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September 12, 2001

G. Cheryl Blundon
Board Secretary
Board of Commissioners of Public Utilities
Suite E210, Prince Charles Building
120 Torbay Road
P.O. Box 21040
St. John's, NF
A1A 5B2

Dear Ms. Blundon:

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

Please find enclosed the original plus seventeen (17) copies of the following:

1) Newfoundland & Labrador Hydro's responses to Requests for Information
IC-247, 249, 250, 254, 256, and 262,
CA-192, 193, 194, 195, 196, 197, 198 and 199;

2) Revision to IC-98; and

3) Supplementary Evidence of D.W. Osmond and J.A Brickhill.

Yours truly,

Newfoundland and Labrador Hydro

____

Maureen P. Greene, Q.C.
Vice-President & General Counsel

MPG/jc

Enclosure

cc: Gillian Butler, Q.C. and Peter Alteen
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Mr. Dennis Peck
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Q. With reference to the $449,659 of purchased “wheeling” power in line 3 of Brickhill’s schedule 4.4, list the sources and destinations of this wheeled power, the energy transmitted and the cost associated with each source.

A. The wheeled power and energy is from Hydro’s Island Interconnected System generation and power purchases. The power and energy is wheeled over Newfoundland Power’s transmission and distribution system to various Hydro Rural distribution systems. The following table provides the destination systems, the energy received and the 2002 forecast payments to Newfoundland Power for each.

Distribution Systems	Energy Received	Cost
Baie Verte Peninsula	47,846 MWh	$229,659
Fleur-de-Lys		
Kings Point		
Little Bay		
Westport		
Bottom Waters		
Farewell Head	22,684 MWh	$220,000
Fogo/Change Islands		
Total	70,530 MWh	$449,659

Q. Further to IC-24:

a. Provide a table that shows total gross generation, net energy production, losses and percentage losses for each year 1992 to 2000.
b. Where is gross generation measured?
c. Where is net energy production measured?
d. Explain where the losses occur and the reason for the changes from year to year.

A. a. The Holyrood production as requested is provided in the following table. There are no system losses attributed to Holyrood and therefore it is assumed the losses in question are what Hydro refers as to station services.

Holyrood Generating Station

Year	Gross Generation (kWh)	Station Service (kWh)	Station Service (%)	Net Energy Production (kWh)
1992	1,812,450,000	106,237,160	5.86%	1,706,212,840
1993	1,661,130,000	102,246,660	6.16%	1,558,883,340
1994	839,760,000	62,865,600	7.49%	776,894,400
1995	1,626,980,000	93,901,920	5.77%	1,533,078,080
1996	1,493,060,000	89,463,880	5.99%	1,403,596,120
1997	1,625,380,000	94,079,080	5.79%	1,531,300,920
1998	1,343,480,000	80,215,940	5.97%	1,263,264,060
1999	993,290,000	73,488,480	7.40%	919,801,520
2000	1,040,450,000	70,166,720	6.74%	970,283,280

b. Gross generation is measured at the terminals of each generator.

c. Net energy production is calculated and not measured. It is the difference between the gross generation and the metered station service use at the plant.

d. The station service is the energy used in the plant for all requirements of the plant such as pump motors, fan motors, heating, lighting etc. The changes that occur from year to year are caused by varying plant production requirements and to some extent the maintenance activities being carried out in the plant.

Q. Further to IC-73, the Rate Stabilization Plan for April 2001, page 14 shows +$696,000 rural change adjustment.

a. Fully explain the details of this charge.

b. How much of this charge was re-allocated to the Industrial Customers?

A. a. Refer to the response to NP-206(a).

b. The amount of $696,000 forms part of the total rural deficit to be re-allocated, as do the credits included in the rural rate alteration. As indicated in the response to IC-216, the allocation is based on year-to-date amounts, and therefore varies from month to month, based on actual activity. In April 2001, the rural allocation to Industrial customers was 18.37% of the total rural amount, or approximately $128,000 of the $696,000.

Q. With reference to IC-98 and IC-206, confirm the forecast industrial rates for the years 2001 to 2005. Reconcile the apparent differences in increases between 2001 and 2004 in table 8 on page 14 of IC-98 and the chart of page 4 in the response to IC-206. What is the forecast percentage increase in Industrial rates (including RSP) between 2001 and 2004?

A. The forecast industrial rates are as outlined in the table below.

	Industrial Rate (IC) as of January 1			
	Energy[1] (¢ per kWh)	Demand[2] ($ per KW)	Average Rate[3] (¢ per kWh)	Industrial Rate[4] Index
2001F	2.214	7.36	3.251	1.000
2002F	2.867	7.01	3.855	1.186
2003F[5]			4.130	1.270
2004F[5]			4.390	1.350
2005F[5]			4.310	1.326

Notes:

1. Energy is the actual Industrial Rate as of January 1 each year inclusive of all adjustments, including RSP.
2. Demand is the actual Industrial Rate as of January 1 each year.
3. Average Rate = Column 1 + (Column 2 ÷ ((365 days X 24 hours X 81% Load factor*) ÷ 1000))
   * Median industrial load factor of 81% for the period used to express energy rate.
4. Industrial Rate Index = Current Year Average Rate ÷ 2001 Average rate
5. 2003F to 2005F average rates were extracted from page 14 of the Newfoundland and Labrador Hydro Financial Plan as filed in response to IC-98.

The 2001 Industrial rate (after RSP adjustment) reported in the 5 Year Plan filed in response to IC-98 contains an error and a revision will be issued. However, there are differences in the increases reported in the response to IC-206 and the Five Year Plan since there are two different methods used in reporting the rate effects. The response to IC-206, and as indicated in the table above, uses a typical Island Industrial customer with an 81% load factor for 2001 and 2002. It is necessary to make some assumptions in regard to usage in both of these years since the 2001 and 2002 forecast is developed on the basis of a two-part rate. The increases reported using this methodology are not directly comparable to the data reported in the Five Year Plan. The data in the Five Year Plan uses total customer class data in calculating rates, specifically, total Island Industrial revenue divided by total Island Industrial sales.

As outlined in the table above, assuming an 81% customer load factor for 2001 and 2002 and assuming the 2003 and 2004 average rates as outlined in the Five Year Plan, there is a projected 35% increase in rates including RSP adjustments projected between 2001 and 2004. As outlined in the commentary on page 13 of the Five Year Plan regarding projected rates *"Detailed cost of service studies have not been completed for 2003 and beyond, however, rates have been estimated using Hydro's planning models that use simplifying assumptions. Projected rates and rate changes are believed to be indicative based on the assumptions used but not as finite as if detailed cost of service studies were available."*

Q. Further to IC-118, provide the total energy supply, the system losses and the system loss percent for the years 1992 to 2000 inclusive.

A. Please refer to the following table:

YEAR	Total Energy Supply (Purchased & Produced) GWh	System Losses (Excluding Distribution) GWh	System Losses %
1992	5,929	195	3.29
1993	6,000	211	3.51
1994	5,818	225	3.86
1995	5,927	197	3.32
1996	5,989	198	3.30
1997	6,164	202	3.28
1998	5,718	211	3.70
1999	5,877	214	3.65
2000	6,141	211	3.43

Q. With reference to NP-122, please clarify that generation and capacity factors listed are net of station service. If not, then please clarify what is removed from gross generation and capacity to arrive at the figures listed in NP-122. Please provide similar tables (i.e. by plant and year) which show the gross production and capacity, the items removed to arrive at the net figures listed in NP-122.

A. In NP-122 gross production was reported instead of net production for some of the smaller plants as either the station service data was not available or the station service data for the plants may not have been consistently available over the period. The station service (internal plant use) was removed from the gross production for all plants except Snooks Arm, Venams Bight, St. Anthony Diesel, Roddickton Diesel, Hawkes Bay Diesel and the Holyrood Gas Turbine.

The attached tables show all available data for all plants with both the gross and net capacity factor. The Holyrood thermal plant and Roddickton thermal plant are the only plants with a significant difference in net and gross capacity due to the relatively large station service demand requirements for thermal plants.

