Q. Provide the following information for each of the past five years, and forecast for the years 2001 through 2006:

- Fixed cost/kWh sold
- Depreciation cost/kWh sold
- Financial charges/kWh sold
- Fixed cost/$ revenue
- Fixed cost/customer served
- Number of administrative employees/total number of employees
- Fuel cost (including purchases)/kWh sold
- Fuel cost (including purchases)/$ revenue
- KWh sales/employee
- Customers/employee
- $ revenue/employee
- km distribution/employee
- Fixed cost associated with distribution system/km of distribution
- O&M cost associated with distribution system/km of distribution
- System average interruption duration index (SAIDI)
- System average interruption frequency index (SAIFI)
- Momentary average interruption frequency index (MAIFI)

A. The requested information for the years 1996 - 2005 is attached. Data for 2003 - 2005 is based on Hydro's Five-Year Financial Plan, which was filed in response to IC-98. Data for 2006 is not available.

Q. Provide an energy budget for the test year balancing expected production and purchases against losses and sales.

A. Please refer to the following table

Energy Budget for 2002

Sales (From HGB Schedule V)	**Energy** (GWh)
Newfoundland Power	4,454.80
Hydro Rural Interconnected	388.90
Corner Brook Pulp & Paper	523.30
Abitibi Consolidated Inc (Grand Falls)	177.30
Abitibi Consolidated Inc (Stephenville)	568.60
North Atlantic Refining	233.60
Total Sales	6,346.50
System Losses	233.70
Rounding Adjustment	-0.10
Total System Energy Requirement	6,580.10
Production and Purchases (From RJH Schedule V)	
Hydroelectric	4,271.67
Thermal	2,162.43
Power Purchases	145.90
Total Production and Purchases	6,580.00
Rounding Adjustment	0.10
Total Adjusted for Rounding	6,580.10

Q. Provide a financial forecast including a statement of all assumptions, planning criteria, perceived changes in the revenue requirement and required rate action for the next five years. Include a column showing the surplus/deficit in the Rate Stabilization Plan.

A. Hydro’s Five Year Plan for the period 2001 to 2005 has been filed in response to IC-98.

Q. Provide a table showing the various types of taxes in terms of revenue requirement and percent of customer rates, actual/forecast for the past five years, and next five years. Include the rural subsidy, but show separately.

A. The taxes paid by Hydro are Payroll Tax paid to the Province and Business Tax paid to various municipalities in which the Corporation is earning revenue or to the Province if the municipality is not incorporated. Details of these taxes are provided in the table below.

The Rural Subsidy has been calculated for 2 years only:

Year	Subsidy	Revenue Requirement
1999 Actual	22,099,837	7.9%
2002 Forecast	26,158,078	8.1%

Year	Business Tax	Payroll Tax	Total Taxes	% of Revenue Requirement
1996 Actuals	1,028,796	997,999	2,026,795	0.7
1997 Actuals	1,029,930	947,410	1,977,340	0.7
1998 Actuals	1,094,041	977,722	2,071,764	0.8
1999 Actuals	1,021,144	1,011,806	2,022,950	0.7
2000 Actuals	1,125,812	1,045,030	2,170,842	0.7
2001 Forecast	1,085,300	989,400	2,074,700	0.7
2002 Forecast	1,085,300	989,400	2,074,700	0.6
2003 Forecast	1,104,835	1,007,209	2,112,045	0.6
2004 Forecast	1,124,722	1,025,339	2,150,061	0.6
2005 Forecast	1,144,967	1,043,795	2,188,763	0.6

Q. Provide the most recent residential electric sales profile available. Submit end-use daily load curves for the typical home (kW versus time) showing electric space heating, electric water heating and the other end-uses as available for a winter weekday and weekend, summer weekday and weekend, spring weekday and weekend and fall weekday and weekend. What is the typical annual consumption of a residential customer:

- With no electric heating or hot water
- With electric hot water, but no electric heating
- With electric hot water and electric heating

A. Customer end-use daily load curves are made possible through load research programs. Hydro has no load research data available for end-use daily load curves for residential customers in its service territory.

As requested, typical annual consumption for residential customers is presented in the table below.

Typical Annual Electricity Consumption for Hydro Rural Households (kWh per Year)		
No Electric Heating or Hot Water	With Electric Hot Water, but No Electric Heating	With Electric Hot Water and Electric Heating
7,297	10,548	32,882
- Information compiled from 2001 survey of households located in Hydro's service territory. - Electricity consumption based on April 2000 to March 2001 billings and is not weather adjusted.		

Q. Provide a comparison of the cost to the consumer to heat a typical home with oil, wood and electricity at current rates. Provide a comparison of the cost to the consumer of hot water for a typical home using oil and electricity at current rates. In the comparison show Hydro's cost of supplying electricity for 1) hot water, and 2) home heating for a typical home.

A. See attached table.

	Space Heating	**Water Heating**
Estimated End-Use Electricity Consumption	22,300	3,300
Annual Cost of Electricity to Consumer 2		
Island Interconnected	$1,507	$223
Labrador Interconnected	$449	$66
Isolated Diesel	$2,893	$269
Annual Cost of Oil to Consumer 3		
Island Interconnected	$1,156	$226
Labrador Interconnected	not available	not available
Isolated Diesel	not available	not available
Annual Cost of Wood to Consumer4		
Island Interconnected	not available	-
Labrador Interconnected	not available	-
Isolated Diesel	not available	-
Hydro's Cost of Electricity Supply5		
Island Interconnected	$2,277	$288
Labrador Interconnected	$487	$62
Labrador Diesel	$11,864	$1,756
Island Diesel	$16,603	$2,457
L'Anse au Loup	$4,981	$626

Notes:

1. Weighted average electricity consumption based on means analysis compiled from 2001 survey of households in Hydro's service terrirory.
2. Cost of electricity based on domestic tariff to consumer at July 1, 2001 excluding HST and discount. Consumer cost of electricty for Labrador interconnected is weighted cost. Isolated diesel customer costs calculated at 3rd block for electric heat and an average of the 1st and 2nd blocks for electric hot water. Excludes equipment and maintenance costs.
3. Costs for oil are illustrated using the July 1, 2001 the residential furnance oil price of a principal fuel oil distributor in St. John's. Furnace efficiency obtained from Natural Resources Canada. Hydro does not regularly collect fuel oil cost data from across the Province. Excludes equipment and maintenance costs.
4. Hydro does not regularly collect firewood prices from across the Province. The high incidence of homeowner procurement makes it difficult to impute prices.
5. Hydro's 2002 Cost of Service as per JAB Schedule 1.3 (Demand and Energy cost for domestic all-electric for space heating and domestic for water heating).

