptional energy may be billed at Gas Turbine rates.

(5) - Contracted and Maximum are monthly. Billed is annual.

(6) - Firm Power on Order not to exceed 35,000 kW.

(7) - Because no energy is forecasted to be billed at those rates there is no forecast required.
All forecasted Interruptible energy is assumed to qualify for the Firm rate.

(8) - Excludes RSP.

Q. Outline, for each of the Industrial Customers, the differences between the proposed Industrial Contracts and the existing Industrial Contracts and provide the forecast financial implication in dollars for 2001 of each of those changes for each of the Industrial Customers.

A. Tables 1-4, attached, set out the differences between the industrial power contracts that Hydro has proposed in its application and those that apply at present. Table 5, attached, compares the financial implications of the proposed rates to the existing rates based upon 2001 forecast loads. Some explanatory comments are required.

First, the existing contractual arrangements comprise a number of formal documents as well as some practices that have been developed over the years between Hydro and its industrial customers to address issues that are not dealt with in the formal contracts. Where appropriate, these practices have been incorporated into the proposed industrial contracts.

Second, Hydro is proposing only minor changes to the basic substance of the legal arrangements between Hydro and its customers and, aside from the change to the firm and non-firm rates, the proposed changes to the contracts would not have financial implications which can be reliably forecast.

Third, 2001 load forecasts for interruptible power and energy were provided by two Industrial Customers only (Corner Brook Pulp and Paper Limited and Abitibi-Consolidated Inc. (Stephenville Division)) and none provided forecasts for Emergency or Exceptional Power. Also, these load forecasts were provided under the existing rate structures for 2001 and, therefore, they cannot be assumed to be representative of customer load forecasts for the proposed rate structures.

TABLE 1

Abitibi-Consolidated Inc. (Stephenville Division)

PROPOSED	EXISTING
2.02 Maximum Power on Order = 90,000 kW	3.02 Power on Order to be between 50,000 kW and 70,000 kW
2.05 If Customer obtains new source of electric generation, Power on Order can be reduced or eliminated on 36 months notice	16.04 If Customer obtains new source of electric generation, Power on Order can be reduced or eliminated on 2 years notice
3.02 Billing Demand = Power on Order, or, lesser of 75% of Power on order in prior calendar year, and the Power on Order for the prior calendar year less 15,000 kW, or, maximum demand (less any Interruptible Demand), whichever is greatest	3.02 Billing Demand = Power on Order (to be between 50,000 kW and 70,000 kW) or maximum demand less 5,000 kW, whichever is greater
5.01 Interruptible Demand at new non-firm rate; amount available limited to lesser of 25% of Power on Order and 5,000 kW	3.05 Interruptible "A" rates the same as firm rates; amount available limited to 5,000 kW
10.01 General Force Majeure clause	11.06 General Force Majeure clause; 11.08(2) Special Force Majeure clause for strikes of mill employees

TABLE 1

Abitibi-Consolidated Inc. (Stephenville Division)

PROPOSED	EXISTING
10.02(10) Hydro may make Billing Demand adjustments to decrease the bill to allow for unforeseen circumstances or to provide for testing of equipment or processes	A practice has arisen whereby Hydro has reduced power bills in some circumstances referred to in 10.02(10) of proposed agreement
12.01 Hydro and Customer indemnify each other for specific risks	13.01 Customer indemnifies Hydro for specified risks; no indemnification of Customer by Hydro
13.04 Customer and Hydro to submit any claims under agreement to the other party within 60 days of having knowledge of the claims	14.04 Claims by Customer to be made on or prior to the last day of the month following the month the claim arose
14.01 Claims shall be submitted to arbitration within 3 months	15.01 Claims may be submitted to an arbitration within 2 months
15.04 Upon abandonment of contract or operations by Customer, liquidated damages become payable being 24 x 85% of Billing Demand for Firm Power plus the remaining book value of Specifically Assigned Plant less its salvage value	16.05 If Customer gives notice to terminate or abandons operations, Customer pays 85% of Billing Demand amount (minimum monthly payment) plus specifically assigned charge for each month remaining in the contract or for 5 years, whichever period is less

TABLE 2

Abitibi-Consolidated Inc. (Grand Falls Division)

