Q. Provide the study supporting the recommendation of using a 2 CP allocator for generation demand cost (JAB, page 8, lines 8-29).

A. See attached report entitled “An Analysis to Determine The Relationship Between Load Factor And System Reserve Requirement”, April 2001.

Q (a) How does Hydro propose to determine excess earnings (KCM, page 56, lines 4-8)?

(b) How does Hydro propose to deal with excess earnings?

(c) Is Kathleen McShane aware of any situations where there was no limitation on a fully regulated utility's earnings or revenue? If so, please describe the situation(s).

A. (a) Because Hydro's earnings are not expected to approach a compensatory return, a specific construct for determining excess returns has not been developed. However, Hydro would anticipate that earnings in excess of a compensatory return would be measured on a utility stand-alone basis using a model similar to that used by the Board to determine excess earnings for Newfoundland Power.

(b) Since Hydro's utility earnings during the test period will not exceed a compensatory level, no specific methodology for dealing with excess earnings has been developed. In principle, however, excess earnings could be returned to customers in the subsequent year via a one-time credit to customer bills.

(c) To Ms. McShane's knowledge, in Canada, only regulators in Newfoundland and Quebec have implemented caps on earnings. In other Canadian jurisdictions, absent an incentive plan which includes an earnings sharing mechanism, all earnings in excess of the allowed return are to the account of the shareholder. The converse is also true: the risk that utility earnings will fall short of the allowed return is the shareholder’s risk.

Q. Further to NP-11 and NP-12, does Hydro have formal written policies to guide the allocation of costs to subsidiaries and the allocation of costs between regulated and non-regulated operations? If so, please provide a copy. If not, why not?.

A. Hydro presently has three subsidiaries of which two are inactive and in the case of CF(L)Co., the procedure for allocation of costs is outlined in the response to NP-11(b).

At the present time, non-regulated operations e.g., sales of recall power and Labrador Hydro project, are not complex enough to warrant formal written policies. Hydro has established practices whereby employees use timesheet reporting to allocate costs and charges are developed to cover occupancy and overhead costs. Wherever possible, suppliers' costs are charged directly to the non-regulated operation.

Q. Provide a schedule showing the ratio of the number of customers per employee for the years 1992 to 2000 (actual) and forecast 2001 and 2002. Provide both the numerator and denominator used in each annual ratio.

A. Refer to the following table:

Year	# of Customers[1]	# of Employees[2]	# of Customers per Employee
1992	32756	1012	32.4
1993	33211	1013	37.8
1994	33504	1011	33.1
1995	33728	961	35.1
1996	34165	918	37.2
1997	34355	904	38.0
1998	34555	889	38.9
1999	34847	901	38.7
2000	34917	891	39.2
2001	34991	855	40.9
2002	35138	855	41.1

[1] Includes a) Rural Customers
b) Industrial Customers
c) Newfoundland Power is included as one customer whereas they serve 215,210 customers (2000 Newfoundland Power Annual Report)

[2] Permanent employees as of December for all years except 2001 which is as of May.

Q. The Board recommended in its July 29, 1996 report '*Referral by the Lieutenant Governor in Council Concerning Rural Electrical Service'* "that preferential rates be phased out. The phase out period should be five years" (page 32). Why has Hydro not started the phase out of preferential rates?

A. Hydro did not start the phase out of preferential rates since this is Hydro's first general rate application since 1992, plus if preferential rates were phased out at this time, the magnitude of the rate increase to Isolated Rural customers, including the general increase, is considered to be significant.

In addition, Mr. Osmond in his evidence on Page 9 lines 4 to 19 outlines that "Considering the overall impact of Hydro's general rate increase on Isolated Rural Customers, combined with the projected increases for Isolated Rural Customers that would arise if all recommendations in the 1996 Report were implemented immediately, Hydro is not proposing to commence the implementation of all of these recommendations starting in 2002. As a first step however, Hydro is proposing to phase in cost based rates for Provincial and Federal Government departments and agencies as outlined in the 1996 Report. Hydro believes that it is appropriate that this rate adjustment be considered by the Board now and in the future in order to keep the rural deficit paid by Newfoundland Power customers and Hydro's Rural Customers on the Labrador Interconnected System, as low as practicable. Hydro will submit at its next Rate Application, for review and approval by the Board, a rate plan outlining alterations in rates over a maximum of five years that will address the remaining recommendations in the 1996 Report (including the phase out of preferential rates and increases in cost recovery from Isolated Rural Customers)."

Q. The current cap on the Retail Rate Stabilization Plan is $50 million.

(a) Provide the rationale for the decision to initially implement the cap and the basis for the amount of the cap established.

