PRODUCTION FORECAST AND METHODOLOGY – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides the production forecasts for the regulated hydroelectric facilities and a description of the methodology used to derive the forecasts. It also presents an overview of outage planning for the regulated hydroelectric facilities.

2.0 REGULATED HYDROELECTRIC PRODUCTION FORECAST

The regulated hydroelectric production for the years 2007 - 2012 is presented in Ex. E1-T1-S1 Table 1. OPG is seeking approval of a test period production forecast of 38.4 TWh (19.4 TWh in 2011, and 19.0 TWh in 2012) for the regulated hydroelectric facilities.

2.1 Forecast Methodology

The regulated hydroelectric production forecast is impacted by water availability. OPG seeks to optimize the use of available water while meeting safety, legal, environmental, and operational requirements. The availability of water is affected by meteorological conditions, particularly precipitation and evaporation. The forecast methodology accounts for operational strategies that attempt to maximize use of available water and minimize spill (unutilized water flow).

Computer models are used to derive flow and production forecasts for the regulated hydroelectric facilities. Forecast monthly water flows, generating unit efficiency ratings, and planned outage information are used to convert forecast water availability into forecast energy production.

With the exception of the change highlighted in section 2.5, the regulated hydroelectric production forecast methodology is essentially the same as the methodology that was approved by the OEB in EB-2007-0905.

2.2 Niagara River Flow and Production Forecast

Forecast water levels and outflows for Lake Huron, Lake St. Clair, and Lake Erie are derived by OPG using the Hydrological Response Model for the Great Lakes, developed by the Great Lakes Environmental Research Laboratory.

Input parameters to this model include:

- "Starting" elevations for Lakes Huron, St. Clair, and Erie based on current month end elevation estimates.
- Default median values for hydrological parameters based on historic data, antecedent conditions, and forecast data from Environment Canada and the U.S. National Oceanic and Atmospheric Administration ("NOAA"). These parameters include basin precipitation, runoff, and lake evaporation for Lakes Michigan, Huron, St. Clair, and Erie flows for the St. Mary's River (Lake Superior outflow), Chicago Diversion, and Welland Canal, and factors to account for the impact of ice retardation on the flow in the St. Clair, Detroit, and Niagara Rivers.

The model produces monthly average water level and outflow forecasts for Lakes Huron, St. Clair, and Erie. The Lake Erie water level and outflow forecast produced by the model is compared with the six-month advance forecast produced by Environment Canada as a consistency check.

Minor adjustments are applied to the forecast monthly Lake Erie outflows, as produced by the Great Lakes Hydrological Response Model, to determine the Grass Island Pool inflow forecast. The Grass Island Pool is the section of the Niagara River immediately above Niagara Falls. Water used by OPG for power production at Niagara is diverted from the river in this area. These adjustments account for seasonal variations in local inflow, and flow reductions due to ice or weed retardation effects. The OPG Grass Island Pool inflow forecast is compared with one produced by the New York Power Authority ("NYPA") as a consistency check. Because of the increasing uncertainty associated with predicting natural systems over time, forecasts for periods beyond two years assume that water availability trends back towards historic monthly medians. This assumption reflects historical trends.

In addition to the forecast monthly Grass Island Pool inflows, flows diverted to the DeCew Falls stations, seasonal restrictions for the Beck waterways, the NYPA's diversion and discharge capacities, and unit availability information for the Sir Adam Beck plants (Sir Adam Beck I, Sir Adam Beck II, and Sir Adam Beck Pump Generating Station), are used in the forecasting of the energy production for the Sir Adam Beck plants in the Niagara Utilization Model – Monthly. Other factors that may be adjusted in the Niagara forecasting application, if necessary, include Lake Ontario water levels, Grass Island Pool leakage level, pump generating station operating patterns, and the Sir Adam Beck 25 cycle system load (to April 2009 only). These adjustments are applied based on regularly updated historical records, and are used to improve forecast accuracy.

The Niagara energy forecasting model uses generating unit efficiency ratings to calculate monthly energy production for the Sir Adam Beck units based on the forecast flow and unit outage information. Based on an assessment of historical performance, the calculated production forecast values are modified to account for losses attributed primarily to automatic generation control, condense-mode operations, and surplus baseload generation.

Potential water transactions with NYPA are also computed in the forecasting application, with adjustments applied based on assessment of historical performance with respect to transactions (see Ex. G1-T1-S1 for a discussion of water transactions). However, the energy associated with potential water transactions is excluded from the production totals presented in the table accompanying this exhibit (Ex. E1-T1-S1 Table 1) because:

- there is no obligation for NYPA to accept water transactions, and
- energy produced by NYPA is delivered to the New York market, not the Ontario market.

Under an agreement between OPG and FortisOntario Inc., energy was returned to FortisOntario (formerly Canadian Niagara Power) as compensation for the utilization of the FortisOntario Niagara water entitlement at the Sir Adam Beck stations. The returned energy attributed to FortisOntario is equivalent to over 650 GWh annually, and was included as part of the total Niagara energy forecast. It is itemized separately in the tables within this exhibit.

This agreement terminated on April 30, 2009 consistent with the expiry of the FortisOntario water lease, after which OPG assumed the water entitlement.

2.3 DeCew Falls Diversion Flow and Production Forecast

The DeCew Falls stations use water diverted from Lake Erie through the Welland Canal to produce electricity. Forecasts of diversion through the Welland Canal are prepared based on actual historical diversion flows, forecast Lake Erie water levels, outages planned for the DeCew plants, scheduled rowing regatta events (OPG adjusts its water use to provide appropriate conditions for major events), and St. Lawrence Seaway Management Corporation navigation needs and plans for canal maintenance.

Energy production forecasts for DeCew Falls I and II are made using a spreadsheet application known as Rivmonth. It uses forecast monthly DeCew Falls diversion flow, DeCew Falls unit availability information based on planned outages, and generating unit efficiency ratings to calculate the combined monthly energy production for the DeCew Falls stations.

2.4 St. Lawrence River Flow and Saunders Production Forecast

Lake Ontario and the St. Lawrence River outflows and levels are regulated by the International St. Lawrence River Board of Control. The International St. Lawrence River Board of Control has established plans to provide for artificial control of the outflows and levels of Lake Ontario to satisfy the various interests that were identified at the time of the plans' development. Each of these plans involves a model that determines the regulated Lake Ontario outflow and level. The International St. Lawrence River Board of Control currently has the authority to deviate from the approved plan under specific conditions.

The initial plan for the regulation of the levels and outflows of Lake Ontario (Plan 1958-A) was implemented in April 1960. Following further studies and several years of operating experience, a second plan, "Regulation Plan 1958-D", was implemented in 1963 and continues in use today. This plan has been reviewed by the International Joint Commission ("IJC") in recent years and the IJC has "concluded that regulation should be based on a revised set of goals and criteria aimed at more natural flows while respecting other interests" (reference IJC website, www.ijc.org) Consultations between the Commission and the Canadian and United States governments are ongoing.

Forecast monthly flow and Lake Ontario levels derived from the Regulation Plan 1958-D model are compared with values produced by each of Environment Canada (Great Lakes – St. Lawrence Regulation Office) and NYPA, as a consistency check. When knowledge of International St. Lawrence River Board of Control plans and strategies that will result in deviations from plan is available, adjustments are applied to reflect this information. Forecast monthly flow and level values are input to the Rivmonth energy production spreadsheet application for up to the first six months of the forecast period. Thereafter, the forecast monthly flows are estimated to be consistent with flow trends predicted by the Niagara River forecast. The R.H. Saunders generating unit efficiency ratings and planned major outages are also incorporated in the Rivmonth application.

2.5 Forecast Surplus Baseload Generation Adjustment

Surplus baseload generation ("SBG") is a condition that occurs when electricity production from baseload facilities is greater than Ontario demand. During 2009, SBG was more prevalent in Ontario than it has been for many years. Increased SBG was due to reduced electricity demand resulting from depressed economic conditions and relatively moderate temperatures, as well as an increase in available electricity supply. Typically, production at Niagara is reduced during periods of SBG when water available for generation at the Beck plants may be rejected and spilled over the Falls because the generation is not required. As indicated in section 2.2, the forecast production values for Niagara are modified to account for reduced production attributable to system operational conditions, including condense-mode operations, the provision of automatic generation control and operating reserve, etc., based on an assessment of historical performance (i.e., representative of typical or normal system conditions). However, this model adjustment did not adequately account for the decreased production attributable to SBG experienced in 2009.

Significant SBG is forecast to continue through the test period based on Ontario electricity demand and generation supply forecasts. Consequently, an additional forecast SBG adjustment has been integrated into the regulated hydroelectric production forecast totals for 2010, 2011, and 2012, and itemized separately in line 21 of Ex. E1-T1-S2 Table 1. The specific SBG adjustments included in the forecast are: 0.2 TWh in 2010, 0.5 TWh in 2011, and 0.8 TWh in 2012.

3.0 OUTAGE PLANNING

Outage planning for OPG's hydroelectric generating stations is based on a streamlined reliability centered maintenance philosophy as described in Ex. A1-T4-S2.

Outages are generally planned to conduct:

- Major overhaul, rehabilitation or upgrade work
- Preventative maintenance
- Condition based maintenance
- Inspection and testing

The normal cyclical patterns of river flow within a year are considered when scheduling outages in order to minimize the spilling of water.

At the Niagara Plant Group, a consistent base maintenance program (utilizing streamlined reliability centred maintenance principles) is used except for major overhauls or upgrades. At Sir Adam Beck I, eight of the ten generating units (all at 60 cycle) are currently available for service. The two remaining units (25 cycle) were deregistered at the end of April 2009. OPG plans to undertake major rehabilitation on three of the Sir Adam Beck I units during the current business plan period. This will impact unit availability. The six pump/generating units at Sir Adam Beck Pump Generating Station were rehabilitated within the past 12 years, which has improved unit reliability. However, to maintain a reasonable level of reliability, more frequent corrective maintenance is required on these reversible pump generators than on conventional units. This is because of the complexity of the reversible pump generators compared to conventional hydroelectric turbine/generators and the increased wear and tear associated with the frequent stops and starts required for storage and peaking. Extended outages are planned for four of the reversible pump generators over the next five years as further described in Ex. F1-T3-S3.

DeCew Falls I was removed from service in December 2008 for penstock replacement and the four units are expected to return to service between July 2010 and April 2011

The outage plan for R.H. Saunders is fairly consistent from year to year. Maintenance outages are scheduled on four units each year, thereby completing inspections and maintenance on each of the 16 units over a four year period. Outages requiring more than two units to be out-of-service simultaneously (e.g., transformer bank outages and black start tests), are typically of short duration (less than three days) and normally scheduled during the fall when St. Lawrence river flows are typically at their lowest. In general, outages do not significantly impact production at R.H. Saunders.

Numbers may not add due to rounding.

Table 1
Production Trend - Regulated Hydroelectric (TWh)

Line No.	Prescribed Facility	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Niagara Plant Group**	11.5	12.0	12.3	12.4	12.4	12.1
2	**Saunders GS**[1]	6.7	7.0	7.1	6.9	7.0	7.0
3	**Total**	18.2	19.0	19.4	19.3	19.4	19.0

	Other:						
4	**CNP Generation**[2]	(0.7)	(0.7)	(0.2)	0.0	0.0	0.0

Notes:
1 Saunders values represent total station production (including energy delivered to HQ).
2 CNP (Canadian Niagara Power) Generation is included in the Niagara Plant Group total production.

COMPARISON OF PRODUCTION FORECAST – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of regulated hydroelectric production, as well as actual versus forecast comparisons for historical years. This evidence supports the approval of the regulated hydroelectric production forecast presented in Ex. E1-T1-S1.

2.0 PERIOD-OVER-PERIOD EXPLANATIONS – TEST PERIOD

As noted in Ex. E1-T1-S1, section 2.5, a forecast surplus baseload generation ("SBG") adjustment has been included in the regulated hydroelectric production totals for the bridge year and test period to account for expected production losses associated with SBG. Surplus baseload generation became significant in Ontario in 2009 and is expected to continue during 2010, 2011, and 2012. The forecast SBG adjustment is presented on line 21 of Ex. E1-T1-S2 Table 1.

2012 Plan versus 2011 Plan

The total regulated hydroelectric production forecast for 2012 is 2 per cent (0.3 TWh) lower than the forecast for 2011 (see Ex. E1-T1-S2 Table 1). This decrease in forecast production is primarily attributable to an increase in forecast SBG in 2012 at the Sir Adam Beck plants.

Flow forecasts for the Niagara and St. Lawrence Rivers are similar (within 1 per cent) for the two years.

2011 Plan versus 2010 Budget

The total regulated hydroelectric production plan for 2011 is very similar to the production plan for 2010 (see Ex. E1-T1-S2 Table 1).