PROPOSED	EXISTING
2.02 Maximum Power on Order = 40,000 kW	3.04 Minimum Power on Order of 20,000 kW, reductions in Power on Order cannot result in Power on Order at levels less than 20,000 kW lower than the previous year
3.02 Billing Demand = Power on Order, or, lesser of 75% of Power on Order in prior calendar year, and the Power on Order for the prior calendar year less 15,000 kW, or maximum demand (less any Interruptible Demand), whichever is greatest	4.01 Billing Demand = Power on Order or maximum demand in that month, whichever is greater
4.01 Interruptible Demand at new non-firm rate; amount available limited to lesser of 25% of Power on Order and 5,000 kW	3.06 Interruptible rates the same as firm rates; amount available limited to 5,000 kW

TABLE 2

Abitibi-Consolidated Inc. (Grand Falls Division)

PROPOSED	**EXISTING**
5.01 Generation Outage Power, charged at non-firm rates, available for emergencies and planned outages up to 59 MW of 60 Hz of generation capacity; Demand Charge prorated for duration of outage (days per month)	8.01 Emergency Power available at energy-only rate based upon incremental cost at Holyrood or cost of gas turbine generation – available for short term emergencies only “Exceptional Power” (collateral to formal agreement)) available for longer term, non-emergency outages – charged at Firm Demand rates prorated for duration of outage (days per month) plus Emergency Energy Rates
No provision for the supply of Energy by Customer	10.01 Supply of Surplus Energy by Customer to Hydro when not required at Stephenville mill
10.01 General Force Majeure clause	13.06 General Force Majeure clause; 13.08(2) Special Force Majeure clause for strikes of mill employees
10.02(10) Hydro may make Billing Demand adjustments to decrease the bill to allow for unforeseen circumstances or to provide for testing of equipment or processes	A practice has arisen whereby Hydro has reduced power bills in some circumstances referred to in 10.02(10) of proposed agreement
12.02 Hydro and Customer indemnify each other for specified risks	15.01 Customer indemnifies Hydro for specified risks; no indemnification of Customer by Hydro

TABLE 2

Abitibi-Consolidated Inc. (Grand Falls Division)

PROPOSED	**EXISTING**
13.04 Customer and Hydro to submit any claims under agreement to the other party within 60 days of having knowledge of the claims	16.04 Claims by Customer to be made on or prior to the last day of the month following the month the claim arose
14.02 Claims shall be submitted to arbitration within 3 months	17.01 Claims may be submitted to arbitration within 2 months
15.04 Upon abandonment of contract by Customer, liquidated damages become payable being 24 x 85% of Billing Demand for Firm Power plus the remaining book value of Specifically Assigned Plant less its salvage value	18.03 If Customer gives notice to terminate or abandons operations, Customer pays present worth of last Billing Demand amount for 5 years or until contract term expires, whichever comes first, plus $64,000 per month of remaining life of the contract

TABLE 3 Corner Brook Pulp and Paper Limited	
PROPOSED	**EXISTING**
2.02 Maximum Power on Order = 70,000 kWh	3 blocks: First block = 18,000 kW, Deer Lake Power block = 2,000 kW; Second block minimum of 15,000 kW (Note [1])
2.05 If Customer increases its generating capacity, Power on Order can be reduced or eliminated on 36 months notice	16.04 If Customer increases its generating capacity, Power on Order can be reduced on 2 years notice
3.02 Billing Demand = Power on Order, or lesser of 75% of Power on Order in prior calendar year, and the Power on Order for the prior calendar year less 15,000 kW, or maximum demand (less any Interruptible Demand) whichever is greatest	4.01 Billing Demand = Power on Order or Maximum Demand in that month, whichever is greater
4.01 Interruptible Demand at new non-firm rate; amount available limited to lesser of 25% of Power on Order and 5,000 kW	3.05 Interruptible rates the same as firm rates; amount available limited to 5,000 kW
Note [1] Unless otherwise stated, references to contract Articles are to “Second block” document	

TABLE 3

Corner Brook Pulp and Paper Limited

PROPOSED	**EXISTING**
5.01 Generation Outage Power charged at non-firm rates, available for emergencies and planned outages to up to 99,100 kW of 60 Hz generation capacity	7.01 (Deer Lake Power Block) Emergency power available for limited period (not beyond weekend following start of outage) for forced outages (except starting failures), and for low water; rate is energy-only rate based upon incremental cost at Holyrood or cost of gas turbine generation. “Exceptional Power” (collateral to formal agreements) available for longer term, non-emergency outages – charged at Firm Demand rates prorated for duration of outage plus Emergency Energy rates
10.01 General Force Majeure Clause	11.06 General Force Majeure clause; 11.08(2) Special Force Majeure clause for strikes of mill employees
10.02(10) Hydro may make Billing Demand adjustments to decrease the bill to allow for unforeseen circumstances or to provide for testing of equipment or processes	No established practice similar to subclause 10.02(10) of the proposed agreement
12.01, 12.02 Hydro and Customer indemnify each other for specified risks	13.01 Customer indemnifies Hydro for specified risks; no indemnification of Customer by Hydro
15.04 Upon abandonment of contract or operations by Customer, liquidated damages become payable being 24 x	16.05 If Customer gives notice to terminate or abandons operations, Customer pays 85% of Billing Demand amount

