Q. Provide the Forecast Cost of Service for 2001.

A. The forecast Cost of Service Study for 2001 is not currently available, but is in progress.

Q. Provide a table showing (a) the total amount contributed by the Industrial Customers to the Rural subsidy in 1995, 1996, 1997, 1998 and 1999 and (b) the amount which would have been contributed by the Industrial Customers in each of those years if the direction of the Legislature in Section 3(a)(iv) of the Electrical Power Control Act, 1994 that the Industrial Customers' contribution to the Rural subsidy 'shall be gradually reduced during the period prior to December 31, 1999" had been implemented to reduce their contribution by 20% in 1995, by 40% in 1996, by 60% in 1997, by 80% in 1998 and by 100% in 1999.

A. The Board, in its Order No. P.U. 23(1999-2000), approved a reduction in the Industrial rates of 10.74% to remove the portion of the Rural Deficit that had been included in these rates. The table below was calculated based on applying this reduction of 10.74% to the total Industrial revenue net of RSP revenue for each year requested to determine the amount contributed by the Industrial Customers to the Rural subsidy.

The total amount contributed by Industrial Customers for each of the years as requested in part (a) is shown in column 3.

The amount that would have been contributed based on the reductions as requested in part (b) is shown in column 4. The amounts in column 4 are based on the requested percentage reductions effective at the end of each year.

Also, please see response to IC-9.

Year	Industrial Revenue (excl. RSP)	Subsidy Portion	Subsidy Based On Reductions
1995	$44,467,369	$4,758,008	$4,758,008
1996	47,526,674	5,104,365	4,083,492
1997	47,689,883	5,121,893	3,073,136
1988	36,269,044	3,895,295	1,558,118
1999	43,453,323	4,666,887	933,377

Q. Explain why Hydro did not apply to the Public Utilities Board in the period June 9, 1994 to November 19, 1999 to implement the power policy of the province as expressed in Section 3(a)(iv) of the Electrical Power Control Act, 1994 that the Industrial Customer's contribution to the Rural subsidy "shall be gradually reduced during the period prior to December 31, 1999."

A. Though the *Electrical Power Control Act, 1994* obtained royal assent on June 9, 1994, it was not proclaimed to come into force until later – effective January 1, 1996. After the Act went into effect, Hydro had discussions with Government as to the reduction of the Industrial Customers' contribution to the Rural subsidy and were advised Government's policy as expressed in Section 3(a)(iv) was under review. One of the options being considered was the repeal of this section.

Clarification/direction was sought by Hydro from 1996-1999. In August of 1998 Government announced it was undertaking an Energy Policy Review that would consider a broad range of regulatory and utility industry structure issues. Hydro received direction from Government to apply for a change to industrial rates in October, 1999 (copy of letter of direction attached).

Q. What amount of interest was credited to the RSP in the years 1992 - 2000, inclusive?

A. Please see response to IC-73.

Q. Provide a Table which shows the following for each of the years 1994 - 2000 inclusive assuming the implementation of the Cost of Service Methodology approved in the Public Utility Board 1993 Report (where the vertical axis represents the years and the horizontal access (*sic*) the following data):

1. the demand rate which would have been charged the Industrial Customers for firm power and for each class of non-firm service;
2. the energy rate which would have been charged the Industrial Customers for firm power and for each class of non-firm service and for wheeling;
3. the Specifically Assigned Charges which would have been charged Industrial Customers, and the total for all Industrial Customers;
4. the total number of kWh sold to the Industrial Customers for those years for firm power and for each class of non-firm service and for wheeling;
5. the total dollar amount which would have been billed to the Industrial Customers in those years, exclusive of sales tax, for firm power and for each class of non-firm service and for wheeling (indicate subtotals for each class of service and overall total);
6. the average cost per kilowatt hour which would have resulted;
7. the total dollar amount which was billed to Industrial Customers;
8. the average cost per kilowatt hour which was billed to Industrial Customers;
9. the difference between (5) and (7).