Slightly more production is forecast for the Sir Adam Beck plants (0.2 TWh) and DeCew Falls (0.1 TWh) for 2011, but this increase is offset by reductions in production due to impacts of forecast SBG at the Beck plants in 2011. The slight increase in production forecast for the Sir Adam Beck plants in 2011 is attributable to a marginal increase (just over 1 per cent) in forecast Niagara River flows for 2011. Increased production at DeCew Falls for 2011 is due to an increase in unit availability expected for DeCew Falls I during 2011. DeCew Falls I was removed from service in December 2008 for penstock replacement and the four units are expected to return to service between July 2010 and April 2011.

Production forecast for R.H. Saunders for 2011 is similar to 2010 (increase of less than 1 per cent). St. Lawrence River flows forecast for 2011 are marginally higher (just over 1 per cent) than those forecast for 2010.

3.0 PERIOD-OVER-PERIOD EXPLANATIONS – BRIDGE YEAR

2010 Budget versus 2009 Actual

The total regulated hydroelectric production forecast for 2010 is marginally lower (less than 0.1 TWh) than the actual production for 2009 (see Ex. E1-T1-S2 Table 1).

Production forecast for the Niagara Plant Group for 2010 is expected to be similar to that achieved in 2009. A slight increase in production (about 3 per cent) is expected at DeCew Falls in 2010 compared to 2009, due to the planned return to service of two DeCew Falls I units during the third quarter of 2010. Production at the Sir Adam Beck plants for 2010 is forecast to be similar to 2009.

The production plan at R.H. Saunders for 2010 is more than 2 per cent (0.2 TWh) lower than actual production for 2009. The reduction in production for 2010 is attributable to a forecast decrease in St. Lawrence River flows for 2010. The annual mean flow forecast for 2010 is about 2 per cent lower that the annual mean flow for 2009.

4.0 PERIOD-OVER-PERIOD EXPLANATIONS – HISTORICAL PERIOD

OPG has included information in E1-T1-S2 Table 1 to illustrate OPG's performance in forecasting production for the regulated hydroelectric facilities. The table presents the "imputed generation" for the historical years. Imputed generation is the production value produced by running the forecast model using actual water flows as inputs (replacing the forecast flows) with all other input variables remaining the same. In essence, the imputed generation shows what the regulated hydroelectric production forecast would have been if the water flows for a given year were known in advance. Imputed generation values are shown at lines 5, 12 and 19 of Ex. E1-T1-S2 Table 1. Actual and imputed generation values tracked very closely during 2007 and 2008 (actual generation exceeded the imputed generation by only 0.1 TWh in each year), indicating accurate model performance. A larger variance occurred in 2009; actual generation was 0.3 TWh lower than the imputed generation. This difference represents reduced generation as a result of increased spill caused primarily by the increase in SBG experienced in 2009.

<u>2009 Actual versus 2009 Budget</u>

The total regulated hydroelectric production during 2009 was 5 per cent (0.9 TWh) above the 2009 plan (see Ex. E1-T1-S2 Table 1). Niagara Plant Group actual production was almost 3 per cent (0.3 TWh) above plan and R.H. Saunders actual production was 9 per cent (0.6 TWh) above plan. While SBG was significant in 2009 and resulted in reduced production due to spill, the effects of SBG were more than offset by flows that exceeded forecast values.

Production at the Sir Adam Beck plants in 2009 was 3 per cent above plan due to Niagara River flows being significantly higher than forecast. Actual annual mean Niagara River flow for 2009 was almost 102 per cent of the historical mean compared to the forecast mean flow of 92 per cent of historical mean corresponding to the forecast plan for 2009 prepared in 2007. Total production at DeCew Falls in 2009 was within 1 per cent of plan.

R.H. Saunders production exceeded plan production by 9 per cent (0.6 TWh) during 2009 due to significantly higher St. Lawrence River flows. Actual annual mean St. Lawrence River flow for 2009 was 103 per cent of the historical mean compared to the forecast mean flow of 93 per cent of the historical mean corresponding to the forecast plan for 2009 prepared in 2007.

Dry conditions existed when the 2009 forecast was prepared in 2007. (Net basin supplies to Lake Erie had been well below normal since May 2007) It was assumed that these conditions would persist in the short-term and that flows would remain below normal during 2008 and 2009. However, above average precipitation occurred during the winter of 2008 and net basin supplies to Lake Erie increased to significantly above average, resulting in Niagara and St. Lawrence River flows recovering to more or less normal for much of 2008 and 2009.

2009 Actual versus 2008 Actual

The total regulated hydroelectric production for 2009 was 2 per cent (0.4 TWh) above 2008 production. (See Ex. E1-T1-S2, Table 1).

Niagara Plant Group production was 2 per cent (0.3 TWh) higher in 2009 than 2008. Production at the Sir Adam Beck plants was more than 3 per cent (0.4 TWh) greater in 2009, while production at DeCew Falls decreased by 8 per cent (0.1 TWh). The increase in Niagara Plant Group production is attributable to termination of OPG's obligation to return "Canadian Niagara Power replacement" energy to FortisOntario (formerly Canadian Niagara Power) as of April 30, 2009 (see Ex. A1-T4-S2). As a result, the quantity of energy returned to FortisOntario in 2009 reduced by about 0.4 TWh.

The 8 per cent (0.1 TWh) decrease in production at DeCew Falls during 2009 is attributable to DeCew Falls I being out of service for the entire year as explained above.

Production at R.H. Saunders increased by 2 per cent (0.1 TWh) from 2008 to 2009, as St. Lawrence River flows increased by 3 per cent. The annual mean St. Lawrence River flow for 2008 was equivalent to the historical mean, while the 2009 mean flow was 103 per cent of historical mean.

2008 Actual versus 2008 Budget

The total regulated hydroelectric production for 2008 was 9 per cent (1.6 TWh) above the budget forecast developed in 2007 and approved by the OEB as part of EB-2007-0905.

Production at the Sir Adam Beck plants exceeded the budget by 7 per cent (0.7 TWh) as Niagara River flows during 2008 were significantly higher than those forecast at the time of budget preparation. The annual mean flow for 2008 was 99 per cent of the historical mean compared to a forecast annual mean corresponding to 89 per cent of the historical mean assumed for the budget.

Production at DeCew Falls was almost 6 per cent (0.1 TWh) above budget due to actual diversion flows exceeding forecast budget flows. In the 2008 budget forecast, lower diversion flows had been assumed coincident with periods of planned Seaway Canal maintenance during January and February of 2008. Actual diversion flows were 20 to 25 per cent higher than expected during these months, resulting in increased production at DeCew Falls.

R.H. Saunders production in 2008 was 12 per cent (0.8 TWh) above budget. St. Lawrence River flows during 2008 were significantly higher than the flows forecast at the time of budget preparation in 2007. The actual annual mean flow for 2008 was equivalent to the historical mean, whereas the annual mean of the budget forecast flows was 88 per cent of historical mean.

Dry conditions existed when the 2008 budget forecast was undertaken in 2007. (Niagara and St. Lawrence River flows were below normal, ranking about lower quartile.) It was assumed that these conditions would persist in the short-term and that flows would remain below normal during 2008 and 2009. However, above average precipitation occurred during the winter of 2008 and net basin supplies to Lake Erie increased to significantly above average, resulting in Niagara and St. Lawrence River flows recovering to more or less normal for much of 2008 and 2009.

<u>2008 Actual versus 2007 Actual</u>

The total regulated hydroelectric production for 2008 was 4 per cent (0.8 TWh) more than the actual production for 2007 (see Ex. E1-T1-S2 Table 1).

The Niagara Plant Group production for 2008 was 4 per cent (0.5 TWh) higher than the actual production for 2007. Production at the Sir Adam Beck plants was almost 3 per cent (0.3 TWh) higher in 2008. Annual mean Niagara River flows increased from 97 per cent of historical mean in 2007 to 99 per cent of historical mean in 2008. Production at the DeCew Falls plants in 2008 increased by 22 per cent (0.2 TWh) when compared to 2007. Production at DeCew Falls II was reduced in 2007 due to a major rehabilitation outage.

Actual production at R.H. Saunders for 2008 was 4 per cent (0.3 TWh) more than the actual production for 2007 due to an increase in St. Lawrence River flows. The annual mean St. Lawrence River flow for 2008 was similar to the historical mean, compared to the actual mean flow for 2007 which was 96 per cent of the historical mean.

<u>2007 Actual versus 2007 Budget</u>

The total regulated hydroelectric production during 2007 was 4 per cent (0.7 TWh) above the 2007 budget. Actual Niagara Plant Group production was 4 per cent (0.4 TWh) above budget and actual R.H. Saunders production was 5 per cent (0.3 TWh) above budget.

Production at the Sir Adam Beck plants in 2007 was almost 5 per cent (0.5 TWh) above budget primarily due to Niagara River flows being above plan. Actual annual mean Niagara River flow for 2007 was about 97 per cent of the historical mean compared to the budget mean flow which was about 91 per cent of the historical mean.

Total production at DeCew Falls during 2007 was 2 per cent lower than budget production. Water availability from the Seaway Canal was restricted at times during November and early December 2007, due to volatile fluctuations in water level elevations on Lake Erie associated with wind activity. Consequently, production was lower than plan for these months.

R.H. Saunders production exceeded budget by almost 5 per cent (0.3 TWh) during 2007 due to higher St. Lawrence River flows. Annual mean St. Lawrence River flow for 2007 was 96 per cent of the historical mean, whereas the budget mean flow was 91 per cent of the historical mean.

Niagara River and St. Lawrence River flows were below normal when the 2007 budget forecast was prepared in early fall of 2006, and below normal flows were expected to continue through 2007. However, local basin supplies to Lake Erie abruptly increased (due to rainfall) and were significantly higher than normal from October 2006 to January 2007, resulting in flows increasing to above normal levels later in the fall and continuing to early 2007. Flows typically remained near or above normal levels during the early part of 2007, but decreased to below normal during the latter part of the year.

Numbers may not add due to rounding.

Table 1
Comparison of Production Forecast - Regulated Hydroelectric (TWh)

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Niagara Plant Group**	11.1	0.4	11.5	0.5	12.0	0.8	11.2
2	**Saunders GS**[1]	6.4	0.3	6.7	0.3	7.0	0.8	6.2
3	**Total**	17.5	0.7	18.2	0.8	19.0	1.6	17.4
	Other:							
4	**CNP Generation**[2]	(0.7)	0.0	(0.7)	(0.0)	(0.7)	0.0	(0.7)
5	**Imputed Generation**[3]			18.1		18.9		
6	**Actual - Imputed Generation** (line 3 - line 5)			0.1		0.1		
7	**Forecast SBG Adjustment**							

Line No.	Prescribed Facility	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
8	**Niagara Plant Group**	12.0	0.3	12.3	0.3	12.0
9	**Saunders GS**[1]	7.0	0.1	7.1	0.6	6.5
10	**Total**	19.0	0.4	19.4	0.9	18.5
	Other:					
11	**CNP Generation**[2]	(0.7)	0.4	(0.2)	0.0	(0.2)
12	**Imputed Generation**[3]	18.9		19.8		
13	**Actual - Imputed Generation** (line 10 - line 12)	0.1		(0.3)		
14	**Forecast SBG Adjustment**					

Line No.	Prescribed Facility	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
15	**Niagara Plant Group**	12.3	0.1	12.4	(0.0)	12.4	(0.3)	12.1
16	**Saunders GS**[1]	7.1	(0.2)	6.9	0.1	7.0	(0.0)	7.0
17	**Total**	19.4	(0.1)	19.3	0.0	19.4	(0.3)	19.0
	Other:							
18	**CNP Generation**[2]	(0.2)	0.2	0.0	0.0	0.0	0.0	0.0
19	**Imputed Generation**[3]	19.8						
20	**Actual - Imputed Generation** (line 17 - line 19)	(0.3)						
21	**Forecast SBG Adjustment**			(0.2)		(0.5)		(0.8)

Notes:
1. Saunders values represent total station production (including energy delivered to HQ).
2. CNP (Canadian Niagara Power) Generation is included in the Niagara Plant Group total production.
3. Imputed Generation refers to the production value resulting from a re-running of the forecasting models using actual water flows, but maintaining all other input variables constant.

HYDROELECTRIC INCENTIVE MECHANISM

1.0 PURPOSE

This evidence provides a description of the hydroelectric incentive mechanism and presents a review of how this mechanism has impacted OPG's operating decisions as required by the OEB in its EB-2007-0905 Decision.

