PRODUCTION FORECAST AND METHODOLOGY – HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to provide a description of the methodology used to derive the hydroelectric production forecasts for 2005 - 2009, as well as to present an overview of outage planning for the regulated hydroelectric facilities.

2.0 HYDROELECTRIC PRODUCTION FORECAST

2.1 Methodology - General

The 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 as discussed in Ex. A1-T4-S2. The availability of water is affected by meteorological conditions, with precipitation and evaporation of particular importance. 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 the production forecasts for the regulated hydroelectric sites. These models use forecast monthly water flows, generating unit efficiency ratings, and planned outage information to convert forecast water availability into forecast energy production.

2.1.1 Niagara River Flow and Energy 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. An updated model (advanced hydrologic prediction service) has been developed by Great Lakes Environmental Research Laboratory for the Niagara River and is being tested by OPG for future use.

Input parameters to the current 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. 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 Environmental Research Laboratory model, to determine the Grass Island Pool inflow forecast. The Grass Island Pool is the section of the Niagara River immediately above the 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 Grass Island Pool inflow forecast is compared with that produced by the New York Power Authority as a consistency check. Because of the increasing uncertainty associated with predicting natural systems beyond a six month period, 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, and unit availability 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 and operating patterns, pump generating station operating patterns, New York Power Authority's diversion and discharge capacities, and the Sir Adam Beck 25 cycle system load and frequency changer limits. These adjustments are based on comparisons of model results with actual values, and are used to improve forecast accuracy.

The Niagara energy forecasting model uses the generating unit efficiency ratings to calculate monthly energy production for the Sir Adam Beck units based on the forecast flows and unit outage information determined above. 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 excess base-load generation.

Potential water transactions with New York Power Authority 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, water transactions with respect to the use of OPG's share of water by New York Power Authority are not included in the production forecast for the regulated hydroelectric facilities.

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

2.1.2 DeCew Falls Diversion Flow and Energy 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 voluntarily reduces generation 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.

2.1.3 St. Lawrence River Flow and Saunders Energy 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 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 was developed in 1963. While this plan, Regulation Plan 1958-D, continues in use today, it is under review by the International Joint Commission, and could be modified or replaced by a new model to better reflect the interests of the multiple users of the water. The International St. Lawrence River Board of Control has the authority to deviate from the approved plan under specific conditions.

As a consistency check, the forecast monthly flow and Lake Ontario levels from Plan 1958-D model are compared with values produced by each of Environment Canada (Great Lakes – St. Lawrence Regulation Office) and New York Power Authority. They are then used as input to the Rivmonth energy production model for up to the first six months of the forecast period. Where 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. 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 outage schedule are also incorporated in the Rivmonth model.

3.0 OUTAGE PLANNING

Outage planning for OPG's hydroelectric generating stations is based on a streamlined reliability centred 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. A major unit rehabilitation/upgrade program at the Sir Adam Beck II plant was started in 1996 and completed in 2005. At Sir Adam Beck I, nine of the ten generating units are currently available for service (seven units at 60 cycle, two units at 25 cycle, and one currently deregistered 25 cycle unit). OPG plans to undertake major rehabilitation on three units during the current business plan period. This will impact unit availability. It has been assumed that the two 25 cycle units will no longer be in-service after April 2009. The six pump/generating units at Sir Adam Beck Pump Generating Station were rehabilitated within the past ten years and the units have become more reliable. However, to ensure a reasonable level of reliability, more frequent corrective maintenance is required on these reversible pump generators than on conventional units because of the complexity of these generating units compared to conventional hydroelectric units and the increased wear and tear associated with frequent stopping and starting associated with its storage and peaking role for the power system.

A major mechanical rehabilitation program has also been completed at DeCew Falls II. Rehabilitation of the first and second units were completed in 2006 and 2007, respectively. There are currently no major rehabilitation programs planned for DeCew Falls I.

There are no major overhauls or upgrades planned for R.H. Saunders Generating Station during the test period. All units were upgraded in the 1990's with new, more efficient equipment which added 118 MW to the original station capacity. In addition, slots were cut between each of the units using a special diamond wire technique, to mitigate the effects of concrete "growth" caused by a phenomenon known as alkali-aggregate reaction. Alkali-aggregate reaction is a chemical reaction between the cement and certain types of aggregate within the concrete resulting in "growth" of the concrete structure.

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 impact production at R.H. Saunders.

4.0 REGULATED HYDROELECTRIC PRODUCTION FORECAST 2005-2009

The regulated hydroelectric production forecast for the period 2005 to 2009 is presented in E1-T1-S1 Table 1.

Numbers may not add due to rounding.

Table 1
Production Trend - Regulated Hydroelectric (TWh)

Line No.	Prescribed Facility	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Niagara Plant Group**	11.9	11.5	11.5	11.2	12.0
2	**Saunders GS**[1]	6.9	6.9	6.7	6.2	6.5
3	**Total**	18.7	18.4	18.2	17.4	18.5

	Other:					
4	**CNP Generation**[2]	(0.6)	(0.7)	(0.7)	(0.7)	(0.2)

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

COMPARISON OF PRODUCTION FORECAST – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to present period-over-period comparisons of regulated hydroelectric production, as well as actual versus forecast (plan) comparisons for historical years.

2.0 PERIOD-OVER-PERIOD EXPLANATIONS – TEST PERIOD

2009 Plan versus 2008 Plan

The total regulated hydroelectric production forecast for 2009 is about six percent (1.1 TWh) higher than the forecast for 2008 (see Ex. E1-T1-S2 Table 1). The reasons for this year-over-year difference are provided below.

The Niagara Plant Group production plan for 2009 is seven percent (0.8 TWh) higher than the plan for 2008. More than one-half of this increase is attributable to the termination of OPG's obligation to return "Canadian Niagara Power replacement" energy to FortisOntario (formerly Canadian Niagara Power) on April 30, 2009 (see Ex. A1-T4-S2). The balance of the increase is primarily attributable to higher forecast flows resulting in increased production at the Sir Adam Beck complex. The annual mean Niagara River flow forecast for 2009 is about 92 percent of historic mean and about 89 percent for 2008.

Outages of Sir Adam Beck units do not have a significant effect on forecast production between the two years because of water supply/diversion limitations to the Sir Adam Beck complex. This limitation will be significantly reduced/improved when the Niagara Tunnel comes into service in 2010.

Forecast production for DeCew Falls is slightly lower (about three percent) for 2009 compared to 2008 due to a reduction in the diversion flows assumed for DeCew during 2009.

The R.H. Saunders production plan for 2009 is five percent (0.3 TWh) higher than the plan for 2008. The increase is attributable to increased flows which are forecast for the St. Lawrence River. The annual mean St. Lawrence River flow forecast for 2009 is about 93 percent of historic mean, compared to about 88 percent assumed for 2008. No major outages are planned for R.H. Saunders in either 2008 or 2009.

2008 Plan versus 2007 Actual

The total regulated hydroelectric production plan for 2008 is about four percent (0.8 TWh) lower than the actual production for 2007 (see Ex. E1-T1-S2 Table 1).

The Niagara Plant Group production plan for 2008 is three percent (0.3 TWh) lower than the actual production for 2007 for the reasons given in the following paragraphs.

Production is forecast to increase by about fifteen percent at DeCew Falls in 2008, compared to 2007, due to increased unit availability at DeCew Falls II. In 2007, there was a major rehabilitation outage that reduced production, whereas in 2008 no major outages are planned for the DeCew Falls I and II stations.

The production plan for the Sir Adam Beck plants in 2008 is about four percent lower than 2007 actual production. This difference is primarily attributable to lower flows forecast for the Niagara River (see Ex. E1-T1-S2 for a discussion of methodology). The annual mean Niagara River flow forecast for 2008 is about 89 percent of historic mean, whereas the annual mean flow for 2007 was about 97 percent of the historic mean.

The R.H. Saunders production plan for 2008 is seven percent (0.5 TWh) lower than actual R.H. Saunders production for 2007 and is attributable to a decrease in the flow forecast for the St. Lawrence River (see Ex. E1-T1-S2 for a discussion of methodology). The annual mean St. Lawrence River flow forecast for 2008 is about 88 percent of the historic mean, compared to the actual 2007 mean flow which was about 96 percent of the historic mean.