A. In its 1993 Cost of Service Report the Board stated “That the cost of service methodology recommended herein be adopted by Hydro for the purpose of the next rate referral”. Hydro has included the Board’s approved methodology in its 2002 Test Year Cost of Service, as recommended. Hydro therefore submits that the requested information is not relevant to this proceeding as it is hypothetical since it does not reflect historic reality and thus no meaningful conclusions can be drawn. Further, Hydro's rate setting is based on forecast costs. When setting rates, Hydro determines margin based on circumstances at that time. Rates were last set for Island Industrial Customers in 1995, using the Interim Methodology, when Industrial Customers were not regulated. The requested information regarding what rates would have been, using the Generic (1993) Methodology, is presently not determinable.

Q. With respect to forecast 2002 Specifically Assigned Charges for each of the Industrial Customers provide a breakdown of the component parts of each of those forecast Specifically Assigned Charges and identify any Specifically Assigned Charges proposed to be included in 2002 Specifically Assigned Charges which have not been charged in previous years and the dollar amount of and rationale for each proposed change.

A. Please refer to IC-177 for a breakdown of the component parts of each of the 2002 forecast specifically assigned charges.

Specifically assigned charges related to the two frequency converters are the only charges not previously charged to Industrial customers. Please refer to IC-41.1(Rev.2) for the component breakdowns associated with these assets.

The frequency converters were reassigned following a review of plant assignments undertaken in preparation for this rate application. In the initial years of the Island Interconnected System, the frequency converters at Corner Brook and Grand Falls were of benefit to each of the industrial customers, Newfoundland Power and the grid as a whole. With the continued expansion of the transmission system and the construction of generating stations at Cat Arm and Hinds Lake, operation of the frequency converters has little impact on the 230 kV system voltage levels. The role of the frequency converters has been reduced to providing local voltage control for the mill power systems and transferring power from 50 Hz to 60 Hz for use within the individual paper mills. With the frequency converters being only of benefit to the respective customers, the assets were specifically assigned to each of the industrial customers they serve.

Q. What is the net change in cost for 2002 to each of Hydro's Customer classes and to each of the Industrial Customers which will result from the proposed changes in Hydro's depreciation policies?

A. Please refer to IC-29 for the net change in cost to each of Hydro's customer classes.

Costs are not available for each Industrial customer. However, the decrease in revenues from each Industrial customer, based on the revenue requirement differences estimated in IC-29, are as follows:

Abitibi Consolidated – Grand Falls	$ 58,000
Abitibi Consolidated – Stephenville	197,000
Corner Brook Pulp and Paper Co. Limited	182,000
North Atlantic Refining Limited	83,000

Q. **Frequency Converter:** (H. G. Budgell at page 21 indicates that the frequency converters at Corner Brook and Grand Falls, previously assigned Common Plant, have been Specifically Assigned to Corner Brook Pulp and Paper and Abitibi Consolidated Inc. – Grand Falls division.)

(1) What is the detail for the calculation of the SAC?

(2) What have the O&M costs been for each of the past five years?

(3) What is the rationale for invoicing these costs now as Specifically Assigned?

A. (1) Detail calculations of specifically assigned charges are attached.

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

(2) The following are the O&M costs for the Frequency Converter Station at Grand Falls and Corner Brook (including the associated Terminal Stations) for the years 1999 and 2000:

1999	$152,077
2000	$154,600

The O&M costs for 1996, 1997 & 1998 are not available as they were not tracked separately for those years.

(3) Please refer to the response to IC-32.

Q. Provide copies of all correspondence or other documents related to the introduction of frequency converters at Grand Falls and Corner Brook for the use of Abitibi Consolidated and Corner Brook Pulp and Paper, or their respective predecessors, all contractual documents between Hydro and either customer which have affected the converters since that time and an explanation of the rationale for installing the converters and regarding them as common assets for cost of service purposes to date.