2.0 HYDROELECTRIC INCENTIVE MECHANISM

Under the incentive mechanism approved in EB-2007-0905, OPG is financially obligated to supply a given quantity of energy ("hourly volume") in all hours and receives the regulated rate for the hourly volume in all hours regardless of the actual output from its regulated hydroelectric facilities. If OPG produces more actual energy than the hourly volume in a given hour, it receives regulated payment amounts up to the hourly volume, and market prices for the incremental amount of energy above this hourly volume. If OPG's actual energy production from its regulated hydroelectric facilities is less than the hourly volume in a given hour, the amount payable to OPG at the regulated rate is reduced by the production shortfall multiplied by the market price.

The hydroelectric incentive mechanism improves OPG's operational drivers by tying operational decisions, regardless of hourly output, to market prices instead of the regulated rate.

3.0 IMPACT OF THE INCENTIVE MECHANISM ON OPERATING DECISIONS

3.1 Overview

OPG's decisions to move energy production from off-peak to on-peak periods are, within the constraints imposed by market, asset and hydrological conditions, based on economics. Specifically, these decisions are based on expectations of short run market conditions (price and demand) and the expected price spread between the off-peak and on-peak periods. The deployment of the Pump Generating Station ("PGS"), in conjunction with the Sir Adam Beck Generating Stations 1 and 2 ("SAB 1 and SAB 2"), can move substantial quantities of energy from off-peak to on-peak periods. The extent to which the PGS is used to move energy between these periods is largely dependent on the difference between on-peak and off-peak prices. While there is some peaking capability at R.H. Saunders and the DeCew Falls Generating Stations, the great majority of peaking activity occurs at the Sir Adam Beck complex.

In real time, the cost of pumping in the off-peak periods (e.g., expected market prices for electricity, incremental/decremental gross revenue charges, non-energy load charges) is continually compared with the forecast value of the additional generation in the next on-peak period(s). Similarly, during on-peak periods, the value of generation is continually compared with the net cost of re-filling the PGS reservoir during the next off-peak period(s). The associated incremental effects of PGS operations on SAB output are also included in these assessments. In both instances, if the expected value of generation exceeds the expected cost of pumping, then the PGS is bid/offered into the market to operate. This economic assessment does not incorporate any consideration of either the regulated price or the hourly volume.

The use of market signals is important to all market participants (and ultimately ratepayers) as this facilitates the movement of energy from low value periods (typically off-peak) to high value periods (typically on-peak) thus reducing overall demand-weighted market prices and hence customer costs.

OPG estimates that between December 2008 and December 2009, usage of the PGS lowered demand-weighted market prices by approximately $1.14/MWh. This value incorporates both the decrease in on-peak prices due to added generation from the PGS and the associated increase in SAB 1 and 2 output, partially offset by an increase in off-peak prices due to additional PGS load and reduced SAB 1 and 2 output. This figure is an estimate because some information - such as the offer prices of other market participants' generation - is not available to OPG and must be estimated. This reduction in market prices demonstrates the value of moving energy from off-peak to on-peak periods.

In EB-2007-0905 at Ex. I1-T1-S1, OPG estimated that the hydroelectric incentive mechanism would provide it with, on a forecast basis, approximately $12M in incremental market revenues in 2009. Between January and December 2009, OPG's actual incremental market revenues have totaled $23.2M. The difference between actual and forecast incremental revenues is attributable to:

- More energy was shifted from off-peak hours to on-peak hours than was forecast. In 2009, actual hourly production in excess of the hourly volume at Niagara (where most time shifting occurs) was 986 GWh which was approximately 25 per cent higher than the forecast of 783 GWh.
- The difference between average on-peak and average off-peak market prices (referred to as the market price spread) was higher than forecast. While actual market prices were well below expectations - the average forecast price was almost $44/MWh versus an actual of $29.5/MWh, off-peak market prices fell at a greater rate than on-peak prices resulting in higher price spreads. The actual market price spread in 2009 was $14.8/MWh; $0.7/MWh higher than forecast.

For the test period, OPG anticipates that the incentive mechanism will result in incremental revenues of $13.3M in 2011 and $16.3M in 2012, as market price spreads are expected to fall relative to 2009. It should be noted that forecasting the value associated with peaking resources, including the PGS, is subject to great uncertainty as the PGS can operate in response to significant short-run differences in hourly prices that are both difficult to forecast and not adequately described by average price spreads.

3.2 Review of Impact of Hydroelectric Incentive Mechanism on Operating Decisions

During EB-2007-0905, OPG undertook to provide a review of the incentive mechanism's effect on operating decisions. The following sections provide the results of that review.

3.2.1 <u>Representative Metrics</u>

To demonstrate the effectiveness of the hydroelectric incentive mechanism, OPG has chosen two measures. Because of limited peaking capability at DeCew and R.H Saunders, these measures relate only to operations at SAB/PGS. The two measures are:

- The total number of hours PGS was pumping and the total number of hours PGS was generating during the review period. This measure provides an illustration of how often the PGS is utilized.
- The daily price spreads between periods when the PGS was generating and when the PGS was pumping. The price spreads are also calculated using production volumes in both modes of operation as weighting factors to further illustrate the economic effectiveness of operating decisions.

3.3 Analysis and Discussion

3.3.1 Number of hours of PGS utilization from December 1, 2008 to December 31, 2009

The PGS was pumping for 27 per cent of the total time and was generating for 44 per cent of the total time. The PGS was not operating for 29 per cent of the total time. Based on the on/off peak price spreads, PGS is used for pumping or generating 71 per cent of the time. When PGS is not operating it is because operation is not considered economic[1]. This demonstrates that, under the incentive mechanism, the PGS appropriately operates in accordance with the financial signals provided by the forecast of on/off peak price spreads. See section 3.3.2 for a detailed discussion of price spreads.

3.3.2 Daily market price spreads during PGS generation and consumption

The column in Table 1 below titled 'Market price spread' shows, by month for the period from December 2008 to December 2009, the difference between the average market prices for the hours that the PGS was generating, and the average market prices for the hours when PGS was pumping.[2] As indicated in section 3.3.1 above, the PGS generates 44 per cent of the time and pumps 27 per cent of the time.

In order to further capture the relationship of price differential and production volume, the column in Table 1 titled 'Production-weighted price spread' shows the difference in market

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[1] Sometimes PGS is utilized for operational reasons as opposed to economic reasons.

[2] On a daily basis, the market price spread is computed as the arithmetic average market price during the hours PGS was generating less the arithmetic average market price when the PGS was pumping. The monthly value is the arithmetic average of all daily values.

prices over the same hours but weighted by the generation and consumption quantities[3]. This assigns higher weighting to prices during instances of high production value, thereby providing a meaningful measure of the success of economic decisions exercised in the scheduling of the PGS. High production-weighted price spreads indicate that the actual operation of the pump storage complex occurred in proportion to the presence of stronger market signals.

Table 1
Price Spreads Between Generation And Pump Operation

Month	Market on/off peak price spread ($/MWh)	Production-weighted price spread ($/MWh)
Dec 2008	18.3	27.8
Jan 2009	15.3	26.6
Feb 2009	14.2	31.7
Mar 2009	13.1	22.0
Apr 2009	18.5	27.1
May 2009	17.6	26.7
Jun 2009	19.0	24.3
Jul 2009	11.1	15.4
Aug 2009	14.3	19.8
Sep 2009	14.5	20.4
Oct 2009	8.8	22.4
Nov 2009	15.2	21.9
Dec 2009	8.4	13.6

[3] On a daily basis, the production-weighted price spread is computed as the sum of hourly generation multiplied by the corresponding hourly market price divided by the daily generation quantity less the sum of the hourly consumption multiplied by the corresponding hourly market price divided by the daily consumption quantity. The monthly value is the arithmetic average of all daily values.

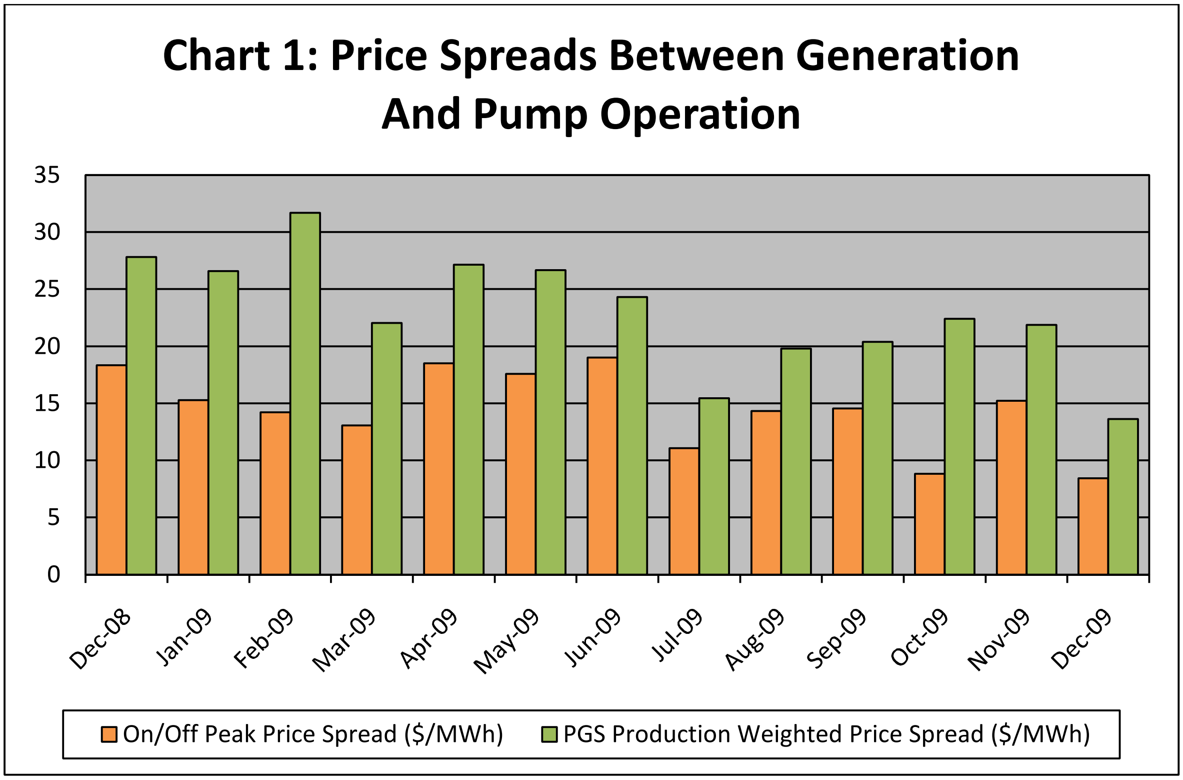

Chart 1: Price Spreads Between Generation And Pump Operation

Table 1 and Chart 1 show that during the period between December 2008 and December 2009, the operation of the PGS occurred when there were positive *market price spreads*, thereby demonstrating operation in accordance with economic drivers.

Further, the notably higher *production weighted price spreads* observed throughout the review period provide additional evidence that operating decisions were made to utilize a greater number of PGS units during instances of higher price spreads. The magnitude of the difference between the market *on/off peak price spread* and the *weighted price spread* is directly related to the success associated with placing the greatest volume of PGS generation in the most appropriately priced hours. Reserving PGS generation for periods of high price is an important factor in capturing and consequently reducing the spreads between on peak and off peak prices.

3.4 Conclusions

As OPG indicated in EB-2007-0905, the new hydroelectric incentive mechanism improves the drivers for operating its peaking facilities by clearly linking decisions to market prices.

As discussed in section 3.3 above, operation of the PGS in 2009 demonstrates the value in moving energy from low- to high-value periods as shown by the decline in demand-weighted market prices. Furthermore, this benefit is realized even during periods of low demand and depressed market prices.

Finally, as discussed in EB-2007-0905, within the constraints imposed by market, asset and hydrological conditions, OPG's decisions regarding the PGS operation include an ongoing assessment of expected short run market price spreads. The measures shown in section 3.3 illustrate that the PGS operates (or does not operate) consistent with the forecast of those market price spreads.

PRODUCTION FORECAST AND METHODOLOGY – NUCLEAR

1.0 PURPOSE

This evidence provides a description of the methodology used to forecast nuclear production, and presents the nuclear production forecast for 2011 - 2012.

2.0 OVERVIEW

OPG is seeking approval of a production forecast of 98.9 TWh for the 2011 - 2012 test period for the nuclear facilities, which is an improvement of 3.9 TWh over the actual production achieved during 2008 - 2009.

OPG operates its nuclear generating stations in compliance with all applicable regulations, requisite licences and approvals in a safe, efficient, and cost effective manner. OPG, in accordance with its Nuclear Safety Policy, conservatively implements unit shutdowns in all circumstances when, in OPG's assessment, the safe operation of the station could be at risk.

Section 3.0 provides a description of the nuclear production planning process which produces an integrated nuclear outage and generation plan ("Integrated Plan"). Section 4.0 presents the nuclear production forecast trend for 2007 - 2012 and describes the key factors impacting each year's production forecast.