Q. For each of the interconnected systems, provide the forecast marginal cost of energy for the peak and off-peak periods of each month for the years 2001 through 2006. In addition, provide the Loss of Load Hours (LOLH) for the years 2001 through 2006 assuming no new generation is added to the system beyond that already committed. Show the proportion of the LOLH attributable to the peak and off-peak periods of each month for the years 2001 through 2006. Provide an estimate of the levelized cost of the least-cost peaking option. Provide the marginal cost of supply on the Rural Isolated Systems and for L'Anse au Loup.

A. The report Marginal Time of Use (TOU) Costs completed in September 1984 indicated that the seasonality of load affected costs more than the daily loads as the ratio of winter costs to summer costs was 1.5 whereas the ratio of on peak costs to off peak in winter was only 1.1. It is expected that this conclusion would not change significantly for current conditions. Marginal costs addressing the peak and off-peak periods within each month are not currently available.

The short run marginal cost of energy for the Labrador Interconnected System in all periods is tied to Hydro's cost of energy from the Churchill Falls hydroelectric project, which is as follows:

Year	Mills/KWh
2001	2.793
2002	2.645
2003	2.610
2004	2.575
2005	2.554

Please refer to Schedule XII of H.G. Budgell's Prefiled Testimony for the LOLH for the years 2001 through 2006 assuming no new generation is added to the system beyond that already committed.

At the present time, Hydro's generation planning model is not able to identify the LOLH attributable to the peak and off-peak periods in each month. However, the seasonal contributions to the annual LOLH for the Island Interconnected System are available and shown in the following table:

Seasonal Contribution to Annual LOLH (hrs)

	2001	2002	2003	2004	2005	2006
January	0.65183	0.91727	0.57046	0.35363	0.49922	0.69829
February	1.75291	2.37583	1.63272	0.83825	1.47770	1.99253
March	0.12459	0.18731	0.11460	0.06848	0.10028	0.14566
April	0.00115	0.00225	0.00088	0.00035	0.00065	0.00119
May	0.00030	0.00068	0.00018	0.00007	0.00012	0.00029
June	0.00000	0.00005	0.00000	0.00000	0.00000	0.00002
July	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
August	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
September	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
October	0.00006	0.00013	0.00001	0.00002	0.00003	0.00006
November	0.01059	0.01761	0.00290	0.00481	0.00765	0.01196
December	0.31518	0.46396	0.12600	0.18659	0.26597	0.37622
Total	2.85663	3.96508	2.44774	1.45218	2.35162	3.22622

The levelized cost of the least-cost peaking option is estimated to be $101/kW-yr.

The attached table gives the short run marginal cost of supply on the Rural Isolated System based on fuel only. The short run marginal cost of supply for L'Anse au Loup is given for both diesel operation and for purchases under the secondary energy contract from Hydro-Quebec.

Short Run Marginal Cost
Rural Isolated Systems and L'Anse au Loup

	2001	2002	2003	2004	2005	2006
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Mary's Harbour	0.116	0.112	0.110	0.107	0.111	0.111
St. Lewis	0.140	0.136	0.133	0.129	0.135	0.135
Ramea	0.110	0.108	0.105	0.102	0.106	0.106
Nain	0.116	0.113	0.110	0.107	0.112	0.112
Little Bay Islands	0.130	0.126	0.123	0.120	0.125	0.125
Charlottetown	0.127	0.123	0.120	0.117	0.122	0.122
Black Tickle	0.139	0.136	0.132	0.129	0.134	0.134
Harbour Deep	0.152	0.148	0.145	0.141	0.147	0.147
Rigolet	0.137	0.134	0.131	0.127	0.132	0.132
Makkovik	0.130	0.126	0.123	0.120	0.125	0.125
Postville	0.146	0.143	0.139	0.136	0.141	0.141
Grey River	0.138	0.135	0.132	0.128	0.133	0.133
Davis Inlet	0.140	0.137	0.134	0.131	0.136	0.136
St. Brendans	0.145	0.141	0.138	0.135	0.140	0.140
McCallum	0.148	0.144	0.141	0.138	0.143	0.143
Rencontre East	0.140	0.136	0.133	0.130	0.135	0.135
Petites	0.225	0.220	0.215	0.210	0.218	0.218
Cartwright	0.135	0.132	0.129	0.126	0.131	0.131
William's Harbour	0.199	0.194	0.190	0.186	0.193	0.193
Port Hope Simpson	0.136	0.132	0.130	0.127	0.131	0.132
Norman Bay	0.201	0.196	0.192	0.188	0.194	0.195
Paradise River	0.202	0.197	0.193	0.188	0.195	0.195
Hopedale	0.153	0.149	0.147	0.144	0.148	0.149
Francois	0.175	0.171	0.168	0.165	0.170	0.171
L'Anse au Loup						
- Diesel	0.138	0.135	0.132	0.129	0.134	0.133
- purchase from HQ	0.051	0.049	0.048	0.046	0.048	0.048

Q. List the demand management and energy efficiency programs that Hydro has implemented in the past five years, and that it intends to implement in the next five years.

A. Hydro has not implemented system wide conservation and load management programs in the past five years and has no definitive plans to undertake system wide programs in the next five years. Hydro has undertaken to complement its customer service delivery function with energy management training and education as outlined in CA-24. Hydro also evaluates opportunities as they arise on isolated systems for conservation and load management with an objective of rural subsidy minimization. See NP-184(e).

Q. Provide system load factors including actuals for the years 1995 through 2000, and forecast for the years 2001 through 2006, and describe the steps that have, and are, being taken to improve load factor.

A. Please see attached table of requested system load factors. Hydro does not have any general programs directed towards improving load factor.