Newfoundland & Labrador Hydro
Capacity Factors

Year	Production Gross (kWh)	Station Service (kWh)	Production Net (kWh)	Capacity Gross (MW)	Capacity Net (MW)	Hours	Capacity Factor Gross	Capacity Factor Net
Bay Despoir								
1992	2,618,582,400	5,558,653	2,613,023,747	580	580	8,784	51.40%	51.29%
1993	2,821,737,600	7,047,723	2,814,689,877	582	582	8,760	55.35%	55.21%
1994	3,289,766,400	7,493,062	3,282,273,338	586	586	8,760	64.09%	63.94%
1995	2,595,039,400	7,317,721	2,587,721,679	590	590	8,760	50.21%	50.07%
1996	2,794,128,000	8,256,165	2,785,871,835	592	592	8,784	53.73%	53.57%
1997	2,854,382,400	8,599,623	2,845,782,777	592	592	8,760	55.04%	54.88%
1998	2,617,219,200	7,982,658	2,609,236,542	592	592	8,760	50.47%	50.31%
1999	3,095,721,600	7,482,726	3,088,238,874	592	592	8,760	59.69%	59.55%
2000	3,122,730,600	7,681,901	3,115,048,699	592	592	8,784	60.05%	59.90%
2001 Forecast			2,598,000,000		592	8,760		50.10%
2002 Forecast			2,598,000,000		592	8,760		50.10%
Average	2,867,700,844		2,812,535,215	589	589	8,767	55.57%	54.44%
Hinds Lake								
1992	309,436,800	1,367,400	308,069,400	75	75	8,784	46.97%	46.76%
1993	355,584,000	1,421,400	354,162,600	75	75	8,760	54.12%	53.91%
1994	460,569,600	1,530,140	459,039,460	75	75	8,760	70.10%	69.87%
1995	404,092,800	1,540,300	402,552,500	75	75	8,760	61.51%	61.27%
1996	353,712,000	1,439,600	352,272,400	75	75	8,784	53.69%	53.47%
1997	409,161,600	1,686,000	407,475,600	75	75	8,760	62.28%	62.02%
1998	410,256,000	1,565,700	408,690,300	75	75	8,760	62.44%	62.21%
1999	347,289,600	1,572,200	345,717,400	75	75	8,760	52.86%	52.62%
2000	389,328,000	1,352,800	387,975,200	75	75	8,784	59.10%	58.89%
2001 Forecast			340,000,000		75	8,760		51.75%
2002 Forecast			340,000,000		75	8,760		51.75%
Average	382,158,933		373,268,624	75	75	8,767	58.12%	56.77%
Upper Salmon								
1992	560,892,000	2,242,400	558,649,600	84	84	8,784	76.02%	75.71%
1993	555,360,000	3,648,900	551,711,100	84	84	8,760	75.47%	74.98%
1994	662,436,000	3,995,800	658,440,200	84	84	8,760	90.02%	89.48%
1995	555,828,000	3,727,400	552,100,600	84	84	8,760	75.54%	75.03%
1996	601,704,000	4,046,700	597,657,300	84	84	8,784	81.55%	81.00%
1997	603,396,000	4,318,100	599,077,900	84	84	8,760	82.00%	81.41%
1998	557,832,000	3,933,600	553,898,400	84	84	8,760	75.81%	75.27%
1999	653,112,000	4,025,800	649,086,200	84	84	8,760	88.76%	88.21%
2000	641,136,000	4,197,500	636,938,500	84	84	8,784	86.89%	86.32%
2001 Forecast			552,000,000		84	8,760		75.02%
2002 Forecast			552,000,000		84	8,760		75.02%
Average	599,077,333		587,414,527	84	84	8,767	81.35%	79.77%

Newfoundland & Labrador Hydro
Capacity Factors

Year	Production Gross (kWh)	Station Service (kWh)	Production Net (kWh)	Capacity Gross (MW)	Capacity Net (MW)	Hours	Capacity Factor Gross	Capacity Factor Net
Cat Arm								
1992	707,500,000	2,989,600	704,510,400	127	127	8,784	63.42%	63.15%
1993	668,500,000	1,611,800	666,888,200	127	127	8,760	60.09%	59.94%
1994	604,400,000	1,538,600	602,861,400	127	127	8,760	54.33%	54.19%
1995	810,000,000	1,548,600	808,451,400	127	127	8,760	72.81%	72.67%
1996	794,800,000	1,603,200	793,196,800	127	127	8,784	71.25%	71.10%
1997	736,800,000	1,884,800	734,915,200	127	127	8,760	66.23%	66.06%
1998	652,100,000	1,687,100	650,412,900	127	127	8,760	58.61%	58.46%
1999	676,300,000	1,445,900	674,854,100	127	127	8,760	60.79%	60.66%
2000	838,400,000	1,633,600	836,766,400	127	127	8,784	75.15%	75.01%
2001 Forecast			735,000,000		127	8,760		66.07%
2002 Forecast			735,000,000		127	8,760		66.07%
Average	720,977,778		722,077,891	127	127	8,767	64.76%	64.86%
Paradise River								
1992	30,840,000	202,480	30,637,520	8	8	8,784	43.89%	43.60%
1993	45,311,000	224,110	45,086,890	8	8	8,760	64.66%	64.34%
1994	34,600,000	211,430	34,388,570	8	8	8,760	49.37%	49.07%
1995	35,888,000	435,190	35,452,810	8	8	8,760	51.21%	50.59%
1996	37,133,000	247,780	36,885,220	8	8	8,784	52.84%	52.49%
1997	35,056,000	297,420	34,758,580	8	8	8,760	50.02%	49.60%
1998	32,324,000	318,490	32,005,510	8	8	8,760	46.12%	45.67%
1999	38,302,000	330,870	37,971,130	8	8	8,760	54.65%	54.18%
2000	36,737,000	295,780	36,441,220	8	8	8,784	52.28%	51.86%
2001 Forecast			39,370,000		8	8,760		56.18%
2002 Forecast			39,370,000		8	8,760		56.18%
Average	36,243,444		36,578,859	8	8	8,767	51.68%	52.16%
Snook's Arm								
1992	3,865,320	N/A	3,865,320	0.56	0.56	8,784	78.58%	
1993	3,571,290	N/A	3,571,290	0.56	0.56	8,760	72.80%	
1994	4,016,700	N/A	4,016,700	0.56	0.56	8,760	81.88%	
1995	3,567,690	N/A	3,567,690	0.56	0.56	8,760	72.73%	
1996	4,394,160	N/A	4,394,160	0.56	0.56	8,784	89.33%	
1997	3,868,290	N/A	3,868,290	0.56	0.56	8,760	78.85%	
1998	4,033,170	N/A	4,033,170	0.56	0.56	8,760	82.22%	
1999	2,981,640	N/A	2,981,640	0.56	0.56	8,760	60.78%	
2000	1,661,760	N/A	1,661,760	0.56	0.56	8,784	33.78%	
2001 Forecast		N/A	3,675,000		0.56	8,760		74.91%
2002 Forecast		N/A	3,675,000		0.56	8,760		74.91%
Average	3,551,113	N/A	3,573,638	0.56	0.56	8,767	72.33%	72.79%

Newfoundland & Labrador Hydro
Capacity Factors

Year	Production Gross (kWh)	Station Service (kWh)	Production Net (kWh)	Capacity Gross (MW)	Capacity Net (MW)	Hours	Capacity Factor Gross	Capacity Factor Net
Venam's Bight								
1992	2,827,140	N/A	2,827,140	0.36	0.36	8,784	89.40%	
1993	2,921,520	N/A	2,921,520	0.36	0.36	8,760	92.64%	
1994	2,564,340	N/A	2,564,340	0.36	0.36	8,760	81.31%	
1995	2,571,420	N/A	2,571,420	0.36	0.36	8,760	81.54%	
1996	2,921,400	N/A	2,921,400	0.36	0.36	8,784	92.38%	
1997	2,816,580	N/A	2,816,580	0.36	0.36	8,760	89.31%	
1998	2,900,520	N/A	2,900,520	0.36	0.36	8,760	91.97%	
1999	2,592,900	N/A	2,592,900	0.36	0.36	8,760	82.22%	
2000	1,151,040	N/A	1,151,040	0.36	0.36	8,784	36.40%	
2001 Forecast		N/A	2,575,000		0.36	8,760		81.65%
2002 Forecast		N/A	2,575,000		0.36	8,760		81.65%
Average	2,585,207	N/A	2,583,351	0.36	0.36	8,767	81.92%	81.86%
Roddickton Mini Hydro								
1992								
1993								
1994								
1995								
1996	386,350	8,860	377,490	0.40	0.40	2,928	32.99%	32.23%
1997	845,400	41,352	804,048	0.40	0.40	8,760	24.13%	22.95%
1998	1,386,000	37,486	1,348,514	0.40	0.40	8,760	39.55%	38.48%
1999	1,146,000	34,310	1,111,690	0.40	0.40	8,760	32.71%	31.73%
2000	792,600	60,660	731,940	0.40	0.40	8,784	22.56%	20.83%
2001 Forecast			1,050,000		0.40	8,760		29.97%
2002 Forecast			1,050,000		0.40	8,760		29.97%
Average	1,042,500		924,812	0.40	0.40	8,764	29.74%	26.38%
THERMAL Holyrood								
1992	1,812,450,000	106,237,160	1,706,212,840	490	466	8,784	42.11%	41.68%
1993	1,661,130,000	102,246,660	1,558,883,340	490	466	8,760	38.70%	38.19%
1994	839,760,000	62,865,600	776,894,400	490	466	8,760	19.56%	19.03%
1995	1,626,980,000	93,901,920	1,533,078,080	490	466	8,760	37.90%	37.56%
1996	1,493,060,000	89,463,880	1,403,596,120	490	466	8,784	34.69%	34.29%
1997	1,625,380,000	94,079,080	1,531,300,920	490	466	8,760	37.87%	37.51%
1998	1,343,480,000	80,215,940	1,263,264,060	490	466	8,760	31.30%	30.95%
1999	993,290,000	73,488,480	919,801,520	490	466	8,760	23.14%	22.53%
2000	1,040,450,000	70,166,720	970,283,280	490	466	8,784	24.17%	23.70%
2001 Forecast			1,971,340,000		466	8,760		48.29%
2002 Forecast			2,157,880,000		466	8,760		52.86%
Average	1,381,775,556		1,435,684,960	490	466.00	8,767	32.17%	35.14%