3.0 PERIOD-OVER-PERIOD EXPLANATIONS – BRIDGE YEAR

2007 Actual versus 2007 Budget

The total regulated hydroelectric production during 2007 was four percent (0.7 TWh) above the 2007 budget. Actual Niagara Plant Group production was four percent (0.4 TWh) above budget and actual R.H. Saunders production was five percent (0.3 TWh) above budget.

Production at the Sir Adam Beck plants in 2007 was almost five percent (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 percent of the historic mean compared to the budget mean flow which was about 91 percent of the historic mean.

Total production at DeCew Falls during 2007 was two percent 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 five percent (0.3 TWh) during 2007 due to higher St. Lawrence River flows. Annual mean St. Lawrence River flow for 2007 was about 96 percent of the historic mean, whereas the budget mean flow was about 91 percent of the historic 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 first half of 2007, but decreased to below normal during the second half of the year.

2007 Actual versus 2006 Actual

The total regulated hydroelectric production for 2007 was one percent (0.2 TWh) lower than the actual production for 2006 (see Ex. E1-T1-S2 Table 1).

Actual production for the Niagara Plant Group for 2007 was very similar to that in 2006.

Production increased by fifteen percent at DeCew Falls in 2007 compared to 2006, due to improved unit availability in 2007. Two major rehabilitation outages occurred at DeCew Falls II during 2006. One unit was out-of-service for the first half of the year, returning to service in late June, while a second unit was removed from service in late October. This second unit returned to service in May 2007, ahead of schedule.

Production at the Sir Adam Beck complex for 2007 was slightly lower (one percent) than 2006 production due to a slight decrease in flows. Annual mean Niagara River flow for 2007 was about 97 percent of historic mean compared to the 2006 annual mean which was about 98 percent of the historic mean.

Production at R.H. Saunders for 2007 was about three percent (0.2 TWh) lower than actual production during 2006. The annual mean St. Lawrence River flow for 2007 was 96 percent of the historic mean as compared to the actual 2006 annual mean flow of about 98 percent of the historic mean.

4.0 PERIOD-OVER-PERIOD EXPLANATIONS – HISTORICAL YEARS

2006 Actual versus 2006 Budget

The total regulated hydroelectric production during 2006 was four percent (0.7 TWh) above the budget that was developed at the end of 2005 (see Ex. E1-T1-S2 Table 1). Actual Niagara Plant Group production was three percent (0.3 TWh) above budget and actual R.H. Saunders production was six percent (0.4 TWh) above budget.

Production at the Sir Adam Beck plants in 2006 was five percent above budget primarily due to Niagara River flows being above plan. Actual annual mean Niagara River flow for 2006 was about 98 percent of the historic mean compared to the historic mean flow of 91 percent corresponding to the budget that was forecast the last quarter of 2005. Dry conditions existed when the budget was developed in October 2005. Based on the best water flow data available when the budget was developed, it was assumed that these conditions would persist in the short-term. However, there was an unexpectedly quick turnaround in water flows (due to heavy precipitation) after the budget forecast was developed, which led to higher actual production than was originally forecast.

Total production at DeCew Falls was approximately 16 percent below forecast due to the extension of the planned major outage at DeCew Falls II by almost three months during 2006. The outage was extended because of discovery work after the unit was taken out of service and dismantled. This discovery work could not have been anticipated in advance without the unit being dismantled. Thus major modifications to the mechanical components had to be performed during the overhaul which were not in the original scope.

R.H. Saunders production exceeded budgeted production by six percent (0.4 TWh) during 2006 due to higher St. Lawrence River flows. Annual mean St. Lawrence River flow for 2006 was about 98 percent of the historic mean compared to a value of 93 percent of the historic mean flow corresponding to the budget forecast.

2006 Actual versus 2005 Actual

The total regulated hydroelectric production for 2006 was about two percent (0.3 TWh) below 2005 production (see Ex. E1-T1-S2 Table 1). Most of the difference was attributable to the reduced production at DeCew Falls, as a result of additional outage time associated with the major overhaul work at DeCew Falls II during 2006 relative to 2005. There were no major outages at DeCew Falls II in 2005.

Total production from the Sir Adam Beck plants was similar for the two years, with 2006 production slightly below 2005. Production at R.H. Saunders was essentially the same for both years. Annual mean flows were very similar for 2005 and 2006 for the Niagara and St. Lawrence Rivers (within one percent for both).

2005 Actual versus 2005 Budget

The total regulated hydroelectric production for 2005 was similar to the budget developed in early 2005 (see Ex. E1-T1-S2 Table 1). Actual production exceeded the budget by about one percent (0.3 TWh). The annual mean flows for both the Niagara and St. Lawrence Rivers in 2005 were very similar to the annual mean flows corresponding to the 2005 budget forecast.

Numbers may not add due to rounding.

Table 1

Comparison of Production Forecast - Regulated Hydroelectric (TWh)

Line No.	Prescribed Facility	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Niagara Plant Group**	11.7	0.2	11.9	(0.4)	11.5	0.3	11.2	(0.0)	11.5
2	**Saunders GS[1]**	6.8	0.1	6.9	0.0	6.9	0.4	6.5	(0.2)	6.7
3	**Total**	18.5	0.3	18.7	(0.3)	18.4	0.7	17.7	(0.2)	18.2

	Other:									
4	**CNP Generation[2]**	(0.7)	0.0	(0.6)	(0.0)	(0.7)	0.0	(0.7)	0.0	(0.7)

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
5	**Niagara Plant Group**	11.1	0.4	11.5	(0.3)	11.2	0.8	12.0
6	**Saunders GS[1]**	6.4	0.3	6.7	(0.5)	6.2	0.3	6.5
7	**Total**	17.5	0.7	18.2	(0.8)	17.4	1.1	18.5

	Other:							
8	**CNP Generation[2]**	(0.7)	0.0	(0.7)	(0.0)	(0.7)	0.4	(0.2)

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

PRODUCTION FORECAST AND METHODOLOGY - NUCLEAR

1.0 PURPOSE

The purpose of this evidence is to provide a description of the methodology used to forecast nuclear production, and present the nuclear production forecast from 2005 - 2009.

Section 2.0 provides a description of the three phased Nuclear Production Planning Process which produces an integrated nuclear outage and generation plan ("Integrated Plan"). Section 3.0 presents the nuclear production forecast for 2005 - 2009 and describes the key factors impacting each year's production forecast. Section 4 discusses past and current initiatives at OPG that are addressing production reliability and outage performance. Definitions of terms italized below can be found in page 19.

2.0 NUCLEAR PRODUCTION PLANNING PROCESS

2.1 Overview – Integrated Nuclear Outage and Generation Plan

Production from a nuclear facility in a given year is equal to the sum of the station units' capacity in terawatt ("TW") times the number of hours in a year, less the number of hours during which the facility is subject to either planned outages or forced production losses. Nuclear facilities are designed as base load generators meaning generator output does not vary with market demand.

The OPG Nuclear production planning process produces an Integrated Plan. For each station, the plan derives a planned outage schedule and an estimate of *forced production losses*, due to unplanned outages and *derates.* OPG is a member of the *World Association of Nuclear Operators* ("WANO") and as such uses the WANO performance indicators to plan, track and assess the performance of OPG Nuclear units. For the purpose of this evidence, *forced production losses* and *planned outages* are defined in the Glossary of Terms as per the *WANO* industry guidelines. The discussion on standard industry benchmarks found in Ex. A1-T4-S3 describes the most common indicators used to plan and track OPG Nuclear performance.

The objectives of the Integrated Plan process include:

- Providing a key input into the annual OPG business planning process.
- Ensuring availability and optimal deployment of internal resources and external resources as needed to execute inspection, modification, and maintenance programs.
- Providing long-term operational plans to allow coordination of nuclear outages across OPG Nuclear, so as to plan reactor outages to occur in periods which have minimal impact on the Ontario electrical grid.
- Complying with the IESO market rules by providing the IESO with information on OPG's nuclear production, capacity, and reliability assumptions.