Hydro System Load Factors (Winter Season)

	Historical (May Include Secondary Demand)						Forecast (Will Exclude Secondary Demand)					
	1995 %	1996 %	1997 %	1998 %	1999 %	2000 %	2001 %	2002 %	2003 %	2004 %	2005 %	2006 %
Total Island Interconnected	56	61	61	57	61	64	60	59	59	59	59	59
Hydro Island Interconnected	51	56	55	50	53	57	54	55	55	55	56	NA
Labrador Interconnected[1]	51	54	58	65	36	51	61	62	62	62	63	NA
Island Isolated												
Francois	32	33	36	33	32	32	33	33	33	33	33	33
Grey River	35	31	34	33	26	26	32	32	32	32	32	32
Harbour Deep	37	34	33	33	33	34	33	33	33	33	33	33
Little Bay Islands	31	30	29	27	32	30	48	48	49	49	49	49
McCallum	34	31	30	34	30	28	30	30	30	30	30	30
Petites	31	31	34	31	28	27	28	28	28	28	28	28
Ramea	44	42	43	42	39	40	40	40	40	40	40	40
Rencontre East	36	41	35	33	35	31	35	35	35	35	35	35
St. Brendans	37	35	36	32	29	29	30	30	30	30	30	30
Labrador Isolated												
Black Tickle	40	47	43	29	51	32	28	28	28	29	29	29
Cartwright	52	46	49	51	52	54	52	52	52	52	52	52
Charlottetown	39	39	38	41	43	47	34	34	34	34	34	34
Davis Inlet	60	42	44	45	46	47	43	43	43	0	0	0
Hopedale	50	43	43	44	46	46	46	46	46	46	46	46
Mary's Harbour	55	57	54	43	48	54	50	50	50	50	50	50
Makkovik	47	46	47	44	48	47	45	46	46	46	46	46
Nain	50	52	52	49	52	48	53	53	53	53	53	53
Norman Bay	26	18	25	26	30	31	29	29	29	29	29	29
Paradise River	34	29	29	29	26	42	42	42	42	42	42	42
Port Hope Simpson	43	44	41	40	41	42	41	41	41	41	41	41
Postville	46	44	41	44	44	44	44	44	44	44	44	44
Rigolet	44	42	43	47	45	44	46	46	46	46	46	46
St. Lewis	48	44	41	39	40	44	41	41	41	41	41	41
William's Harbour	57	56	44	44	46	42	44	44	44	44	44	44
L'Anse au Loup	48	48	44	46	48	44	47	47	47	47	47	47

Notes:
1. Low load factor in 1999 largely reflects very low sales to IOCC in 1999.

Q. Does Newfoundland Power provide value to its customers, or does it simply introduce another level of administration costs? Lists the efficiencies and value added by Newfoundland Power to the electricity consumers of Newfoundland; i.e., relative to Hydro, or a combined Hydro/Newfoundland Power entity providing all electric service within the Province.

A. Information concerning Newfoundland Hydro's view of Newfoundland Power's role and contribution to the utility environment in Newfoundland is not relevant and is not necessary to understand the matters to be considered in this proceeding which concern Newfoundland Hydro's application for approval of, inter alia, rate increases for its customers.

Q. Mr. Wells (page 19, lines 30/31 and page 20, line 1 of Prefiled Testimony) refers to an annual residential customer survey conducted as a means to identify those areas of greatest concern to customers and to measure progress in meeting those concerns. Provide a summary of survey results, and Hydro's progress in meeting customer concerns. Provide the most recent survey.

A. Please see the response to NP-27(b) for most recent survey. Section 4.0, pages 13 to 17 of the 2000 Customer Satisfaction Survey lists the attributes to which service delivery was measured, their importance to customers (page 14) and how Hydro is performing (page 16). Comparison of the 2000 survey with the 1999 survey shows how Hydro is measuring its progress. We will continue to use the 16 attributes within the same five key dimensions in our annual survey both as a measure of progress and as a planning tool for addressing customers' main areas of concern.

Q. Mr. Wells (page 20, lines 1 to 8 of Prefiled Testimony) refers to an enhanced energy management program to provide personnel with a better understanding of energy management issues that are important to customers. Provide details of the energy management program. What other programs does Hydro have in place to respond to customer needs?

A. In 2000, Hydro retained the services of Seneca College in Ontario to conduct an internal training needs assessment in the area of energy management. The purpose of this assessment was to identify the key areas of the Corporation and the training required to best address customers energy efficiency needs. To date information sessions have been held for Meter Readers and Customer Service Representatives. In addition five (5) technical staff have completed the full “House as a System” Course through Seneca College.

In addition to ensuring staff are adequately trained to address customer energy management needs Hydro has also undertaken the following initiatives:

- Partnering with the Conservation Corps of Newfoundland and Labrador to promote energy efficiency to customers and to respond to high consumption inquiries.
- Established a library of energy efficiency brochures from Natural Resources Canada that are available in all Regional Offices and upon request from customers.
- Use the Natural Resources Canada HOT2000 Program to provide residential energy analysis to customers for new home construction.

- On-site energy audits for customers, on request and in response to high consumption complaints.

As a complement to these initiatives, Hydro is currently implementing a customer assistance database that was designed to record and monitor customer requests for assistance, including energy efficiency needs. The database ensures the requests are logged, assigned with a priority to the appropriate staff member and monitored to ensure the customer receives a timely response.

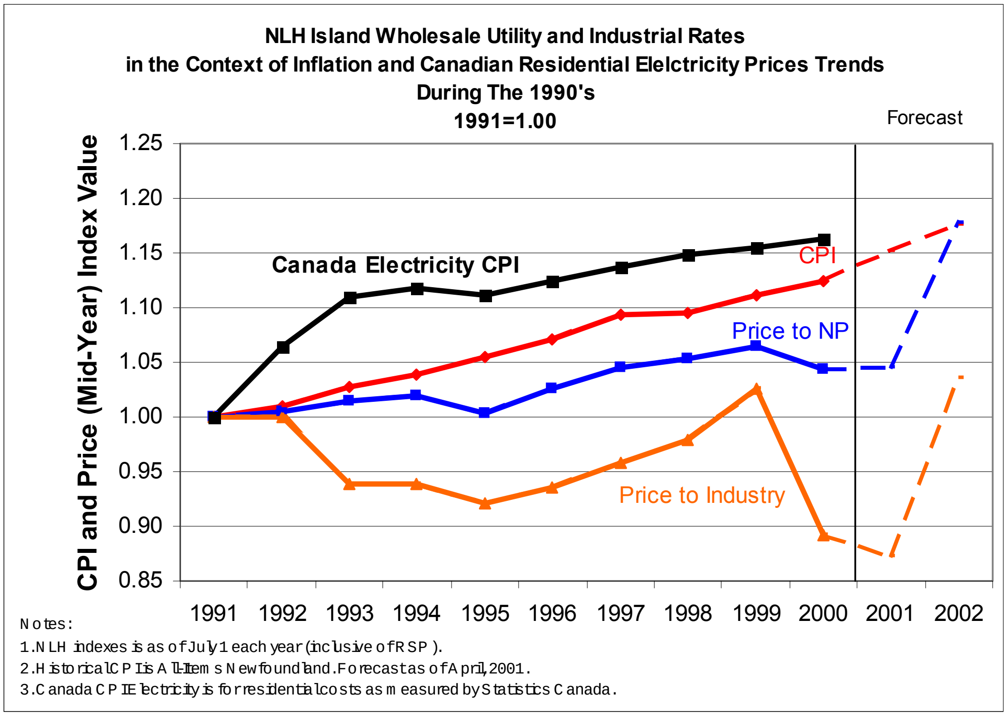
Q. Mr. Wells states (page 15, lines 7 to 10 of Prefiled Testimony) that it is absolutely essential that the Board send a clear signal to the financial markets of its views as to what a normal ROE should be for Hydro in the future. Specifically, what is Hydro asking the Board to do in order to send this signal to the financial markets?