TABLE 3

Corner Brook Pulp and Paper Limited	
PROPOSED	**EXISTING**
85% of Billing Demand for Firm Power plus the remaining book value of Specifically Assigned Plant less its salvage value	(minimum monthly payment) plus specifically assigned charge for each month remaining in the contract or for 5 years, whichever period is less
17.01 Claims shall be submitted to arbitration within 3 months	15.01 Claims may be submitted to arbitration within 2 months
No provision requiring continued supply of the frequency converter	8.01 (First block 18,000 kW); 9.01 (DLP Contract 2,000 kW) Hydro to continue to provide the existing frequency converter

TABLE 4 North Atlantic Refining Limited	
PROPOSED	**EXISTING**
2.02 Customer declares Power on Order, not to exceed 45,000 kW	3.01/6.02 Customer agrees to purchase or pay for an amount not less than 20,000 kW, nor more than 35,000 kW
2.05 If Customer obtains new source of generation, Power on Order can be reduced or eliminated on 36 months notice	15.04 If Customer installs its own generation, it can reduce the minimum amount of power (20,000 kW) by giving one year's notice if up to a 10,000 kW reduction and by giving two years notice if more than a 10,000 kW reduction
3.02 Billing Demand = Power on order, or lesser of 75% of Power on order in prior calendar year, and the Power on Order for the prior calendar year less 15,000 kW, or maximum demand (less any Interruptible Demand), whichever is greatest	4.01 Billing Demand is maximum demand during previous 12 months
4.01 If Hydro has Secondary Energy available it will deliver it to the Customer for use in its electric boilers at a rate to be set by the PUB	No Secondary Energy provision
5.01 Interruptible Demand at new non-firm rate; amount available limited to lesser of 25% of Power on Order and 5,000 kW	No Interruptible Power provision
14.01 Claims shall be submitted to arbitration within 3 months	14.01 Claims may be submitted to arbitration within 2 months
15.04 Upon abandonment of contract or	15.05 Upon abandonment of the

TABLE 4

North Atlantic Refining Limited	
PROPOSED	**EXISTING**
operations by Customer, liquidated damages become payable being 24 x 85% of Billing Demand for Firm Power plus the remaining book value of Specifically Assigned Plant less its salvage value	contract or operations by the Customer, Customer pays as liquidated damages a lump sum of 85% of Billing Demand (minimum monthly payment) plus specifically assigned charges for each month remaining in the contract or for 5 years, if 5 years notice of termination is given

TABLE 5

Comparison of Revenue and RSP
Existing Rates vs. Proposed Rates
Based on 2001 Load Forecast
(Excludes HST)

	Revenue								
	Firm		Non-Firm		RSP (Using 2001 Rate)		Total Billing		
Customer	Existing 2001 Rate	Proposed 2002 Rate	Existing 2001 Rates	Proposed 2002 Rates	Existing	Proposed	Existing	Proposed	Proposed Increase / (Decrease)
ACI - Grand Falls	$4,776,819	$5,233,006	$0	$0	$409,612	$409,612	$5,186,431	$5,642,618	$456,187
ACI - Stephenville	$16,943,143	$18,734,844	$184,285	$272,352	$1,568,081	$1,554,188	$18,695,509	$20,561,384	$1,865,875
Corner Brook P&P	$12,251,830	$13,537,813	$234,204	$368,638	$1,139,127	$1,120,137	$13,625,161	$15,026,588	$1,401,427
North Atlantic Refining	$7,475,045	$8,224,146	$0	$0	$654,080	$654,080	$8,129,125	$8,878,226	$749,101

Q. Provide a table(s) showing the demand and energy rates available to each of the Industrial Customers for non-firm service under their existing contracts including rates for emergency power, secondary energy, Interruptible “A” power, and any other non-firm services, the demand and energy rates for each such service pursuant to the proposed Industrial Rates and contracts and the forecast dollar impact for each Industrial Customer in 2002 of each of those proposed changes in rates.