During the test period, OPG forecasts improved production performance across its entire nuclear fleet, as a result of a reduction in the number of planned outage days and improvements in forced loss rate ("FLR") at Pickering A and B.

3.0 NUCLEAR PRODUCTION PLANNING PROCESS

3.1 Integrated Nuclear Outage and Generation Plan

Through the nuclear production planning process, OPG seeks to establish accurate and reliable annual production forecasts for its individual nuclear units and an aggregated forecast for each station. Nuclear facilities are designed as base load generators; meaning generator output is not intended to vary with market demand. Therefore, the annual nuclear production forecast is equal to the sum of the generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages or forced production losses (i.e., unplanned outages and derates). As such, the production planning process is focused on establishing annual planned outage schedules, in accordance with established outage scheduling guidelines, and on estimating forced production losses.

OPG is a member of the World Association of Nuclear Operators ("WANO") and uses WANO performance indicators to plan, track and assess the performance of its nuclear units. For the purpose of this evidence, forced production losses and planned outages are defined as per WANO (see Attachment 1). Phase 1 of the ScottMadden Report (see Ex. F5-T1-S1) provides additional background on standard industry benchmarks used to plan and track nuclear generation performance.

The objectives of the production planning process are to:

- Provide a key input into the annual OPG business planning process.
- Ensure availability and optimal deployment of the internal and external resources needed to execute the inspection, modification, and maintenance programs.
- Provide long-term operational plans to allow coordination of nuclear outages across OPG so that reactor outages are planned to occur in periods that have minimal impact on the Ontario electrical grid.
- Comply with the IESO Market Rules by providing information on OPG's nuclear production, capacity, and reliability assumptions.

The nuclear production planning process generates an annual Integrated Plan, with the following deliverables:

- A five-year planned outage schedule for all stations that includes unit outage start dates, end dates, and durations.
- A summary of major elements comprising the scope of work that will be executed during each outage, with a higher level of specificity for scope elements occurring in outages during the first two years of the Integrated Plan.

- Operational reliability performance targets such as unit capability factor and the level of targeted forced production losses represented by the forced loss rate (“FLR”). The process for setting these performance targets is discussed at Ex. F2-T1-S1.
- Outage resource requirements and cost estimates for inclusion in the outage OM&A budget. Further discussion of the outage OM&A forecast can be found at Ex. F2-T4-S1.
- Five-year generation forecasts in terawatt-hours (“TWh”) for individual nuclear units and an aggregated forecast for each station.

3.2 Generation Planning Methodology

The outage and generation planning process mandates three formal planning and review sessions over a 12-month period, culminating in a final Integrated Plan. The process reflects the dynamic nature of outage planning and ensures that all regulatory, operational or maintenance issues that have arisen since the prior period are incorporated into the plan, including:

- “Lessons learned” from recent OPG outages, internal operating experience, emergent discovery work, or short-term updates to life cycle management programs.
- Operating experience from others in the nuclear industry.
- Unanticipated regulatory orders/decisions/requirements (e.g., Canadian Nuclear Safety Commission, (“CNSC”) Technical Standards and Safety Authority), or a failure to obtain regulatory concurrence for plans, such that OPG must undertake unanticipated work activities.

The timing of the three planning and review sessions is as follows:

- In the late fall, the then current five-year Integrated Plan is reviewed and material updates, if any, to the outage schedule are identified.
- In the spring, the first draft of the new Integrated Plan is produced and any material updates to the current outage schedule are identified.
- In the summer, the final Integrated Plan is produced. It is incorporated into the OPG Nuclear business plan which is approved by the Chief Nuclear Officer (“CNO”) and then

submitted as part of OPG's business planning process (see Ex. A2-T2-S1 for a discussion of the corporate business planning process**).**

As noted by ScottMadden (see Ex. F5-T1-S2 page 16), the gap-based business planning process introduced in 2009 as part of the Phase 2 Nuclear Benchmarking Initiative was overlaid on the nuclear planning process already underway. The final Integrated Plan generated in the summer of 2009 and used in the 2010 - 2014 nuclear business plan therefore reflects the combination of the "bottom-up" analysis from the draft Integrated Plan prepared in the spring and the performance targets (i.e., forced loss rate and unit capacity factor) generated during the gap-based, top down, target setting process. Further discussion of the process by which target setting impacted the development of the final Integrated Plan can be found in section 3.2.1.2.

In addition to the three formal planning and review sessions, non-routine meetings are also convened when developments in program assumptions or outage schedules need to be addressed. On limited occasions, significant developments may necessitate updates to the current outage schedule, if they impact the immediate two year outage planning horizon.

The final Integrated Plan and all non-routine updates are approved by the CNO.

At each stage of the planning process, material updates are communicated to the IESO. Planned outages must be registered with and "time-stamped" by the IESO. OPG files its nuclear outage schedule in order to secure an early "time-stamp" date for its outages, which determines their standing in the IESO's outage queue. All outages in the queue are subject to final approval by the IESO, which can deny this approval at any time up to the start of the outage.

The following describes in greater detail the stages in the preparation of the final Integrated Plan:

3.2.1 Integrated Plan Development

In the fall of each year, each station submits an initial outage outlook for the five-year period commencing in January of the next calendar year. For example, the generation plans reviewed during 2009 covered the 2010 – 2014 timeframe. The initial outage outlook will reflect any regulatory, operational or maintenance issues that have arisen since the finalization of the prior Integrated Plan. Often outage durations are amended to reflect analysis of data obtained from recent outages experienced at OPG or other nuclear stations.

Outages during the first two years of the five year planning cycle are subject to the most extensive review and planning.

At the end of this stage, OPG Nuclear has identified:

- An updated, five-year planned outage schedule for each unit in the nuclear fleet, with the addition of a fifth year, as described below.
- Forced production loss and Unit Capability Factor (“UCF”) targets, as described below.
- Generation targets and the underlying rationale for the changes from the prior Integrated Plan.

3.2.1.1 Planned Outage Schedule

Planned outage scope and duration are primarily determined by the station’s life cycle plan (as discussed below). This plan identifies the inspections and maintenance necessary to ensure the continued safe, reliable, long-term operation of the plant and compliance with regulatory requirements. With regard to the scope of regulatory requirements, the nuclear industry stands apart from other regulated industries and other forms of electrical generation due to the complex nature of its technology, the criticality of safety in its operations and nuclear regulations. Consequently, the key drivers associated with OPG’s nuclear operations (i.e., safety, complexity, training, material standards, work environment, non-standard fleet, aging technology, evolving regulatory standards, and achievements in technology) that are outlined in the base OM&A exhibit (Ex. F2-T2-S1) are equally applicable to outage scope, duration, and cost.

The outage scheduling guidelines considered during the planning process are:

- Eliminate/minimize overlap of planned outages.
- Minimize the scheduling of planned outages during peak seasonal periods.
- Ensure outage changes impact minimally on planned production targets.
- Proactively minimize the probability of inter-site work and schedule conflicts related to shared resources and tooling (e.g., inspection maintenance services campaigns and feeder replacement projects; optimize use of roving maintenance crews).
- Ensure standard intervals are applied between planned outages at each unit.

Outages involve many OPG divisions and individuals working together, and as such they require high levels of coordination. Outages require focus, expertise, and a level of detail that exceeds major construction projects. They require careful preparation and the safe execution of a well-developed plan that accounts for nuclear, radiological, and industrial safety, as well as, the efficient achievement of production goals and cost controls.

Outages consist of a combination of "routine" inspection and maintenance activities and "non-routine" activities specific to a particular outage. They involve thousands of work tasks, representing many person-hours of labour, sequenced in the optimal order to ensure safe and effective execution. As an example of the complexity of outage planning, Attachment 3 includes a Level 1 schedule for the Pickering B Unit 6 2009 planned outage.

Examples of routine activities would be preventive maintenance programs, feeder inspections and water lancing of steam generators, to maintain performance and reliability. Non-routine activities include corrective and elective maintenance programs and could include upgrades, replacements or modifications to the equipment or plant configuration that can only be done when the unit is shut down, such as single fuel channel replacement or low level drain state.

Even though OPG Nuclear is transitioning to standard baseline outage templates as discussed in Attachment 2, any outage will have unique aspects based on its specific scope. Approximately 60 per cent of the work activities in an outage typically relate to routine preventative maintenance and inspection activities while the remaining 40 per cent relate to work activities for non-routine upgrades and modifications. Within this split, the planned outage scope would primarily consist of pre-defined work activities and related work tasks. However, approximately 15 per cent of planned outage scope is contingency work activities that are anticipated to arise from discovery work during the routine inspection and preventive maintenance activities. These contingency activities are carefully selected based on risk assessments and historical experience. This approach allows OPG to proactively plan for, and be in a position to quickly respond to, such discovery work as it is identified over the course of the outage. Including contingency work activities within the planned outage scope minimizes the potential disruption to the outage schedule due to critical path and bulk work delays, as well as improving the accuracy of the Integrated Plan.

In addition, in order to avoid a significant disruption to the outage schedule, OPG may postpone completion of non-critical, non-safety related discovery work until after the outage. A decision to postpone work can lead to reduced production reliability during the post-outage period and require that future planned outages include the deferred items. By providing for a prudent level of contingency work activity in the planned outage scope, OPG balances the risk of outage extension due to discovery work against post-outage production reliability (i.e., the risk of more and longer force outages which impacts FLR).

Though outage duration is determined by the critical path of outage inspections and maintenance, it is also impacted by CANDU design (i.e., fuel is not offloaded during the outage) and the availability of the mandatory minimum equipment required for protection of the reactor fuel. Historically, the bulk of the outage critical path duration has been fuel channel and steam generator work. Recently, feeder piping inspections and maintenance are emerging as an additional critical path driver on some units. Pickering B Continued Operations, as discussed at Ex. F2-T2-S3, will result in additional planned outage days in 2010 - 2012 due to the need to perform additional Spacer Location and Relocation (“SLAR”) work as well as other work activities.

The following steps outline the process that yields each station's planned outage schedule:

- Each station identifies the inspection and maintenance activities required to comply with the aging and life cycle management programs and to ensure the safe and reliable operation of the facilities for the duration of their planned lives. The aging and life cycle management programs outline specific objectives for the major plant components (e.g., fuel channels, steam generators, feeders). The programs detail the frequency and nature of inspections, and the recurring preventive maintenance work required to ensure fitness for service and to maintain the reliability and safety of the plant. While outages will always include routine inspections and maintenance activities, the equipment affected will vary from one outage to the next, in accordance with the schedule specified in the aging and life cycle management programs. The variation in the scope of outages comes from corrective maintenance, projects and other non-routine activities. These variations are required to respond to issues specific to a station or to a unit(s) within a station, as units do not necessarily age according to the same pattern or at the same rate. The critical path of an outage can be impacted by these variations.
- OPG's nuclear operating licenses issued by the Canadian Nuclear Safety Commission ("CNSC") (further described in Ex. A1-T6-S1) require that a number of tests and maintenance activities be performed at specified intervals to ensure continued safety. In some instances, the requirement necessitates the shut down of all the units within the station because the test or the work involves a common safety system or component (e.g., vacuum building outage at Darlington in 2009 and in Pickering in 2010). The stations develop high level planned outage schedules with the input of several organizations, including Engineering, Inspection Maintenance and Commercial Services ("IM&CS"), and Projects and Modifications. To accommodate constraints around inter-site sharing of certain resources and tooling, this input is a significant factor in determining both the scheduled outage dates and the sequencing of major critical path activities. It helps ensure effective deployment of inspection and maintenance resources between the units on outage, particularly in those instances where overlapping, multi-site outages occur. For example, IM&CS staff will review the outage schedule to ensure that the planned activities can be completed with the available resources and external commitments. This review is critical due to the limited availability of highly specialized

nuclear tooling and personnel. Efforts are also made to schedule outages at different sites sequentially to facilitate the sharing of operations and maintenance resources. As well, the planned outage schedule is reviewed to identify and resolve potential conflicts between stations over the use of shared specialty resources such as project crews, contract staff, and major component spares such as turbine spindles or feeder replacement tooling. At this stage, the outage OM&A costs are estimated based on several factors including historical experience, projected contractors' costs, parts and projected equipment costs, and staffing requirements. Further discussion about outage OM&A costs can be found at Ex. F2-T4-S1. Station staff prepare resource, duration, and cost estimates at a detailed level for the outages. This allows the stations to prioritize work activities and examine the economic justification for necessary but non-essential activities, relative to other competing needs. The outage schedules involve development of detailed logic diagrams that identify the start and end dates for individual activities within each outage. The critical path for upcoming outages is also determined at this stage of the planning.

- Each station's planned outage schedule includes an allowance for uncertainty in the outage duration related to potential discovery work. The allowance for uncertainty reflects a station level assessment of past outages, known and unknown technological risks specific to the outage, the number of inspections that may result in discovery work and resource capability and availability.