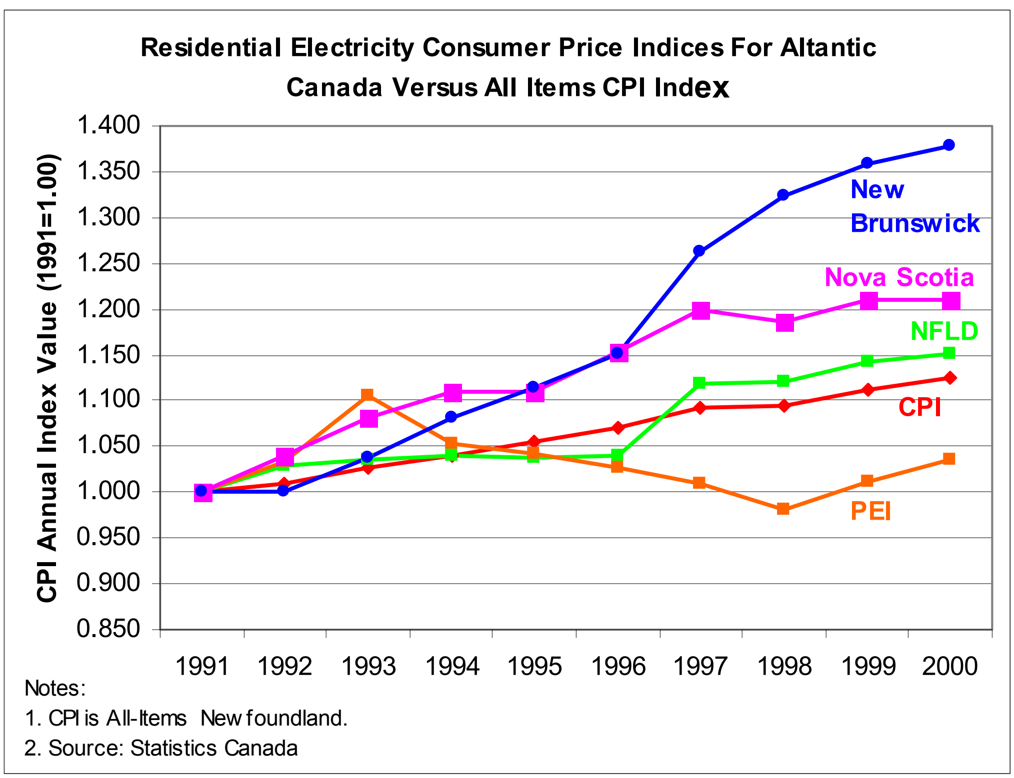
A. See response to PUB-67.1.

Q. Why has the price to industry trailed the price of electricity to NP; i.e., about 89% for industry, 105% for NP and 113% for CPI (see chart on page 28 of Mr. Wells' Prefiled Testimony). Provide the same chart, but include the average price of electricity to consumers in Canada. Please provide a similar chart for consumers in Atlantic Canada.

A. The main reason for the lower price to industry, in comparison to Newfoundland Power, is the three separate rate reductions Industrial customers have experienced in base rates since 1991. Hydro's Board of Directors approved rate decreases for Industrial customers in each of 1993 and 1994 totaling approximately 8%. In 1999 the PUB approved an 11% reduction effective January 1, 2000 when the rural deficit was eliminated from Industrial rates. These rate decreases have been partially offset by increases in the RSP over the period.

Residential electricity costs are consistently tracked by Statistics Canada as a component of the overall consumer price index. The charts attached provide the data for Canadian and Atlantic Canada consumers as requested.


NLH Island Wholesale Utility and Industrial Rates
in the Context of Inflation and Canadian Residential Elelctricity Prices Trends
During The 1990's
1991=1.00
Forecast
CPI and Price (Mid-Year) Index Value
1.25
1.20
1.15
1.10
1.05
1.00
0.95
0.90
0.85
Canada Electricity CPI
CPI
Price to NP
Price to Industry
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
Notes:
1. NLH indexes is as of July 1 each year (inclusive of RSP).
2. Historical CPI is All-Items Newfoundland. Forecast as of April, 2001.
3. Canada CPI Electricity is for residential costs as measured by Statistics Canada.


Residential Electricity Consumer Price Indices For Altantic
Canada Versus All Items CPI Index
CPI Annual Index Value (1991=1.00)
1.400
1.350
1.300
1.250
1.200
1.150
1.100
1.050
1.000
0.950
0.900
0.850
New
Brunswick
Nova Scotia
NFLD
CPI
PEI
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
Notes:
1. CPI is All-Items New foundland.
2. Source: Statistics Canada

Q. On page 8, lines 12 to 21 of her Prefiled Testimony, Ms. McShane indicates that Newfoundland Power periodically performs a lead/lag analysis. How does Newfoundland Power’s current lead/lag analysis compare to Newfoundland & Labrador Hydro’s lead/lag analysis both in terms of days, and in percentage terms? Reconcile any differences.

A. Newfoundland and Labrador Hydro does not have detailed information with respect to Newfoundland Power's current lead/lag analysis to enable it to provide the comparison and reconciliation requested.

Q. What programs are being pursued to improve on revenue lag? How does Newfoundland & Labrador Hydro's revenue lag compare to other Canadian utilities?

A. With the installation of Hydro's Utility Customer Information System the revenue lag has been reduced by two weeks as a result of a more streamlined meter reading and billing process. As well, planned changes to the discount offered for prompt payment, the introduction of interest on overdue accounts and an equal or levelized payment plan in line with proactive collections by the Customer Services Representatives and the closer proximity of Distribution System Representatives to the customer for more timely disconnection, should help in reducing the revenue lag.