A. See the attached table.

Rates for Non-firm Service re Existing Contracts

Interruptible "A"			Emergency		Exceptional			Secondary
Demand Rate	Firm Energy Rate (Note 2)	Gas Turbine Energy Rate	Bunker 'C' Energy Rate	Gas Turbine Energy Rate	Demand Rate (Note 5)	Bunker 'C' Energy Rate	Gas Turbine Energy Rate	
$7.36	$0.02214	(Note 3)	(Note 4)	(Note 3)	$7.36	(Note 4)	(Note 3)	N/A

Notes:

(1) - Energy rates are $ per kWh ; Demand rates are $ per kW.

(2) - Includes RSP portion.

(3) - Maximum of $0.03200 and ($0.03200 ÷ $14.00 X Average Consumption Price per Barrel of No. 2 fuel).
The Average Consumption Price is calculated monthly so the Energy rate may change monthly.

(4) - Maximum of $0.01500 and ($0.01500 ÷ $7.50 X Average Consumption Price per Barrel of No. 6 fuel).
The Average Consumption Price is calculated monthly so the Energy rate may change monthly.

(5) - Exceptional demand (kW) is prorated by the ratio of days in use to days in the month of billing.

Proposed Rates for Non-firm Service

Demand Rate (Note 3)	Energy Rate
$1.50	(Note 2)

Notes:

(1) - Energy rate is $ per kWh ; Demand rate is $ per kW.

(2) - Formula to determine Energy rate:

{(A ÷ B) x (1+C)} where

A = the monthly average cost of fuel per barrel for the energy source in the current month, or in the month the source was last used,

B = the conversion factor for the source used (kW.h/bbl), and

C = the administrative and variable operating and maintenance charge (10%).

The energy sources and associated conversion factors are:

1. Holyrood, using No. 6 fuel with a conversion factor of 610 kWh/bbl.
2. Gas turbines, using No. 2 fuel with a conversion factor of 475 kWh/bbl.
3. Diesels, using No. 2 fuel with a conversion factor of 556 kWh/bbl.

(3) - Demand (kW) re Generation Outage is prorated by the ratio of days in use to days in the month of billing.

Non-firm Sales per 2002 Load Forecast

Customer	Charge per Existing Demand Rate	Charge per Proposed Demand Rate	Charge per Existing Energy Rate	Charge per Proposed Energy Rate	Demand Increase / (Decrease)	Energy Increase / (Decrease)	Total Increase / (Decrease)
Corner Brook Pulp and Paper	$70,100	$15,000	$164,623	$293,996	($55,100)	$129,373	$74,273
ACI - Stephenville	$84,120	$18,000	$30,276	$54,125	($66,120)	$23,850	($42,270)

Note: All Non-firm sales forecasted for 2002 were Interruptible "A".

Q. Which of Hydro's customers is capable of wheeling energy?

A. The following customers are capable of wheeling energy:

- Newfoundland Power;
- Abitibi Consolidated Inc. – Grand Falls Division; and
- Corner Brook Pulp and Paper Limited.

Q. Will the opportunity to wheel energy be provided to all customers who are capable of or wish to wheel energy?

A. Requests for wheeling would be considered by Hydro from the perspective of ensuring system efficiency and recovery of system costs.

Q. If not, which customers will be permitted to wheel energy?

A. See response to IC-36.

Q. If the answer to 36 is no, on what basis and in what circumstance does Hydro propose that wheeling be permitted.

A. See response to IC-36.

Q. Provide a Table setting out the estimated energy supply costs (year 2002 cents/kWh: indicate separately costs for fuel, other O&M and capital recoveries). Estimated MW capacity, firm and average annual energy capability, and nearest reasonable potential in service date for each of the following proposed potential developments for additional system generation noted in the evidence of H.G. Budgell (page 11):

1. Granite Canal hydro electric project;
2. Island Pond hydro electric project;
3. A combined cycle plant at Holyrood;
4. Holyrood Unit 4 conventional steam.

A. Please see attached table.

	Levelized Costs (cents/kWh) *			Net Capacity (MW)	Annual Energy (GWh)		Earliest Inservice ***
	Fuel	O&M	Capital		Firm	Average	
1. Granite Canal	n/a	0.37	5.05	40	216	224	2003
2. Island Pond	n/a	**	**	36	186	203	2005
3. Combined cycle at Holyrood	**	**	**	170	1340	1340	2005
4. Holyrood IV conventional steam	**	**	**	142.5	936	936	2006

* The levelized cost is the cost expressed in dollars of each year over the life of the project.
** For reasons of commercial confidentiality, Hydro cannot provide this information.
*** In addition to time required for project environmental review, design and construction, the earliest inservice date assumes a 6 month allowance for PUB review.