Newfoundland & Labrador Hydro
Capacity Factors

Year	Production Gross (kWh)	Station Service (kWh)	Production Net (kWh)	Capacity Gross (MW)	Capacity Net (MW)	Hours	Capacity Factor Gross	Capacity Factor Net
Hardwoods GAS TURBINE								
1992	2,030,400	3,383,760	(1,353,360)	54	54	8,784	0.43%	-0.29%
1993	626,400	973,461	(347,061)	54	54	8,760	0.13%	-0.07%
1994	2,822,400	1,901,507	920,893	54	54	8,760	0.60%	0.19%
1995	925,200	679,388	245,812	54	54	8,760	0.20%	0.05%
1996	972,000	685,972	286,028	54	54	8,784	0.20%	0.06%
1997	590,400	634,808	(44,408)	54	54	8,760	0.12%	-0.01%
1998	557,200	761,470	(204,270)	54	54	8,760	0.12%	-0.04%
1999	792,000	1,006,544	(214,544)	54	54	8,760	0.17%	-0.05%
2000	223,200	885,632	(662,432)	54	54	8,784	0.05%	-0.14%
2001 Forecast			1,590,000		54	8,760		0.34%
2002 Forecast			2,240,000		54	8,760		0.47%
Average	1,059,911		223,333	54	54	8,767	0.22%	0.05%
Stephenville GAS TURBINE								
1992	705,600	1,182,060	(476,460)	54	54	8,784	0.15%	-0.10%
1993	1,015,200	687,840	327,360	54	54	8,760	0.21%	0.07%
1994	288,000	499,440	(211,440)	54	54	8,760	0.06%	-0.04%
1995	338,400	515,458	(177,058)	54	54	8,760	0.07%	-0.04%
1996	648,000	623,940	24,060	54	54	8,784	0.14%	0.01%
1997	36,000	546,480	(510,480)	54	54	8,760	0.01%	-0.11%
1998	374,400	973,260	(598,860)	54	54	8,760	0.08%	-0.13%
1999	201,600	454,800	(253,200)	54	54	8,760	0.04%	-0.05%
2000	36,000	589,460	(553,460)	54	54	8,784	0.01%	-0.12%
2001 Forecast			1,200,000		54	8,760		0.25%
2002 Forecast			1,200,000		54	8,760		0.25%
Average	404,800		(2,685)	54	54	8,767	0.09%	0.00%
Holyrood GAS TURBINE								
1992	215,000	N/A	215,000	10	10	8,784	0.24%	
1993	156,100	N/A	156,100	10	10	8,760	0.18%	
1994	471,000	N/A	471,000	10	10	8,760	0.54%	
1995	124,000	N/A	124,000	10	10	8,760	0.14%	
1996	255,000	N/A	255,000	10	10	8,784	0.29%	
1997	189,000	N/A	189,000	10	10	8,760	0.22%	
1998	248,000	N/A	248,000	10	10	8,760	0.28%	
1999	296,000	N/A	296,000	10	10	8,760	0.34%	
2000	124,000	N/A	124,000	10	10	8,784	0.14%	
2001 Forecast		N/A	440,000		10	8,760		0.50%
2002 Forecast		N/A	750,000		10	8,760		0.86%
Average	230,900	N/A	595,000	10	10	8,767	0.26%	0.68%

Newfoundland & Labrador Hydro
Capacity Factors

Year	Production Gross (kWh)	Station Service (kWh)	Production Net (kWh)	Capacity Gross (MW)	Capacity Net (MW)	Hours	Capacity Factor Gross	Capacity Factor Net
St. Anthony Diesel								
1992								
1993								
1994								
1995								
1996	1,051,700	82,200	969,500	8	8	2,928	4.49%	4.14%
1997	257,398	459,600	(202,202)	8	8	8,760	0.37%	-0.29%
1998	395,200	406,400	(11,200)	8	8	8,760	0.56%	-0.02%
1999	216,000	396,000	(180,000)	8	8	8,760	0.31%	-0.26%
2000	139,200	366,800	(227,600)	8	8	8,784	0.20%	-0.32%
2001 Forecast			204,000		8	8,760		0.29%
2002 Forecast			204,000		8	8,760		0.29%
Average	251,950		(35,500)	8	8	8,764	0.36%	-0.05%
Hawkes Bay Diesel								
1992	192,000	N/A	192,000	5	5	8,784	0.44%	
1993	168,000	N/A	168,000	5	5	8,760	0.38%	
1994	115,200	N/A	115,200	5	5	8,760	0.26%	
1995	600,000	N/A	600,000	5	5	8,760	1.37%	
1996	600,000	N/A	600,000	5	5	8,784	1.37%	
1997	129,600	N/A	129,600	5	5	8,760	0.30%	
1998	115,888	N/A	115,888	5	5	8,760	0.26%	
1999	170,056	N/A	170,056	5	5	8,760	0.39%	
2000	51,100	199,960	(148,860)	5	5	8,784	0.12%	-0.34%
2001 Forecast			120,000		5	8,760		0.27%
2002 Forecast			120,000		5	8,760		0.27%
Average	237,983		198,353	5	5	8,767	0.54%	0.45%
Roddickton Diesel								
1992								
1993								
1994								
1995								
1996	180,960	51,180	129,780	2.85	2.85	2,928	2.17%	1.56%
1997	66,000	116,980	(50,980)	2.85	2.85	8,760	0.26%	-0.20%
1998	122,400	90,560	31,840	2.85	2.85	8,760	0.49%	0.13%
1999	19,800	75,840	(56,040)	2.85	2.85	8,760	0.08%	-0.22%
2000	0	77,600	(77,600)	1.70	1.70	8,784	0.00%	-0.52%
2001 Forecast			24,000		1.70	8,760		0.16%
2002 Forecast			24,000		1.70	8,760		0.16%
Average	69,400		(17,463)	2.85	2.28	8,764	0.28%	-0.09%

Newfoundland & Labrador Hydro
Capacity Factors

Year	Production Gross (kWh)	Station Service (kWh)	Production Net (kWh)	Capacity Gross (MW)	Capacity Net (MW)	Hours	Capacity Factor Gross	Capacity Factor Net
Roddickton Woodchip								
1992								
1993								
1994								
1995								
1996	993,800	361,940	631,860	5	4.6	2,928	6.79%	4.69%
1997	77,550	514,782	(437,232)	5	4.6	8,760	0.18%	-1.09%
1998	228,670	488,522	(259,852)	5	4.6	8,760	0.52%	-0.64%
1999	0	410,481	(410,481)	5	4.6	8,760	0.00%	-1.02%
2000								
Average	153,110		(369,188)	5	4.6	8,760	0.35%	-0.92%
Island Interconnected								
1992	6,049,536,660		5,926,373,147	1,488	1,448	8,784	46.29%	46.59%
1993	6,116,081,110		5,998,219,216	1,490	1,450	8,760	46.86%	47.22%
1994	5,901,809,640		5,821,774,061	1,494	1,454	8,760	45.10%	45.71%
1995	6,035,954,910		5,926,288,933	1,498	1,458	8,760	46.00%	46.40%
1996	6,084,327,560		5,977,960,323	1,500	1,460	8,784	46.18%	46.61%
1997	6,273,052,218		6,159,873,193	1,516	1,476	8,760	47.23%	47.65%
1998	5,623,572,648		5,525,111,462	1,516	1,476	8,760	42.34%	42.74%
1999	5,812,431,196		5,722,117,726	1,511	1,481	8,760	43.91%	44.11%
2000	6,072,960,500		5,985,529,687	1,508	1,475	8,784	45.84%	46.19%
2001 Forecast			6,246,588,000		1,486	8,760		47.99%
2002 Forecast			6,434,088,000		1,486	8,760		49.43%
Average	5,996,636,271		5,974,902,159	1,502	1,468	8,767	45.53%	46.42%

Q. Does Hydro, as a practice, intervene in Newfoundland Power's Capital Budget Applications?

A. No, Hydro generally does not intervene in Newfoundland Power's Capital Budget Applications but it does intervene in those instances where there are issues of particular concern to Hydro.