The following outage scheduling guidelines are considered during the planning process:

1. Eliminate/minimize overlap of planned outages in the Integrated Plan.
2. Minimize scheduling of planned outages during peak seasonal periods including summer and winter seasons.
3. Ensure outage changes impact minimally on planned production targets.
4. Proactively minimize probability of inter-site work and schedule conflicts re: shared resources and tooling (e.g. inspection maintenance services campaigns and *feeder* replacement projects; optimize use of roving maintenance crews).
5. Ensure standard intervals are applied between planned outages at each unit.

The Integrated Plan is generated annually in parallel with business planning and produces the following deliverables:

- A five year planned outage schedule for all stations. The schedule includes unit outage start dates, end dates, and durations.
- A summary of major elements of the work scope to 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 forced production losses represented by the *forced loss rate* ("FLR"). Discussion on such performance targets can be found at Ex. A1-T4-S3.

- Annual generation forecasts, in terawatt-hours ("TWh"), for individual nuclear units and an aggregated forecast for each station.

2.2 Generation Planning Methodology

The outage and generation planning process mandates three formal planning and review sessions per year which culminate in a final Integrated Plan:

- Phase 1: In the spring, based on a review of the previous five-year Integrated Plan, changes are projected and a first draft of the new Integrated Plan is produced. The first draft of the Integrated Plan is an input in the Nuclear business planning process.
- Phase 2: In the summer, a revised second draft of the Integrated Plan is produced. The second draft is incorporated into the initial nuclear submission to the OPG business planning process.
- Phase 3: In the fall, outage and nuclear generation forecasts are reviewed and finalized for the next five years in the final Integrated Plan for that year which is incorporated into the final nuclear submission to the OPG business planning process.

In addition, reviews are conducted on an ongoing basis to identify, assess and quantify any emergent developments and planning assumption changes that may impact a station generation plan. Outage and generation changes are incorporated into the draft Integrated Plan as updates occur over the three planning and review sessions during the year. Non-routine meetings are also conducted, in addition to the three mandated planning sessions, when developments in program assumptions or outage schedules need to be addressed. On limited occasions, significant developments may necessitate adjustments to the current approved Integrated Plan, if they impact on the immediate two year outage planning horizon. Examples of significant developments would include:

- *Lesson learned review* analysis from recent OPG outages, internal operating experience, emergent discovery work, or short-term updates to *life cycle management programs*.
- Operating experience incorporated from others in the nuclear industry.
- Unanticipated regulatory orders/decisions/requirements (e.g., Canadian Nuclear Safety Commission, Technical Standard and Safety Authority), or a failure to obtain regulatory

concurrence for plans, such that OPG must proceed with work activities which it had anticipated would not be required.

The draft Integrated Plan, and all non-routine updates to the current approved plan are approved by the Chief Nuclear Officer.

The following describes the stages in the preparation of the draft Integrated Plan.

2.2.1 Phase 1: Station Submission and Outlook

Generation planning begins at the start of the year with each station submitting an initial outage outlook for the five-year period commencing January of the next calendar year. For example, the station's generation planning review during 2006 covered the 2007 - 2011 timeframe. The process consists of a review and an update of years two to five of the currently approved five-year Integrated Plan. Outages for the first two years (year one in particular) of the five year planning cycle are subject to the most extensive review and planning. Outage details and generation data are also added for one additional year beyond the five years covered by the currently approved Integrated Plan.

The update process ensures that any regulatory, operational or maintenance issues that have arisen since the last Integrated Plan was finalized are reflected in the new Integrated Plan. Often outage durations are amended to include life cycle plan adjustments to inspections or maintenance needed to preserve the asset, or for disposition of regulatory concerns that have been identified through analysis of data obtained from recent outages experienced at either OPG or other nuclear industry participants. Major adjustments to the first year of the Integrated Plan are less likely than adjustments to subsequent years because the first year of the outage plan would have been subject to repeated reviews and updates over previous planning cycles. The deliverables in phase 1 are:

1. A five-year planned outage schedule for each unit in the nuclear fleet, as described below.
2. Targeted levels for forced production losses, as described below.

3. Generation targets and the underlying rationale for the changes relative to the currently approved Integrated Plan.

Planned Outage Schedule

Outage scope and duration for a planned outage are primarily determined by the station's life cycle plan (as discussed below), which includes the inspections and maintenance necessary to ensure safe, reliable long-term operation and 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 operations and the nature of 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 with respect to base OM&A in Ex. F2-T2-S1 are equally applicable and impact outage scope, duration, and cost.

Outage periods involve many plant organizations and individuals working together, and as such require high levels of coordination. Indeed, outages require focus, expertise, and a level of detail, which exceeds that of a major construction project. Careful preparation and execution of a well-developed plan are necessary for nuclear, radiological, and industrial safety as well as efficient achievement of production goals.

Outages consist of a combination of "routine" inspection and maintenance activities generally repeated for any outage, plus "non-routine" activities specific to a particular outage, all of which involve thousands of work tasks, representing extensive person-hours of labour, logically sequenced in the optimal order to ensure safe and effective execution of the outage. As an example of the complexity of outage planning, attached in Appendix A are level 1 schedules for the Pickering B Unit 6 2007 planned outage and the Darlington Unit 4 2007 planned outage.

Examples of routine activities would be *preventive maintenance programs*, *feeder* inspections or water lancing of *steam generators*, to maintain performance and reliability. Non-routine activities could include changes, 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 intends to transition to standard baseline outage templates, any outage will have unique aspects based on specific outage scope. Approximately 60 percent of the work activities in an outage scope typically relate to routine preventative maintenance and inspection activities while the remaining 40 percent relate to work activities for non-routine upgrades and modifications. Within this split, the station's planned outage scope would primarily consist of pre-defined work activities and related work tasks. However, approximately 15 percent of planned outage scope is contingency work activities 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 planned outage scope minimizes potential disruption to the outage schedule due to *critical path and bulk work* delays, as well as improving the credibility of the Integrated Plan.

In addition, in order to avoid a significant disruption to the outage schedule, OPG may have to postpone completion of non-critical, non-safety related discovery work activities until a following outage. This decision to postpone work activities can lead however to reduced production reliability during the post-outage period and require that future planned outages include deferred items from previous outages. By providing for a prudent level of contingency work activity in planned outage scope, OPG can balance the risk of outage extension due to discovery work against post-outage production reliability.

Outage duration is determined by the *critical path* of outage inspections and maintenance. It is also impacted by the configuration of the generating unit required to support complex logistical requirements of outage activities 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 based on *fuel channel and steam generator* work. Recently feeder piping inspections and maintenance are emerging as an additional critical path driver at some units.

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 long-term objectives of the aging and life cycle management programs, and to ensure safe and reliable operation of OPG Nuclear facilities for the duration of their planned lives. The aging and life cycle management programs outline specific objectives for all of the major plant components (e.g*., fuel channels*, *steam generators, feeders*). The program also details the frequency and nature of inspections, and recurring preventive maintenance work required to ensure unit fitness for service and maintain reliability and safety of the plant. While outage scope will always include routine inspections and maintenance activities, the equipment affected will vary from one outage to the next, in accordance with the inspections and maintenance schedule specified in the integrated aging and life cycle management programs. 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 (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 Pickering and station containment outage at Darlington).
- The stations develop high level planned outage schedules with the input and joint effort of several organizations, including Engineering, Inspection Maintenance Services, and Projects and Modifications. To accommodate constraints around inter-site sharing of

certain resources and tooling, this integrated input is a significant factor in determining both the scheduled outage dates and the sequencing of major critical path activities to 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: Inspection Maintenance Services staff will review the planning outage schedule to ensure that, given available resources, the scoped activities are executed and coordinated across all OPG stations, as well as providing additional review to ensure Inspection Maintenance Services external commitments are met. This 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 in 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 of planning, the outage OM&A costs are also estimated based on several factors including historical experience, projected contractor's costs, parts and projected equipment costs, and staffing requirements. Further discussion about the components and derivation of the forecasted outage OM&A costs can be found at Ex. F2-T4-S1.

Station staff prepares resource, duration, and cost estimates at a detailed level for outages. The analysis is more detailed for the initial years of the Integrated Plan. This analysis 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 start and end dates for individual activities within each outage. The *critical path* for upcoming outages is also determined at this level of planning.