A. Attached are copies of:

- a power contract dated December 10, 1982 between Hydro and The Bowater Power Company Limited (later Deer Lake Power Company Limited and now amalgamated into Corner Brook Pulp and Paper Limited) – please see Article 9.01; and
- a power contact between Hydro and Bowater Newfoundland Limited (now Corner Brook Pup and Paper Limited) dated December 10, 1982 – please see Article 8.01.

Please also refer to Hydro's response to IC-56 which contains reports that supported the decisions to install the frequency converters.

The rationale for installing the frequency converters is explained in detail in the response to IC-56. At the time of the development of Bay D'Espoir and the construction of the Island transmission grid it was decided that all future development would be at 60 Hz and that every effort should be made to convert existing 50 Hz load to 60 Hz operation. The frequency converters provided the mechanism that allowed the 50 Hz and 60 Hz systems to be

interconnected and function as a single system while an orderly conversion to 60 Hz was implemented over time.
At the time of system development the 50 Hz generation and load in the Grand Falls and Corner Brook areas constituted a significant portion of the total system load and the 50 Hz systems through the frequency converters provided support to the 60 Hz system as did the 60 Hz system provide support to the 50 Hz systems. It is this interdependence of the 50 Hz and 60 Hz systems that led to the frequency converters being regarded as common.

The Island interconnected system today is quite different. There is very little 50 Hz load remaining and the 60 Hz generation and transmission network has developed to the stage where the support provided by the converters is virtually insignificant. The primary function of the frequency converters today is to convert the customers' excess 50 Hz generation to 60 Hz to supply 60 Hz loads at the customers' mills in Corner Brook and Grand Falls-Windsor. It is because of this change in the significance of the converters that the assignment has been changed from common to specifically assigned.

Q. With regard to H. Budgell's evidence, page 21, lines 5 – 10, provide the 2002 Forecast Cost of Service assuming that the line to Long Harbour and the Long Harbour Terminal Station were taken out of service.

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

Q. With reference to Budgell's evidence page 17, lines 7 – 12, for each year since 1996, provide the annual generation, annual radial load and net delivered to the 230 kV grid from the Great Northern Peninsula 1996 interconnection.

A. The annual generation including the Roddickton mini-hydro and the annual radial load of the Great Northern Peninsula 1996 interconnection for the period 1997 to 2000 is summarized in the following table:

Great Northern Peninsula 1996 Interconnection St. Anthony – Roddickton System Annual Generation and Radial Load 1997 – 2000						
Year	Gross Generation (MWh)					Annual Load MWh
	St. Anthony Diesel	Roddickton Diesel	Roddickton Wood Chip	Roddickton Mini-hydro	Total Generation	
1997	257	66	78	845	1,246	46,067
1998	395	122	229	1,386	2,132	47,978
1999	216	20	0	1,146	1,382	50,323
2000	139	0	0	793	932	53,653

The St. Anthony and Roddickton diesel units operated for only planned and forced transmission line outages during the period 1997 to 2000. The generation at Roddickton Wood Chip and the mini-hydro displaced energy from Holyrood during the period 1997 to 2000.

Q. Using the same format as Brickhill's schedule 3.1A, column 3, provide the actual 2CP kW for each year from 1992 to 2000 inclusive.

A. The 2 CP kW for 1999 and 2000 are attached. As well, an estimate of the 2CP kW, at the transmission level for 1994-2000, may be found in the response to IC-137. IC-137 also contains the reasons 1993 and 1992 data is unavailable. The individual class data for rural rate classes was not determinable, so the 2 CP data is presented for bulk rural deliveries.

