Q. Indicate the average energy capability of each of Hydro's hydro-electric generating stations for the years 1992 to 2002 and identify the changes to such capability associated, in each year, with the addition of the previous year's hydrological data to the long term average (and with any other changes). Explain the assumptions and derivation of Schedule III of R.J. Henderson's evidence on total system energy storage by month (minimum energy storage target and maximum energy operating level), and provide equivalent schedules for each year from 1992 to 2000.

A. The attached table on page 3 of 14 provides the average energy capability by year for each of Hydro's hydro-electric generating stations, along with the year-to-year changes in the same. A review of the annual average energy capability is made in most years but the averages are only updated when significant differences are observed. They were updated in 1993, 1996, 1998 and 2000. The tables on pages 4 and 5 of 14 provide the changes in average energy capability associated with the factors which impact its calculation as described in NP-44.

Schedule III of R.J. Henderson's evidence shows the combined energy in storage for all of Hydro's major reservoirs as compared to the minimum that should be maintained in each month, and the maximum level below which total storage must remain or water spillage must occur. The minimum levels are established by using simulations to determine the amount of energy that must be retained in storage in order to ensure that all firm loads can be met should the historical dry sequence recur. The maximum operating level represents the physical limitation of the system with respect to storage and dam safety. The physical volume of water in storage related to the maximum operating level, actual storage and minimum levels are converted to energy by applying an appropriate water to energy conversion factor. For an example of the calculations used to translate live storage into energy in storage, see demand for particular NP-46. The attached graphs show the daily energy in storage for the period 1992 to 2000. Note that until 2001, storage targets were based upon guide curve simulations. Guide curve simulations provide the levels below which maximum thermal production is required in order to meet firm loads in the event of the recurrence of the critical dry sequence. The guide curve simulations did not integrate operation of the Cat Arm and Hinds Lake reservoirs with the Bay D'Espoir river system. In 2000, Hydro implemented the Vista decision support system, which integrated all reservoir operations in the development of the minimum storage levels. Minimum storage levels developed using Vista represents the level above which total energy storage should remain, even using maximum thermal production, in order to protect against a repeat of the critical dry sequence.

Annual Average Energy Capability by Plant
1992-2000
(GWh)

	Year	Bay D'Espoir	Upper Salmon	Hinds Lake	Cat Arm	Paradise River
1992	Capability	2541	541	342	745	36.3
1993	Capability	2535	541	340	735	38.2
	Change	*-6*	*0*	*-2*	*-10*	*+1.9*
1994	Capability	2535	541	340	735	38.2
	Change	*0*	*0*	*0*	*0*	*0*
1995	Capability	2535	541	340	735	38.2
	Change	*0*	*0*	*0*	*0*	*0*
1996	Capability	2570	543	341	742	39.37
	Change	*+35*	*+2*	*+1*	*+7*	*+1.2*
1997	Capability	2570	543	341	742	39.37
	Change	*0*	*0*	*0*	*0*	*0*
1998	Capability	2587	549	339	736	39.37
	Change	*+17*	*+6*	*-2*	*-6*	*0*
1999	Capability	2587	549	339	736	39.37
	Change	*0*	*0*	*0*	*0*	*0*
2000	Capability	2598	552	340	735	39.37
	Change	*+11*	*+3*	*+1*	*-1*	*0*

Bay d'Espoir Annual Average Energy Changes

Year	Average Annual Energy	Change	Factor Causing the Change			
			Hydrological Data	Spill History	Fisheries Compensation History	Conversion Factor
		GWh	GWh	GWh	GWh	GWh
1992	2541					
1993	2535	-6	-10	4	-1	1
1996	2570	35	28	-1	-3	11
1998	2587	17	9	2	-1	7
2000	2598	11	17	-5	0	-1

Upper Salmon Annual Average Energy Changes

Year	Average Annual Energy	Change	Factor Causing the Change			
			Hydrological Data	Spill History	Fisheries Compensation History	Conversion Factor
		GWh	GWh	GWh	GWh	GWh
1992	541					
1993	541	0	-1	1	0	0
1996	543	2	4	-3	-1	2
1998	549	6	3	1	0	2
2000	552	3	3	0	0	0

Hinds Lake Annual Average Energy Changes

Year	Average Annual Energy	Change	Factor Causing the Change			
			Hydrological Data	Spill History	Fisheries Compensation History	Conversion Factor
		GWh	GWh	GWh	GWh	GWh
1992	342					
1993	340	-2	-2	0	0	0
1996	341	1	2	0	0	-1
1998	339	-2	2	0	-1	-3
2000	340	1	2	-1	0	0