Q. What effect would any revision to the values for Newfoundland Power's rate base, for use in the automatic adjustment formula for the calculation of return on rate base by the Public Utilities Board, have on Newfoundland Hydro's revenues? If there is a change in the rate of return following the application of the automatic adjustment formula, would any such change have an effect on Newfoundland Hydro's revenues?

A. Any change in Newfoundland Power's rate base or rate of return, which results in changes to their customers' rates, will also result in changes to Hydro's Rural Isolated and Island Interconnected customers' rates, thus affecting Hydro's revenues. There is, however, a provision included in the RSP requiring that the RSP be credited or charged with all revenue resulting from such rate changes.

Q. Did Newfoundland Power consult with Newfoundland Hydro prior to making an application to the Public Utilities Board for the consent of the Board to relocate a gas turbine generator from Salt Pond on the Burin Peninsula to Newfoundland Power's Wesleyville station in Bonavista North?

A. Newfoundland Power informed Hydro's Planning Department in June 2000 that they were looking at generation options at the end of their radial systems as a means to improving reliability. In May of 2001, at a joint utility meeting, our Systems Operations Department was informed of a study to relocate the Salt Pond gas turbine to Wesleyville.

Q. Has Newfoundland Hydro been consulted by Newfoundland Power in reference to various options and cost efficiencies for improving reliability of service in Bonavista North prior to deciding to relocate a gas turbine from the Salt Pond Substation to Wesleyville?

A. No.

Q. Has Newfoundland Power consulted Newfoundland Hydro in reference to Newfoundland Power's project as outlined in the 2002 Capital Budget to construct primary and secondary lines to connect new customers to the electrical distribution system which may require additional supply capacity?

A. Newfoundland Power has not consulted Hydro with respect to these items, however, Hydro would expect that any requirement for additional supply would be included in the aggregate load forecast that Newfoundland Power provides Hydro annually.

Q. When was Newfoundland Hydro given notice by Newfoundland Power of a Pole Sale Agreement between Newfoundland Power and Aliant? Why did Newfoundland Hydro intervene in that Application? What was the cost of Newfoundland Hydro's intervention?

A. Hydro received verbal notice of the Pole Sale Agreement on March 2, the same day that Aliant and Newfoundland Power issued a joint press release on the matter.

Hydro intervened in the Application made by Newfoundland Power for the approval of the Pole Sale Agreement because there were a number of issues that potentially affected Hydro's operations including the ownership by another electric utility of poles upon which Hydro had attachments in Hydro's service territory. Another issue was the protection of rights held by Hydro under a joint-use agreement with Aliant. Hydro also provided information and argument pertaining to the appropriateness of the inclusion of non-electric assets in an electric utility's rate base.

Hydro's costs in the intervention were minimal as no external resources were utilized.

Q. Please provide a copy of the joint study in which Newfoundland Hydro participated in 1997 with Newfoundland Power into the potential for mini-hydro in the island rural isolated systems?

A. Please refer to the response to CA-171.

Q. Please advise as to the ownership of the transmission assets in Labrador West and any ownership by Hydro in reference to these assets?

A. Twinco is the owner of all 230 kV transmission assets serving Labrador West (transmission lines and associated terminal station).

Hydro is the owner of 44 km of 46 kV sub-transmission assets used in distributing energy in Labrador City and Wabush and providing an emergency interconnection between Labrador West and Fermont, Quebec.

Q. Provide the 2002 Forecast Cost of Service assuming that the three generating sources referred to in Budgell's evidence page 10, lines 1 B 4 are in service. Use the 2004 forecasted load for the Island Interconnected System.

A. Attached are revised pages of Hydro's Five-Year Plan. The revisions to the plan include:

- The date on the Cover was updated to September 10, 2001.

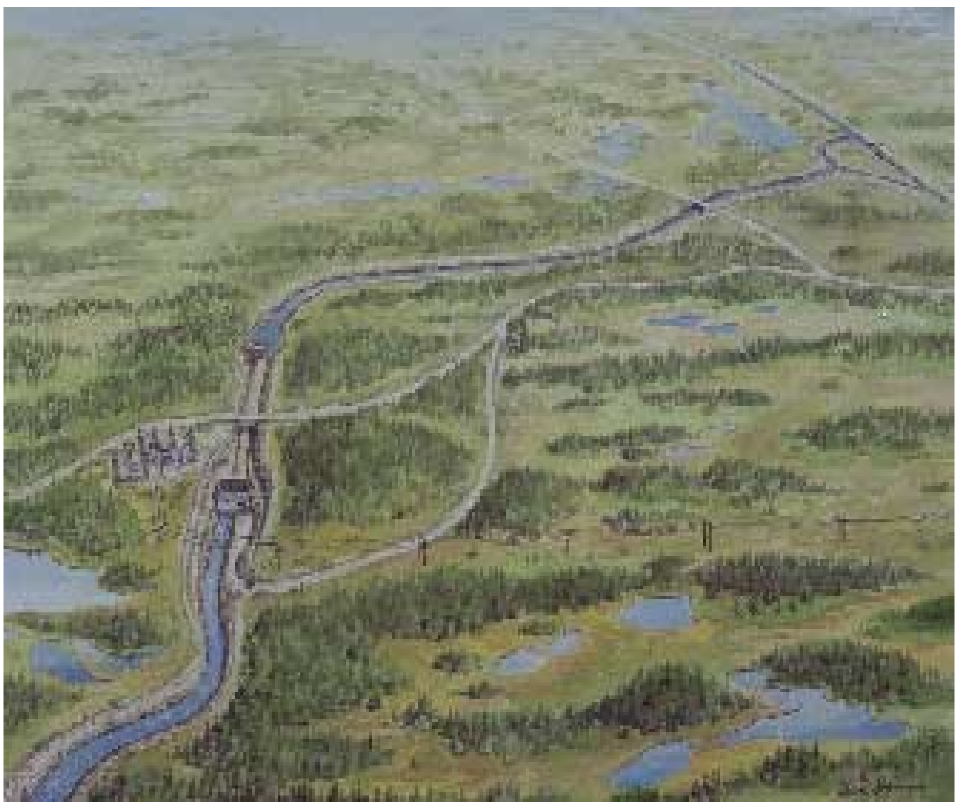
- The forth last bullet list item in the Executive Summary was revised to reflect the current revenue projection for 2001, i.e. $335 million ($337 million in the prior Plan).

- The Industrial rate after the RSP adjustment presented in Table 8 on page 14 was revised from 35.6 mills to 33.9 mills for 2001.

- The Income Statement (page 16) for 2001 was revised to reflect the combined $11.5 million RSP recovery (previously $13.8 million) and the corresponding amortization of costs in the RSP.

- The Statement of Cash Flows on page 17 was corrected for 2001 to show the combined effect of the plan balance net of the write-off (revised from $65.6 million to $63.3 million) and to show the revised projection for the Industrial collections (revised from $6.1 million to $3.8 million), the end result being no incremental increase or decrease in cash flows.

NEWFOUNDLAND AND LABRADOR HYDRO
FINANCIAL PLAN
2001 TO 2005



Granite Canal Development

September 10, 2001

EXECUTIVE SUMMARY

This document outlines Newfoundland and Labrador Hydro's (Hydro's) financial plan for 2001 to 2005.

The highlights are:

- The year 2001 is based on forecast results and 2002 is based on the "Test Year" as filed with the Board of Commissioners of Public Utilities in the 2001 rate application.
- The years 2002, 2004, and 2005 are assumed to be "Test Years" meaning that rates will be set to recover each year's costs.
- Target regulated rate of return on rate base is set at three percent for 2002 and 11.25 percent for 2004 and 2005.
- Debt to capital ratio targets are set to achieve a 75 percent dividend payout for the Hydro dividend portion during 2003 to 2005. Over the 2001 to 2005 time frame $334 million in dividends are projected to be paid to the Province of Newfoundland and Labrador consisting of $261 from Hydro and $73 million from Churchill Falls (Labrador) Corporation Limited (CF[L]Co).
- Granite Canal's estimated total cost is $135 million. This new source of generation is scheduled to begin production during midyear 2003. Capital expenditures for this development from 2001 to 2003 are projected to be $129 million.
- Power purchases are estimated to increase over 2002 levels by an average of $13 million during 2003 through 2005 due to new purchase agreements with non-utility generators.
- Other than exceptional items, operating and maintenance expenses are predicted to increase by the rate of inflation after 2002.
- New debt issues totalling $550 million are necessary during the planning period to replace existing debt and to finance capital expenditures.
- At the end of the forecast period in 2005, the overall balance in the Rate Stabilization Plan (RSP) is projected to be $40 million. It has been assumed that fuel price rebasing will occur as part of the rate revisions projected to occur on January 1, 2002.
- Excluding the Labrador River Project, total capital expenditures are $317 million during the period.
- Total revenue is projected to increase from $335 million in 2001 to $432 million in 2005.
- Average compound annual growth of two percent is forecast in energy sales to Newfoundland Power over the period.
- Average compound annual growth of one percent is forecast in total energy sales over the period.
- Excluding the effects of the Rate Stabilization Plan, wholesale rates to Newfoundland Power and Island Industrial rates are projected to increase at an annual compound rate of four percent over the planning period.