Newfoundland and Labrador Hydro
2 CP kW - Island Interconnected
1999 and 2000

Line No.	Description	1999 Production Demand (2 CP kW)	2000 Production Demand (2 CP kW)
	Amounts		
1	Newfoundland Power	1,705,289	1,801,636
2	Industrial - Firm	315,525	263,624
3	Industrial - Non-Firm	-	-
	Rural		
4	1.1 Domestic	50,772	50,906
5	1.12 Domestic All Electric	65,499	64,492
6	1.3 Special	127	129
7	2.1 GS 0-10 kW	5,661	6,184
8	2.2 GS 10-100 kW	18,514	18,564
9	2.3 GS 110-1,000 kVa	10,649	11,509
10	2.4 GS Over 1,000 kVa	11,598	9,451
11	4.1 Street and Area Lighting	1,617	1,584
12	**Subtotal Rural**	**164,438**	**162,819**
13	**Total**	**2,185,252**	**2,228,078**
	Ratios Excluding Return on Equity		
14	Newfoundland Power	0.7804	0.8086
15	Industrial - Firm	0.1444	0.1183
16	Industrial - Non-Firm	-	-
	Rural		
17	1.1 Domestic	0.0232	0.0228
18	1.12 Domestic All Electric	0.0300	0.0289
19	1.3 Special	0.0001	0.0001
20	2.1 GS 0-10 kW	0.0026	0.0028
21	2.2 GS 10-100 kW	0.0085	0.0083
22	2.3 GS 110-1,000 kVa	0.0049	0.0052
23	2.4 GS Over 1,000 kVa	0.0053	0.0042
24	4.1 Street and Area Lighting	0.0007	0.0007
25	**Subtotal Rural**	**0.0752**	**0.0731**
26	**Total**	**1.0000**	**1.0000**

Q. Provide the same information as requested in questions 144-148 above for the gas turbine units at Stephenville and Hardwoods.

A. **RE: IC-144**

At the time of the last rate referral both the Stephenville and Hardwoods gas turbines were assigned common.

RE: IC-145

Neither the Stephenville nor Hardwoods gas turbines were specifically assigned at the time of the 1992 Report.

RE: IC-146

In 1992, the Stephenville and Hardwoods gas turbines were classified 100% demand-related. The same treatment has been accorded gas turbine generation in the 2002 Forecast Cost of Service.

RE: IC-147

1. The table below shows when the generating plants in question became a part of the Island Interconnected System.

Generation Source	Available to Island Interconnected System
Stephenville Gas Turbine	May, 1977
Hardwoods Gas Turbine	November, 1978

2. Records back to 1977 and 1978 for the Stephenville and Hardwoods Gas Turbines are not readily available, thus data since 1992 are used to answer this question. The table shows the number of times during 1992 through 2000 when each of the plants were operated. To list every incident of operation and the reason for operation is impractical because of the limited detail available on the cause of operation. However, operation of these units for testing and synchronous condenser are excluded from the table.

Year	Stephenville Gas Turbine	Hardwoods Gas Turbine
1992	17	22
1993	12	17
1994	10	34
1995	11	15
1996	10	12
1997	1	8
1998	3	17
1999	1	19
2000	1	17

Over this period, Stephenville and Hardwoods gas turbines were used for meeting system generation peak requirements, during emergency situations and for transmission security. When operated for peak requirements all customer classes were served by both gas turbines. When operated for emergency supply and for transmission security the customers in the area of the system where the unit is located would have benefited. For the Stephenville gas turbine the customers benefiting would be Abitibi Consolidated, Newfoundland Power and

Hydro Rural customers. For the Hardwoods gas turbine the customers benefiting would be North Atlantic Refining and Newfoundland Power.

3. The table below provides the number of kWh generated by each unit, the amount of fuel consumed by that unit, the cost of the fuel consumed, operating and maintenance costs and capital costs for each year from 1992 to 2000.