R. Henderson's Testimony

Q. .1) Provide all the terms and conditions of the longstanding agreements to buy energy"?

.2) Describe Hydro's underfrequency load shedding program and the benefits provided to the grid by the participation in this program by Industrial Customers.

A. .1) The agreement with Corner Brook Pulp and Paper was signed on May 13, 1977 between Bowater Power Company Limited and Hydro. The agreement with Abitibi Consolidated Inc. was signed June 23, 1982 and amended on June 20, 1995. A copy of these agreements are attached.

.2) Maintaining proper system frequency at or near 60 Hz is a critical requirement in power systems. Failure to maintain system frequency near 60 Hz can result in significant damage to both generating equipment and customer loads. Deviations as little as 2.5 Hz below nominal frequency can pose a significant hazard to rotating machines. In particular, if there is a sudden loss of generation the system frequency will immediately begin to reduce. A failure to rapidly correct this will result in continued frequency deterioration, further loss of generation and eventual system collapse.

The maintenance of system frequency is based upon a match between generation and load. In the North American grid, loss of large generating units is compensated for by the spinning reserve (spare generation and rotating inertia) maintained in the grid. For isolated systems, such as Newfoundland's island interconnected system, it is not economically feasible to carry sufficient spinning reserve to completely compensate for the sudden loss of large generating units. In these cases, utilities employ underfrequency load shedding programs to automatically reduce loads upon loss of generation, thereby re-establishing the balance between generation and load.

The underfrequency load shedding program operated on the island interconnected system is based upon participation by industrial customers, Newfoundland Power, and Newfoundland and Labrador Hydro. The attached table provides the participation schedule for these customers in the current scheme. Loads shown on the table indicate the amount of load that can be shed under peak conditions. If an underfrequency event occurs at a time other than peak, then the amount of load shed by each customer will depend upon the load connected at the time.

By participating in the underfrequency load shedding scheme, industrial customers contribute to the overall stability and security of the system. Based upon the attached table, industrial customers represent roughly 24 % of the total load allocated to the underfrequency load shedding program.

UNDERFREQUENCY LOAD SHEDDING PARTICIPATION SCHEDULE Revision 1 (99/12/16)	
CUSTOMER	**LOAD (MW)**
Newfoundland Power	406.50
Corner Brook Pulp & Paper	23.00
Abitibi Consolidated	
Grand Falls	55.50
Stephenville	60.00
Newfoundland & Labrador Rural Customers	31.00
System Total	576.00

Q. Industrial Contracts - Schedule "C"

1. Article 2.02 - how is the maximum "amount of power on order" determined? Has this changed from previous years? If so, how?

2. Interruptible "B" - how may all ICs participate in this program?

3. Non-firm energy - what is the rationale for a 10% surcharge, i.e., component C?

A. 1. A limit on the amount of power on order is required to permit Hydro time to build necessary additions to its transmission and terminal equipment or add generating capacity to the system to reliably supply the load.

The maximum amount of power on order was determined by first analyzing the capability of the transmission and terminal equipment supplying the customer. It was then decided to make the maximum "amount of power on order" the lesser of approximately 20 MW above the current power on order, and the capability of the equipment supplying the customer, rounded to the nearest 5 MW increment.

Please refer to the following table for determination of each customer's Maximum Amount of Power on Order:

Customer	Capability	Current Power on Order	Power on Order +20 MW	Maximum Amount of Power on Order
North Atlantic Refining Ltd.[1]	50 MVA (45 MW)	30 MW	50 MW	45 MW
Abitibi Consolidated Inc. (Grand Falls)	100 MVA (95 MW)	22 MW	42 MW	40 MW
Abitibi Consolidated Inc. (Stephenville)	156 MVA (148 MW)	70 MW	90 MW	90 MW
Corner Brook Pulp & Paper[2]	75 MW	51 MW	71 MW	70 MW

Notes: 1. North Atlantic Refining Ltd. does not currently have a Power On Order Contract, but has a maximum demand of approximately 30 MW.

2. Corner Brook Pulp and Paper shares transformers with Newfoundland Power and therefore the capability is common and 75 MW was estimated.

In previous years the maximum amount of power on order was determined through contract negotiations. This change is occurring now as this is the first time all contracts have changed at the one time.