Table 8: Wholesale and Island Industrial Rates
(Mills per kWh)

	2001	2002	2003	2004	2005
Basic Rate					
Wholesale	45.0	48.0	49.7	54.5	55.1
Island Industrial	31.1	34.3	35.4	38.7	39.0
After RSP Adjustment					
Wholesale	46.7	51.2	54.7	59.4	58.9
Island Industrial	33.9	39.5	41.3	43.9	43.1

Non-consolidated Pro-forma Statements of Income

For the years ended December 31
($ 000,000)

	2001	2002	2003	2004	2005
REVENUE					
Energy sales	323.1	352.2	366.6	401.3	407.6
Recovery of costs in RSP	11.5	22.0	31.5	30.5	23.9
TOTAL REVENUE	334.6	374.2	398.1	431.8	431.5
EXPENSES					
Operating and administration	89.2	89.1	92.5	92.9	95.1
Fuels	51.5	82.3	85.3	78.4	79.4
Amortization of costs in RSP	11.5	22.0	31.5	30.5	23.9
Power purchases	19.2	18.9	22.5	36.9	37.0
Depreciation	32.7	31.8	33.9	34.9	36.1
Interest and guarantee fee	91.6	92.8	103.5	105.2	103.3
Loss on disposals	1.2	0.8	0.5	0.5	0.5
TOTAL EXPENSES	296.9	337.7	369.6	379.4	375.4
NET INCOME BEFORE OTHER REVENUE (EXPENSE)	37.7	36.5	28.5	52.4	56.1
OTHER REVENUE					
Equity in net income of CF(L)Co	11.5	12.2	14.9	17.5	18.2
Preferred dividends from CF(L)Co	7.2	7.8	9.3	10.1	10.2
Interest on share purchase debt	(2.5)	(2.3)	(1.8)	(1.7)	(1.6)
TOTAL OTHER REVENUE	16.1	17.8	22.4	25.9	26.8
NET INCOME	53.8	54.3	50.8	78.3	82.9
RETAINED EARNINGS AT BEGINNING OF YEAR	528.4	528.9	478.3	490.3	501.7
DIVIDENDS	(53.3)	(104.9)	(38.8)	(66.9)	(70.5)
RETAINED EARNINGS AT END OF YEAR	528.9	478.3	490.3	501.7	514.1

Non-consolidated Pro-forma Statements of Cash Flows

For the years ended December 31
($ 000,000)

	2001	2002	2003	2004	2005
CASH PROVIDED BY (USED IN):					
OPERATIONS:					
Net income from operations	53.8	54.3	50.8	78.3	82.9
Add (deduct) items not involving					
a cash flow:					
Depreciation	32.7	31.8	33.9	34.9	36.1
Amortization	0.7	1.2	3.3	3.3	3.3
Employee benefits provision	2.2	2.2	2.2	2.2	2.2
Equity in CF(L)Co	(11.5)	(12.2)	(14.9)	(17.5)	(18.2)
Rate stabilization plan	(63.3)	(32.4)	(18.2)	(6.0)	(4.2)
ADJUSTED NET INCOME	14.7	44.9	57.0	95.2	102.1
Net change in other non-cash working					
capital items	(2.5)	(2.5)	1.8	(0.3)	(1.2)
Employee benefits paid	(1.5)	(0.7)	(0.7)	(0.7)	(0.7)
CASH PROVIDED BY OPERATING ACTIVITIES	10.7	41.7	58.2	94.2	100.2
RATE STABILIZATION PLAN:					
Utility collected (returned)	7.7	14.3	22.7	22.9	18.0
Industrial collected (returned)	3.8	7.7	8.8	7.6	5.9
CASH PROVIDED BY RSP ACTIVITIES	11.5	22.0	31.5	30.5	23.9
DIVIDENDS PAID	(53.3)	(104.9)	(38.8)	(66.9)	(70.5)
FINANCING:					
Long-term debt issued	250.0	300.0	-	-	-
Long-term debt retired	(157.1)	(106.9)	(7.1)	(3.1)	(3.6)
Increase in promissory notes	40.8	(24.8)	38.0	(26.5)	(17.3)
CASH PROVIDED BY FINANCING ACTIVITIES	133.7	168.3	30.9	(29.6)	(20.9)
INVESTMENTS:					
Increase in sinking funds	(11.4)	(13.6)	(14.0)	(14.8)	(15.7)
Change in fixed assets	(91.8)	(118.1)	(72.4)	(27.3)	(31.6)
Dividends received from CF(L)Co	4.6	4.6	4.6	13.8	14.5
CASH USED IN INVESTING ACTIVITIES	(98.6)	(127.1)	(81.8)	(28.2)	(32.8)
NET DECREASE (INCREASE) IN INDEBTEDNESS	4.0	-	-	-	-
BANK INDEBTEDNESS, BEGINNING OF YEAR	4.0	-	-	-	-
BANK INDEBTEDNESS, END OF YEAR	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
SUPPLEMENTARY EVIDENCE OF D.W. OSMOND

Q. What is the purpose of this supplemental evidence?

A. The purpose of this evidence is to respond to the recommendation by certain expert witnesses that the Rate Stabilization Plan (RSP) should be eliminated and to outline Hydro's position on the continuing significant benefit, to customers, of the RSP.

Q. Would you please give a brief history of the implementation of the RSP?

A. Prior to 1986 Hydro used a fuel adjustment charge formula whereby the fuel related cost of thermal generation in excess of those costs included in Hydro's rates, was recovered from customers in the month following when those costs were incurred through a fuel adjustment charge formula. This enabled Hydro to be reimbursed monthly for fuel costs, but it resulted in significant volatility in rates for customers, especially during the winter months when their consumption was the highest.

In addition, Hydro recorded a water equalization provision to levelize the effect of thermal generation costs due to fluctuations in water availability. Hydro charged or credited fuel expense in its income statement annually with an amount calculated to adjust generation costs to an average annual water condition. The calculation was based on historical water inflow data compiled over a period of 35 years. The offsetting debit or credit was included in the water equalization provision account.

The water equalization provision had a maximum limit of $36 million which was considered sufficient to absorb the adverse effects of a reoccurrence of the three consecutive driest years ever recorded. The provision was calculated monthly and if the provision at year-end was greater than $36 million, the excess was refunded to Hydro's customers in January of the succeeding year.

While the fuel adjustment charge formula enabled Hydro to be reimbursed monthly for fuel costs, customers saw significant rate spikes in their monthly electricity bills, especially during the winter period when their consumption was the highest. This was due to rising fuel prices and increased consumption of fuel at Hydro's Holyrood Generating facility.

The RSP was recommended by Hydro in 1985, in response to a significant public outcry regarding high electricity bills, due to the inclusion of the monthly fuel adjustment charge and was approved by the Board for implementation on January 1, 1986. The positive balance in the water equalization provision at that time was returned to Newfoundland Power and Island Industrial customers over a three-year period commencing in 1986.

The primary purpose of the RSP is to provide rate stability to customers. As well, it continues to provide a mechanism to eliminate volatility in Hydro's revenue requirement, due to events beyond Hydro's control, such as changes in hydrology, fluctuations in the price of No. 6 fuel consumed at Hydro's Holyrood Thermal Generating facility and variations in load.

Since 1986 the RSP has functioned as originally envisaged with an annual adjustment, based on the recovery, or re-payment of one-third of the previous year end balance on each subsequent July 1st for Newfoundland Power and January 1st for Industrial customers. July 1st was selected for Newfoundland Power so as to further minimize any rate shocks to customers during the winter months, when energy consumption is typically highest. January 1st was selected for Industrial customers based on their request to base the adjustment on the previous September balance, so that the effect on rates would be available for their annual budgeting purposes.

Q. At this hearing several expert witnesses have recommended the elimination of the existing RSP. Please provide Hydro's view of this recommendation.