- Each station's planned outage schedule includes some allowance for uncertainty to outage duration although the amount of allowance for uncertainty is not mandated nor standardized across all OPG stations, or even within the same station from one outage to the next. The station allowance for uncertainty to outage duration is reflected in the derivation of the *critical path* that underpins the planned outage duration and will reflect a station assessment of such factors as knowledge gained from past outages, assessment of the known and unknown technological risks specific to the outage, the number of inspections that may result in *discovery work* and resource capability and availability.

Forced Production Losses

With respect to *forced production losses*, all generating units face the risk of unscheduled equipment problems that may require unplanned shutdowns or derating the generating units. Accordingly, the stations develop targets that reflect the risk of such *forced production losses* for all units in the station. For planning purposes, the targets are derived as a forecast FLR.

Force loss rate target assumptions are determined by station management with input from Outage and Strategic Planning Departments, Engineering, and Finance. The FLR target assumptions incorporate the plants' recent historical 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 known risks. Further discussion on FLR target assumptions can be found at section 3 (OPG Nuclear production forecast trend) below.

Initial Draft Integrated Outage and Generation Plan

Using each station's initial planned outage schedule and FLR target assumptions, the Nuclear Finance Business Planning group prepares a draft Integrated Plan. The draft Integrated Plan provides outage schedules and targeted *forced production losses* for each station and for the entire OPG fleet, and is an input to the Nuclear business planning process.

The Nuclear Finance Business Planning group uses a generation planning model to calculate generation production targets (TWh) for each station. The model generates production and reliability targets using two independent variables: the number of planned outage days and the FLR target assumption. The model generates unit specific targets, as well as station and Nuclear fleet level summaries.

The draft Integrated Plan prepared by the Nuclear Finance Business Planning group provides monthly and annual generation TWh targets, planned outage days, and corresponding generation performance indicators including unit capability factor at the unit, station and fleet level, for each of the five years of the Integrated Plan.

2.3 Phase(s) Two and Three: Final Integrated Outage and Generation Plan

Following the preparation of the spring draft Integrated Plan, two subsequent Integrated Plans are prepared in the summer and fall as part of the three step planning process. The summer and fall updates follow up on phase one by responding to the latest generation related information from across OPG Nuclear and any changes in the overall nuclear program direction. The station outage schedules and station FLR target assumptions developed in phase one are reviewed for achievability and the economic rationale by station management, the Chief Nuclear Officer, and the Nuclear Executive Committee as part of the business planning process. These reviews can potentially identify revisions necessary to maintain the Integrated Plan in alignment with the business plan objectives, while ensuring the nuclear mandate of safe and reliable long-term operation is also maintained. The summer review (phase two) yields a preliminary set of nuclear generation targets which are incorporated into the five-year Nuclear business plan in October. The purpose of the October review (phase three) is to allow for corporate finalization, and approval in December of the final Integrated Plan in support of the final OPG business plan. The reviews also incorporate the fleet level uncertainty adjustment as discussed below.

The outage planning process also requires communication with OPG Energy Markets throughout the process and that their feedback is taken into account to:

1. Increase the probability of the proposed schedule being approved by the IESO, based on anticipated (i.e., 18 month forward looking) provincial supply and demand at the time of the proposed outage.

2. Take mitigating actions where the probability of obtaining IESO outage approval is at risk (e.g., re-schedule other OPG non nuclear outages).

   Planned outages must be registered with and "date-stamped" by the IESO. OPG Energy Markets files the OPG Nuclear outage schedule for the coming 18 months (and beyond) in order that OPG's outages secure an early "time-stamp" date, which determines their standing in the IESO's outage queue. All outages in the queue are subject to final approval by IESO, which can deny final approval of any planned outage at any time up to the start of the outage.

<u>Fleet Level Uncertainty Adjustment</u>

OPG incorporates a Nuclear fleet adjustment to the challenging station targets to arrive at a likely forecast of output from the overall Nuclear fleet. This fleet level uncertainty adjustment is a prudent way to manage fleet production forecasts. This adjustment is applied by nuclear management following the submission of the station production targets. This adjustment, which is typically 0.5 TWh (or one percent of forecast production), is intended to bring the fleet level production forecast to within acceptable confidence limits.

This adjustment for uncertainty is intended to address generic planned outage issues of the fleet. This differs from station planning where the prime focus is on risk assessment of a specific unit planned outage. The fleet adjustment recognizes the potential for concurrent or unexpected events not predictable from a station unit perspective in a given year. The fleet assessment is intended to mitigate threats that could emanate from general fleet aging issues, complexity in the fleet level activities (e.g., traveling crews and Inspection and Maintenance Services) in support of outages.

The fleet level uncertainty assessment is based on past experience, and recognizes the potential for unexpected additional inspections or maintenance that could impact the duration of a planned outage or the potential for forced outages within the fleet. The fleet adjustment which results from this assessment is formalized by applying adjustments to the planned outage duration for each station's planned outage schedule. The adjustment reflects the probability that there will be some major scope additions or delays resulting in an extension of a planned outage for at least one of OPG's nuclear units during the period. The fleet allowance reflects the integration of OPG's nuclear fleet and is not the sum of discrete outage by outage adjustments.

Over the past several years, actual lost production due to concurrent or unexpected events has exceeded the budgeted adjustment level provision. However, the fleet level uncertainty adjustment was not increased in the test period but remains in the typical 0.5 TWh range. This is because of expectations that the number of initiatives undertaken or that are being implemented, as discussed in section 4.0 below, will improve outage performance and reduce the factors that have compromised our forecast certainty in the past as well as maintaining the incentive for fleet operations to achieve a challenging production target.

3.0 OPG NUCLEAR PRODUCTION FORECAST TREND

The nuclear production forecast for 2008 - 2009 is shown in Ex. E2-T1-S1 Table 1 based on the business plan approved in December 2007, along with comparable historic figures for the period 2005, 2006 and 2007.

As shown in Ex. E2-T1-S1 Table 1, the expected trend in nuclear production over the period 2005 - 2009, consistent with the Integrated Plan finalized as of December 2007, shows a gradual but steady improvement in generation output. In 2009, the slight reduction in output is due to the simultaneous four unit outage for routine vacuum building inspection at Darlington.

The improving trend in nuclear production post 2005 reflects in part that prior to 2005, OPG Nuclear instituted a series of programs to address a previous lack of investment in many aspects of its operations, including maintaining the plant material condition of its nuclear assets and the lack of robust outage planning procedures and processes. In 2003, it was determined that, while some improvements (primarily safety and human performance related and inspection results) had been achieved, concerns remained over OPG Nuclear's future performance capabilities. The most significant risk identified was that the material condition of the nuclear plants was deteriorating as the plants entered the mid-points of their lives.

Since 2004, OPG Nuclear has focused on increased investment in the material condition of the units, through activities such as the Pickering B spacer location and relocation program, *feeder* replacements, and *steam generator* inspections. This investment was aimed at improving the long-term, performance, and reliability of the OPG nuclear generating stations.

The 2008 and 2009 test year forecasts take into account these past initiatives (e.g., investment in plant material condition) as well as other initiatives, discussed in section 4.0, which will lead to more sustainable, reliable, and predictable performance. Indeed, although 2007 annualized production did not meet target due to the unique events described in Ex. E2-T1-S2, recent positive results confirm the success of these initiatives including:

- The successful completion, five days shorter than the business plan target, of the 2007 spring Darlington Unit 4 planned outage. In addition, the duration of the 2007 fall Darlington Unit 2 planned outage was also less than the business plan target. This is the second successive outage where the site has met or bettered the target business plan outage duration.
- The Darlington Unit 3 unbudgeted planned outage, while outside the business plan, was pivotal in obtaining Canadian Nuclear Safety Commission regulatory approval for and successful pilot use of a previously unused reactor heat sink configuration. This reduced the mandatory outage duration by 11 days and promises significant potential benefits for future outages at Darlington.
- Improved organizational performance at Pickering B resulted in the completion of maintenance work activities during the maintenance window of the Pickering B Unit 5 planned spring outage on schedule and with the highest production task rate (work activities per outage day) ever achieved by Pickering B. However, the Unit 5 outage had to be extended due to equipment failures during the start-up window. Also the Pickering B fall outage was completed in 77 days, an improvement over previous outage performance of comparable scope which has required around 100 days.