Stephenville Gas Turbine

	Energy Produced (Gross kWh)	Fuel Consumed (gallons)	Fuel Cost	O&M Cost	Capital Cost
1992	705,600	73,760	$99,292	$154,390	$80,437
1993	1,015,200	88,359	$110,442	$169,659	$9,321
1994	288,000	32,510	$37,994	$189,418	$0
1995	338,400	27,156	$31,321	$157,763	$0
1996	648,000	72,472	$82,438	$140,075	$0
1997	36,000	3,292	$3,715	$262,885	$0
1998	374,400	36,687	$41,397	$101,048	$16,408
1999	201,600	24,446	$27,608	$206,053	$979,631
2000	36,000	11,265	$13,877	$2,065,850	$449,443

Hardwoods Gas Turbine

	Energy Produced (Gross kWh)	Fuel Consumed (gallons)	Fuel Cost	O&M Cost	Capital Cost
1992	2,030,400	130,836	$127,384	$183,106	$0
1993	626,400	59,459	$57,826	$687,156	$0
1994	2,822,400	274,783	$257,736	$347,429	$0
1995	925,200	130,244	$120,958	$575,565	$51,095
1996	972,000	71,207	$66,130	$163,619	$319,196
1997	590,400	50,680	$47,066	$128,142	$604,268
1998	557,200	59,100	$54,886	$338,782	$111,031
1999	792,000	82,638	$76,309	$279,329	$0
2000	223,200	33,739	$34,573	$359,940	$0

Operating and maintenance costs include the gas turbine operator's salary for 1992 to 1997. For 2000, the O&M cost includes the gas turbine operator and other required labour expenses.

RE: IC-148

The annual revenue for Stephenville and Hardwoods was determined using the same methodology as IC-148. See table below.

Year	Stephenville	Hardwoods
1992	$30,370	$87,104
1993	$43,146	$26,622
1994	$12,499	$122,492
1995	$14,484	$39,599
1996	$27,929	$41,893
1997	$1,588	$26,037
1998	$17,410	$25,910
1999	$9,435	$37,066
2000	$1,634	$10,133

Q. Provide the same information as requested in questions 144-148 above for the Roddickton mini-hydro plant.

A. **RE: IC-144**

At the time of the last rate referral the Roddickton mini-hydro plant was connected to the isolated St. Anthony-Roddickton system and was specifically assigned.

RE: IC-145

At the time of the 1992 Report, the Roddickton mini-hydro was specifically assigned to Hydro Rural as part of the cost of service for all Isolated Rural Systems.

RE: IC-146

In 1992, the Roddickton mini-hydro plant was classified 50% demand-related and 50% energy-related, in accordance with the methodology approved by the Board in April, 1992. The basis for hydraulic classification was changed to system load factor following the Board's February, 1993 report.

RE: IC-147

1. The table below shows when the generating plants in question became a part of the Island Interconnected System

Generation Source	**Available to Island Interconnected System**
Roddickton Mini Hydro	September 7, 1996

2. The Roddickton mini-hydro plant is a run of river plant and is used when water is available. It automatically shuts down when there isn't sufficient water for operation. It is used only as a system energy source and displaces the energy costs at Holyrood.

3. The table below shows the kWh generated, operating and maintenance costs and capital costs from 1996 to 2000.

Roddickton Mini Hydro

	Energy Produced (Gross kWh)	O&M Costs	Capital Costs
1996	386,350	$809	
1997	845,400	$12,455	
1998	1,386,000	$3,686	$6,195
1999	1,146,000	$13,812	
2000	792,600	$18,011	

RE: IC-148

The annual revenue for Roddickton mini-hydro was determined using the same methodology as IC-148. See table below.

Year	Roddickton Mini Hydro
1996	$16,652
1997	$37,282
1998	$64,449
1999	$56,633
2000	$35,984

Q. In Hydro's 2002 Forecast Cost of Service was based on the last forty (40) years lowest historic inflow sequence experienced, would the revenue requirement change? If so, how?

A. Under the stated circumstances, hydraulic production for 2002 would decrease by 640 GWh. Thermal production would therefore increase accordingly. This would result in an increase in the total revenue requirement of approximately $20 million.