A. In Hydro's view, the principle of the RSP that was established in 1985, "to provide rate stability to customers", is equally applicable today and it is Hydro's recommendation that the RSP continue. In coming to this conclusion, Hydro considered the information provided from calculating the fuel adjustment charge for 2001, if the formula was still in effect, to determine the volatility that would still take place on customers' bills.

Schedule 1 provides a comparison for 2001 of the impacts on domestic and Industrial customers monthly bills, if a monthly fuel adjustment charge was in effect, as compared with the monthly RSP that currently applies. An all-electric domestic customer, using electric space heating would see fuel adjustment charges ranging from approximately 15% to 20% of their normal monthly bill, in each of the months from January to April 2001. This compares to an approximate 2% monthly adjustment for the existing RSP. For Industrial customers, the fuel escalation charge would range between approximately 40% to 55% of the normal monthly bill for the same period. This compares to the existing 9% adjustment for the RSP.

Q. Based on your supplementary evidence, has Hydro changed its opinion regarding the continued operation of the RSP?

A. No, the RSP still smoothes the impact of rate spikes for customers, which was a major issue with customers in 1985. Hydro expects that rate spikes would still be a major concern for customers today. As noted earlier the stabilization of rates to customers was the primary reason for the implementation of the RSP, as approved by the Board in 1985 and Hydro continues to believe that rate stability is still of primary concern for customers today.

Newfoundland and Labrador Hydro
RSP vs Fuel Escalation Comparison
Forecast for the Year 2001

All-Electric Domestic Customer (Electric Space Heating)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Typical Customer kWhs (1)	2,794	2,818	2,467	2,046	1,605	1,100	711	705	858	1,398	1,983	2,642
Total Bill Before HST - No RSP	$198	$199	$177	$149	$120	$88	$62	$62	$72	$107	$145	$187
RSP Charge	$5	$5	$4	$3	$3	$2	$1	$1	$1	$2	$3	$4
Fuel Escalation Charge (2)	$43	$42	$29	$23	$16	$8	$0	$0	$9	$15	$22	$29
% Increase / Decrease Using RSP	2.3%	2.3%	2.3%	2.3%	2.2%	2.1%	2.0%	2.0%	2.0%	2.2%	2.3%	2.4%
% Increase / Decrease Using Fuel Escalation	21.9%	21.1%	16.2%	15.4%	13.0%	9.4%	0.0%	0.0%	12.5%	14.1%	15.1%	15.6%

Industrial Customer

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Bill Before HST - No RSP	$1,436,490	$1,375,704	$1,466,892	$1,436,490	$1,314,938	$1,436,490	$1,466,892	$1,466,892	$1,406,107	$1,466,892	$1,436,490	$1,423,640
RSP Charge	$132,006	$123,206	$136,408	$132,006	$114,408	$132,006	$136,408	$136,408	$127,607	$136,408	$132,006	$129,206
Fuel Escalation Charge (2)	$815,223	$733,351	$623,604	$574,173	$419,934	$350,482	$150	$197	$448,390	$542,365	$563,538	$570,962
% Increase / Decrease Using RSP	9.2%	9.0%	9.3%	9.2%	8.7%	9.2%	9.3%	9.3%	9.1%	9.3%	9.2%	9.1%
% Increase / Decrease Using Fuel Escalation	56.8%	53.3%	42.5%	40.0%	31.9%	24.4%	0.0%	0.0%	31.9%	37.0%	39.2%	40.1%

(1) Based on Hydro Rural Island Interconnected data.
(2) Billing is assumed to coincide with the month of occurrence.

NEWFOUNDLAND & LABRADOR HYDRO
SUPPLEMENTARY EVIDENCE OF J.A. BRICKHILL

Q. What is the purpose of this supplemental testimony?

A. This testimony addresses three general areas in the testimony of other expert witnesses: 1) the applicability of marginal cost-based rates for Hydro, 2) the energy-only rate for Newfoundland Power proposed by Hydro, and 3) certain cost allocation recommendations pertaining to Hydro's embedded cost model.

Q. Specifically, which recommendations relative to marginal costs are you addressing?

A. Dr. Wilson recommended that Hydro should prepare and file rates reflecting seasonal cost variations and that marginal cost considerations should receive greater attention in designing rates.

Mr. Bowman stated that Hydro's rates fail to meet its design criteria, particularly market efficiency and cost based rates. In this regard he recommended that the Board hire an independent consultant to review and recommend rate designs for customers in Newfoundland and table the report at a public hearing. Additionally he proposed that Hydro should do an analysis of time-of-use rates and a marginal cost study.

Q. Please comment on these recommendations.

A. I agree that marginal cost rates generally convey better price signals and achieve greater allocative efficiency than embedded cost rates. However, marginal cost-based rates for regulated customers and the likely controversy related thereto have no meaningful relevance to Hydro generally unless there are significant changes in Government and Board policy pertaining to Hydro.

Hydro's cost of service study in the instant case follows the Board's guidelines set forth in its 1993 report on Hydro's Cost of Service Methodology which set out the ground rules for the next case, which happens to be this case. The first of these guidelines was "That Hydro's Cost of Service Study be of the embedded type and that the methodological objective be to allocate costs to rate classes in a fair and equitable manner based on causal responsibility for cost incurrence." Further, the Board stated, "The cost of service methodology recommended herein be adopted by Hydro for the purpose of its next rate referral." Nowhere in its recommendations did the Board mention marginal cost based rates or time-of-use rates or seasonal rates.

Therefore, Hydro's filing of an embedded cost-of-service study was consistent with the Board's recommendations and entirely appropriate.

Q. Why do you say marginal cost-based rates for regulated customers have no meaningful relevance to Hydro generally unless there are significant changes in Government and Board policy?

A. The emphasis on sending the "right" price signals to consumers appears inconsistent with the environment in which Hydro operates. By government policy, Hydro's rural customers are heavily subsidized by other retail customers, and until recently, Hydro's Industrial customers. Thus, to begin with, price signals are distorted. One class of customers is subsidized by Government policy, two other categories of customers pay the subsidy, and one class of customers is neither subsidized nor subject to paying the subsidy.

As well, the Rate Stabilization Plan (RSP) is antithetical to the transmission of proper price signals. When the RSP was implemented in 1985, circumstances were similar to those that exist now – oil prices had risen substantially. The RSP was implemented to mitigate the effects of those circumstances on consumers. The underlying purpose and operation of the RSP is to stabilize rates. It takes current costs out of current rates and puts these costs into future rates over a three-year period. The RSP was designed to protect the consumer from volatility in oil prices, among other things. However, as a practical matter, it acts to ensure that customers don't see current oil prices. This is highly significant in the context of a discussion of marginal cost-based rates, since Holyrood, an oil-based intermediate load thermal plant, is the marginal source of power for the Island Interconnected System most of the year.

Thus, the existence of the rural deficit subsidy and the RSP confuse the picture on marginal cost-based rates.

Hydro proposes in this filing to defer $8.00/bbl ($28-$20) of its expected oil price for the 2002 test year through the RSP. No intervener has objected to this obfuscation of price signals. Mr. Bowman recommended that the Board eliminate the RSP, but gradually, to spread the rate impact over time. Dr. Wilson said consideration should be given to eliminating the RSP, but, as far as I can tell, did not object to Hydro diffusing the true cost of oil in next year's rates.

Thus it appears to me that Hydro's customers, the provincial government and its regulator give more weight to stability, fairness, and absolute levels of rates than to proper price signals.

Q. Does Hydro take marginal costs into consideration when designing rates?

A. When it is clearly appropriate, Hydro takes marginal costs into consideration when designing rates.

The non-firm service rate design for Industrial Customers reflects Hydro's marginal costs. As indicated earlier, Holyrood, which uses No. 6 fuel oil, is the marginal source of generation during most of the year for Hydro. On peak, diesel generators or gas turbines, both using No. 2 fuel oil, may be the marginal source of generation. Non-firm customers are charged for the applicable marginal source of generation at current fuel prices as shown on IC-33, page 3 of 4.

Q. Will the proposed energy rates of Newfoundland Power and the Industrial Customers cover marginal costs in the test year?

A. In the case of Newfoundland Power, yes, and in the case of the Industrial Customers, no. Newfoundland Power's energy rate includes its allocated demand costs, the rural deficit, and the RSP. This results in the marginal revenues received from Newfoundland Power exceeding the marginal energy costs of supplying Newfoundland Power by Hydro.

Q. Does the fact that Hydro's Industrial Customers are not, or will not be, covering marginal costs through their energy charges disadvantage Hydro's other customers?

A. No. No costs are shifted to Hydro's other customers as a consequence of the Industrial Customers not covering marginal costs in their energy rates. Hydro ultimately recovers its marginal costs from the industrials through the RSP, which simply defers for later recovery from the firm industrials what the firm industrials do not pay now.