For the 2008 - 2009 test period, the forecast number of planned outage days is 254 days in 2008 and 343 in 2009. This is a significant reduction from the 386 outage days (346 planned outage and 40 forced extension to a planned outage) experienced in 2005 and the 490 outage days (324 planned outage and 167 forced extension to a planned outage) experienced in 2006. Similarly, the FLR for the combined fleet of nuclear assets is expected to improve, with an anticipated drop from 11.7 percent in 2007, to a target of 4.2 percent by 2009. This improvement in the forecast FLR for the combined fleet in 2009 reflects the improved operating experience at Darlington and Pickering B which has allowed a reduction in the FLR target to 2 percent and 5 percent respectively offset by the ongoing reliability challenges at Pickering A reflected by an increased 2009 FLR target of 10 percent.

4.0 OPG NUCLEAR INITIATIVES TO IMPROVE OUTAGE PERFORMANCE AND PRODUCTION

OPG has implemented or is undertaking a number of initiatives to improve outage performance, the benefits of which are anticipated to emerge over time, including:

- Improving Outage Planning: Previous outage planning, particularly at Pickering B, was focused on major initiatives such as the spacer location and relocation program, resulting in “non-routine” outages typically longer than 100 days. OPG’s expectation moving forward is that there will be shorter duration, “routine” planned outages, supported by the following initiatives:
    - Commencing in 2006, OPG began implementing improved industry-standard outage planning milestones in the planned outage process, to transition to industry best practices. Examples of the standard planning milestones are shown in Appendix B. The milestones are used to improve outage management by facilitating better outage planning. The milestones define and describe discrete deliverables, accountabilities, timeframes, due dates for completion, and the criteria to be used to verify completion of the deliverable. The revised process also establishes requirements for earlier identification of labour and material requirements in support of annual business planning and the Supply Chain initiative described below.

- Improving processes to better manage outage scope with the intent to reduce the number of planned outage days. Scope management initiatives include prioritization of the proposed outage activities by various criteria including cost justification and need, thereby ensuring that the highest priority activities are undertaken and deferring lower priority activities. Another scope management initiative is to reduce scope "churn" (i.e., adding or removing work activities after implementing scope freeze).
- Establishing outage templates. Internal benchmarks detailing the amount of time and resources required for "routine" outage work activities. This initiative will improve long-term outage planning as well as establish metrics for benchmarking outage performance.
- Implementing the recommendations from *lesson learned reviews* following *planned outages*.

• Improved Outage Execution: OPG has initiated steps to improve outage execution performance thereby reducing future outage duration and costs including:
  - Outage Control Centre development. 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 the outage on schedule.
  - 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. These teams manage specific non-routine work activities.
  - Co-ordination of Operations and Maintenance: Operations staff perform 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 have 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. The processes allow OPG to quickly respond to, and more effectively manage *forced outages.* OPG is also taking steps to improve the organizational focus on and adherence to such procedures, including completion of l*esson learned reviews* following *forced outages.*
- Reducing the Number of Outage Days: The current plant material condition at Darlington is allowing OPG to implement a three-year cycle for planned outages compared to the current two-year cycle. Under a two-year cycle plan, each unit would be subject to 80 outage days (a 56 day outage after 28 months and a 24 day outage after 18 months). Under the three-year cycle, each unit is to be subject to 51 day outage every 34 months, reducing the average outage days per year for the four Darlington units over the cycle from 80 to 68 days.
- Improving Material Availability: Project management of outages requires that materials and replacement parts are available as required to minimize delays in completion of the outage. As discussed at Ex. F2-T2-S1, Nuclear Supply Chain has implemented an initiative starting in 2005, which focuses on reducing the average cycle time required to deliver materials and replacement parts to the stations. Preliminary indications are that this initiative, in conjunction with the outage planning milestones described above, is improving work planning and material procurement resulting in improved performance.
- Improving Future Reliability By Reducing Maintenance Backlogs: This initiative is focused on efforts to reduce the number of corrective and elective maintenance backlogs at all three stations. Maintenance backlogs represent deficiencies at the plant and are used as an indicator of station health. In the past, as discussed at Ex. A1-T4-S3, OPG reduced its investment in reducing maintenance backlogs. Moving forward, OPG will be focusing 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.

At Darlington and Pickering A, the focus is on reducing elective backlogs which are above industry standard benchmarks of 350 work orders per unit. The level of corrective backlogs is comparable with industry standards of 20 to 25 work orders per unit.

For Pickering B, initial focus has been on reducing corrective backlogs before major steps can be made to reduce the elective maintenance backlogs. In 2007 Pickering B was able to achieve its target of reducing corrective backlogs to industry standards.

CHART 1
ONLINE ELECTIVE AND CORRECTIVE MAINTENANCE BACKLOGS PER UNIT

Station	Backlog **Description**	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008 Plan**	**2009 Plan**
Pickering A	Elective	541	558	428	425	375
	Corrective	8	17	14	20	15
Pickering B	Elective	805	885	926	700	575
	Corrective	148	71	22	25	25
Darlington	Elective	767	584	373	350	325
	Corrective	20	14	13	15	15

- Improving the material condition of the plant: As noted above, during the period 2004 - 2007, OPG made major investments in improving the material condition of the Nuclear generating stations with the expectation of improved plant reliability and reduced forced production losses. This included investments to complete life cycle programs for major components at Pickering B and Darlington such as *feeder* replacement, *steam generator* inspections, and the completion of the spacer location and relocation program. Another initiative includes the plant reliability list program: The plant reliability list is a comprehensive identification and prioritization 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 across OPG Nuclear. 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 overall improved plant reliability.

Some of the major factors that are forecast to impact production in 2008 and 2009, and which are discussed in more detail at Ex. E2-T1-S2 are:

- The progress of Darlington in shifting from a two-year outage cycle to a three-year outage cycle beginning in 2006 (i.e., each unit will undergo a planned outage every third year as opposed to every second year).
- A vacuum building outage at Darlington in 2009, a regulatory requirement set out in our Operating Licences, will require all four units to be shut down for approximately four weeks.
- Reductions in the duration of planned outages at Pickering B, as steps are taken to implement a targeted outage duration of 40 to 50 days.
- Improvement in the forecasted FLR at Darlington and Pickering B reflecting recent improved operating performance, offset by an increase in the FLR target at Pickering A. Pickering A has also been subject, starting in August 2007, to a three percent derate of Units 1 and 4 due to an inability by OPG to obtain Canadian Nuclear Safety Commission concurrence with OPG's shutdown system trip set point methodology.

GLOSSARY OF OUTAGE DEFINITIONS AND GENERATION PERFORMANCE INDICATORS

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

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

Forced Outage: As per WANO industry performance reporting guidelines, a forced outage is a generator outage or derate 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 would represent an estimate of expected lost production due to forced outages and forced derates.

Elective Maintenance: Any work on power block equipment that is degraded.

Feeder: There are several hundred 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 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 with the Canadian Nuclear Safety Commission for their concurrence and approval.

Forced Extensions of 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.

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 schedule 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.

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

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.

Operating Capacity Factor: A standard WANO indicator of performance reliability. Operating capacity factor = 100-FLR.

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

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 Extensions: 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.

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

- Maintenance procedures.
- Recalibrations.
- Work package planning and preparation.
- Obtaining/preparing work permits for work packages.
- Lubrication programmes.
- Interval replacements of equipment components.

Steam Generator*:* A heat exchanger that transfers heat from the heavy water coolant to ordinary water. The ordinary water boils, producing steam to drive the turbine. The *steam generator* tubes separate the reactor coolant from the rest of the power-generating system.

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

Unit Capability Factor: Unit capability factor is a standard WANO indicator of performance reliability. Unit capability factor is the percentage of maximum energy generation that a unit/plant were 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.

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.