Q. Provide detailed particulars and calculations showing how a credit was applied by Hydro in favour of Newfoundland Power in respect of the Southside Steam Plant when the plant was functioning.

A. Please refer to NP-126. When the Southside Steam Plant was functioning, the Installed Thermal Capacity was 30 MW rather than 0.0 MW as is currently the case. The calculation methodology was the same except reserve was set at 18% in 1992.

Installed Capacity	(MW)
Thermal	30.0
Less 18% Reserve*	4.6
Capacity Credit	25.4

* Note - expressed as a percent of load and calculated as 30 (1-1/1.18)

Q. Explain in detail the basis for each of the estimated Specifically Assigned amounts set out in Schedule 3.3A of the Cost of Service, as well as each of the allocations to NP and each IC set out therein.

A. The detailed calculation for the Specifically Assigned amounts, by customer are attached. Note: These charges have been slightly revised from those calculated in JAB-1 due to the inadvertent omission of approximately $25,000 of plant from the customer plant ratios on JAB-1, p41.

Q. What amounts were contributed by the Industrial Customers to subsidize the cost of power provided to rural customers between January 19, 1996 and December 31, 1999?

A. Please see response to IC-8.

Q. **Impacts re: Interconnections of Isolated Rural Systems to Island Interconnected System**

1. Provide a table indicating for each year from 1992 to 2002 inclusive the following information related to interconnections of Isolated Rural Systems to the Island Interconnected System that has been undertaken during this period (based on H.G Budgell, pages 13 and 14, these include the interconnection of the Petite Forte community in 1993, St. Anthony-Roddickton System in 1996, the community of Westport in 1996, the community of South East Bight in 1998, and the community of LaPoile in 1999):

   (a) Indicate for each year the operating load (actual or forecast) applicable if the community or system is on the Isolated Rural System (for years after interconnection, this load is to be estimated); indicate sales separate from distribution losses.
   (b) Based on (a), indicate for each year the net reduction in Isolated Rural System load due to interconnections to date.
   (c) Based on (a) and (b), estimate for each year the change in Isolated Diesel System revenue requirement costs of service and contribution to the Rural Deficit due to interconnections to date.
   (d) For each year starting with interconnection, indicate the new operating load contributed to the Island Interconnected System by these each interconnection (indicate sales separately for Hydro Rural Interconnected and NP, and also indicate transmission losses separately).

(e) Based on (d), indicate for each year the net increase in Island Interconnected System load due to interconnections to date.

(f) Based on (d) and (e), estimate for each year the change in Island Interconnected System revenue requirement costs of service and contribution to the Rural Deficit due to interconnections to date.

(g) Based on (c) and (f) above, indicate for each year the net change in the Rural Deficit for that year, and (separately) any net change in the RSP for that year, due to interconnections to date.

2. Based on the information developed in response to (1) above, compare COSS estimates (including Rural Deficit) as presented in Schedule 1.2 of Exhibit JAB-1, page 3 of 94 for the 2002 test year with estimated COSS (and Rural Deficit) that would apply if none of the interconnections set out in (1) above had taken place to date. Provide all supporting schedules for the new COSS estimate.

3. Provide a COSS analysis for the Island Interconnected System for test year 2002 assuming that the Great Northern Peninsula system 138 kV and 66 kV transmission lines and associated terminal station equipment connecting the Hawkes Bay Diesel Plant, St. Anthony Diesel Plant and Roddickton generation plant to the main gird are assigned to Hydro Rural Sub-transmission rather than to Common.

4. Adjust the COSS in (3) above to assume that the generation assets in the Great Northern Peninsula system are also assigned to the rural system.

5. Provide a copy of all studies conducted by Hydro evaluating the cost effectiveness of each of the interconnections in (1) above, either before or after each interconnection.