(b) If there is no cap in place for the Industrial Rate Stabilization Plan, explain the rationale for the decision not to implement the cap.

(c) If there is a cap on the Industrial Rate Stabilization Plan, provide the basis for the amount of the cap established.

A. (a) During the 1985 Hydro Rate Hearing, Hydro indicated rate stability was the goal of the Rate Stabilization Plan. There was a concern that the balance in the plan could reach a level beyond which its amortization would have a destabilizing effect on the consequent retail rates. Hydro proposed that it initiate an appearance before the Board if the net balance in the Rate Stabilization Plan, (applicable to retailers) reached a certain level (either positive or negative). At that appearance Hydro would propose alternative rates in light of the circumstances at that time. The amount of the cap, set in 1985, was a matter of judgment made in light of circumstances at that time.

(b) There is presently no cap in place for the Industrial portion of the Rate Stabilization Plan. It is felt that having a cap on the Newfoundland Power portion of the Rate Stabilization Plan would trigger discussion with the Public Utilities Board, which would cover issues that would impact the overall plan balance, including the Industrial portion.

(c) There is presently no cap established for the Industrial portion of the Rate Stabilization Plan.

Q. The Board recommended in its July 29, 1996 report *'Referral by the Lieutenant Governor in Council Concerning Rural Electrical Service'* "that a new rate be designed for federal and provincial departments and agencies and these rates, phased in over five years, should recover full costs" (page 32). Why has Hydro waited five years to start the phase out of government rates?

A. Any changes in rates requires approval by the Public Utilities Board during a formal hearing process. Hydro's current rate application is the first rate application that it has deemed necessary for financial reasons, to seek revisions in rates, since its last rate application in 1992.

Q. Provide a breakdown of the firm energy capability forecast in GWh by hydroelectric, thermal and energy purchases for the years 2001 to 2010 (HGB, Schedule XII).

A. A breakdown of the firm energy capability in GWh by hydroelectric, thermal and purchases for the years 2001 to 2010 is detailed in the attached table:

Newfoundland and Labrador Hydro
Island Interconnected System

		Annual Firm Energy Capability (GWh)		
	Total			
Year	(Schedule XII)	Hydroelectric	Thermal	Purchases
2001	8,275	5,172	2,996	107
2002	8,280	5,177	2,996	107
2003	8,442	5,289	2,996	157
2004	8,715	5,402	2,996	317
2005	8,715	5,402	2,996	317
2006	8,715	5,402	2,996	317
2007	8,715	5,402	2,996	317
2008	8,715	5,402	2,996	317
2009	8,715	5,402	2,996	317
2010	8,715	5,402	2,996	317

Q. Provide the calculation of the return on rate base of 9.5% (DWO, page 4, line 24).

A. Please see table below:

	PROPORTION	COST	WEIGHTED COST
Debt	60%	8.35%	5.0%
Equity	40%	11.25%	4.5%
Return on Rate Base			9.5%

Q. Provide evidence to support the statement by WEW that “commencing in 1995, Government, as shareholder, required Hydro to pay dividends”. (WEW, page 15, lines 20-21).

A. On March 23, 1995 the Government’s 1995/96 Budget was read in the legislature, and contained the following statement:

“Mr. Speaker, Newfoundland and Labrador Hydro will pay the people of the Province a return on their investment in the electrical industry. Accordingly, Government will receive an annual dividend, starting in 1995-96. In the initial year, this dividend will be $19.6 million. The major portion of this dividend represents profits earned by Hydro on its electrical sales throughout Newfoundland and Labrador. The balance represents that part of the annual dividend, which Hydro receives from Churchill Falls (Labrador) Corporation which is in excess of Hydro’s cost of servicing the debt related to the purchase of shares in that corporation.”

Q. Treat the $26.2 million subsidy as a component of return on equity rather than an allocation of the deficit between classes of customers and recalculate return on equity as a percentage from 1992 to 2000 and forecast for 2001 and 2002.

A. As requested, the attached schedule shows the calculation of return on equity if a $26.2 million subsidy were treated as a component of return on equity.

Q. The Board stated in its October 10, 1995 report "*Referral by the Lieutenant Governor in Council Concerning Rural Electrical Service*": "The surcharge upon Hydro's customers is financially and economically equivalent to a hidden tax upon a single commodity, namely electricity" (page 175, item 4). Given the above statement, how does Hydro reconcile the evidence of D.G. Hall, page 12, line 26, which appears to be contrary to the Board's previous ruling.