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

LIST OF ATTACHMENTS

Appendix A: Level 1 Planned Outage Schedules (Pickering B Unit 6 and Darlington Unit 4)

Appendix B: Planned Outage Milestones

APPENDIX A

Level 1 Planned Outage Schedules (Pickering B Unit 6 and Darlington Unit 4)

APPENDIX B

PLANNING OUTAGE MILESTONES

Milestone #/ Title	Accountable Manager(s)	CNO Tier 1 Indicators	Milestone TCD
01: Outage Objectives and Milestone Schedule	Manager, Outage (Strategic Planning) Manager, Outage (Pickering A)		PO-30
02: Major Scope Identified	Manager, Outage (Strategic Planning) Manager, Outage (Pickering A)		PO-24
03: Design Mods Scope Identified	Director, Engineering		PO-24
04: Revision 'A' Schedule Issued	Manager, Outage		PO-21
05: Long Lead Materials Identified	Manager, Supply Chain		PO-18
06: Phase I Assessment Complete	Manager, Maintenance		PO-14.5
07: POs Issued for LL Materials	Manager, Supply Chain		PO-14
08: Scope/Cost Challenge Meetings	Director, Work Management Manager, Outage (Pickering A)		PO-12.5
09: Scope Freeze	Manager, Outage	YES	PO-12
10: Design Permanent Mods Documents Issued	Manager, Design		PO-12
11: Labour Contracts/ PSAs Awarded	Manager, Maintenance		PO-11
12: Outage Execution Organization Identified	Manager, Outage		PO-11
13: Design Temporary Mods Documents Issued.	Manager, Engineering		PO-09
14: Revision B Schedule Issued	Manager, Outage		PO-08
15: Outage Support Documents/ Revisions Issued	Manager, Outage	YES	PO-08
16: Work Package Assessing Complete	Manager, Maintenance	YES	PO-06
17: Contingency Planning Complete	Manager, Outage		PO-04
18: Outage Pre-Reqs Scheduled	Manager, Work Control		PO-04
19: Revision C Schedule Issued	Manager, Outage	YES	PO-03
20: 95% Materials Onsite	Manager, Materials	YES	PO-03
21: Regulatory Approvals Obtained.	Manager, Engineering		PO-03
22: Pre-Outage Readiness Review Complete	Manager, Outage		PO-03
23: Work Permits Field Ready	Manager, Operations	YES	PO-02
24: Resource Profile Reconciled	Manager, Maintenance		PO-02

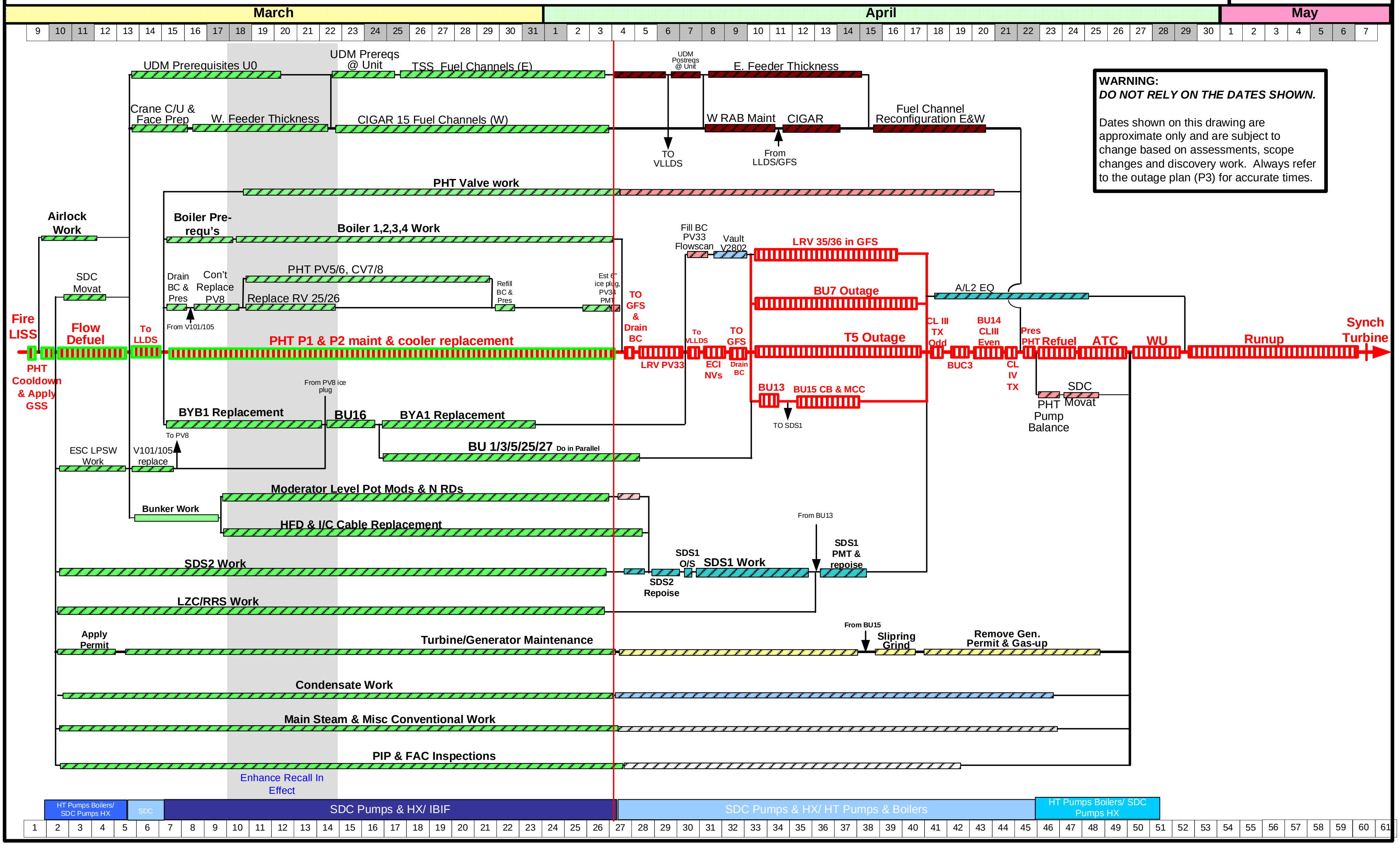
Milestone #/ Title	Accountable Manager(s)	CNO Tier 1 Indicators	Milestone TCD
25: Radiation Protection Support Prepared	Manager, Radiation Protection		PO-01
26: Outage Materials Staged	Manager, Maintenance		PO-01
27: Revision "0" Schedule Issued	Manager, Outage		PO-00.5
28: Walk- Downs Complete	Manager, Maintenance		PO-00.5
29: Outage Briefing Packages Ready	Manager, Outage		PO-00.5
30: Outage Metrics Prepared	Manager, Outage		PO-00.25
31: Outage Pre-requisites Complete	Manager, Maintenance	YES	PO-00
32: Outage Tools, Equipment and Facilities.	Manager, Maintenance		PO-00
33: Training Complete	Manager, Training Programs		PO-00
34: Outage Lessons Learned Compiled	Manager, Outage		PO+02