Newfoundland and Labrador Hydro has not undertaken any research with respect to the revenue lag experienced by other Canadian Utilities, therefore the comparision requested is not available.

Q. What steps are being taken by Hydro to improve management of foreign exchange?

A. Hydro's foreign exchange risk is now limited to its requirement to fund purchases of No. 6 fuel oil with U.S. dollars. In an effort to mitigate this risk, Hydro uses an approach, whereby buying opportunities in advance of the shipment date are identified, and portions of the total U.S. dollar requirement are bought forward. This strategy helps avoid exposing the entire requirement to exchange rates on a given day.

Q. On page 16, lines 16 to 19 of her Prefiled Testimony, Ms. McShane states that she starts with the proposition that a utility should be financed in a manner that is compatible with commercial viability on a stand-alone basis, without subsidies among stakeholders (ratepayers vs. investors or among classes of ratepayers). Is this a reasonable proposition given the many, and substantial, subsidies proposed among classes of ratepayers and between ratepayers and investors?

A. Yes. The fact that the results of the regulatory process include various cross-subsidies does not change the validity of the principles which should be followed.

Q. On page 56, lines 10 to 16 of her Prefiled Testimony, Ms. McShane states that a range for the rate of return on rate base would only be relevant if the Board decided to make a determination of an appropriate capital structure, return on equity and return on rate base. If the Board were to make a determination of an appropriate capital structure, return on equity and return on rate base, and establish rates accordingly, what, in Ms. McShane's opinion, would be the appropriate range for the rate of return on rate base?

A. In Ms. McShane's view, if the Board were to set an appropriate capital structure and return on equity, a reasonable range for the return on rate base for the purpose of determination of over and under earnings would be plus or minus 1% of the established range. With the guarantee fee still in place, a reasonable capital structure would contain 70% debt and 30% equity. If the Board were to approve a return on equity of 11.25%, the "point" estimate of return on rate base for the establishment of the revenue requirement would be:

	Proportion	Cost Rate	Weighted Component
Debt	70%	8.35%	5.845%
Equity	30%	11.25%	3.375%
Return on Rate Base			9.22%

A review of the rates would be triggered if the return on rate base exceeded 10.2% (9.2% + 1.0%).

Q. On page 13, lines 8 to 13 of his Prefiled Testimony, Mr. Hall states that if the results are caused by unusual circumstances, and if the Board has evidenced concern with the situation and provided guidelines to the utility for improvements, and if the utility has programs in place to return to more prudent levels in the medium term, it is likely that Hydro can retain the categorization of its debt as “self-supported”, even in the face of poor results in the short-term. What does Mr. Hall recommend should be included in the Board’s report that would meet these criteria?

A. Please refer to PUB-67.1.

Q. On page 11, lines 1 to 10 of his Prefiled Testimony, Mr. Reeves states that a review of outages showed that on average, a simultaneous outage due to lightning was occurring once every 2 ½ years. He indicates that this was an unacceptable outage rate for such a large number of customers.

(a) What criteria are used to determine the acceptable level of outages?

(b) Mr. Reeves goes on to say that the installation of lightning arrestors would significantly improve the outage return rate of a simultaneous outage as a result of lightning. How much of an improvement is expected (i.e., from one outage every 2 ½ years to ?), and what is the estimated value to customers in terms of reduced generation costs and/or unsupplied energy?

(c) Have there been any simultaneous outages due to lightning since these lightning arrestors were installed in March of this year?

A. (a) Canadian utilities typically use statistics produced by the Canadian Electricity Association (CEA) as a basis for acceptable levels of performance. Transmission lines TL 202 and TL 206 perform individually in a satisfactory manner with lightning outage rates of approximately 0.6 per 100 km. yrs compared to the CEA average of 0.8 per 100 km. yrs for adverse weather in this voltage class. Similar CEA statistics for simultaneous outages on parallel lines are not available.

Simultaneous outages due to lightning on both TL 202 and TL 206, have caused an abnormally high number of significant power interruptions on the bulk electrical system. These outages, primarily to the Avalon and

Burin Peninsulas, have occurred at a frequency of approximately 1 in 2.5 years. Outages of a similar nature to parallel lines on the remainder of Hydro's grid are rare and estimated to occur at a frequency between 1 in 25 to 1 in 40 years.

(b) Theoretically, the application of lightning arrestors should improve the simultaneous outage rate of TL 202 and TL 206 to 1 in 38 years.

Based on typical numbers from other utilities for the estimate of outage costs for customers, the value for a 20-minute outage is estimated to be $0.25 for residential customers and $455 for commercial customers. In the outage area affected by these lines, there are approximately 108,000 residential and 11,000 commercial customers, and one major industrial customer. The value of a 20-minute outage for only residential and commercial customers is over $5,000,000.

(c) There have been no simultaneous outages since the installation of the lightning arrestors.

Q. Provide the analysis that is used to determine whether a diesel plant should be upgraded as opposed to connecting the communities served by the plant to one of the interconnected systems (Reeves Prefiled Testimony, page 12, lines 22 to 30). Provide an actual case study using the La Poile plant.

A. The purpose of an interconnection study is to determine the most cost-effective means for servicing an isolated rural system: interconnection or remaining on diesel generation.

The first step is to determine a realistic year for the interconnection. Then, long-term forecasts (usually 30 years) for both isolated and interconnected scenarios are developed. From the forecasts, potential expansion alternatives are developed and evaluated to determine technical feasibility, including an assessment of the operating impacts and sequence of development. For each technically acceptable alternative, capital and operating costs are developed, using appropriate economic parameters such as escalation rates, discount rates, fuel prices, etc.

A comparison is made between the costs of an isolated diesel alternative and each interconnection alternative by calculating the cumulative present worth difference. Sensitivity analyses to such things as discount rate, capital costs of the interconnection, diesel fuel prices, interconnected energy prices, and the load forecasts are also carried out.

For interconnection studies, it is normal to plot the accumulated cost (capital plus operating costs) of all expansion alternatives discounted to a point in time. The payback period gives the time required for the higher investment in one alternative to be offset by the higher operating costs of another expansion alternative.

The preferred expansion alternative is the one with the lowest cumulative present worth cost that also meets the economic evaluation criteria. In order for a project to proceed, Hydro has set a minimum economic guideline that interconnection projects must have payback periods not exceeding 15 years when compared to the existing operation. This allows for a reasonable level of risk associated with the long-term cost (capital and operating) of the expansion alternative.