3.2.1.2 Forced Production Losses and Unit Capability Targets

All generating units face the risk of unscheduled equipment problems that may require unplanned shutdowns or a derating of the generating unit. Accordingly, the stations develop forced loss rate ("FLR") targets that reflect the risk of such forced production losses for all units in the station.

In 2010, FLR targets were developed by station management with input from the Outage and Strategic Planning Departments, Engineering, and Nuclear Finance. FLR targets are based on the plants' recent performance, any known improvements or deterioration in plant material condition, past and future investment in reducing corrective and elective maintenance backlogs to improve reliability and other performance improvement initiatives, as well as known risks.

As part of the Phase 2 Nuclear Benchmarking initiative (Ex. F2-T1-S1), OPG introduced a change to its production forecast methodology related to the use of gap-based target setting to establish top-down, station FLR and Unit Capability Factor targets. The targets were initially set for the fifth year (2014) of the Nuclear business plan. The stations then reviewed their bottom-up FLR and Unit Capability Factor ("UCF") targets for the prior years (2010 - 2013) for reasonableness and consistency with the 2014 operational targets.

3.3 Initial Draft Integrated Plan

Using each station's initial planned outage schedule and the FLR and UCF target assumptions, Nuclear Finance prepares a draft five-year Integrated Plan. The draft Integrated Plan includes monthly and annual generation targets (TWh), planned outage days, and corresponding generation performance indicators at the unit, station and fleet level, for each of the five years of the Integrated Plan.

Included in the draft Integrated Plan is a fleet-level uncertainty adjustment. The fleet level adjustment recognizes the potential for events that are not predictable from a station level perspective. These events could impact the duration of a planned outage resulting in forced extensions of planned outages. The fleet level adjustment is intended to address planned outage risks including those that could emerge from fleet aging issues, or the complexity in fleet level activities (e.g., traveling crews and IM&CS) in support of outages. The fleet level adjustment is implemented by applying adjustments to the planned outage duration for each station's planned outage schedule. The combined fleet level uncertainty adjustment directly applied to the station production targets is 0.3 TWh in 2011 and 0.35 TWh in 2012.

3.4 Final Integrated Plan Approval

The Integrated Plan is finalized after the CNO reviews the station's nuclear generation targets, planned station outage schedules, and generation performance indicators included in the draft Integrated Plan. This review identifies revisions to the generation plan to reflect the latest generation-related information from across Nuclear or any changes in the overall nuclear program direction. The final Integrated Plan is incorporated into OPG's overall business planning process. Once approved through the OPG business planning process, the Integrated Plan will not change until the completion of the subsequent business planning cycle.

3.5 Forecast for Major Unforeseen Events

On average from 2005 - 2008, OPG's actual nuclear production has been less than the approved nuclear business plan forecast by approximately 3.5 TWh. An analysis of these production shortfalls revealed that they were largely the result of Nuclear's experience with forced outages and forced extensions to planned outages due to major unforeseen events. Accordingly, OPG has adjusted its production forecast methodology in the 2010 - 2014 Business Plan to include a 2.0 TWh per year allowance for major unforeseen events on the expectation that these types of events will occur in the future. (see Attachment 4 for analysis).

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The Nuclear business unit strives to maximize nuclear production while ensuring safe and reliable operations. In order to incent and challenge the nuclear organization, OPG has established a stretch performance target that is 2.0 TWh higher than the 2010 - 2014 Business Plan production forecast. The performance of OPG Nuclear's management will be assessed in part against its ability to achieve this stretch target (including payouts under the Annual Incentive Plan).

4.0 OPG NUCLEAR PRODUCTION FORECAST TREND

The expected trend in nuclear production starting from 2007 is for production to decline over the period 2008 - 2010 followed by an increase in 2011 and a further increase in 2012. This data is provided in Ex. E2-T1-S1 Table 1.

The major factors influencing the trend in production over 2007 - 2012 are:

- An expectation of improved performance at the Pickering units. The performance improvements at Pickering B during 2009 reflect the impact of various initiatives that have been undertaken since 2004. Improvements at Pickering A are expected by the end of the test period as a result of the Pickering A Equipment Reliability program. In addition, both stations will be positively impacted by new programs arising from the 2009 Nuclear Benchmarking initiative, designed to improve outage performance as discussed below in Attachment 1.
- A vacuum building outage at Darlington in 2009 which required all four Darlington units to be shut down for approximately four weeks.
- A vacuum building outage at Pickering in 2010 that will require all four Pickering B units and the two Pickering A units to be shut down for approximately four weeks.
- Extended scope and duration of planned outages at Pickering B over the period 2010 - 2012 as a result of the Pickering B Continued Operations initiative. There are 167 additional planned outage days in the test period for Continued Operations corresponding to a reduction of 1.9 TWh in the production forecast in the test period.
- An improvement in the forecast FLR at Pickering A starting in late 2009 reflecting recent CNSC concurrence with OPG's shutdown system trip setpoint methodology resulting in the elimination of the three per cent derate that was imposed in 2007.

The Nuclear production forecast for the 2011 - 2012 period does not include a specific provision for reduced production due to surplus baseload generation. OPG was not subject to material reductions in nuclear generation due to surplus baseload generation situations in 2008 or 2009 and is currently not anticipating a significant impact on its nuclear facilities during the test period.

LIST OF ATTACHMENTS

Attachment 1:	Glossary of Outage and Generation Performance Terms
Attachment 2:	OPG Nuclear Initiatives to Improve Outage Performance and Production.
Attachment 3:	Level 1 Planned Outage Schedule - Pickering B Unit 6
Attachment 4:	Forecast for Major Unforeseen Events

ATTACHMENT 1

GLOSSARY OF OUTAGE AND GENERATION PERFORMANCE TERMS

Calandria Tubes: Tubes that span the calandria and separate the pressure tubes from the moderator. Each calandria tube contains one pressure tube.

Corrective Maintenance: Activities associated with the repair or replacement of plant systems, equipment, components, etc., which are found to be defective, and repairing, altering, adjusting, or bringing them into conformity or making them operable. This means any work on power block equipment that has failed or is significantly degraded to the point that failure is imminent prior to the next scheduled maintenance window. Such equipment no longer conforms to, or is incapable of, performing its design function.

Critical Path: The longest series chain of work which determines the outage duration based on the concept that you cannot start some activities until others are finished. These activities need to be completed in a specified work sequence, with each stage being more-or-less completed before the next stage can begin. **Bulk Work** activities are activities that do not drive the critical path and can be completed "in parallel" thus not impacting outage duration.

Derate: A derate is where a unit is delivering a portion but not all of its full electrical power. Derates include:

- **Planned Derate**, a planned reduction in available power generation, scheduled with the IESO at least 28 days in advance.
- **Forced Derate**, an unplanned reduction in available power generation, which can include deratings due to equipment, safety, environmental reasons, or Canadian Nuclear Safety Commission requirements.

Discovery Work: Work required to correct a deficiency that is discovered in the field after an outage begins.

Elective Maintenance: Any work on power block equipment that is deficient or degraded that needs to be remedied but which does not represent a loss of functionality of a major component or system.

Feeder: There are several hundred fuel channels in the reactor that contain fuel. The feeders are pipes attached to each end of the channels used to circulate heavy water coolant between the fuel channels and the steam generators.

Feeder Replacement*:* OPG will inspect feeders to assess the condition of feeder wall thickness relative to Technical Standard and Safety Authority standards; OPG will replace feeders which, in OPG's assessment, encroach on the Technical Standard and Safety Authority standard; with such assessments reviewed by the Canadian Nuclear Safety Commission ("CNSC") for their concurrence and approval.

Forced Extensions to Planned Outages: An extension to a planned outage which is not scheduled with the IESO at least 28 days in advance, and is unavoidable because the unit is not capable of safe operation at the scheduled outage completion time (e.g., an unexpected condition discovered during the scheduled outage which drives critical path).

Forced Loss Rate ("FLR"): FLR is a WANO indicator of performance reliability. FLR is a measure of the percentage of energy generation during non-planned outage periods (non-planned outage periods exclude forced extensions of planned outages) that a plant is not capable of supplying to the electrical grid because of forced production losses, such as forced outages or unplanned derates.

Forced Outage: As per WANO industry performance reporting guidelines, a forced outage is a generator outage for which OPG did not provide at least 28 days advance notice to the IESO. For purposes of clarification, the IESO defines a forced outage as an unplanned electricity system component failure (e.g., immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed completely from service immediately. For the purposes of the filing, the WANO definition has been used unless otherwise stated.

Under certain infrequent circumstances (e.g., protection of equipment or the public), a utility is permitted by the IESO market rules to force a unit offline even though a request for a planned outage has been declined by the IESO. This would be classified a forced outage by OPG, and is subject to follow-up investigation by the IESO at their discretion.

Forced Production Losses: Forced production losses represent lost production due to forced outages and forced derates.

Lessons Learned Review: At the completion of an outage, a review of areas for improvement is conducted and documented. The review includes an analysis of actual performance against scheduled performance for the purpose of improving schedule and performance for similar work in the future. The focus of the review includes: (1) scope control, (2) schedule accuracy, adherence, and stability, (3) organization effectiveness and communication, (4) work package readiness, (5) strengths, (6) improvement areas, including action plans for resolution, (7) resource availability and utilization, and (8) contingency plans.

Level I Schedule: An outage schedule produced at a summary level of detail, identifying major activities within a scheduled period of unavailability for a particular system or sub-system, with a pre-defined start and end date.

Life Cycle Plan: Life cycle management is the integration of safety management, ageing management and business management decisions, together with economic considerations over the life of a nuclear power plant in order to:

- Maintain an acceptable level of performance including safety.
- Optimize the operation, maintenance and service life of structures, systems, and components.
- Maximize returns on investment over the operational life of the nuclear power plant.
- Take account of strategies for life cycle funding (including decommissioning), fuel management, and waste management.

MegaWatt (MW = 10^6 watt): The productive capacity of electrical generators operated by utility companies. For reference, about 10,000 100-watt lightbulbs or 5,000 computer systems would be needed to draw 1 megawatt.

Maximum Continuous Rating: A station’s maximum capacity measured in MW.

Operating Capacity Factor (“OCF”): A standard WANO indicator of performance reliability, OCF is a measure of the percentage of energy generation that a plant is capable of supplying to the electrical grid during non-planned outage periods (e.g., OCF = 100-FLR).

Planned Outage: A planned outage is an outage which has been scheduled with the IESO at least 28 days in advance of the start date. It is subject to final approval by the IESO, the starting time of which could be postponed up to the scheduled hour of shutdown. The schedule must include the planned completion date. The planned outage duration cannot be revised (increased or decreased) after the planned outage has commenced.

Planned Outage Extension: An extension to a planned outage which has been scheduled with the IESO at least 28 days in advance of the planned outage extensions occurrence. A planned outage extension may be approved by the IESO, although the unit could be made capable of safe operation at the scheduled outage completion time, if it is more economical to continue the existing outage than to have another outage later.

Pressure Tubes: Tubes that pass through the calandria and supports the fuel bundles. Pressurized heavy water flows through the tubes, cooling the fuel.

Preventive Maintenance: The activities associated with forestalling or preventing anticipated problems or the breakdown of a system, part, etc. For example:

- Overhaul
- Testing
- Calibrations
- Lubrication programs
- Elastomer replacements

Steam Generator*:* A heat exchanger that transfers heat from the heavy water coolant to light water. The light water boils, producing steam to drive the turbine.

TeraWatt (TW = 10^6 MW): The productive capacity of electrical generators operated by utility companies.

Unbudgeted Planned Outages: An unbudgeted planned outage is an emergent outage that was not included in the approved integrated nuclear outage and generation plan that underpins the business plan, but which OPG had sufficient time to notify the IESO at least 28 days prior to the start date. Although unbudgeted, this allows the outage to be categorized as ‘planned’ for performance reporting purposes as per WANO industry guidelines. If OPG moves forward with the outage but is unable to so notify the IESO within the 28 days timeframe, the outage would be designated a forced outage.

Unit Capability Factor (“UCF”): Unit capability factor is a standard WANO indicator of performance reliability. Unit capability factor is the percentage of maximum energy generation that a unit is capable of supplying to the electrical grid, limited only by factors within control of plant management. Unit capability factor is derived as the ratio of generation available from a unit over a specified time period divided by the maximum generation that the unit is able to produce under ambient conditions and at maximum reactor power during the same period. The available generation is reduced by planned and unplanned production losses deemed under station management’s control. However, the derivation of available generation is not affected by losses due to events not under station management’s control including environmental conditions (e.g., loss of transmission, lake water temperature derates, labour disputes, and potential low demand periods). While these events do impact production, they do not penalize unit capability factor as the units are considered available to produce at these times.