ONTARIO POWER GENERATION

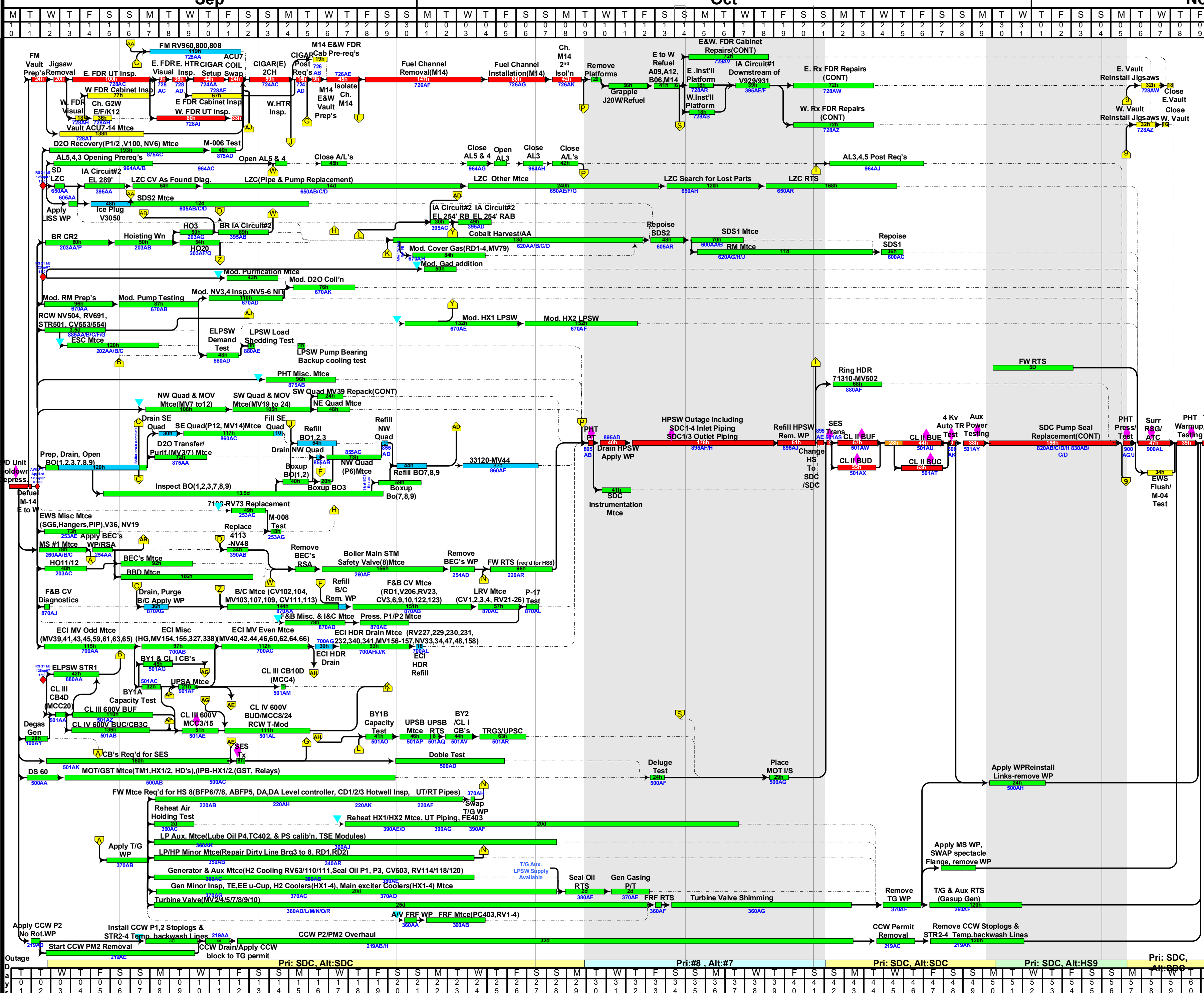
Darlington Nuclear

UNIT 4 2007 OUTAGE OVERVIEW (D741)

Rev 2 April 4, 2007



Unit 6-2007 Planned Outage



REV 0

Date: Aug 26, 2007 | Revised By:
REV. 44 | C. Duque

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Red Bar = Critical Path
Yellow = Near Critical Path
Outline Bar = Progress
Indicates Float between Windows
Indicates No Float between Windows
Blue = Iceplug Req'd/D2O Movement
IPTE Required
Constrained Start
Blue Line = Data Date @ 08:00 hrs

Legend

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

Numbers may not add due to rounding.

Table 1
Production Forecast Trend - Nuclear (TWh)

Line No.	Prescribed Facility	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Darlington NGS**	27.6	27.0	27.2	28.6	26.6
2	**Pickering A NGS**	3.6	6.4	3.6	7.1	7.3
3	**Pickering B NGS**	13.9	13.5	13.4	15.7	16.0
4	**Total**	45.0	46.9	44.2	51.4	49.9
5	**Unit Capacity Factor (%)**	83.8	81.5	77.1	88.7	86.2
6	**Planned Outage Days**	345.8	323.5	331.2	254.1	343.4
7	**FEPO Days**	39.8	167.0	131.2	0.0	0.0
8	**FLR (%)**	5.4	6.4	11.7	5.1	4.2

COMPARISON OF PRODUCTION FORECAST – NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of Nuclear production forecasts.

2.0 OVERVIEW

Nuclear's production data from 2005 budget to 2009 plan can be found in Ex. E2-T1-S2 Table 1.

OPG seeks through its extensive outage planning process to establish accurate and reliable production forecasts, while maintaining challenging targets. However, there are many unanticipated factors that can contribute to variances between actual and forecast production. In particular, *forced extensions of planned outages* can occur because inspections during an outage can lead to unanticipated requirements for additional work to be completed on *critical path* before the reactor can be restarted, either for safety, regulatory, or economic reasons.

The number of planned outage days per station reflects the work activity needed to enable completion of routine maintenance, inspections and project work, which can only be performed while the units are shut-down. The force loss rate ("FLR") reflects the forecast of the number of unplanned outage days per station, to accommodate any unforeseen events that result in unit shutdowns and forced derates. OPG's objective is to operate its nuclear generating stations in compliance with all applicable regulations and requisite licences and approvals in a safe, efficient, and cost effective manner. OPG will, in accordance with its Nuclear Safety Policy, conservatively implement unit shutdowns in all circumstances, when in OPG's assessment the safe operation of the station could be at risk.

OPG Nuclear's actual outage schedule (e.g., planned and forced) for 2005 and 2006 are set out in Appendix A and Appendix B, respectively. Appendix C sets out descriptions and related details of each outage in 2005, 2006 and 2007. Appendix C also includes a discussion of OPG's ongoing initiatives to minimize the reoccurrence of specific outage causal factors such as failures in the primary heat transport system and liquid zone controls. In addition, a discussion of the broad initiatives that have been undertaken by OPG (e.g., investment in plant material condition, improved forced outage readiness, and improved outage planning based in part on lessons-learned reviews) to transition OPG Nuclear to a more sustainable, reliable, and predictable level of performance by reducing the number of planned outage days and the level of forced production losses can be found in section 3 (OPG Nuclear Production Forecast Trend) in Ex. E2-T1-S1.

OPG Nuclear's planned outage days by month for 2007 - 2009 are set out in Chart 1 below:

Chart 1

Nuclear Planned Outage Days by Month 2007 - 2009[1]

	2007 Actual	**2008 Plan**	**2009 Plan**
Jan	0	0	0
Feb	0	11	0
Mar	23	35	29
Apr	58	48	68
May	53	31	88
Jun	10	10	30
Jul	0	0	6
Aug	0	0	0
Sep	30	19	13
Oct	77	49	36
Nov	60	47	56
Dec	20	4	17
Total	**331**	**254**	**343**

1. Numbers may not correspond to numbers in Ex. E2-T1-S2 Table 2b due to rounding in Chart 1. The numbers in Ex. E2-T1-S2 Table 2b are based on start dates and end dates that include mid-day starts.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2009 Plan versus 2008 Plan

The OPG nuclear fleet production forecast for 2009 of 49.9 TWh is 1.5 TWh less than the 2008 plan of 51.4 TWh.

The reduction in planned production in 2009 compared to 2008 is driven by a significant increase in the number of planned outage days at Darlington due to the station containment/vacuum building outage (“VBO”). This outage will take all four Darlington units off-line for approximately four weeks. The VBO is 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 Canadian Nuclear Safety Commission and are required to maintain Darlington’s operating licence (Canadian Nuclear Safety Commission licensing is further discussed at Ex. A1-T6-S1). Consequently, in 2009 Darlington will require 100.3 additional outage days versus the 2008 plan and produce 2.1 TWh less generation than the 2008 plan.

Other outage work activities planned for Darlington include replacement of feeders which cannot be completed in tandem with the VBO, but must be undertaken by way of a series of separate planned outages. The VBO makes the containment function unavailable, thereby restricting operations and maintenance on systems/equipment that require containment availability. There are also logistical and resource constraints that limit the outage work activities during the VBO.

While 2009 production for the combined nuclear fleet is forecast to be lower than in 2008 due to the VBO at Darlington, OPG is forecasting an 0.3 TWh generation increase at Pickering B due to a 14 day reduction in Pickering B’s planned outage program. The reduction in planned outage days at Pickering B in 2009 compared to 2008 reflects completion of steam generator repairs and service water work in 2008. Pickering A’s planned outage program for 2009 also contains 3 fewer Planned Outage days then the 2008 schedule.

Another offset to the negative Darlington VBO impact on production in 2009 is an expectation of additional production in 2009 compared to 2008 due to a decline in the FLR for the combined nuclear fleet. In that regard, OPG's current business plan reflects resolution by 2009 of the derate at Pickering A, which is discussed in the 2008 plan versus 2007 actual comparison below.

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

As shown in Ex. E2-T1-S2 Table 2b, the nuclear fleet production forecast for 2008 of 51.4 TWh is 7.2 TWh greater than the 2007 actual production of 44.2 TWh.