Q. Does the energy rate to firm industrials as proposed by Hydro alter the operation of the Industrial Customers' hydraulic units?

A. No, the energy charge exceeds the marginal costs of hydraulic units so the Industrial Customers have the incentive to maximize the use of their own hydraulic units.

Q. Do you think it very important for Hydro to transmit "correct" price signals to Newfoundland Power?

A. No, not under the rather unique circumstances that exist between the two.

Hydro generates, transmits and sells most of the generation capability on the Island. Newfoundland Power buys the majority of Hydro's generation and sells at retail in the more populated areas of the Island. Therefore, Hydro is the primary generator on the Island and Newfoundland Power is the dominant retailer. If the two were combined, the combined entity would be similar to a typical integrated electric utility.

Moreover, although separate entities, there is operational coordination between the two companies to ensure the hydraulic generation is optimized and to avoid spillage thus minimizing thermal production. When required, Hydro directs the operation of Newfoundland Power's generating plants during system peaks in order to optimize the generation that is online. Normally, Newfoundland Power does not use its thermal generation for peaking purposes unless requested to do so by Hydro. As another example of coordination, Hydro sometimes calls upon Newfoundland Power to increase hydraulic production during daily peak periods to assist in meeting load during outages to system equipment and, if available, Newfoundland Power provides the service.

On occasion, since there is coordination of generation on peak, the two companies are effectively operating as an integrated whole with respect to generation. The structure of the internal transfer price within this effective entity is therefore irrelevant from the standpoint of economic efficiency. Rather, economic efficiency is achieved if Newfoundland Power's rates reflect marginal cost concepts. Newfoundland Power is not in a position to respond fully to Hydro's price signals, since its demand is derived from the demands of its customers.

I might further note that the level of charges is important in the above circumstances, but not the mode in which the charges are made.

Q. Do you think it is very important to send the right price signals to the Industrial Customers?

A. Yes, in the case of demand charges as discussed below.

Unlike Newfoundland Power, the Industrial Customers are end-users who can and will modify behaviour in response to price signals. But between the marginal energy rate and the demand rate, it is the latter that is critical. The demand component of the firm industrial rate discourages industrials from over-contracting of power-on-order (kW demand levels) which could cause Hydro to increase its investment in generation and transmission capacity.

Q. Why is it reasonable for Hydro to charge Newfoundland Power entirely through an energy charge?

A. The selection of a rate concept to be used for billing Newfoundland Power, i.e., a one-part rate such as a demand only or energy only rate, or a two-part rate having a demand and an energy component, is influenced by factors such as:

- Fairness
- Matching of revenue and cost
- Impact on load pattern
- Economic efficiency
- Ease of administration

Fairness in a regulated environment is generally achieved by adherence to the “cost standard” which holds that the fair price of a good is the cost of producing it. That standard is met by means of the cost of service analysis which apportions the total annual cost of service or revenue requirement to the various customer or rate classes.

The matching of revenue and cost is achieved by the level of the revenue derived by the rate applied to the billing units of each rate class. In theory this could be achieved by a demand-only rate, an energy-only rate, or a multi-part rate having demand charges, energy charges, customer charges, each with the potential for seasonal and daily variations. It could also be accomplished by calculating the cost of operation for each month or year, and rendering a bill to cover the calculated amount.

If the rate is applied solely to the energy sold in the billing period, e.g., use of an energy only rate, there will be a potential for over or under collection if kWh sales are more or less than the forecasted sales level due to variations in weather, level of the economy, and growth in energy usage different from the forecast amount due to various causes such as a change in usage patterns or number of customers.

If the rate is applied solely to the level of customer demands in the billing period, e.g., use of a demand-only rate, there will be a potential for over or under collection caused by demand being more or less than the forecast demand level due to the same causes enumerated above for an energy-only rate form.

If the rate is applied to both energy and demand levels, there could be a potential for over or under collection for the same reasons. Thus, no rate design can be depended upon to eliminate an excess or shortfall of revenue as compared to cost of service.

At the present time, a more precise matching of revenue and cost is achieved by means of the RSP in conjunction with an energy-only rate. Of course the RSP could be modified to allow a matching to be achieved with a demand-only, or multi-part demand-energy, rate. This would introduce greater complexity and possible greater controversy.

Since the use of energy-only billing in conjunction with the RSP will achieve a matching of revenue and cost, the need for an alternative rate concept will depend on other factors.

The impact of a choice of rate concept on the load pattern depends upon the response of the end-user to the prices paid for service. Such prices become the cost to the end-user. In this instance, Newfoundland Power is not an end-user, so the load pattern supplied by Hydro is a derived demand. It is derived from the demand of Newfoundland Power's customers as they respond to the rate structure of that firm.

A claimed disadvantage of an energy-only rate is that such a rate will encourage or, at least not discourage, wasteful use of capacity. Similarly, a claimed disadvantage of a demand-only rate is that it will not discourage wasteful use of energy. However, so long as the rate design used by Newfoundland Power to bill its customers reflects the proper recovery of demand, energy, and customer components of the total cost of service of Newfoundland Power, including its purchases from Hydro, there will not be an adverse impact on the load pattern, i.e., a wasteful use of demand caused by Hydro's energy-only rate for service to Newfoundland Power.

Moreover, as noted above, although separate entities, there is operational coordination between Hydro and Newfoundland Power. Hydro directs the operation of Newfoundland Power's generating plants during system peaks in order to optimize the generation that is online. Normally Newfoundland Power does not use its thermal generation for peaking purposes unless requested to do so by Hydro. Consequently, some of Newfoundland Power's thermal generating capacity is not on-line during peaks. If a demand charge existed, Newfoundland Power's most significant means of impacting its demand would be through its generation. This could result in cost shifts from Newfoundland Power to other customers and less than optimal use of resources.

Newfoundland Power's operation of its hydraulic units could also be altered by demand charges. Newfoundland Power could decide during certain periods to keep hydraulic units off to ensure adequate capacity for peaks, resulting in a higher potential for spillage and more use of Holyrood, with higher marginal costs for Hydro and its customers. Therefore, demand charges to Newfoundland Power could well send the wrong price signals rather than the right price signals.

For these reasons I have no issue with the use of an energy-only rate in conjunction with the RSP for billing Newfoundland Power for wholesale service. Were the RSP eliminated, however, it would be appropriate for

Hydro to seek an alternative rate form in order to maintain the stability of its revenues.

Q. Mr. Brockman is critical of the use of 2CP for the generation costs for the Island Interconnected System and advocates use of a 4CP allocator. Please respond.

A. In my opinion, 4CP would be inappropriate since it is not as reflective of cost causation as either 2CP or 1CP. I have reviewed historical data for the Island Interconnected System and in the majority of instances, the peak occurs at the coldest time (measured by wind chill) of the year, subject to a "holiday" effect. That is, the peak can also occur during the Christmas/New Year's period if the weather is cold, but not necessarily the coldest of the year.

Mr. Brockman's rationale seems to be the timing of the peak. He notes that the peak occurs December through March, and asks, which one(s) do you choose.

In response, from a system planning perspective, it is not when between December to March the peak occurs, but the fact that a peak will occur during the winter that is important. Hydro cannot predict the exact timing of severe weather, but it can reasonably design its system for the peak conditions it knows will occur in the winter. 2CP or 1CP link investment costs with what drives the investment costs far better than 4CP.

Q. Mr. Brockman also recommends that the allocator be calculated on the basis of historical data. Please comment.

A. This is inconsistent with the test year concept which is the basis of Hydro's filing in this case. All the data in the cost of service case are forecast –

using a historical CP allocation would be inserting a “square peg” into a “round hole” unless the historical period used had identical loads to those embodied in the forecast.

Q. In contrast to Mr. Brockman who recommended a 4CP allocator, Mr. Bowman recommends use of a 1CP allocator for generation demand costs on the Island Interconnected System in lieu of the 2CP allocator as filed by Hydro. Please respond.

A. A 1CP allocator would be acceptable and generally consistent with cost causation (as is 2CP). 2CP is more consistent with the results of the LOLH study which the Board recommended, but both 1CP and 2CP capture the cold weather cost causation better than the 4CP recommended by Mr. Brockman

Q. Do you agree with Dr. Wilson’s proposal classifying a portion of the transmission cost as energy related?

A. No, I do not. I believe that cost classification should track cost behaviour. The cost driver of a transmission network is the coincident peak demand served by that network. If that parameter increases, reinforcement of the transmission network will ultimately be required.

