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	70.6	2.9	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.