Please see NP-93 for "LaPoile Interconnection Study" – October 1998.

Q. What did it cost to build the Northern Interconnection and by how much is the Rural Deficit reduced annually because of the interconnection? What is the annualized cost of the Northern Interconnection?

A. The Great Northern Peninsula Interconnection in 1996 cost $31,418,995.00. Hydro received $5.0 million Canada/Newfoundland Infrastructure grant resulting in a net cost of $26,418,995.00. It is not possible to determine by how much the Rural Deficit is reduced for reasons referenced in the response to IC 203(1)(c). The estimated annualized cost associated with the net cost of the Northern Interconnection is $2.29 million.

Q. Show the initial capital expenditure and the annualized cost, and the corresponding reduction in the rural deficit under the following scenarios:

a) Interconnection to the Labrador grid of Nain, Davis Inlet, Hopedale, Postville and Makkovik;
b) Interconnection to the Labrador grid of Rigolet, Cartwright, Black Tickle, Paradise River, Norman Bay, Charlottetown, Williams Harbour, Port Hope Simpson, St. Lewis, Mary's Harbour and L'Anse au Loop (show L'Anse au loop separately); and
c) Interconnection to the Island Grid all Isolated Island Systems.

A. Hydro has not prepared detailed interconnection studies for each of the remaining isolated diesel systems as it has been self-evident to Hydro that there is no economics in interconnecting them to the appropriate main grids. A preliminary desk top analysis was completed to identify the initial capital expenditure to interconnect each community based upon an order of magnitude cost per km for transmission lines and distribution lines, an order of magnitude cost per terminal station and a straight-line line routing which avoids major bodies of water but does not consider the topography of the land. The cumulative present worth (CPW) cost of interconnection of the communities was calculated for the period 2002 to 2022 and was based upon annual costs for energy, line losses and line maintenance. The cumulative present worth (CPW) cost of continued diesel operation was calculated for each system for the period 2002 to 2022 and was based upon diesel fuel, variable O&M and fixed O&M costs over the twenty-year period. A comparison of the CPW for interconnection and the CPW of continued diesel was used to determine if there is sufficient economics to warrant a detailed interconnection study and provides an indication on the magnitude of the impact an interconnect may have on the rural deficit. It should be noted that the preliminary analysis did not consider the technical implications (i.e. voltage regulation) on very long 69 kV transmission lines. The results of preliminary analysis are provided below.

a) The following table provides the initial capital expenditure to interconnect and compares the CPW cost of interconnection to the CPW cost of continued diesel operation for the isolated diesel communities in Labrador north of Happy Valley – Goose Bay.

Initial Capital Expenditure, CPW of Interconnection and CPW of Continued Diesel for Interconnection of Labrador Communities North of Happy Valley – Goose Bay

Diesel Plant	Intertie Point	Line Length (km)	Capital Cost to Interconnect $	CPW to 2022 Interconnection $	CPW to 2022 Continued Diesel $	CPW Preference For Diesel $
Rigolet	Happy Valley	188	24,560,000	29,047,000	5,155,000	
Makkovik	Rigolet	206	25,720,000	28,108,000	7,402,000	
Postville	Makkovik	90	11,800,000	12,863,000	4,666,000	
Hopedale	Postville	142	18,040,000	19,754,000	8,010,000	
Davis Inlet	Hopedale	118	16,832,000	18,461,000	12,327,000	
Nain	Davis Inlet	193	24,160,000	26,573,000	12,261,000	
Total		937	121,112,000	134,806,000	49,821,000	84,985,000

The combined interconnection of all communities north of Happy Valley – Goose Bay would result in a substantial increase in cost with a subsequent increase in the rural deficit. There is an $84,985,000 preference for continued diesel operation for communities north of Happy Valley - Goose Bay.

b) The interconnection of the communities south of Happy Valley – Goose Bay requires the construction of a 69 kV transmission system from the Labrador Interconnected System at Happy Valley – Goose Bay. The transmission system would follow the proposed route of the Southern Labrador Highway. It is inappropriate to compare the CPW cost of interconnection to the CPW cost of continued diesel on an individual community basis as the initial capital cost of interconnection for each community assumes that all communities between it and the original interconnected system (i.e. Happy Valley) have already been interconnected. As a result one must compare the total CPW costs for interconnection and continued diesel options for the entire interconnection plan. The following table provides the initial capital expenditure to interconnect and compares the CPW cost of interconnection to the CPW cost of continued diesel operation for Labrador communities south of Happy Valley – Goose Bay.

Initial Capital Expenditure, CPW of Interconnection and
CPW of Continued Diesel for
Interconnection of Labrador Communities South of Happy Valley – Goose Bay

Diesel Plant	Intertie Point	Line Length (km)	Capital Cost to Interconnect $ (1)	CPW to 2022 Interconnection $	CPW to 2022 Continued Diesel $	CPW Preference For Diesel $
Paradise River	Happy Valley	300	111,880,000	115,132,000	2,167,000	
Cartwright	Paradise River	47	6,640,000	7,391,000	8,939,000	
Charlottetown	Paradise River	120.3	13,736,000	15,025,000	8,687,000	
Black Tickle	Charlottetown Tap	86	13,578,000	14,584,000	4,341,000	
Norman Bay	Charlottetown	37	3,090,000	3,298,000	979,000	
Port Hope Simpson	Charlottetown Tap	30.2	4,624,000	5,116,000	5,608,000	
Williams Harbour	Port Hope Simpson	44.5	6,477,000	6,713,000	2,337,000	
St. Lewis	Port Hope Simpson	49.5	5,540,000	6,004,000	4,992,000	
Mary’s Harbour	St. Lewis	38	5,500,000	6,155,000	7,896,000	
L’Anse au Loup	Mary’s Harbour	143	18,160,000	20,287,000	12,637,000	
Total		895.5	189,225,000	199,705,000	58,583,000	141,122,000

Notes

(1) The capital cost to interconnect a community assumes that the 69 kV transmission system has already been extended from Happy Valley – Goose Bay to the community’s intertie point (i.e. interconnection cost for Cartwright includes only the cost from Paradise River to Cartwright and assumes Paradise River has already been interconnected to Happy Valley – Goose Bay).

The combined interconnection of all communities south of Happy Valley – Goose Bay would result in a substantial increase in cost with a subsequent increase in the rural deficit. There is a $141,122,000 preference for continued diesel operation for communities south of Happy Valley - Goose Bay. If one were to remove L'Anse au Loup from the interconnection plan, there would be a preference of $133,472,000 for continued diesel operation in southern Labrador.

c) The following table provides the initial capital expenditure to interconnect and compares the CPW cost of interconnection to the CPW cost of continued diesel operation for the isolated diesel communities on the Island.