World Association of Nuclear Operators (“WANO”): An internationally recognized body with standardized performance indicators for nuclear reactors (against which OPG Nuclear benchmarks).

ATTACHMENT 2

OPG NUCLEAR INITIATIVES TO IMPROVE OUTAGE AND PRODUCTION PERFORMANCE

Since 2004, OPG Nuclear has instituted a series of programs to invest in aspects of its operations, including: i) improving the material condition of its nuclear assets, and ii) improving outage planning procedures and processes to increase productivity and reduce outage duration.

Since 2006, the success of the improved plant material condition and improved outage planning procedures and processes initiatives is beginning to emerge. As noted by ScottMadden in the 2009 Benchmarking Phase 1 report, Darlington's forced loss rate ("FLR") was within the best quartile (Ex F5-T1-S1 page 86). Positive results also emerged in 2009 for Pickering B, with the successful completion of the Unit 6 fall outage ahead of schedule. The actual FLR for Pickering B in 2009 was 5.8 per cent as compared to the two-year trend of 12.5 per cent in 2007 and 24.2 per cent in 2008. At Pickering A, Unit 1 achieved best quartile performance with a UCF of 91.4 per cent in 2009, an improvement compared to 39.0 per cent in 2007 and 62.3 per cent in 2008. The Unit Capacity Factor ("UCF") best quartile benchmark is 91.0 per cent (see Ex F5-T1-S1). Pickering A Unit 1's FLR in 2009 was 8.1 per cent which is an improvement from the two-year trend of 50.8 per cent in 2007 and 37.2 per cent in 2008.

The following provides additional details on past and future initiatives to improve outage and production performance:

i) Improving the Material Condition of the Nuclear Units

Improving the material condition of the nuclear units is expected to improve the long-term performance and reliability of OPG's nuclear generating stations. Investments are focused on completing life cycle programs for major components such as feeder replacement, steam generator inspections, and the completion of the Spacer Location and Relocation program ("SLAR"). Another initiative relates to the plant reliability list program. The plant reliability list is a comprehensive, prioritized list of critical work orders based on system and component health assessments. The plant reliability list integrates a number of initiatives into one plan where previously such initiatives had been managed separately. This allows OPG Nuclear to focus on the highest priority, most critical work. The execution of the plant reliability list program, which is continuous and ongoing, is expected to result in improved system health, plant material condition, and improved plant reliability.

At Darlington, the focus is on completing life cycle programs for major components such as feeder replacements. At Pickering B, the focus is on completing major life cycle programs including the completion of the SLAR program. At Pickering A, the focus since 2005 has been on the return to service of its units after their extended shut-down. Starting in 2009, Pickering A introduced the Pickering A Equipment Reliability program. The objective of this program is to restore Pickering A's plant performance to the historically achieved levels, reduce forced losses and improve generation performance. Discussion of the Pickering A Equipment Reliability program is found at Ex F2-T2-S1 Attachment 2.

OPG's efforts to maintain and improve the material condition of its plants are also focused on reducing the number of corrective and elective maintenance backlogs at all three stations. Maintenance backlogs represent deficiencies at the plant and are an indicator of station health. Prior to 2004, OPG reduced its investment in reducing maintenance backlogs. Moving forward, OPG is refocusing its resources on elective and corrective maintenance programs to reduce backlogs and improve station health, thereby improving reliability and reducing the potential for forced production losses.

CHART 1
Elective and Corrective Backlogs - 2005-2012

Station	Backlog Description	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Pickering A	Elective	541	558	428	420	333	350	335	320
	Corrective	8	17	14	17	11	10	10	10
Pickering B	Elective	805	885	926	681	554	500	425	400
	Corrective	148	71	22	24	20	25	20	20
Darlington	Elective	767	584	373	313	279	275	250	235
	Corrective	20	14	13	8	7	9	8	7
OPG	Elective	737	699	605	482	400	380	337	318
	Corrective	69	37	17	16	13	16	13	13

As reported in the Phase 1 Benchmarking Report, all three OPG stations are worse than median for both elective and corrective maintenance backlogs compared to North American peers. As part of the gap-based target setting process introduced as part of the Phase 2 Nuclear Benchmarking Initiative (Ex F2-T1-S1), five-year elective and corrective backlog targets were set to narrow this performance gap by reducing the level of elective backlogs at all three sites, and stabilizing the level of corrective backlogs at Pickering.

ii) Outage Planning Procedures and Processes - Station Led Initiatives

OPG's nuclear stations have undertaken steps since 2006 to introduce robust outage planning procedures and processes designed to improve outage performance. These initiatives include:

- Improving Outage Planning: OPG Nuclear is planning for shorter duration, "routine" planned outages, supported by the following initiatives:
    - Implementing improved industry-standard outage planning milestones in the planned outage process, to transition to industry best practices. Improving processes to better manage outage scope so as to reduce the number of planned outage days.
    - Establishing standard outage templates. Internal benchmarks detailing the amount of time and resources required for "routine" outage work activities. Implementing the recommendations from "lessons learned" reviews following planned outages.
- Improving Outage Execution: Improve outage execution performance to reduce outage duration and costs including the following steps:
    - Creating an Outage Control Centre: Using industry best practices, OPG centralized the oversight and project management of outage execution at each site into an Outage Control Centre in 2006. The centre is staffed with senior line management who have the authority to make the immediate decisions necessary to keep outages on schedule.
    - Developing Specialized Teams: As noted above, outage scope consists of routine and non-routine work activities. OPG has recently initiated a process to create specialized work teams and provide them with advanced preparation and training.
    - Co-ordination of Operations and Maintenance: Operations staff performs activities associated with preparing and placing systems and components in-service and out of

service for maintenance, while maintenance staff perform all activities directly related to the preventative, elective, and corrective maintenance. Consequently, maintenance staff cannot initiate maintenance activity until operations staff had completed their work. Recent initiatives have been directed at improving co-ordination between operations and maintenance staff as well as allocating more operations staff to support the outage thereby increasing productivity and reducing inefficiencies.

- Improving Forced Outage Readiness: OPG has reviewed and adopted best industry practices related to forced outage management readiness to quickly respond to, and more effectively manage, forced outages.
- Improving Material Availability: OPG is seeking to minimize delays in the completion of outages by ensuring materials and replacement parts are available as required. Nuclear Supply Chain is focusing on reducing the average cycle time required to deliver materials and replacement parts to the stations.

iii) Outage Planning Procedures and Processes – Fleet-wide Initiatives

With the benefits from the outage improvement initiatives at the station level emerging since 2006, OPG believes that additional improvements in outage performance and costs can be obtained by moving towards an integrated, fleet-wide approach. Outage planning and execution are station accountabilities. As a result, past outage improvement initiatives were generally implemented separately by each station. OPG uses peer teams composed of representatives from each station to provide a forum for the sharing and implementation of best practices.

During Phase 2 of the 2009 Benchmarking Initiative, a new fleet-wide initiative (“Outage Improvement Strategy”) was identified as one of seven top priorities for implementation. The Outage Improvement Strategy represents the consolidation of various actions to improve outage execution and planning and it will be implemented through an integrated fleet approach. The objective is to develop an integrated Outage Improvement Plan that looks at the performance gaps across the fleet and addresses key drivers and program changes on a fleet-wide basis, necessary to drive improved outage performance and lower cost. This approach is similar to the process used successfully by Exelon Corporation, which operates the largest fleet of nuclear stations in the United States.

The Outage Improvement Strategy that was developed during the 2009 Phase 2 Benchmarking is comprised of the following sub-initiatives:

- Improve Contractor Management Process
- Improve Outage Scoping Process
- Implement Outage Duration Improvement Program
- Standardize Outage Control Centre across fleet
- Formalize Continuous Fleet Outage Improvement Program
- Outage Training Performance Improvement Initiative
- Execution Rate Improvement Plan

The Outage Improvement Strategy builds upon past work at the sites to introduce optimal fleet-wide processes and procedures. OPG will focus on improving fleet contractor management procedures (how work is managed, what work is performed, when the work is scheduled, what support is available), improving contractor productivity/efficiency by increasing the amount of work done each day. Other key areas targeted are the scoping process where OPG is committed to improving the timely identification and assessment of the planned outage work prior to the scope freeze milestone date. Improving OPG's ability to pre-plan and assess the level of work and resources required will avoid delays in execution of the outage and/or higher costs. Another component of the Outage Improvement Strategy is to review and implement fleet-wide standards for minimum staffing requirements based on best in fleet organizational practices.

Another separate initiative aimed at improving outage planning and processes is the roll-out of the Primavera P6 software planning tool. Primavera P6 is a construction project management product created for prioritizing, planning, scheduling, managing and executing projects. Primavera P6 enhances OPG's ability to model and optimize resource usage for outage execution on a fleet-wide basis, thereby increasing outage productivity and reducing outage duration.

Unit 6 - 2009 Planned Outage (P961)

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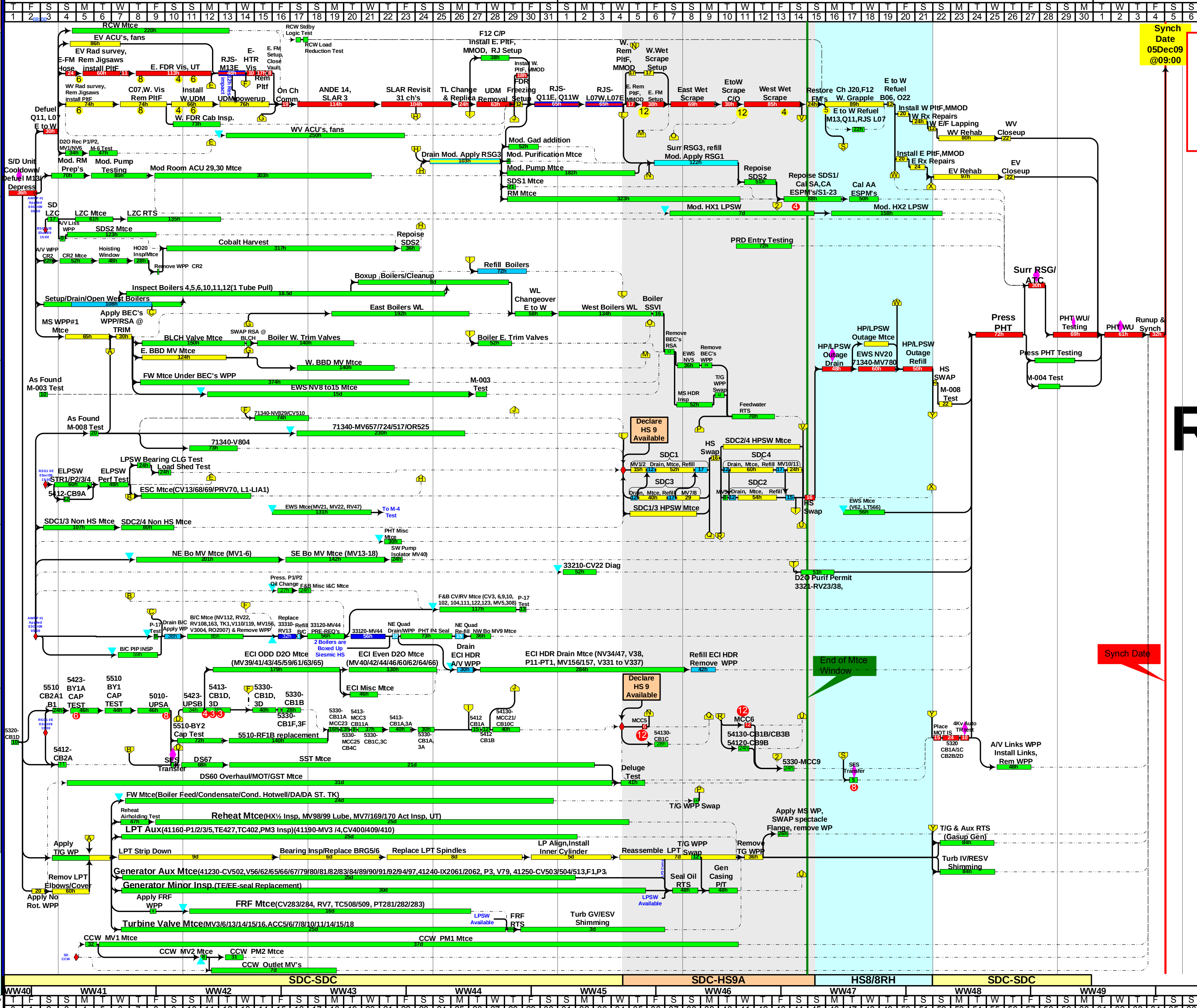
Exhibit E2-1-1
Attachment 3



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Legend

Activity A Finish
Activity B Start
Activity B Finish
A
B
Activity A = 3 day Duration
Activity B = 3 day Duration

- 6 Critical Path Impact duration
- 6 Electrical Interruption Duration
- Red Bar = Critical Path
- Yellow = Near Critical Path
- Outline Bar = Progress
- Indicates Float between Windows
- Indicates No Float between Windows
- Blue = D2O Movement
- Dark Blue = Ice Plug
- IPTE Required
- Constrained Start
- Blue Line = Data Date @ 08:00 hrs

Attachment 4

Forecast for Major Unforeseen Events

This attachment describes the derivation and rationale for the 2.0 TWh forecast for major unforeseen events described in section 3.5.

