Q. Using the format of Table 1, Reserve Calculation Summary, please provide two additional tables; the first showing what the Reserve Calculation Summary would have been if the PPUCVR had been retained and the ESCVA and DMI had not been implemented (i.e., the supply cost variance calculation for the years 2005 through 2008 based on the PPUCVR for all years); the second showing what the Reserve Calculation Summary would have been if the PPUCVR had been replaced by the ESCVA and DMI prior to 2005 (i.e., the supply cost variance calculation for the years 2005 through 2008 based on the DMI for all years).

A. *1. Background*

Prior to 2005

Prior to 2005, Newfoundland Power's electricity supply from Newfoundland and Labrador Hydro ("Hydro") was priced on an energy-only basis. The rate consisted of a single ¢ per kWh price that applied to all purchases from Hydro. Therefore, there was no variability in the *unit cost* of purchased power as a result of variability in peak demand requirements or energy purchases.

Consequently, prior to 2005, no reserve mechanisms were required or existed to deal with unit cost variances in supply costs.

Changes to Wholesale Pricing Structure

In Order No. P.U. 44 (2004), the Board approved a demand and energy wholesale pricing structure for Hydro's electricity supply to Newfoundland Power. The pricing structure included a demand charge and a two-block energy charge with the second block priced to reflect Hydro's production costs at its Holyrood facility. This pricing structure was intended to provide an incentive to Newfoundland Power to take reasonable actions to minimize peak demand requirements of its customers.

To mitigate the risk of insufficient recovery of Newfoundland Power's supply costs under the new pricing structure, the Board approved the creation of the Purchased Power Unit Cost Variance Reserve ("PPUCVR"). The PPUCVR effectively captured variances in supply costs that resulted from variances from the *forecast* unit cost of supply that were in excess of 1% of Newfoundland Power's demand supply costs ($588,000 in 2005). For the purposes of determining if transfers to the PPUCVR were required, the forecast unit cost of supply was updated annually.

Change in System Cost Dynamics

In January 2007, the 2nd block of the wholesale energy rate from Newfoundland Hydro increased from 4.7¢ per kWh to 8.805¢ per kWh (the "Marginal Energy Supply Cost"). The increased Marginal Energy Supply Cost was the result of higher fuel costs related to production at Holyrood.

This increase in the Marginal Energy Supply Cost resulted in a dramatic increase in the cost to Newfoundland Power to supply annual increases in customer load, which primarily result from the addition of new customers.

The change in wholesale energy cost dynamics resulted in the cost to Newfoundland Power of additional energy purchases exceeding the average energy supply cost reflected in customer rates ("the Average Energy Supply Cost").

Required Changes to Mechanism
To ensure reasonable recovery by Newfoundland Power of prudently incurred energy supply costs, the Board, in Order No. P.U. 32 (2007), approved a change to the Rate Stabilization Clause to provide for the recovery of the difference between the Marginal Energy Supply Cost and the Average Energy Supply Cost (the "Energy Supply Cost Variance") for the period 2008 to 2010. Transfers to the Rate Stabilization Account ("RSA") for recovery of the Energy Supply Cost Variance ("ESCV") are calculated based upon annual variances in purchases from *test year*.

The approval of the ESCV effectively established the unit cost of energy supply for Newfoundland Power as a fixed ¢ per kWh cost (i.e., the Average Energy Supply Cost) until there is either a change in Hydro's wholesale rate or an approval of a new test year.

The PPUCVR was not designed to deal with the supply cost dynamics on the system created by the January 2007 increase in the Marginal Energy Supply Cost. To ensure transparency and avoid duplication with the ESCV, the Board approved the Demand Management Incentive Account ("DMI") to replace the PPUCVR in dealing with demand supply cost variability.

The DMI isolated demand cost variability and provided greater transparency of impacts of the Company's efforts to reduce peak demand. Transfers resulting from the operation of the DMI are calculated based upon annual variances from *test year* unit demand supply cost whereas transfers to the PPUCVR were based on variances from the *forecast* annual unit cost of supply.

Conclusion
The differences in the purpose and the mechanics of the reserves impact the comparability of the reserve transfers resulting from the operation of the PPUCVR, on the one hand, and the combined operation of the ESCV and DMI, on the other hand.

Prior to 2005, Newfoundland Power was subject to the financial impacts of variances from forecast (i.e., the net impact of changes in revenues and supply costs). The demand and energy wholesale pricing structure, in combination with the reserves that have been implemented since that time; have effectively served to *increase* the financial impacts of supply cost variances by ±1% of annual wholesale demand costs.