6. In 1995, the Board recommended "that the prudence of costs associated with the St. Anthony/Roddickton interconnection be reviewed at the next Hydro rate referral, following the interconnection, for the purpose of determining recoverable costs." Provide all evidence available to Hydro as to why this interconnection was undertaken, and that the costs were prudently incurred and in the best interest of customers on the Island Interconnected System.

A. 1. (a) See IC 203A on attached table.

(b) See IC 203B on attached table.

(c) Subsequent to interconnection, costs on a hypothetical non-interconnected or isolated basis are no longer tracked, as they no longer reflect the operations nor financial situation of the company. It would not be possible to complete the requested information, as significant material data is unavailable. Moreover, the information requested is unnecessary for a satisfactory understanding of the matters regarding Hydro's application before the Board.

(d) See IC 203D on attached table.

(e) See IC 203E on attached table

(f) Please refer to the response to 1(c) above.

(g) Please refer to the response to 1(c) above.

2. Please refer to the response IC-203 1(c) above.

3. Please refer to the response to IC-180.

4. Please refer to the response to IC-87.

5. See attached Interconnection Studies as requested.

6. See attached reports.

Referenced Table for Responses to IC 203 A,B,D,&E

		1992 MWh	1993 MWh	1994 MWh	1995 MWh	1996 MWh	1997 MWh	1998 MWh	1999 MWh	2000 MWh	2001 MWh	2002 MWh	Forecast Year (Diesel)
IC 203A	System & Interconnection Year												
	Petite Forte 1993	352	382	394	405	416	428	439	451	463	475	487	1991
	St. Anthony Roddickton 1996	40411	40123	39819	39667	41417	41820	42224	42599	42974	43368	43762	1994
	Westport 1996	1294	1329	1318	1314	1326	1336	1343	1350	1354	1358	1362	1996
	South East Bight 1998	345	363	376	394	412	437	430	437	443	450	457	1996
	LaPoile 1999	452	435	446	452	472	529	528	525	521	517	509	1998
	Total Sales	42854	42632	42353	42232	44043	44550	44964	45362	45755	46168	46577	
	Distribution Losses	4607	5189	4601	4217	4771	4760	4837	4918	4961	5097	5141	
	Total Load	47461	47821	46954	46449	48814	49310	49801	50280	50716	51265	51718	
IC 203B	**Net Reduction in load**		407	420	431	47873	48344	49273	50280	50716	51265	51718	

		1993 MWh	1994 MWh	1995 MWh	1996 MWh	1997 MWh	1998 MWh	1999 MWh	2000 MWh	2001 MWh	2002 MWh
IC 203D	System & Interconnection Year										
	Petite Forte 1993	128	436	456	458	452	455	460	462	479	479
	St. Anthony Roddickton 1996				14451	42870	45203	46997	50478	51452	51983
	Westport 1996				264	1404	1417	1453	1494	1532	1548
	South East Bight 1998 1						358	518	527	535	540
	LaPoile 1999 2							533	567	667	680
	Additional Sales	128	436	456	15173	44726	47433	49961	53528	54665	55230
	Distribution Losses	21	38	36	950	3226	2707	3451	2829	3486	3527
	Additional Load	149	474	492	16123	47952	50140	53412	56357	58151	58757
	Transmission Losses 3	6	20	18	571	1688	2002	2104	2074	2122	2258
IC 203E	**Additional Load on Island Interconnected System**	155	494	510	16694	49640	52142	55516	58431	60273	61015

1. South East Bight is metered with Monkstown. Distribution losses are estimated
2. LaPoile is metered with Grand Bruit & Hope Brook. Distribution losses are estimated

Q. **NUG cost benefits for ratepayers**:

(1) Indicate the overall cost benefits to ratepayers (through reduced revenue requirements in 2002 and subsequent years) provided by each of the NUGs implemented since 1992.

(2) Indicate the forecast kWh for 2002, and actual numbers for each year to date of operation, of the generation for each NUG during the winter months (January to March and November and December) and the other months (April to October).