Cat Arm Annual Average Energy Changes

Year	Average Annual Energy	Change	Factor Causing the Change			
			Hydrological Data	Spill History	Fisheries Compensation History	Conversion Factor
		GWh	GWh	GWh	GWh	GWh
1992	745					
1993	735	-10	-6	0	0	-4
1996	742	7	2	11	0	-6
1998	736	-6	-1	3	0	-8
2000	735	-1	2	-1	0	-2

Paradise River Annual Average Energy Changes

Year	Average Annual Energy	Change	Factor Causing the Change			
			Hydrological Data	Spill History	Fisheries Compensation History	Conversion Factor
		GWh	GWh	GWh	GWh	GWh
1992	36					
1993	38	2	0	1	0	1
1996	39	1	-1	0	0	2
1998	39	0	0	0	0	0
2000	39	0	0	0	0	0

Q. Recalculate the LOLH as shown on Schedule X of the evidence of H. G. Budgell assuming that the Corner Brook Pulp and Paper and Abitibi Consolidated hydro plants did not exist and assuming that the total load was reduced by an amount equal to the amount of load which those facilities are forecast to meet in each year.

A. Starting with the analysis upon which Schedule X is based, and then removing the Corner Brook Pulp and Paper and Abitibi Consolidated hydro plants from the overall system capability, and also reducing the total load forecast by an amount equal to the amount of load which these facilities are forecast to meet each year, results in the following LOLH indices:

Year	LOLH Hrs/yr
2001	2.86
2002	3.96
2003	4.70
2004	5.50
2005	8.48
2006	11.14
2007	15.05
2008	17.52
2009	24.37
2010	26.45

Q. Provide the 2002 Forecast Cost of Service with the Bottom Brook to Doyles - Port-aux-Basques 138 kV & 66 kV lines and associated terminal stations treated as specifically allocated rather than common.

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. For the Island Interconnected System, provide actual system load factor information in the same format as Brickhill's schedule 4.2 for each year 1992 to 2000 inclusive plus the 2001 forecast.

A. Please refer to the response to NP-128.

Q. Provide the 2002 Forecast Cost of Service assuming that the Island Interconnected System load factor was 58.14%.

A. See attached. It is important to note that the components of the system load factor – Sales plus Losses and Coincident Peak – were not adjusted. Adjustments to either of these would have consequences, within the Cost of Service, beyond the calculation of system load factor; therefore it is not possible to draw meaningful conclusions from the response to this question.

Q. Provide Holyrood capacity factor data for the five years 1996 - 2000 in the same format as in Brickhill's schedule 4.3.

A. Please refer to the response to NP-122.

Q. Provide the 2002 Forecast Cost of Service with the Holyrood capacity factor being the average for the five year period 1996-2000.

A. See attached.

Q. Provide the 2002 Forecast Cost of Service with generation demand costs allocated between rate classes by means of a 1CP allocator rather than a 2CP allocator.

A. See attached.

Q. Provide the 2002 Forecast Cost of Service assuming that the 1996 interconnection of the Great Northern Peninsula had not occurred.

A. 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.

Q. Provide the 2002 Forecast Cost of Service using the currently approved method for determining the net salvage value of utility assets.

A. There are no changes proposed to the method of determining the net salvage value of utility assets. The 2002 Forecast Cost of Service, as filed, uses the currently approved method.

Q. Provide the annual production (in gwh) for the 2002 Forecast Cost of Service for each of the hydraulic generating stations on the Island interconnected system. Use the following format:

BAY D'ESPOIR	UPPER SALMON	HINDS LAKE	CAT ARM	PARADISE RIVER	OTHER HYDRAULIC	TOTAL

A. Please refer to the response to NP-44.

Q. Provide actual costs for Newfoundland & Labrador Hydro for each of the years 1993 to 1999 inclusive in the same format as in Schedule 1 of J.C. Robert's evidence.

A. Please see response to NP-3.

Q. Provide margin and interest coverage ratios for Newfoundland and Labrador Hydro for each of the years 1992 to 2000 inclusive. Include sales of recall energy to Hydro-Quebec.

A. The following table shows the margin and interest coverage for Hydro including sales of recall energy to Hydro-Quebec.

	Margin	Interest Coverage
1992	16,249	1.12
1993	13,717	1.10
1994	8,274	1.06
1995	22,617	1.17
1996	20,127	1.15
1997	30,910	1.23
1998	51,257	1.42
1999	31,715	1.33
2000	17,296	1.18

The above includes non-regulated sales to IOCC.

Q. Provide margin and interest coverage ratios for Newfoundland and Labrador Hydro for each of the years 1992 to 2000 inclusive. Exclude sales of recall energy to Hydro-Quebec.