2. Response

Table 1 provides a *pro forma* Reserve Calculation Summary if the PPUCVR had been in use for the years 2005 through 2008.

Table 1
Pro Forma Reserve Calculation Summary
PPUCVR 2005 – 2008
($000s)

	2005	2006	2007	2008
Purchased Power Unit Cost Variance[1]	(439)	(2,779)	(1,003)	(1,577)
Company (Savings) Cost[2]	(439)	(714)	(521)	(529)
Customer (Savings) Cost	-	(2,065)	(482)	(1,048)

This request for information asks for a second table showing what the Reserve Calculation Summary would have been if the PPUCVR had been replaced by the ESCV and the DMI *prior to 2005*. As described in the Background to this response the Company observes that prior to 2005 no variance in supply costs would be captured by the PPUCVR, the ESCV, or the DMI. Therefore, Table 2 only deals with the period since the implementation of the wholesale demand and energy rate.

[1] The Purchase Power Unit Cost Variance is determined relative to forecast unit supply cost. The forecast used is the demand and energy forecast prepared by Newfoundland Power in the previous year and used in preparing the Company's Capital Budget Application or a General Rate Application, whichever is most appropriate.

[2] Excludes income tax effects.

Table 2 provides a *pro forma* Reserve Calculation Summary assuming the ESCV mechanism and the DMI mechanism had been in use for the years 2005 through 2008.

Table 2
Pro forma Reserve Calculation Summary
DMI and ESCV
($000s)

	2005	**2006**	**2007**	**2008**
Energy Supply Cost Variance[3]	699	990	2,310	(389)
Demand Supply Cost Variance[4]	(1,169)	(2,243)	(2,707)	(1,170)
Total Variance	(470)	(1,253)	(397)	(1,559)
Company (Savings) Cost[5]				
Demand Management Incentive	(588)	(714)	(521)	(529)
Customer (Savings) Cost				
Demand Supply Cost Share	(581)	(1,529)	(2,186)	(641)
Energy Supply Cost Variance	699	990	2,310	(389)
Total (Savings) Cost	118	(539)	124	(1,030)

Comparison of Table 1 and Table 2 illustrates the difference and similarities between the operation of the PPUCVR and its replacement with the ESCVR and the DMI.

For 2008, Table 1 shows that if the PPUCVR had been in place, the Purchased Power Unit Cost Variance would have been ($1,577,000). This is essentially the same variance as the Total Variance for the combined operation of the ESCV and DMI from Table 2 of ($1,559,000).[6] The results are equivalent because the annual forecast used in the operation of the PPUCVR for 2008 is the same as the 2008 test year forecast used in the operation of the ESCV and DMI.

For 2005 to 2007, the Purchased Power Unit Cost Variances in Table 1 differ from the Total Variances in Table 2. These differences are primarily due to the Purchased Power Unit Cost Variance being determined relative to an annual forecast whereas the Total Variances resulting from the operation of the DMI and the ESCV were determined relative to the 2004 test year. Essentially, as described in the background to this response, the Total

[3] The Energy Supply Cost Variance is determined relative to test year unit supply cost. For 2005 through 2007 the reference test year was the 2004 test year. For 2008, the reference test year was 2008.

[4] The Demand Supply Cost Variance is determined relative to test year. For 2005 through 2007 the reference test year was the 2004 test year. For 2008, the reference test year was 2008.

[5] Excludes income tax effects.

[6] The difference between the ($1,577,000) 2008 Purchased Power Unit Cost Variance in Table 1 and the ($1,559,000) 2008 Total Variance in Table 2 is the result of rounding within the operation of the reserves.

Variance for the ESCV and the DMI captures the impact of load growth year-over year while the Purchased Power Unit Cost Variance did not.

The sharing of the variances between customers and the Company is also different between the PPUCVR and the combined effect of the ESCV and DMI. For 2005, the Purchased Power Unit Cost Variance in Table 1 of ($439,000) is very similar amount to the Total Variance in Table 2 of ($470,000). However, the sharing of the variance in Table 1 shows the Company incurring the full variance of ($439,000), while in Table 2 the Company incurs a variance of ($588,000) and customer effects are a total of $118,000. This difference reflects that the PPUCVR was replaced by two mechanisms, one which provides recovery of prudently incurred energy supply costs and the other which provides an incentive to manage peak demand.