(3) Compare mill/kWh costs for each NUG (as set out in Schedule IX to R. J. Henderson's evidence) to costs forecast for existing thermal facilities and for other new generation options available to Hydro.

(4) Explain the basis for setting NUG charges higher in 5 winter months relative to the other months, and indicate the extent to which these differences reflect Hydro's variability in seasonal time-of-use costs.

A. (1) On a go-forward basis, the overall forecast cost benefit to ratepayers provided by Algonquin Power and the Star Lake Partnership for the period from 2002 to 2006 is shown below. The expansion plan beyond 2006 has not been finalized. The total forecast benefit is comprised of an energy component and a capacity component. The energy component is based on avoided thermal energy production including fuel and variable O&M, as produced by Hydro's generation planning model. The capacity component is based on the capital cost of a similar amount of simple cycle gas turbine capacity which is Hydro's least costly capacity alternative. In addition to these direct benefits, other benefits such as reduced emissions from Hydro's thermal plants are also derived from the NUGS contracts.

	(mills/kWh)				
		Algonquin Power		Star Lake Hydro	
Year	Avoided Costs	Project Costs	Variance	Project Costs	Variance
2002	73.5	69.8	3.6	67.9	5.5
2003	64.6	71.2	-6.5	68.5	-3.8
2004	59.0	71.9	-12.9	69.1	-10.1
2005	59.9	72.7	-12.8	69.9	-10.0
2006	63.0	73.5	-10.5	70.6	-7.6

(2) Please refer to table below:

Newfoundland & Labrador Hydro
NUGS Power Purchases

Star Lake Hydro Partnership

Actual	January to March (kWh)	April to October (kWh)	November to December (kWh)
1998	0	3,036,448	23,590,499
1999	35,357,979	79,806,714	23,623,995
2000	36,942,083	81,419,129	24,689,199
Forecast			
2001	29,181,000	76,691,000	22,129,000
2002	29,181,000	76,691,000	22,129,000

Algonquin Power (Rattle Brook) Partnership

Actual	January to March (kWh)	April to October (kWh)	November to December (kWh)
1998	0	112,056	2,502,760
1999	3,796,698	10,449,273	3,130,405
2000	2,997,733	11,431,296	3,397,398
Forecast			
2001	1,650,000	12,980,000	3,270,000
2002	1,650,000	12,980,000	3,270,000

(3) The comparison of mill/kWh costs for each NUG to forecast costs for existing thermal facilities and Granite Canal is shown below. For reasons of commercial confidentiality, Hydro cannot provide similar information for other new generation options available to Hydro.

	Mills/kWh		
	2001	2002	2004
Algonquin Power	69.8	70.6	
Star Lake Partnership	67.3	67.9	
Existing Holyrood[1]	52.9	51.0	
Existing Gas Turbine[1]	115.6	112.0	
Existing Diesel[1]	103.4	100.3	
Granite Canal[2]			54.2

[1] Costs for existing thermal plant reflect fuel and variable O&M costs
[2] Cost for Granite Canal reflects the levelized capital recovery and O&M costs for the first full year of operation.

(4) In the 1992 RFP for non-utility generation from small scale hydro projects, Hydro set a maximum price schedule for proposals whereby proponents could elect to submit those prices or an alternative lower schedule of prices.

Only the demand component of the pricing structure varied between winter and summer. The energy portion was held constant for the year. The basis for setting the demand component of the price higher for the winter months was the September 1984 study of Marginal Time of Use (TOU) Costs. That study indicated that the seasonality of load affected costs whereby the ratio of winter costs to summer costs was 1.5.

To factor seasonal TOU into avoided costs, the Loss of Load Expectation (LOLE) index was used to allocate the capacity component of costs throughout the year. This resulted in a distribution of capacity costs of 60% during November to March and 40% for the remaining months.