A. In a subsequent July 29, 1996 report "Referral by the Lieutenant Governor in Council Concerning Rural Electrical Service", the Board revisited this matter and stated: "Government has determined its policy whereby a cross-subsidy by ratepayers, with the phasing out of industrial customers by December 31, 1999, will be implemented. This determination precludes further investigation and consideration by the Board. Therefore, the Board is making no recommendation on the issue of funding."

We believe that these statements supersede those to which you refer.

Q. For each of the years 1992-2000 provide a comparison of budget vs. actual capital expenditures by project, and explain any individual project variances greater than $50,000.

A. Please refer to NP-97 which provides the 1992-2000 comparison of budget vs. actual by asset class. Individual project variances greater than $50,000 have been provided to PUB as part of the Year-End Capital Expenditure Reports from 1996 to 2000. Copies of these reports, as filed with PUB, are attached. Hydro was not required to file these same reports for the years 1992 to 1995, and did not prepare such reports. Therefore the explanations of variances for those years are not available.

Q. With regard to Hydro's budget and control processes:

a) What process is followed to develop the capital and operating budgets?

b) Does Hydro calculate variances or expected variances from its capital and operating budgets? If so, how frequently is it done?

c) If variances are calculated, who are they reported to?

d) Who is responsible for dealing with the variances?

e) What action is taken when variances are identified?

A. a) The process followed to develop the capital and operating budgets is outlined on Pages 3 to 6.

b) Variances related to Capital are calculated on a monthly basis. Variances related to Operating are reported on a monthly basis by means of a comparison to the latest operating forecast which is prepared as required and also on a mandatory basis twice a year, once during the preparation of the annual budget and again in October.

c) Capital variances are reported monthly to the Project Managers. Operating variances are reported monthly to the Directors and Vice-Presidents and CEO.

d) The Project Managers are responsible for Capital variances. The Business Unit Managers, Asset Managers, Directors and V/P's are all responsible for dealing with Operating variances.

e) When Capital variances are identified, appropriate action is taken and if necessary a Change Order issued and a reforecast prepared for review and approval by the appropriate levels of management.

When Operating variances are identified, appropriate action is taken and if necessary a reforecast is requested from the applicable Business Unit Manager who is required to submit a reforecast of operating expenditure with appropriate approvals if the annual expense is going to be greater than or less than the previous forecast.

Capital Budgeting Process:

The Capital budgeting process within Hydro is a very intensive and essential process that involves the input of supervisory personnel with budgetary responsibility all the way through each level of Management until it is eventually approved by Hydro's Board of Directors before being forwarded to the Public Utilities Board for approval. This process spans approximately nine months, from start to finish and involves the review and evaluation of every capital budget proposal that is prepared, to determine if it should move forward for approval to the next level of supervision.

The first step is for supervisory personnel to review their requirements with the regional managers and plant managers to identify potential projects that meet the criteria for "Capital" expenditure. Examples of these requirements would be:

a) Purchases of new equipment that have a useful service life that is expected to extend over several years.
b) Replacement of units of property (e.g. A diesel engine, vehicle, transformer, etc.).
c) Major upgrading of transmission or distribution systems.
d) Construction of generating plants.
e) Payments for feasibility studies and environmental assessments.

Once these requirements are identified, the various directors undertake a review of the individual proposals (usually in March) of the dollar estimates. Projects are assessed based on the following criteria:

i. To protect human life;
ii. To prevent imminent interruption of service to customers;
iii. To protect Hydro's assets against loss or damage;
iv. To maintain power system reliability and availability;
v. To comply with pertinent regulations, standards, etc. and environmental standards;
vi. To meet projected customer load demand; and,
vii. To reduce costs and improve efficiency.

These capital plans are prepared to cover the budget year in question as well as estimates for four subsequent years. After the directors finish their review, and revisions made, the proposals are further reviewed by the Vice-President of each Division, then, in May, the Management Committee does its review and reassesses each proposal according to the criteria listed above.

The Management Committee refers to the four subsequent year estimates as an indicator of future dollars to be spent and considers this information in assessing the current capital budget year dollars under review. After Management Committee has reviewed the capital budget it is then forwarded to the Hydro Board of Directors for their review and approval. This normally takes place in September or early October. After Board approval is received, the capital budget is then forwarded to the Public Utilities Board for public review and approval.

<u>Operating Budget Process</u>

The basic budget reporting unit is called a Business Unit. In total, there are approximately 150 Business Units, which need to be budgeted. A budget is prepared on each of these units on an account-by-account basis.

The operating budget process normally begins in March of each year when a detailed set of budget instructions is forwarded to all Directors and Managers by the Controllers Department. Each area has approximately 4 weeks to prepare their budgets.