A. The following table shows the margin and interest coverage ratios for Hydro excluding sales of recall energy to Hydro-Quebec.

	Margin	Interest Coverage
1992	16,249	1.12
1993	13,717	1.10
1994	8,274	1.06
1995	22,617	1.17
1996	20,127	1.15
1997	30,910	1.23
1998	25,307	1.21
1999	(3,766)	0.96
2000	5,714	1.06

The above includes non-regulated sales to IOCC.

Q. Provide Hydro's debt/equity ratio for each year 1992 -2000 inclusive.

A. Please refer to response to NP-71.

Q. Reconcile the return on equity of $9,610,000 for 2002 forecast on Robert's schedule 1 line 41 with the $5,662,858 on Brickhill's schedule 1.1, page 1, line 21.

A. Please see response to NP-142.

Q. Reconcile the revenue requirement of $322,300,000 for 2002 forecast on Robert’s schedule1 line 42 with the $318,846,984 on Brickhill’s schedule 1.1. page 1, line 22.

A. Please see response to NP-1.

Q. Reconcile the difference in interest coverage ratio of 1.08 indicated in Hall's evidence page 10, line 30 and interest coverage ratio of 1.10 in Robert's evidence on page 7, line 7.

A. Please see response to NP-174.

Q. With reference to Robert's evidence page 9, lines 9 - 11, provide a copy of the 1986 KPMG depreciation study and the 1998 KPMG update study.

A. Please see response to NP-55.

Q. Reconcile the No. 6 fuel cost of $100,585,000 for 2002 forecast on Robert's schedule 1 line 6 with the $75,493,351 on Brickhill's schedule 1.1, page 1, line 2.

A. Brickhill's schedule 1.1, page 1, line 2 represents all fuels for the Holyrood Thermal Plant and the reconciliation is as follows:

No. 6 Fuel, JCR Schedule 1	$	100,584,804
Less: Rate Stabilization Plan		(25,490,222)
Additives		130,000
Indirects		54,600
Environmental Fuel Handling		102,238
Ignition		111,931
Fuels - No. 6 Fuel, JAB-1	$	75,493,351

Q. With respect to Henderson's evidence page 2, line 28, provide the calculation to show how the 59% was derived. Reconcile this data with the 4271.5 GWh referred to on Henderson's evidence page 3, line 13 and Brickhill's 6,287,568 MWh on schedule 1.3.2 page 1, line 13.

A. The 59% was determined as follows:

Hydro's Hydroelectric Average Energy Capability	4271.67 GWh
Hydro's Thermal Average Energy Capability	2996.00 GWh
Hydro's Total Average Energy Capability	7267.67 GWh

Hydroelectric Average Energy Capability as a percentage is:

$$\frac{4271.67}{7267.67} = 59\%$$

The value on line 13 of page 3 of R. J. Henderson's evidence should be 4,271.67 GWh and not 4,271.5 GWh. The increase referenced on line 14 of page 3 should be 59.77 GWh.

The 4,271.67 GWh on Henderson's evidence page 3 is the average annual energy capability of Hydro's hydroelectric plants. The 6,287,568 MWh referenced on Brickhill's evidence schedule 1.3.2 page 1, line 13 is total system energy sales. These values are unrelated.

Q. With respect to Henderson's schedule VIII, are the annual prices for No. 6 fuel oil the weighted average purchase prices taking into account the variation in monthly prices and monthly purchases? If not, provide the weighted average purchase price for each year from 2002 to 2005 inclusive.

A. The annual oil prices for No. 6 fuel oil for 2002 to 2005 are not weighted to take into account the variations in monthly prices and purchases. The PIRA Energy Group only provided annual average prices for 2002 to 2005. Monthly prices are provided only for the near term (6 to 18 months).

Q. With respect to the application, page 8, for each of the Industrial Customers, list the components that make up the Specific Allocated Charge and the amount of each component.

A. See 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.

Newfoundland and Labrador Hydro
Components of Specifically Assigned Charges

		Abitibi Grand Falls	Abitibi Stephenvill e	Corner Brook Pulp & Paper	North Atlantic Refining Limited	Total
(1)	Operating and Maintenance	64,052	19,564	48,454	32,079	164,150
(2)	Depreciation	24,349	20,093	2,734	56,070	103,245
(3)	Gain/Loss on Disposal of Fixed Assets	184	354	183	542	1,263
(4)	Return on Debt	20,836	40,062	20,691	61,262	142,851
(5)	Return on Equity	1,375	2,644	1,366	4,043	9,428
(6)	Revenue Credit Allocation:	(89)	(67)	(59)	(124)	(339)
(7)	Total Specifically Assigned Charges	110,708	82,651	73,367	153,871	420,597

Q. With reference to the Rate Stabilization Plan in Schedule A:

1. Detail all the changes from this schedule to the existing plan.

2. Since Jan. 1, 2000 how has the appropriate portion of the hydraulic variation, fuel price variation and the fuel component of the load variation been allocated to the Rural Island Interconnected Customers?