2. There are two possible means whereby it would be possible for all IC's to have the opportunity to participate in this program. Hydro could access interruptible demand when a requirement arises through a request for proposals process or alternatively Hydro could include the provision in a special non-firm (curtailable) load service. Hydro has not made any decisions on proceeding with either of these options.

3. The 10% surcharge is applied to recover the following:

   a) an allowance for incidental operating costs of staff and facilities involved in dealing with the request and subsequent processing of the associated bill;
   b) an allowance for non-fuel items such as lube oil and fuel additives and;
   c) an allowance for profit.

   All Hydro Industrial rates, both firm and non-firm, have historically included such allowances.

Q. Provide a copy of the opening balance sheet of Hydro on its initial incorporation showing only items which affect those operations of Hydro which would, under current legislation be regulated at this date. Provide copies of balance sheets prepared on the same assumptions for each year from the date of incorporation to this date and identify the source of any change in the amount of equity shown on such balance sheets year over year.

A. The Newfoundland Power Commission was established in 1954 by The Newfoundland Power Commission Act, 1954 (1954 S.N. No. 72), was continued as the Newfoundland and Labrador Power Commission in 1965 (under The Newfoundland and Labrador Power Commission Act 1970 R.S.N. c.250), was continued as the Newfoundland and Labrador Power Corporation in 1974 (The Newfoundland and Labrador Power Corporation Act, 1974, 1974 S.N. No. 91) and was continued as Newfoundland and Labrador Hydro-Electric Corporation in 1975 (1975 S.N. No. 3).

The request to provide a balance sheet each year for 46 years (back to 1954) with the requested information is unduly onerous. Moreover, the provision of such information is not necessary to understand the matters to be considered in this proceeding and is not material to the issues before the Board.

Q. Explain in detail how the island grid and any components related thereto would have had to have been designed, engineered or constructed differently if the frequency converters had not been provided at the time that the Bay d'Espoir project was put in service and provide copies of all reports on these issues in Hydro's possession at the time the decisions were taken.

A. Had the frequency converters not been provided when the Bay d'Espoir project was put in service there were two alternatives at hand for the development of the Island transmission grid. The first alternative would be a single frequency system where all loads on the system would operate at the same frequency, most likely 60 Hz. This alternative would involve the conversion of all 50 Hz loads on the system to 60 Hz.

The second alternative would be to continue to operate as two separate systems. One at 50 Hz and one at 60 Hz. This alternative would involve providing transmission and generation from Bay d'Espoir at both frequencies.

The reports "Frequency Standardization Program – Presentation to Atlantic Development Board" January 8, 1965, and "Presentation to the Royal Commission on Electrical Power and Energy" July 1965, summarize the issues surrounding system development at the time Bay d'Espoir was constructed.

Q. So far as Hydro is aware, what is the policy of the Government of Newfoundland as to (a) issuance of shares of Hydro to itself or any other person, (b) the continued provision of a guarantee of Hydro's debt, (c) the injection of additional equity into Hydro and (d) the requirement that Hydro continue to pay dividends to the Government?

A. As far as Hydro is aware at this time:

(a) there are no plans for further issuance of shares,

(b) there will be continuation of the guarantee of Hydro's debt and the payment of a 1% guarantee fee, by Hydro, to the Province,

(c) there will be no injection of additional equity into Hydro,

(d) there will continue to be a requirement to pay dividends to the Government.

Q. (a) Indicate for each year from 1992 to 2000, and projections for 2001 and 2002, the amount of dividends declared (or forecast to be declared) by Hydro with respect to its utility operations, the level of utility net income for the year, and the percent that dividends are of such net income each year.

(b) What was the rationale for the Board of Directors decision to start declaring dividends?

(c) What is the Board of Directors' rationale for the specific levels of dividend declared?

(d) What would be the utility's 2002 test year capital structure if no dividends had been declared to date and none were declared for 2002?

A. (a) Please refer to NP-72.

(b) Please refer to NP-168.

(c) Please refer to NP-169.

(d) Please see schedule attached.