On average from 2005 to 2008, OPG's actual nuclear production has been less than the approved business plan forecast by approximately 3.5 TWh. An analysis undertaken in 2009 revealed that these unplanned variances were largely the result of high forced loss rates due to major unforeseen events (2.05 TWh, on average) and forced extensions to planned outages (1.19 TWh, on average) (Table 1). Examples of major unforeseen events include losses due to feeder thinning (2005); the inter-station transfer bus issue (2007); the resin release issue (2007) and calandria tube deterioration (2008).

Table 1

Average TWh Variance to Business Plan, 2005 to 2008

Station	Planned Outage Variances	Forced Losses		Forced Extension to Planned Outages		Other Losses[1]	Total Average Variance
		Major Unforeseen Events	Balance	Major Unforeseen	Balance		
Pickering A	0.41	-1.18	-0.51	0.00	-0.27	0.04	-1.51
Pickering B	0.11	-0.87	-0.05	-0.09	-0.64	-0.17	-1.71
Darlington	-0.12	0.00	0.54	0.00	-0.28	-0.45	-0.30
Total Fleet	0.39	-2.05	-0.02	-0.09	-1.19	-0.57	-3.52

A forecast for major unforeseen events was not included in the nuclear generation forecast presented in EB-2007-0905. For the 2010 - 2014 Business Plan, a forecast of generation

[1] Other losses are comprised of grid losses, net lake losses and consumption (i.e. station operating and outage)

losses due to major unforeseen events has been included in the nuclear production forecast. This reflects OPG's recent actual experience as well as OPG's expectation that there will be future production losses due to these major unforeseen events. The average amount (2.0 TWh) incurred over the last 4 years is considered a realistic projection of the expected losses.

The adjustment to the nuclear production forecast of 2 TWh for major unforeseen events results in a more accurate and reasonable production forecast for OPG.

Numbers may not add due to rounding.

Table 1
Production Forecast Trend - Nuclear (TWh)

Line No.	Prescribed Facility	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Darlington NGS**	27.2	28.9	26.0	27.8	28.9	29.0
2	**Pickering A NGS**	3.6	6.4	5.7	6.6	7.4	7.7
3	**Pickering B NGS**	13.4	12.9	15.1	13.7	14.6	15.3
4	**Forecast for Major Unforeseen Events**	0.0	0.0	0.0	(2.0)	(2.0)	(2.0)
5	**Total**	44.2	48.2	46.8	46.2	48.9	50.0

COMPARISON OF PRODUCTION FORECASTS – NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of nuclear production forecasts. This evidence supports the approval of OPG's nuclear production forecast for the test period.

2.0 OVERVIEW

Variances between actual and forecast production in any year are typically the result of OPG experiencing more or fewer forced outages, forced extensions to planned outages, or unplanned outages than budgeted:

- The number of planned outage days per station in the production forecast reflects the work needed to complete the routine maintenance, inspections and project work that can only be performed while the units are shut-down. Forced extensions to planned outages ("FEPO") typically occur from unanticipated requirements for additional work resulting from inspections during the outage.
- The budgeted Forced Loss Rate ("FLR") in the production forecast is OPG's best estimate of the number of unplanned outage days that OPG will experience in the year due to unforeseen events that result in unit shutdowns (forced outages) and forced derates. Actual experience at a station may lead to the number of unplanned outage days exceeding or being less than the budgeted FLR.

A discussion of the work undertaken to transition OPG Nuclear to a more reliable and predictable level of performance can be found in Ex. E2-T1-S1.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2012 Plan versus 2011 Plan

The nuclear production forecast for 2012 of 50.0 TWh is 1.1 TWh higher than the 2011 Plan of 48.9 TWh.

The improved nuclear production performance in 2012 relative to 2011 is primarily due to a forecast of increased production at Pickering B, driven by a reduction in the number of planned outage days (i.e., a reduction of 50 days). This year-over-year reduction in planned outage days is due to lower planned outage days for the Pickering B Continued Operations initiative (55 days) offset by slightly higher planned outage days (5 days) for other planned outage activities in 2012, including feeder replacements. An explanation of the Pickering B Continued Operations initiative can be found at Ex. F2-T2-S3. Planned outage days at Darlington and Pickering A, year-over-year, are also slightly lower.

There is also increased production at Pickering A and Pickering B in 2012 compared to 2011 due to a forecast year-over-year improvement in the FLR at these stations while Darlington's FLR is forecast to remain constant. The forecast improvement in FLR at Pickering A and Pickering B is due to expected improvements in outage planning and execution as well as improvements to the material condition and reliability of these stations as a result of various initiatives being undertaken by OPG.

<u>2011 Plan versus 2010 Budget</u>

The production forecast for 2011 of 48.9 TWh is 2.7 TWh higher than the 2010 budget of 46.2 TWh.

A major contributor to this improvement is a decrease in the number of planned outage days at all three sites in 2011. Pickering B's planned outage days decline by 69 days in 2011 as compared to 2010. This decline is largely a result of the fact that there is no Vacuum Building Outage ("VBO") scheduled at Pickering B in 2011. Pickering is undertaking a VBO in 2010. This planned outage will take all six Pickering units off-line for approximately four weeks. The VBO is required to complete a thorough inspection and maintenance program on the station's containment system. The inspection and maintenance activities are prescribed by the Canadian Nuclear Safety Commission ("CNSC") and are required to maintain Pickering's operating licence. However, the reduction of 152 VBO planned outage days in 2011 as compared to 2010 is offset by 83 additional planned outage days for the Pickering B Continued Operations initiative.

Planned outage days are also forecast to decline in 2011 as compared to 2010 at Pickering A and Darlington. Pickering A's decline in planned outage days is primarily driven by the fact that there is no VBO at Pickering A in 2011 as there was in 2010. The reduction in the number of planned outage days at Darlington is primarily the result of its 36 month outage cycle, resulting in only one planned outage in 2011 as compared to the two planned outages in 2010.

Nuclear production is also forecast to improve in 2011 versus 2010 due to an expected year-over-year improvement in the FLR at all three stations. The forecast fleet-wide improvement in FLR is due to the material condition and reliability improvements at the stations, as discussed in Attachment 1 of Ex. F2-T1-S1 and to fewer and shorter duration forced outages based on improvements in OPG's outage planning procedures and processes to increase productivity and reduce outage duration.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2010 Budget versus 2009 Actual

The nuclear production forecast for 2010 of 46.2 TWh is 0.6 TWh lower than the 2009 actual production of 46.8 TWh. There are various factors impacting the year-over-year change in planned production.

Production is forecast to decrease in 2010 compared to 2009 due to an increase in the number of planned outage days at Pickering A and Pickering B as a result of:

- Pickering A and B undertaking a VBO in 2010. This planned outage will take all six Pickering units off-line for approximately four weeks.
- An additional 28 planned outage days at Pickering B in 2010 as part of the Continued Operations initiative. There was no planned outage days in 2009 related to Continued Operations.

Production at Darlington in 2010 compared to 2009 is forecast to increase due to a reduced number of planned outage days at this station. The Darlington VBO in 2009 resulted in a significant number of planned outage days as all four Darlington units were off-line for approximately four weeks. There is no Darlington VBO in 2010. However, the 36-month outage cycle at Darlington will result in two planned outages in 2010 at this station compared to one planned outage in 2009. This will partially offset the reduction in planned outage days due to the VBO.

Nuclear production is also anticipated to improve in 2010 as compared to 2009 due to an expected year-over-year improvement in the FLR at Pickering A and Pickering B, while Darlington's FLR remains flat. The forecast 2010 FLR for the nuclear fleet is 3.5 per cent compared to 6.4 per cent in 2009. The primary driver of the improved fleet FLR in 2010 is the expectation that Pickering A's FLR will decline to 8 per cent in 2010 from 24.6 per cent in 2009.

The 2010 nuclear production forecast includes an allowance for major unforeseen events of 2.0 TWh, as described at Ex. E2-T1-S1.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

<u>2009 Actual versus 2009 Budget</u>

The actual nuclear production for 2009 of 46.8 TWh is 3.1 TWh lower than the 2009 forecast of 49.9 TWh.

Darlington's performance was 0.5 TWh lower than forecast, primarily due to a Unit 3 forced extension of the planned outage related to the VBO. Darlington's actual FLR for 2009 of 1.64 per cent was better than the forecast of 1.7 per cent.

Pickering A's actual 2009 production was 1.6 TWh less than forecast. This difference was driven by a 32.5-day forced extension to the Unit 4 planned outage. The forced extension was required due to discovery during the planned outage that additional work was required on the shutdown cooling system and repairs were needed to the turbine release valves. Pickering A's actual production was also lower than forecast due to higher than forecast FLR. The actual 2009 FLR was 24.6 per cent compared to a forecast FLR of 11.5 per cent. Pickering A Unit 4 experienced a 21.1-day forced outage in order to repair the main output transformer, and three separate forced outages, totaling 74 days, due to problems with Unit 4's liquid zone control system. Pickering A's FLR benefited from a decision by the CNSC on November 16th, 2009 to remove the forced derate (3.0 per cent annually) at Pickering A.

Pickering B's actual 2009 production was 1.0 TWh less than budget primarily as a result of a 27.7-day forced extension to the Unit 5 planed outage to address high pressure service water and shutdown cooling pump discovery work. Pickering B's actual FLR in 2009 was 5.8 per cent, an improvement over the forecast FLR of 6.2 per cent. A significant achievement at Pickering B during 2009 was the successful completion of the 70 day planned outage at Unit 6 ahead of schedule.

2009 Actual versus 2008 Actual

The nuclear production for 2009 of 46.8 TWh was 1.4 TWh lower than the 2008 actual nuclear production of 48.2 TWh. As shown in Ex. E2-T1-S2 Table 1b, Darlington and Pickering A production in 2009 is lower than in 2008, while Pickering B's production is greater.

The main reason that Darlington's production in 2009 was lower than 2008 is the increase in the number of planned outage days due to the 2009 VBO. This outage resulted in all four Darlington units being off-line for approximately four weeks. The VBO was required to complete a thorough inspection/maintenance program of the station's containment system, one of its major safety systems. The inspection/maintenance activities are prescribed by the CNSC and are required to maintain Darlington's operating licence (CNSC licensing is further discussed at Ex. A1-T6-S1). Consequently, in 2009, Darlington required 101.2 additional outage days as compared to 2008 resulting in a production decline of 2.9 TWh compared to 2008. Darlington's performance was also impacted by a total of 11.9 days of forced extension to the planned outages related to the VBO.

Darlington's 2009 FLR also increased from 2008. Darlington's FLR in 2008 was exceptionally good at 0.7 per cent. While Darlington's FLR in 2009 of 1.6 per cent exceeded Darlington's 2008 FLR, Darlington's 2009 FLR was still better than forecast.

The improvement in Pickering B production in 2009 versus 2008 is primarily a result of the significant improvement in Pickering B's FLR. In 2008, Pickering B's Unit 7 was subject to a lengthy 237.5-day forced outage due to a calandria tube replacement and Unit 8 experienced a 25.7-day forced outage due to a heat transport system leak, resulting in an FLR of 24.2 per cent for the year. In 2009, Pickering B was able to reduce the number and duration of forced outages (28.1 forced days spread across 5 outages) that it experienced, such that the FLR for the year was 5.8 per cent. Offsetting the improved FLR at Pickering B were additional planned outage days and a 27.7-day forced extension to the Unit 5 planned outage for shutdown cooling pump discovery work and system maintenance.

Pickering A's 2009 production of 5.7 TWh was slightly less than the 2008 production of 6.4 TWh. The lower production in 2009 was mainly due to an increase in the number of planned outage days. In 2009, Pickering A's Unit 4 underwent a combined 74-day planned outage that was also subject to a 32.5-day FEPO. In 2008 there were no planned outages or FEPO days at Pickering A as a result of the deferral of Pickering A's Unit 4 outage from the fall of 2008 to 2009.

Offsetting the increase in planned outage days in 2009 was a reduction in 2009 in the number and duration of forced outages. Pickering A's FLR was 24.6 per cent in 2009 compared to 27.9 per cent in 2008. Pickering A's FLR was also positively impacted in November 2009 when OPG obtained CNSC concurrence to remove the 3 per cent derate on the Pickering A units imposed in August 2007.