3. Since Jan 1, 2000, has any portion that may have been allocated to the Rural Island Interconnected Customers been re-allocated to the Island Industrial Customers?

4. What is the rationale for using the 12 months-to-date kWh?

5. Assuming that this allocation was in effect in 2000, provide the allocators (prior to re-allocation) for each of the three customer groups for each month in the year 2000.

6. Provide the kWh consumed by each of the three customer groups for each month in 2000.

A. 1. The Rate Stabilization Plan (RSP), as proposed with the 2001 Rate Application, includes several minor details, which are different from current practice, as follows:

a. Hydraulic Production Variation:

- Addition of mini-hydro plants to the calculation of hydraulic production variation.
- Holyrood conversion factor changed from 605 kWh/bbl to 610 kWh/bbl.

b. Load Variation:

Interruptible energy no longer included in the plan. Barrels related to this energy are also excluded from the fuel price variation calculation (along with the existing exclusion for barrels related to emergency sales).

c. Customer Splits:

RSP split no longer based on Test Year Cost of Service Study (COS); instead, 12-month-to-date invoiced / bulk transmission energy used, as well as Test Year Rural deficit allocation.

d. Rate Calculation:

Energy rates established on the same basis as split; i.e., 12-month-to-date invoiced / bulk transmission energy.

e. Other

- Finance charge changed from Hydro's embedded cost of debt to Hydro's WACC.
- RSP cap for NP of $50 million increased to $100 million.

2. Since Jan 1, 2000 the appropriate portion of the hydraulic variation, fuel price variation and the fuel component of the load variation have been allocated to the Rural Island Interconnected Customers based on the 1992 test year Cost of Service. The test year fuel expense has

been adjusted by the annual RSP activity, and the test year load data has been adjusted to agree with the annual load activity. The results of this modified test year Cost of Service determine the allocation of the annual activity to Newfoundland Power, Island Industrials, and Labrador Interconnected customers.

3. For 2000 and 2001 to date, the RSP allocations are based on the 1992 test year, as described in Question 2. Since the 1992 test year allocated deficit to the Industrial Customers, and no other test year has yet been approved by the Board, the Industrial Customers are being allocated a portion of the RSP activity attributable to the rural customers.

4. As outlined on Page 15 of Mr. Brickhill's evidence, the current COS methodological changes permit the RSP plan activity to be split based on transmission energy only. Historically, annual energy numbers were determined by using year-to-date current numbers, and test year amounts for other months. The change to 12 months to date is intended to keep customer splits throughout the year reflective of current customer load, as well as more indicative of the December split, which still uses 12 months-to-date of actual kWh.

5. See attached.

6. See attached.

2000 ALLOCATORS kWh Before allocating rural deficit, and re-allocating rural portion- Using proposed 2002 Allocations

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Newfoundland Power Co. Ltd.	4,069,413,434	4,120,685,384	4,150,173,171	4,153,531,659	4,211,085,252	4,231,868,585	4,233,823,479	4,242,667,843	4,246,896,639	4,232,968,019	4,233,301,474	4,263,083,656
Total Industrial	1,171,718,499	1,175,581,579	1,186,752,760	1,181,980,867	1,187,922,519	1,197,930,628	1,205,887,472	1,239,676,154	1,242,869,288	1,232,732,609	1,249,430,174	1,247,717,321
Bulk Rural	369,329,529	371,908,084	374,243,995	376,030,725	380,432,505	385,411,987	387,268,658	388,527,296	388,464,666	387,847,684	386,862,446	388,755,591
Total	5,610,461,462	5,668,175,047	5,711,169,926	5,711,543,251	5,779,440,276	5,815,211,200	5,826,979,609	5,870,871,293	5,878,230,593	5,853,548,312	5,869,594,094	5,899,556,568