DIVIDEND IMPACT ON EARNINGS

	Dividends Pd to Date	Embedded Cost of Debt	Interest Impact	Cumulative Impact
1995	14,500	9.70%		14,500
1996	9,688	9.60%	1,392	25,580
1997	12,357	8.95%	2,289	40,226
1998	10,489	8.80%	3,540	54,255
1999	1,309	8.55%	4,639	60,203
2000	10,026	8.40%	5,057	75,286
2001	11,976	8.35%	6,283	93,545
2002	70,147	8.35%	7,806	171,498
	140,492		31,006	

CAPITAL STRUCTURE

	AS FILED		REVISED	
	2002	%	2002	%
Total Debt at end of year	1,380,949	85.51%	1,209,451	74.89%
Employee Future Benefits	25,123	1.56%	25,123	1.56%
Total Equity at end of year	208,830	12.93%	380,328	23.55%
	1,614,902	100.00%	1,614,902	100.00%

Q. Describe how the Roddickton Mini-hydro, the Hawkes Bay Diesel, the St. Anthony Diesel and the Roddickton mobile diesel plants would be utilized, in the event of a major failure or otherwise, to supply any service to any customer of Hydro other than Rural Interconnected Customers and include in this answer the actual and forecast loads north of Deer Lake for the years 2000 – 2002.

A. The Roddickton Mini-hydro plant is a run of the river facility and is operated when sufficient water exists. It operates primarily as an energy source and reduces fuel costs at Holyrood for the benefit of all customers on the Island Interconnected System.

The diesel generation at Hawke's Bay, St. Anthony and Roddickton is operated to supply power to the Island Interconnected System to the benefit of all customers based upon unit availability and cost, no different than the gas turbines at Hardwoods and Stephenville. In the event of a failure to a hydro unit, for example, the diesel generation would be called upon to supply power depending upon system load and availability of lower cost generating units. The diesel units at Hawke's Bay and St. Anthony can be remotely operated by the Energy Control Center to provide fast start capacity for any generation forced outage.

The actual and forecast loads north of Deer Lake for the years 2000 – 2002 are as follows:

2000 Actual and 2001 – 2002 Forecast Loads Great Northern Peninsula North of Deer Lake		
Year	MWh	kW
2000	177,354	35,699
2001	174,428	38,762
2002	176,561	39,249

Q. Outline the assumptions on provincial economic activity and relative energy prices used in formulating the Long Term Planning Load Forecast, including inflation, exchange rates, and borrowing costs for different short and long term debt.

A. The assumptions on Provincial economic activity are as per summary of Key Economic Indicators summary presented in response to IC – 82(Rev). The exchange rate and short and long term borrowing costs do not factor explicitly into the Long Term Planning Load Forecast (PLF) and are not inputs. The response to IC – 190 provides medium term exchange rate assumptions utilized in the formulation of the rate referral. The key relative price consideration for the Long Term Planning Load Forecast is for home heating fuel oil for the space heating market. The average domestic prices for home heating fuel oil and electricity used in the 2001 PLF:

Relative Energy Prices[1] in 2001 PLF		
	Fuel Oil ($/GJ)	Electricity ($/GJ)
2000 A	18.35	21.85
2001	15.75	21.85
2002	14.60	23.55
2003	14.40	23.25
2004	14.05	22.90
2005	13.85	22.50
2006	13.75	22.15
2007	13.65	21.90
2008	13.65	22.25
2009	13.60	23.20
2010	13.60	23.10

1. 2000$ for marginal price to a user (rounded to nearest $0.05).

Q. In reference to the Evidence of K.C. McShane:

1. P.9, lines 1-3. Please explain why “fuel expense” should be eliminated from the estimate of working capital.

2. P. 17, line 22. Please explain more fully why “fuel cost risk (e.g. thermal efficiency)” is a “challenge” for Hydro.

3. P.23, line 28-p.24, line 2. Please provide the record of dividends paid by Hydro to the Province of Newfoundland for all years from initial incorporation to the present. Please also separate the portion that can be attributed to “regulated earnings.”

4. P. 31, lines 12-16. Please explain more fully what you have in mind by your reference to “the administered nature of short-term rates.”

5. P. 40, Table 4. Are all companies in the TSE 300 included in the 14 TSE 300 Group Indices? If so, how is it possible for the average standard deviation of the 14 Groups to be less than the standard deviation of the TSE 300?

6. P.53, lines 1-2. Please provide a copy of the report referenced.

A. 1. Fuel expense is excluded from the lead lag analysis of <u>cash</u> working capital needs, because it is included as a separate item in the working capital estimate (fuel inventory).

2. Rates are set on the basis of forecast thermal efficiency (kWh//barrel). To the extent that the achieved thermal efficiency is less than provided for in rates, Hydro is at risk for underrecovery of fuel costs.

3. Please refer to NP-72(b).

4. Short-term rates are primarily driven by monetary policy, i.e., the decisions of the Bank of Canada to raise or lower the bank rate to control inflation or stimulate economic activity.