<u>2008 Actual versus 2008 Budget</u>

The actual nuclear production in 2008 of 48.2 TWh was 3.3 TWh lower than the 2008 production forecast of 51.4 TWh.

Darlington exceeded expectations by achieving a 94.5 per cent Unit Capability Factor ("UCF"). The positive results from Darlington are a function of the station's ability to realize a FLR of 0.7 per cent compared to a budgeted FLR of 2.2 per cent. There were no FEPO days in 2008 and the actual planned outage days were lower than budget due to the early completion of the Unit 1 planned outage in the spring.

Pickering A's actual 2008 production of 6.4 TWH was 0.7 TWh lower than the budget of 7.1 TWh, as production at Pickering A was negatively impacted by forced outages, reflected in an actual FLR of 27.9 per cent. Production was positively impacted by zero planned outage days in 2008 compared to the budget of 67.0 days as a result of a decision to defer Pickering A's Unit 4 planned outage from the fall of 2008 to 2009.

Pickering B's actual 2008 production of 12.9 TWh was 2.8 TWh lower than the budget of 15.7 TWh. The Pickering B Unit 7 extended forced outage was the major cause of reduced production in 2008. It was subject to a forced outage from April 6 to November 29. The FLR for Pickering B was 24.2 per cent compared to the budgeted FLR of 6.2 per cent. Offsetting the FLR increase was a reduction in the number of planned outage days from 112.0 days to 62.1 days, reflecting, in part, the fact that OPG was able to complete most of the fall Unit 7 planned outage work during the Unit 7 forced outage.

<u>2008 Actual versus 2007 Actual</u>

As shown in Ex. E2-T1-S2 Table 1a, nuclear production for 2008 of 48.2 TWh was 3.9 TWh higher than the actual production in 2007 of 44.2 TWh.

The improvement in 2008 production is due, in part, to a reduction in the number of planned outage days from 331.2 days in 2007 to 131.2 days in 2008. The main drivers for the reduction in planned outage days are:

- Darlington's move to a three-year outage cycle from a two-year cycle was completed in 2007. Accordingly, only one Darlington unit went through a planned outage in 2008, reducing by 65 days the number of planned outage days in the year.
- There were zero planned outage days in 2008 at Pickering A compared to 65.1 planned outage days in 2007. The reduction in the number of planned outage days in 2008 was a result of Pickering A's Unit 4 fall planned outage being deferred to 2009.

- OPG was able to complete most of the Pickering B Unit 7 fall planned outage work during the Unit 7 forced outage.

Partially offsetting the impact of reduced planned outage days on nuclear production in 2008 was a higher fleet-wide FLR in 2008 as compared to 2007. The increase in fleet-wide FLR was primarily due to a major unforeseen event, the extended forced outage at Pickering B Unit 7 which increased Pickering B's FLR from 12.5 per cent to 24.2 per cent. Partially offsetting the increase in FLR at Pickering B were decreases in FLR at Darlington and Pickering A. The year-over-year reduction in Pickering A's FLR is a reflection of the fact that Pickering A's 2007 FLR had been significantly impacted by a major unforeseen event at Unit 1 and Unit 4 due to the inter-station transfer bus issue. Pickering A's FLR improved from 49.8 per cent to 27.9 per cent. Pickering A experienced several extended forced outages in 2008, including a 59 day forced outage of Unit 1 due to an in-operable fuel loading machine, and a 23.5-day forced outage at unit 4 due to problems with the heat transport system related to pump seal design. Pickering A's FLR in 2008 also experienced the full year impact of the 3 per cent derate of the Pickering A Units 1 and 4 that started in August 2007 due to an inability of OPG to obtain CNSC concurrence with OPG shutdown system trip set methodology.

<u>2007 Actual versus 2007 Budget</u>

As shown on Ex. E2-T1-S2 Table 1a, OPG's 2007 actual nuclear generation was 5.6 TWh lower than the 2007 budget production.

Darlington's production exceeded the budget by 0.4 TWh, largely due to Darlington's better than budgeted FLR results (15.1 days of forced loss equivalent versus a budget of 44.4 days).

At Pickering A the 2007 production was 3.6 TWh, 3.9 TWh below the 2007 budget of 7.5 TWh. The decrease in actual production compared to budget is primarily due to the increased in FLR equivalent days in 2007 as a result of a series of unique, major unforeseen events at Pickering A (the inter-station transfer bus issues) which impaired generation.

At Pickering B the actual 2007 generation was 13.4 TWh, 2.2 TWh less than the 2007 budget of 15.6 TWh. The decrease in actual generation compared to budget was due to a combination of additional planned outage days compared to budget and additional forced loss rate equivalent days. The main driver to the additional forced loss equivalent days was the inadvertent release of resin into the station's demineralized water supply by a contractor. This release resulted in an unscheduled loss of 60 production days and in FEPO days at Pickering B.

Numbers may not add due to rounding.

Table 1a
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington NGS							
1	**TWh**	26.8	0.4	27.2	1.6	28.9	0.3	28.6
2	**Unit Capability Factor (%)**	87.3	2.2	89.5	5.1	94.5	1.7	92.8
3	**PO Days**	131.0	3.3	134.3	(65.2)	69.1	(6.0)	75.1
4	**FEPO Days**	0.0	2.7	2.7	(2.7)	0.0	0.0	0.0
5	**FLR (%)**	4.1	(3.0)	1.14	(0.4)	0.7	(1.5)	2.24
6	**FLR Days Equivalent**	44.4	(29.3)	15.1	(5.2)	9.9	(21.3)	31.1
	Pickering A NGS							
7	**TWh**	7.5	(3.9)	3.6	2.8	6.4	(0.7)	7.1
8	**Unit Capability Factor (%)**	83.7	(42.3)	41.3	30.5	71.8	(7.2)	79.0
9	**PO Days**	66.2	(1.1)	65.1	(65.1)	0.0	(67.0)	67.0
10	**FEPO Days**	0.0	60.2	60.2	(59.1)	1.1	1.1	0.0
11	**FLR (%)**	8.0	41.8	49.8	(21.9)	27.9	14.9	13.0
12	**FLR Days Equivalent**	53.1	246.6	299.7	(96.6)	203.1	116.6	86.4
	Pickering B NGS							
13	**TWh**	15.6	(2.2)	13.4	(0.5)	12.9	(2.8)	15.7
14	**Unit Capability Factor (%)**	86.3	(11.4)	75.0	(3.6)	71.4	(15.2)	86.6
15	**PO Days**	121.0	10.8	131.8	(69.7)	62.1	(49.9)	112.0
16	**FEPO Days**	0.0	68.3	68.3	(49.8)	18.5	18.5	0.0
17	**FLR (%)**	6.2	6.3	12.5	11.7	24.2	18.0	6.2
18	**FLR Days Equivalent**	83.0	73.4	156.4	176.8	333.2	249.4	83.8
	Totals							
19	**Unit Capability Factor (%)**	86.3	(8.9)	77.5	6.4	83.8	(4.9)	88.7
20	**PO Days**	318.2	13.0	331.2	(200.0)	131.2	(122.9)	254.1
21	**FEPO Days**	0.0	131.2	131.2	(111.5)	19.7	19.7	0.0
22	**FLR (%)**	5.4	6.3	11.7	0.6	12.3	7.2	5.1
23	**FLR Days Equivalent**	180.5	290.7	471.2	74.9	546.1	344.7	201.4
24	**Subtotal TWh**	49.9	(5.6)	44.2	3.9	48.2	(3.3)	51.4
25	**Forecast for Major Unforeseen Events**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	**Total TWh**	49.9	(5.6)	44.2	3.9	48.2	(3.3)	51.4

Numbers may not add due to rounding.

Table 1b
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
	Darlington NGS					
1	**TWh**	28.9	(2.9)	26.0	(0.5)	26.6
2	**Unit Capability Factor (%)**	94.5	(8.6)	85.9	(0.5)	86.5
3	**PO Days**	69.1	101.2	170.3	(1.4)	171.7
4	**FEPO Days**	0.0	11.9	11.9	11.9	0.0
5	**FLR (%)**	0.7	0.9	1.6	(0.4)	2.0
6	**FLR Days Equivalent**	9.9	11.0	20.9	(4.9)	25.8
	Pickering A NGS					
7	**TWh**	6.4	(0.7)	5.7	(1.6)	7.3
8	**Unit Capability Factor (%)**	71.8	(7.6)	64.2	(15.4)	79.5
9	**PO Days**	0.0	74.0	74.0	0.0	74.0
10	**FEPO Days**	1.1	31.4	32.5	32.5	0.0
11	**FLR (%)**	27.9	(3.3)	24.6	13.1	11.5
12	**FLR Days Equivalent**	203.1	(50.5)	152.6	77.2	75.4
	Pickering B NGS					
13	**TWh**	12.9	2.2	15.1	(1.0)	16.0
14	**Unit Capability Factor (%)**	71.4	12.6	84.0	(3.2)	87.2
15	**PO Days**	62.1	63.4	125.5	23.5	102.0
16	**FEPO Days**	18.5	9.2	27.7	27.7	0.0
17	**FLR (%)**	24.2	(18.3)	5.8	(0.4)	6.2
18	**FLR Days Equivalent**	333.2	(257.3)	75.9	(8.3)	84.2
	Totals					
19	**Unit Capability Factor (%)**	83.8	(1.9)	82.0	(3.7)	85.6
20	**PO Days**	131.2	238.6	369.8	22.1	347.7
21	**FEPO Days**	19.7	52.4	72.1	72.1	0.0
22	**FLR (%)**	12.3	(5.8)	6.4	1.6	4.8
23	**FLR Days Equivalent**	546.1	(296.7)	249.4	64.0	185.4
24	**Total TWh**	48.2	(1.4)	46.8	(3.1)	49.9
25	**Forecast for Major Unforeseen Events**	0.0	0.0	0.0	0.0	0.0
26	**Total TWh**	48.2	(1.4)	46.8	(3.1)	49.9

Table 1c
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington NGS							
1	**TWh**	26.0	1.8	27.8	1.1	28.9	0.1	29.0
2	**Unit Capability Factor (%)**	85.9	4.4	90.3	3.6	93.9	0.2	94.1
3	**PO Days**	170.3	(51.5)	118.8	(50.5)	68.3	(2.8)	65.5
4	**FEPO Days**	11.9	(11.9)	0.0	0.0	0.0	0.0	0.0
5	**FLR (%)**	1.6	0.1	1.7	(0.2)	1.5	0.0	1.5
6	**FLR Days Equivalent**	20.9	1.6	22.5	(1.6)	20.9	0.1	21.0
	Pickering A NGS							
7	**TWh**	5.7	0.9	6.6	0.8	7.4	0.3	7.7
8	**Unit Capability Factor (%)**	64.2	9.5	73.7	8.9	82.6	2.7	85.3
9	**PO Days**	74.0	71.0	145.0	(63.0)	82.0	(7.0)	75.0
10	**FEPO Days**	32.5	(32.5)	0.0	0.0	0.0	0.0	0.0
11	**FLR (%)**	24.6	(16.6)	8.0	(1.0)	7.0	(2.0)	5.0
12	**FLR Days Equivalent**	152.6	(105.8)	46.8	(1.4)	45.4	(12.5)	32.9
	Pickering B NGS							
13	**TWh**	15.1	(1.4)	13.7	0.9	14.6	0.7	15.3
14	**Unit Capability Factor (%)**	84.0	(7.9)	76.1	4.9	81.0	3.7	84.7
15	**PO Days**	125.5	165.5	291.0	(69.0)	222.0	(50.0)	172.0
16	**FEPO Days**	27.7	(27.7)	0.0	0.0	0.0	0.0	0.0
17	**FLR (%)**	5.8	(0.8)	5.0	(0.5)	4.5	(0.5)	4.0
18	**FLR Days Equivalent**	75.9	(17.4)	58.5	(2.8)	55.7	(4.0)	51.7
	Totals							
19	**Unit Capability Factor (%)**	82.0	1.3	83.3	4.8	88.1	1.7	89.8
20	**PO Days**	369.8	185.0	554.8	(182.5)	372.3	(59.8)	312.5
21	**FEPO Days**	72.1	(72.1)	0.0	0.0	0.0	0.0	0.0
22	**FLR (%)**	6.4	(2.9)	3.5	(0.3)	3.2	(0.4)	2.8
23	**FLR Days Equivalent**	249.4	(121.6)	127.8	(5.8)	122.0	(16.4)	105.6
24	**Total TWh**	46.8	1.4	48.2	2.7	50.9	1.1	52.0
25	**Forecast for Major Unforeseen Events**	0.0	(2.0)	(2.0)	0.0	(2.0)	0.0	(2.0)
26	**Total TWh**	46.8	(0.6)	46.2	2.7	48.9	1.1	50.0