Initial Capital Expenditure, CPW of Interconnection and
CPW of Continued Diesel for
Interconnection of Isolated Island Communities

Diesel Plant	Intertie Point	Line Length (km)	Capital Cost To Interconnect $	CPW to 2022 Interconnection $	CPW to 2022 Continued Diesel $	CPW Preference For Diesel $
St. Brendans	Burnside	20	12,718,000	13,392,000	3,226,000	10,166,000
Little Bay Islands	Beachside	10	5,654,000	6,421,000	3,561,000	2,860,000
Rencontre East	English Hr. West	41	6,170,000	7,183,000	3,246,000	3,937,000
Harbour Deep	Coney Arm	49	4,309,000	5,053,000	2,822,000	2,231,000
McCallum	Gaultois	27	18,299,000	18,662,000	2,178,000	16,484,000
Petites	Hr. Le Cou	5.8	1,527,000	1,643,000	1,475,000	168,000
Ramea	Burgeo	50	13,159,000	15,730,000	10,655,000	5,075,000
Grey River	Grandy Brook	60	9,200,000	10,271,000	2,281,000	7,990,000
Francois	Grey River	40	6,050,000	6,949,000	2,825,000	4,124,000
Total		302.8	77,086,000	85,304,000	32,269,000	53,035,000

The combined interconnection of the remaining isolated diesel communities on the Island would result in a substantial increase in cost with a subsequent increase in the rural deficit. There is combined $53,035,000 cumulative present worth preference for continued diesel operation on the Island.

Q. Quantify the benefits in dollar terms to consumers resulting from the ice-loading upgrades to the transmission lines on the Avalon Peninsula (page 14, lines 19 to 24, Reeves Prefiled Testimony).

A. The benefits in dollar terms to consumers resulting from the ice-loading upgrades to transmission lines on the Avalon Peninsula are difficult to quantify. These would result from the prevention of forced outages and the costs of these power interruptions to customers.

The actual value would be dependent on the number of outages, the number of customers affected and the outage duration of the interruptions prevented by the upgrade.

Upgrading of the transmission lines on the Avalon Peninsula is justified in terms of improved system reliability, customer satisfaction, reduced repair costs and revenue continuity.

Q. On page 6, lines 13 to 19 of his Prefiled Testimony, Mr. Henderson indicates that the Power Purchase Agreements with the Non-Utility Generators have winter rates for the period November to March and non-winter rates for the remainder of the year. Schedule IX indicates a non-winter price ratio for the fixed cost component of about 2.1(*sic*). The variable component of the purchase price is about 46% of the total purchase price, and is the same in winter and non-winter months.

a) Does the ratio of 2.1 (*sic*) reflect the relative value of capacity to the system in the two seasons?
b) Does the fixed/variable split represent the difference in actual fixed and variable costs for a typical hydro generating facility?
c) Is there no difference in the value of energy to the system in winter and non-winter months?

A. a) The ratio of 2:1 reflects the ratio of the actual prices bid by the two NUGS for the fixed cost component of the price for energy. See IC 208 (4) for a description of the basis for Hydro's 1992 maximum pricing structure for the fixed component of the NUG energy rate.

b) The fixed/variable split does not represent the difference in actual fixed and variable costs for a typical hydro facility. For example the fixed cost for Granite Canal is approximately 93% of the total annual costs (Please see response to IC 42(Rev) for further details).

c) The value of energy to the Island Interconnected System varies throughout the year depending on the relative utilization of the system's thermal resources. It is for the most part tied to Holyrood's variable production cost due to the large storage capability of Hydro's hydroelectric facilities, which permits Hydro to purchase energy in one time period and defer hydroelectric production to another time period. The exception occurs when energy for peaking is required.

Q. Provide the cost of power from each generation and purchase source on the interconnected and non-interconnected systems.

A. Please see response to IC-202.2(d) regarding the cost of power from each generation source.

The cost of power from each purchase source for 2002 is as follows:

Purchase Source	**Amount**
Star Lake Hydro Partnership	$ 8,695,426
Algonquin Power (Rattle Brook) Partnership	1,263,192
Churchill Falls (Labrador) Corporation Limited	2,756,851
Abitibi Consolidated Inc.	1,326,848
Hydro-Québec (L'Anse au Loup)	625,131
Corner Brook Pulp and Paper Company Limited	13,704

Q. For each interruption under the contract with ACI in Stephenville, list the date, duration and the cost to consumers. Does Article 5 of the contract (Schedule C, page 6 of 71) indicate that the maximum Interruptible Demand at ACI Stephenville is 5 MW?

A. The information requested for each interruption is provided in the following table:

Interruptible B Interruptions

Event	Date	Duration (hr:min)	Incremental Cost
1	12/16/1993	5:15	$8,111.06
2	12/30/1993	4:15	$4,673.94
3	01/17/1994	5:45	$15,016.02
4	02/09/1994	8:45	$19,156.70
5	02/13/1994	1:15	$2,289.18
6	12/10/1994	2:15	$7,031.09
7	12/11/1994	8:00	$23,434.39
8	02/14/1995	8:30	$13,610.45

Please note that the costs in the table were paid by Hydro and are in addition to the $1,297,200 paid annually for the right to interrupt. These costs prior to 2002 have not been passed on to consumers.

The maximum Interruptible Demand sold to Abitibi Consolidated Inc. Stephenville is 5 MW. It should be noted that this demand is associated with load taken by Abitibi Consolidated Inc. beyond its firm Power On Order. The amount referred to in the first half of this question is related to Interruptible "B" load which is for firm Power On Order that Hydro has purchased the right to interrupt. The Interruptible "B" load is 46 MW.

Q. What is the basis for the forecast fuel price shown in Schedule VIII of Mr. Henderson’s Prefiled Testimony? Is it the PIRA Energy Group forecast for 2.2% sulfur No. 6 fuel oil for Holyrood? If not, what is the PIRA Energy Group forecast?

A. The basis for the forecasted fuel prices shown in Schedule VIII of Mr. Henderson’s Prefiled Testimony is the PIRA Energy Group for US dollar market prices. In the case of 2.2% sulphur No. 6 fuel oil for Holyrood, Hydro applies a nominal contract discount (e.g. $0.11 US / BBL) and an exchange rate to arrive at a landed price for Holyrood.