5. Yes. The standard deviation of the TSE 300 as a portfolio is less than the average of the 14 Group Indices due to the impact of diversification on the size of the standard deviation. To illustrate with a simple example:

Assume you have two stocks, each worth $100 in Year 0. The two stocks perform as follows:

Year	**Stock 1**		**Stock 2**		**Portfolio**	
	Value $	**Return %**	**Value $**	**Return %**	**Value $**	**Return %**
0	100.00		100.00		200.00	
1	110.00	10	95.00	-5	205.00	2.5
2	115.50	5	114.00	20	229.60	12
3	144.38	25	125.40	10	269.55	17.4
4	137.16	-5	131.67	5	268.47	-0.4
5	164.59	20	164.59	25	328.61	22.4
Standard Deviation		**11.9**		**11.9**		**9.7**

The average standard deviation of the two stocks is less than the portfolio standard deviation, because the annual returns for each stock are not perfectly correlated.

6. The requested publication is proprietary. The summary pages relied upon are attached.

Q. Provide the 2002 Forecast Cost of Service with the generation assets, the associated terminal stations and the 138 kV & 66 kV transmission lines on the Great Northern Peninsula assigned as specific to the Rural Interconnected Customers.

A. See attached. Please note that this Cost of Service Study does not incorporate any changes to revenues, or any related impacts associated with interest and return on rate base, from those filed in Exhibit JAB-1.

Q. Provide the 2002 Forecast Cost of Service using the interim cost of service classifications and allocations approved by the Board in 1992. Assume the same assignments as in the 2002 forecast.

A. See attached. Please note that this Cost of Service Study does not incorporate any changes to revenues, or any related impacts associated with interest and return on rate base, from those filed in Exhibit JAB-1.

Q. Provide actual costs for the Island Interconnected system for each of the years 1992 to 2000 inclusive plus the 2001 estimate. Use the same format as in Schedule 1 of J.C. Robert's evidence.

A. The costs for the Island Interconnected system can only be derived using the Cost of Service (COS) Study. The COS Study uses data in a more summarized fashion than that shown in Schedule 1 of J.C. Roberts' evidence and therefore the requested information is not available.

Q. Assuming no additional assets, provide the depreciation for the Island Interconnected system for each year 2003 through 2010.

A. Assuming no additional assets, the depreciation for the Island Interconnected system for 2003 through 2010 would be as follows:

Year	Amount
2003$	27,855,268
2004	26,026,553
2005	25,752,713
2006	24,899,907
2007	23,987,863
2008	23,597,803
2009	23,706,330
2010	22,798,738

Q. With respect to Henderson's evidence page 3, line 20, what has been the total annual energy produced from the St. Anthony diesel plant, the Roddickton mini-hydro and the mobile diesel units in Roddickton for each year since connection to the interconnected system.

A. Please refer the response to NP-122 for all production except the mobile diesel unit in Roddickton . The mobile diesel units were connected to the system in late 2000. They have only been operated for testing and have therefore produced a negligible amount of energy.

Q. Supply the data used in calculating the 4% loss as used in the wheeling rate.

A. The 4% losses used in the wheeling rate is the average percentage losses on the Hydro system as determined for 1999 rounded off to the nearest whole point above that determined. This is consistent with the existing agreement with Abitibi Consolidated Inc. as referenced in IC-43.

The losses in 1999 were as follows:

Total Energy Supply (Purchased and Produced)	5,877 GWh
System Losses (Excluding Distribution)	214 GWh
System Losses Percent	3.6%

Q. With reference to the proposed Industrial - Non-Firm rate, Schedule A, page 3:

1. Provide the detailed reasons and calculations used in determining $1.50 per month per kilowatt.
2. Provide the details to support the administrative and variable operating and maintenance charge of 10%.

A. 1. Please see response to NP-183

2. Please see response to IC-44(3).

Q. With reference to Well's evidence page 9. lines 11 – 17, what is the proposed percentage increase to the fish plants, churches and community halls?

A. The fish plants in the Isolated Rural Systems pay the same rates as Island Interconnected General Service customers therefore their percentage increase is estimated at 3.7%. Churches and community halls pay the Domestic Diesel rate therefore their basic customer charge and the first 700 kWh block would be the same as the Island Interconnected Domestic rate. The end block would receive the same percentage as the overall general increase applied by Newfoundland Power therefore the overall estimated increase for churches and community halls is also 3.7%.