Dr. Wilson states on page 15 of his Report “Utilities typically use transmission for two purposes: to reduce generating costs and to mitigate the need to add resources.” I believe the principal purpose of transmission is to supply load centers on the distribution system. If customers increase their use of energy, transmission investment should remain unaffected unless load factors rise to a point where electrical loss reduction by means of larger conductor sizes becomes economically feasible.

Under certain circumstances transmission can also link remotely located generation to the integrated transmission network, thereby reducing the cost of transporting power. Engineers, in considering the feasibility of such remotely connected generation, treat the added transmission needed to connect such generation facilities to the network in the same manner as added cost of generation. For that reason it is a common practice to classify the cost of such lines in the same fashion as the remotely located generation, and in fact Hydro has allocated transmission from hydraulic units to the network on the same basis as the hydraulic units, i.e., system load factor. Thus, where appropriate Hydro has allocated some transmission based on energy.

While certain lines, included as segments of the transmission network, may have originally been constructed to tap a hydro resource to obtain lower cost energy, the lines now serve all of the purposes of transmission enumerated by Dr. Wilson and myself. Thus, the goal of low-cost energy does not alter the fact that the size of those lines is determined by the energy, or kWh, that is to be transported in a time interval such as 15 minutes or an hour. Demand in kW results from kWh/h, where h = hour. Obviously, kWh/h = kW. The cost driver of the size of a line segment is the energy transported in a given time interval, usually an hour or less, and not the energy in a lengthy time period, such as a year. For example, the necessary width of a bridge or roadway is determined by peak period traffic, not annual traffic.

Q. Both Dr. Wilson and Mr. Bowman recommended that distribution demand costs be allocated on the basis of non-coincident peak rather than coincident peak. Please respond.

A. Hydro's cost-of-service filed in this case reflects the coincident peak method (1CP). The 1CP method reflects the Boards recommendation to use that method in the instant case.

At the outset, it should be noted that since Newfoundland Power and the Industrial Customers are allocated no distribution costs, the issue only pertains to Hydro's Island Interconnected Rural Customers (whose rates are not determined by the cost-of-service study), Isolated Rural Customers, and Labrador Interconnected Rural Customers.

Dr. Wilson's and Mr. Bowman's rationale for the NCP method is that distribution equipment is sized to meet local peak load as opposed to system peak load. Their rationale may very well be true in many markets <u>not</u> served by Hydro but is inappropriate for the communities served by Hydro.

The rural isolated communities and their load patterns served by Hydro are not like what Dr. Wilson and Mr. Bowman envision. There are no high-rise office buildings or condominiums, shopping malls or large manufacturing plants. Rather, these rural isolated communities consist of clustered one to two story residential buildings with some commercial establishments interspersed between the homes. There are no distinct "local loads" within the typical rural community that determine distribution plant requirements.

As for the communities of Labrador City, Happy Valley/Goose Bay and Wabush on the Labrador Interconnected System, the 1CP method is also preferable to the NCP method. The majority of load on the Labrador Interconnected System is on feeders which serve both residential and commercial customers. Since the load of both rate classes is temperature sensitive and the distribution network is sized based on a cold weather driven peak, the 1CP method links cost causation and costs better than the NCP method.

NCP may well be appropriate in circumstances where an industrial park is served by one substation, a commercial office district is served by another substation, and a predominately residential area is served by a third substation. But these are generally not the circumstances in the communities served by Hydro.

The appropriateness of the NCP method for allocating distribution cost depends upon the design of the distribution system as well as the load characteristics of the rate classes served by the distribution system. Firstly, the distribution system consists of multiple segments, each performing a separate function:

a) Distribution substations
b) Primary voltage lines
c) Distribution transformers
d) Secondary voltage lines
e) Services
f) Meters

The distribution substations serve to step-down the transmission or sub-transmission voltage to primary voltage level. Since each substation serves a considerable geographic area, i.e., one to ten square miles it will therefore serve multiple rate classes. Its capacity or size will be based upon the combined peak demand of all of the load connected to the substation. For that reason, the non-coincident peak demand will only be suitable if separate distribution substations are installed to serve each rate class. This is not the practice followed by Hydro, and therefore, use of the

1CP method for allocation of the cost of distribution substations is clearly appropriate.

Primary voltage lines used by Hydro serve a wide geographic area and are not segregated by rate class. For that reason they are sized based upon their coincident peak demand which depends upon the total combined peak demand of all of the rate classes served by the respective primary lines. Therefore, use of the 1CP method for allocation of the cost of primary lines is appropriate. I acknowledge that in large Canadian and U.S. cities, situations may exist wherein most of the customers in a specific area are of the same rate class, and where individual primary feeders may therefore serve only a single rate class, and therefore, use of the NCP method may be appropriate. This is not the case for Hydro.

The single coincident peak demand applicable to the individual distribution functions I have enumerated and used for allocation purposes is not the coincident peak demand of the total system. The load of the industrial customers is excluded, as well as the loads served and related line losses supplied by a given segment. For example, the load served by distribution transformers does not include loads supplied directly at primary voltage.

Distribution transformers are classified in part as customer related and in part as capacity or demand related. The demand related portion is allocated on a 1CP basis.

Secondary lines are classified in part as customer related and in part as capacity or demand related. The demand related portion is allocated on a 1CP basis in the same manner as the distribution transformer used to supply those secondary voltage lines.

Services and meters are classified in their entirety as customer related.

Q. Why do you regard a portion of the cost of distribution to be customer related?

A. I regard a portion of the cost of distribution facilities to be customer related because I regard customers as one of the causes of cost in terms of investment in distribution lines. The logic of any statement that line cost is unrelated to the number of customers served fails if you consider the initial service to a single customer requires a 100 ft. line extension. If an average lot is 50 ft. wide, a second customer could locate midway between the source and the service connection. However, connecting an additional ten or 100 customers would most certainly require an additional line extension unless all residents are to be located in a single high-rise apartment. Zoning and land use preferences result in an average spacing between residences which must be traversed by an electric line of at least an average size. For single-family residences, this spacing, or average feet of line per residential customer, is a function of average lot width, plus street crossing width per lot. For most U.S. electric systems, the feet of electric line per customer remains a relatively stable statistic so long as real estate expansion does not become solely high-rise. Thus, Manhattan is an exception. Nevertheless, a distance factor remains. Larger demands are met by increasing the size of the conductor, and not by putting more lines in parallel.

The communities served by Hydro are generally like the subdivisions described above, and therefore a customer component is clearly appropriate.

Q. Is it your position that all distribution cost that is required to connect new customers to the system should be regarded as customer related?

A. No, that is not my position. The customer component included in Hydro's cost of service study based on the zero-intercept method is for a so-called zero-demand system, *i.e.*, a minimum size facility. All investment in the system, in excess of that minimum amount, is deemed to be demand related.

Q. Do you concur with the opinion expressed by Bonbright in the quotation on pages 29 and 30 of Dr. Wilson's Report wherein Bonbright quotes Mr. D. Lessels with respect to the correlation between the mileage of a distribution system to the number of customers served?

A. No I do not. A review of the referenced paper by Lessels causes me to believe that Bonbright, *et al.*'s confidence in its relevance may be misplaced.[1] Mr. Lessels, an employee of the U.S. Rural Electrification Administration (REA), limited his analysis to electric distribution borrowers of that institution. The REA, which provides low-cost loans to cooperatives for the purpose of extending electric service in rural areas, had essentially accomplished its objective of providing service to all farms by the mid-1950s. Mr. Lessel's database covers the period from 1971 through 1978. In the period starting in the mid-1950s, the number of farms began to decline (average size of the farm increased). Many of the farmhouses, no longer occupied by farm families, however, continued to be used for residential purposes. Customer growth of the REAs in the 1970s was primarily in the areas adjacent to the towns and cities. Since these customers were closely spaced as compared to the original farms in rural areas, there is little wonder that investment per customer, as well as expense per customer, declined, leading to Mr. Lessel's conclusion that the costs were not correlated with the change in year-round farm and residential customers. Also, it is interesting to note that Bonbright goes on

[1] David J. Lessels, "The Economics of Electric Distribution System Costs and Investments," *Public Utilities Fortnightly*. Dec. 4, 1980, pg. 37–40.

to state that "[i]n actual practice the vast majorities of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts."[2]

Q. Dr. Wilson recommends that network distribution costs be classified principally to demand and energy. Please comment.

A. I believe that network distribution costs should be classified entirely to demand and customer. Dr. Wilson's recommendation in regard to energy classification is not supported or discussed in his report except for his recommendation. I might note that to the best of my knowledge, there is no electric utility in North America that classifies distribution costs to energy.

Since the distribution system is not a source of energy, nor is energy a cost driver in terms of distribution network investment or expense, classification to energy runs counter to cost causality.

Q. Does that conclude your supplemental testimony?

A. Yes.

[2] Bonbright, *et al.*, pg. 492.