Q. Provide contract details of the power purchase agreement with CF(L)Co.

(a) What services are purchased and what are the rates for each service?

(b) What are the terms and conditions concerning ‘recall” of the power and energy (Henderson Prefiled Testimony, page 14, lines 22 to 25)?

(c) Why are maximums set at 300 MW and 2362 GWh annually when purchases in 2002 are expected to total only 1042 GWh?

(d) Why did the CF(L)Co rate decrease in September 1, 2001 (Henderson Prefiled Testimony, page 16, lines 8 to 9)?

A. The power purchase agreement with CF(L)Co was provided in response to NP-40.

(a) Hydro is purchasing recall power and energy from CF(L)Co in the amount of 300 MW and 2,362 GWh. The payment is made based on three components:

(i) Basic Contract Demand;
(ii) Energy Taken; and
(iii) Interest Payment

The rate for the Basic Contract Demand and Energy Taken is fixed at \$0.0025426 per kWh from September 1, 2001 to August 31, 2016. After that date the rate falls to \$0.0020000 per kWh for the remainder of the contract.

The Interest Payment is based on the interest expense CF(L)Co incurs which would have been paid by Hydro Quebec if Hydro was not purchasing energy from CF(L)Co.

(b) CF(L)Co through its contractual arrangement with Hydro Quebec has the right to recall power and energy from Hydro Quebec up to 300 MW and 2,362 GWh per year. Hydro purchases the power and energy recalled by CF(L)Co under the terms and conditions in the agreement provided in response to NP-40.

(c) Hydro is purchasing 300 MW and 2,362 GWh annually to supply loads in Labrador and to sell unused power and energy to Hydro Quebec. The purchase of 1,042 GWh is the forecast use in Labrador.

(d) The rates paid by Hydro are equal to the rates paid by Hydro Quebec to CF(L)Co. The rate decrease matches the rate decrease in the CF(L)Co/Hydro Quebec Power Contract.

Q. Schedule III of Mr. Henderson's Prefiled Testimony indicates that total system energy storage in April and May of 2001 was below the Minimum Energy Storage Target. Why?

A. During April and early May, the total system energy storage was below the minimum storage target. Inflows were light during this period, like most of the winter, as snow accumulated. Runoff from snow melt was expected to be above normal as a result. A snow survey performed at the end of March showed well above average snow on the ground. Therefore, Hydro expected to be well above the minimum target by June 30, when the large snow accumulation had melted. This projection held throughout the spring period and at the end of the runoff, the storage was approximately 120-125% of the minimum target.

Q. What planning is Hydro doing that requires a 20-year forecast as stated in Mr. Budgell's Prefiled Testimony, page 3, lines 4 to 10?

A. Hydro uses a 20-year forecast as input into its long term generation planning studies. These analyses are used to produce a number of potential long term plans, with the focus being to determine the longer term impacts of probable future events on the more immediate resource decisions.
Hydro also requires long term forecasts for carrying out financial analysis.

Q. How does Hydro recover its planning costs from consumers?

A. Hydro recovers its planning costs from consumers in the rates it charges. The recovery is dependent upon the system being served. Transmission planning, for instance, is allocated among systems based on transmission plant. It is also classified based on transmission plant. Distribution and generation planning costs, once systemized, are classified based on distribution and generation plant, respectively. The classified costs are allocated among the rate classes based on the allocation factors specified on Schedule 3.1 of the Cost of Service.

Cost recovery is dependent upon the system and rate class for which service is being provided. Isolated systems, L'Anse au Loup and Rural Island Interconnected customers contribute to the rural deficit, rather than paying cost-based rates. Island Industrial Customers pay cost-based rates. Newfoundland Power and Labrador Rural Interconnected customers pay their costs, as well as a portion of the rural deficit.

Q. Provide the effects of “judgment” on the planning load forecast referenced on page 7, line 3 of Mr. Budgell’s Prefiled testimony.

A. In the forecast process for the Long Term Planning Load Forecast, the term “judgment” is used in a broad sense in that it represents the experience and decision making of the analyst undertaking the load forecast in the context of the energy and economic environment prevailing at the time. A number of key analytical judgments are made respecting the forecasted economic environment. The tangible example of this is that for the purposes of analyzing historical demand and forecasting demand, Hydro requests the Department of Finance to provide it with an adjusted Gross Domestic Product (GDP) series for the Provincial economy. These adjustments exclude large blocks of income that will be earned by non-resident owners of Provincial mega-projects, notably oil developments and more recently applicable for Voisey’s Bay minerals production and processing. This adjusted GDP is more conservative than GDP growth as conventionally reported and forecasted, and in Hydro’s judgment, better reflects growth in economic activity that generates income for the residents of the Province and subsequently local electricity demand. Additional judgments would be to not include in the industrial load forecast any provision for unforeseen industrial loads that may materialize across the forecast horizon, and to treat as a sensitivity case analysis prospective industrial loads that are not yet committed, e.g. on-Island industrial load associated with the Voisey’s Bay resource development.

Q. Provide details of the potential for the Voisey's Bay nickel smelter/refinery and a Labrador Infeed discussed on page 9, lines 17 to 22 of Mr. Budgell's Prefiled Testimony.

A. As indicated in the referenced testimony, the magnitude and timing of on-island industrial load associated with the Voisey's Bay nickel resource development represented a principal demand uncertainty during the 1990s. Based on initial communications with INCO, Hydro began a process that would have resulted in a power supply for a 200 MW smelter and refinery to be located at Argentia starting in 2000. A 200 MW increase in load represented approximately a 15 percent increase in demand for the Island interconnected system. Hydro's assumptions for associated on-island industrial load for the Voisey's Bay development subsequently decreased to a 100 MW load provision, and with the change in process technology, is now 50 MW assuming hydro-met ore processing technology and a commencement date of 2007. This load is now treated as a sensitivity case to a base case long-term load forecast.

Uncertainty on the supply side was driven by the demand uncertainty outlined above, and also uncertainty surrounding the outcome of negotiations between the Province and Hydro-Quebec concerning further developments on the Churchill River and a high voltage 800 MW transmission interconnection between Labrador and the Island portion of the Province. If a Labrador Infeed is committed, the objective would be to minimize new generation capital on the Island prior to Infeed commissioning.

At this point in time Hydro has no service requests from INCO to supply an on-island industrial load associated with the Voisey's Bay resource development. On the supply side, the Province has not yet been successful in reaching applicable agreements leading to the development of the Lower Churchill and a Labrador Infeed.