2000 CUSTOMER kWh

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Newfoundland Power Co. Ltd.	478,521,288	455,607,415	423,053,322	351,948,474	323,010,324	265,025,188	253,832,042	253,945,829	256,527,213	323,694,696	381,364,864	496,553,001
Total Industrial	108,400,336	97,686,325	106,896,688	100,854,513	97,967,062	107,031,923	110,550,686	109,411,025	104,832,064	98,226,060	108,244,837	97,615,802
Bulk Rural	39,500,830	36,894,366	36,121,774	32,469,564	32,474,300	28,541,966	28,320,177	26,860,249	24,829,320	30,217,641	32,379,819	40,145,585
Total	626,422,454	590,188,106	566,071,784	485,272,551	453,451,686	400,599,077	392,702,905	390,217,103	386,188,597	452,138,397	521,989,520	634,314,388

Q. With reference to Well's evidence page 16, lines 20 – 21, what is the amount of the investment that the taxpayers, through the Government, has invested in each of the five systems: Island Interconnected, Labrador Interconnected, Island Isolated, Labrador Isolated and L'Anse au Loup system.

A. As per Schedule XI of J. C. Roberts prefiled testimony, Shareholder's Equity in the form of Retained Earnings, is $269,367,000 at the end of 2001 and $208,830,000 at the end of 2002. The average of $239,098,000 can be considered to be the amount that the taxpayers, through the Government, are projected to invest in total in 2002. This amount of Retained Earnings has accumulated since the inception of Hydro and a breakdown by system is not available.

Q. With reference to Well's evidence page 18, lines 18 to 21, quantify the fuel savings (in barrels and dollars) for each year 1992 to 2000 inclusive.

A. It is difficult to quantify the savings in fuel costs as a result of effective water management. However, the following describes initiatives undertaken to maximize the benefits from Hydro's water resources and at the same time improve Holyrood Plant efficiency.

In 1991, Economic Dispatch, a software routine on Hydro's Energy Management System, was implemented. Economic dispatch optimally loads hydraulic generation on-line to meet system load, increasing overall hydraulic efficiency and reducing operating costs.

Hydro, in 1995, implemented plans to reduce the amount of operating time for Holyrood generation. This effectively increases the average load and thereby the efficiency of the Holyrood units. Each summer since 1995 the Holyrood plant has been shutdown for all or part of the summer period in order to have higher unit loads while in operation.

A unit commitment program for operating Bay d'Espoir units was developed and implemented in 1999. This program lets system operators know the best commitment of Bay d'Espoir units to meet the system load. This works side by side with Economic Dispatch. Unit commitment determines the optimum number of units to place in service while economic dispatch loads in-service units optimally.

In 2000, the VISTA program was implemented. This long term water management tool optimally decides the coming week's hydro-thermal generation from historical inflow sequences and other operational inputs. This is an improvement over its predecessor which essentially simulates each of the hydraulic inflow sequences with no optimization and did not economically integrate the operation of the Cat Arm and Hinds Lake plants with the Bay d'Espoir system.

All of these tools, from long term to real time, are used to optimally dispatch hydraulic and thermal resources to meet Hydro's system load requirements, resulting in reduced production costs.

Q. With reference to Well's evidence page 18, lines 4 - 9:

1. List the expenses that Hydro considers "controllable".
2. For each of the years 1992 to 2000 inclusive, what was the actual amount these "controllable expenses"?
3. What were the actual costs for salaries and benefits for each year 1992 to 2000 inclusive?

A.

1. The expenses that Hydro considers controllable are the Other Costs shown on J.C. Roberts, Schedule I.
2. Please see response to NP-3.
3. Please see response to NP-8 (a).

Q. With regard to the Great Northern Peninsula interconnected in 1996:

1. Which customer classes benefited from the interconnection?

2. How did each benefit? Quantify the amount of benefit?

3. Did the interconnection increase the revenue requirement to any class of customers? If so, which class or classes and by how much?

A. 1. There were three customer classes that changed due to system interconnection. These were Rate 1.2 Domestic Diesel, Rate 1.23 Churches, Schools, and Community Halls, and Rate 2.5 General Service Diesel. All of these classes benefited from the interconnection.

2. The comparison between the actual 2000 revenues against the revenue at applicable diesel rates is shown in the table below.

Class	Actual 2000 Revenue	Revenue @ Diesel Rates	Difference
Rate 1.2	$2,369,848	$2,644,740	$274,892
Rate 1.23	96,281	144,361	48,080
Rate 2.5	1,397,673	4,153,091	2,755,418

3. 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.

Q. With regard to the 7.4% RSP adjustment quoted in Osmond's evidence page 3, line 3:

1. What is the 2001 Industrial RSP adjustment in mills per kWh?

2. What is the projected 2002 Industrial RSP adjustment in mills per kWh?

A. 1. The 2001 Industrial RSP adjustment is 2.8 mills per kWh.

2. The 2002 projected Industrial RSP adjustment is 5.58 mills per kWh.