Operating Costs – The process of budgeting for operating costs uses the JD Edwards system. On-line access to the system is available to all areas and as a result much of the budget process is being de-centralized by having staff in the areas prepare their budgets and then input the information on-line to the JD Edwards system. Budget department staff assists in the process by giving direction and guidance.

Once all the data has been input, reports are prepared for review at different levels of responsibility up to and including the Management Committee, which normally takes place in June of each year.

Load, Fuel and Power Purchase Forecasts - The short-term load forecast is received from Systems Planning department in May. Using existing rates, the preliminary revenue figure is obtained. The hydraulic/thermal split and related fuel information is received from the Operations department in early June. All information on fuel, load, and revenue is input to the Rate Stabilization Plan (RSP). The final output is the finalized fuel budget (net of recoveries through the RSP) and the finalized load forecast.

Power purchase estimates are provided to the Budgeting department in June by the Operations Planning department. These estimates are based on the latest load forecast for Labrador, the contract for recall of power from CF(L)Co, and current non-utility generators (NUGS) contracts.

Depreciation Budget - Based on the latest capital budget and the most recent information regarding work in process and estimates of in-service dates, the Plant Ledger department will prepare the Depreciation expense budget by mid-June.

Revenue / Interest Budget - The load forecast generated above is then computed at the existing approved PUB rates to determine the revenue budget. Based on the operating costs and fuel budgets, a monthly cash flow forecast is prepared which is provided to the Treasury Department for input to an interest model. Information regarding existing debt and future borrowing requirements are also inputs to the model. The output of the model is an interest expense budget and an estimate of the debt guarantee fee.

Review & Approval - All elements of the operating budget are now combined. At this point, a final budgeted net income statement and budgeted balance sheet is prepared for review by the Management Committee in September of each year.

During the Management Committee review, further clarification may be required on various items. Explanations are provided by the Budget Department. Any revisions to the budget as a result of the Management Committee review are then made.

The operating and capital budgets are combined at this point, and are presented to the Board of Directors for review and approval in October of each year. Once the Board has approved the budget, a copy is sent to the Minister of Energy.

Q. Section 80 of the *Public Utilities Act* states that a utility “is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board”. In Hydro’s opinion, would Section 80 allow rates to be set using an interest coverage model? If not, why not (KCM, page 27, lines 10-18)?

A. No. “Just and reasonable” return is typically estimated by reference to three standards. Ability to attract capital on reasonable terms; maintenance of creditworthiness; and opportunity to earn returns commensurate with those of alternative investments of comparable risk. An interest coverage model does not address the third standard at all, and the first only in a narrow sense. Interest coverage can be one test of whether the return allowed is just and reasonable, but it cannot be the point of departure for estimating a just and reasonable return.

Q. Provide the PUB Order which is relied upon at WEW, page 3, lines 19-22 which states “That portion of the costs previously paid by Hydro’s Island Industrial Customers for the rural subsidy must be allocated to Hydro’s other customers by Order of the Board”.

A. The statement is not intended to refer to an existing Order of the Board. It refers to the fact that the costs, previously paid by Hydro’s Island Industrial Customers for the rural subsidy, may only be allocated to other customers of Hydro by the Public Utilities Board. This is one of the subject matters of the Application, which is to be dealt with by the Board.

Q. Provide details of the determination of the rate proposed for Interruptible A, Emergency Power and Exceptional Power (PRH, Schedule I).

A. The demand charge portion of the Industrial Non-firm Rate is not a specifically calculated, cost-based charge. Rather it is a charge to reflect some value of the generation plant in place to provide the non-firm service. The calculation below reflects the demand related production costs adjusted to remove a portion of the cost that is representative of the cost of providing the reserve margin associated with providing firm supply. The actual rate being proposed is $1.50 as it reflects a reasonable value in light of the calculation below. The energy charge portion is to recover the fuel related costs of providing the non-firm energy.

	Production Demand Costs		
	Hydraulic	Thermal	Total
Depreciation Expense per COS Sch. 2.5A			
Production	$ 1,301,396	$ 2,974,974	$ 4,276,370
Trans/Term Stations	351,186	198,108	549,294
Sub-Total			$ 4,825,664
O&M Expenses per COS Sch. 2.4A			
Production	$ 3,013,873	$ 10,733,870	$ 13,747,743
Trans/Term Stations	625,417	287,370	912,787
Overheads			11,401,822
Sub-Total			$ 26,062,352
Total			$ 30,888,016
System Firm Peak (kW) per COS Sch. 4.2			1,259,335
Average annual cost per kW			$ 24.53
Reserve Adj @ 18.5% per kW			(4.54)
Net Annual Cost per kW			$ 19.99
Net Monthly Cost per kW			$ 1.67