The forecast 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 254.1 days in 2008. The main drivers for the reduction in planned outage days are:

- The 2007 non-routine primary heat transport valve work at Pickering B will not be repeated in 2008.
- Darlington's move from two-year to a three-year outage cycle was completed in 2007. Accordingly, only one Darlington unit will go through a planned outage in 2008, reducing by 59.2 days the number of planned outage days and increasing by 1.2 TWh Darlington's 2008 generation.

The other main factor driving the forecast of increased production in 2008 as compared to 2007 is a targeted improvement in the FLR at Pickering A and Pickering B. For both Pickering A and B, the improvement reflects an expectation that a series of unique, one-time events that attributed to major losses of generation at the Pickering site in 2007 will not be repeated in 2008. These events, which are discussed in greater detail in Appendix C, are:

- Broken adjuster rod cable repair that resulted in a forced extension of the 2006 Pickering A Unit 1 planned outage into 2007.
- Pickering A forced outages on Unit 1 and Unit 4 due to inter-station transfer bus modifications and liquid zone control system problems.
- Contamination of Pickering demineralized water supply by a third party contractor inadvertent release of resin into the system.

For Pickering B, the change reflects improvements made in plant material condition and other initiatives discussed in Ex. E2-T1-S1.

Offseting OPG's forecast of improved production in 2008 as compared to 2007 is the reduction, on an annualized basis, of 0.25 TWh related to the derate of the Pickering A Units 1 and 4 that started in August 2007 due to an inability of OPG to obtain Canadian Nuclear Safety Commission concurrence with OPG shutdown system trip set methodology.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2007 Actual versus 2007 Budget

As shown on Ex. E2-T1-S2 Table 2b, OPG's 2007 actual nuclear generation of 44.2 TWh is 5.7 TWh lower than the 2007 budget production of 49.9 TWh.

Darlington actual generation of 27.2 TWh exceeded the budgeted target of 26.9 TWh, by 0.3 TWh. Pickering A and Pickering B experienced several unique, one-time events that resulted in unplanned generation losses. Details surrounding these events can be found in section 3 above and in Appendix C.

At Pickering A the actual 2007 generation was 3.6 TWh, 3.9 TWh below the 2007 budget of 7.5 TWh. The decrease in actual 2007 generation compared to 2007 budget is primarily due to the increased in force loss rate equivalent days in 2007 as a result of a series of unique, one-time events at Pickering, as discussed above, which impaired generation.

At Pickering B the actual 2007 generation was 13.4 TWh, 2.2 TWh less then the 2007 budget of 15.6 TWh. The decrease in actual 2007 generation compared to 2007 budget is 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 due to the inadvertent contractor release of resin into the station demineralized water supply which resulted in unscheduled loss of 60 production days and which also resulted in forced extension of planned outage days at Pickering B. Other Pickering B outages are set out in Appendix C.

At Darlington better then budgeted FLR results (actual 24.6 days forced loss equivalent days vs. budget of 54.5 days) are the main reason for higher than budget production (+0.3 TWh).

2007 Actual versus 2006 Actual

As shown on Ex. E2-T1-S2 Table 2a, OPG's 2007 Actual nuclear generation of 44.2 TWh, is 2.7 TWh lower than 2006 actual production of 46.9 TWh.

A main driver to the decrease in actual generation in 2007 compared to 2006 is the 247.6 additional forced loss rate equivalent days experienced in 2007 at Pickering A and Pickering B. This increase and the resulting loss in production, is largely a result of a series of unique, one-time events. These events are described in Section 3 above as well as in Appendix C.

Changing lake conditions have also contributed to the above average forced losses due to restricted cooling water intake flows caused by algae. While OPG has experienced *forced derates* due to algae in the past, the magnitude of algae build-up experienced in 2006 and 2007 has been unprecedented. Higher lake water temperatures also impacted production due to reduced condenser efficiency causing lower electrical output. Lost generation due to algae and higher lake water temperatures was 0.3 TWh in both 2006 and 2007.

The following summarizes the major variances between the 2007 actual and 2006 actual by station:

At Pickering A:

- 65.1 planned outage days and 60.2 forced extension of planned outage days compared to 74.0 planned outage days, and 21.0 forced extension of planned outage days in 2006.
- 299.6 forced loss equivalent outage days, compared to 108.9 days in 2006.

The small reduction in planned outage days was due to the fact that in 2006 Pickering A underwent a unbudgeted planned outage to replace coolers on the primary heat transport system (heavy water circulating system) pump motors.

With respect to the 2007 FLR, after having experienced 108.9 forced loss equivalent days at Pickering A in 2006 OPG's expectation for 2007 was for improved performance. In particular, Unit 4 had completed its first planned outage in 2006 following the return to service project, during which OPG completed maintenance to address post return to service reliability issue. OPG's 2007 budget therefore anticipated an improvement in Pickering A's FLR in 2007.

Despite these expectations, Pickering A experienced a further increase in its forced loss equivalent outage days in 2007 (along with increase in FEPO days) largely as result of a series of unique, one-time events that impaired generation, as described in Section 3 and in Appendix C.

At Pickering B:

- 131.8 planned outage days and 68.3 forced extension to planned outage days in 2007, compared to 154.5 planned outage days and 120.5 forced extension to planned outage days in 2006.
- The total number of forced loss equivalent outage days was 159.9 in 2007, compared to 84.2 days in 2006.

The planned outage reduction for Pickering B in 2007 reflects the fact that an extensive Pickering B spacer location and relocation campaign was concluded in 2006. Also, in 2006, Pickering B registered 120.5 days of forced extension to planned outage resulting from primary heat transport pump seal leaks and unplanned steam generator and service water maintenance work, for which corrective actions undertaken in 2007 have managed to mitigate reoccurrence.

With respect to the FLR, Pickering B experienced a further increase in its forced loss equivalent days in 2007 largely as a result of a series of unique, one-time events that impaired generation, as described in section 3 and in Appendix C, the most significant being the inadvertent release by a third party contractor of resin into the demineralized water system

At Darlington:

- 134.3 planned outage days and 2.7 forced extension to planned outage days in 2007, compared to 95.0 planned outage days and 25.5 forced extension to planned outage days in 2006.
- 24.6 2007 forced loss equivalent outage days in 2007, compared to 43.4 days in 2006.

The increase in planned outage days in 2007 is partly due to Darlington transitioning from a two-year to a three-year outage cycle. There was an increase in the scope of some outage work completed in 2007, including steam generator inspections, because of reduced outage frequency after 2007. In addition, Darlington inspected several fuel channels and replaced some feeders in 2007.

Darlington's forced loss equivalent outage days at 24.6 days in 2007 reflects continued success in achieving operational results consistent with, or better than its industry peers as discussed at Ex. A1-T4-S3.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2006 Actual versus 2006 Budget

As shown on Ex. E2-T1-S2 Table 2a, net generation for the year 2006 was 46.9 TWh, which was 2.5 TWh (five percent) lower then the 2006 budget of 49.4 TWh. Some of the major factors that resulted in actual lower production than budgeted in 2006 are:

- Actual FLR exceeded budgeted FLR, resulting in unplanned losses exceeding the 2006 business plan forced loss rate targets. The unplanned loss was equivalent to 12.2 days of production across OPG's nuclear generating stations.
- Across OPG nuclear facilities, there were 25 fewer planned outage days in 2006 than in the business plan target. However, despite the 25.0 fewer planned outage days, there were an additional 167.0 days related to unbudgeted *planned outage extensions* and forced

- extension to planned outage in 2006, such that the 2006 business plan target was exceeded by 142 days.

2005 Actual versus 2006 Actual

Total actual OPG Nuclear generation for the year 2005 was 45.0 TWh, 1.9 TWh less than the 2006 Actual of 46.9 TWh. The primary reason for the higher generation in 2006 was the return to service of Unit 1 at Pickering A in 2006. This was partly offset by the forced extension of the 2006 Pickering Unit 6 planned outage.

2005 Actual versus 2005 Budget

Total actual OPG Nuclear net generation for the year 2005 was 45.0 TWh, 0.2 TWh lower than the 2005 budget of 45.2 TWh. The main reasons for lower than planned generation include:

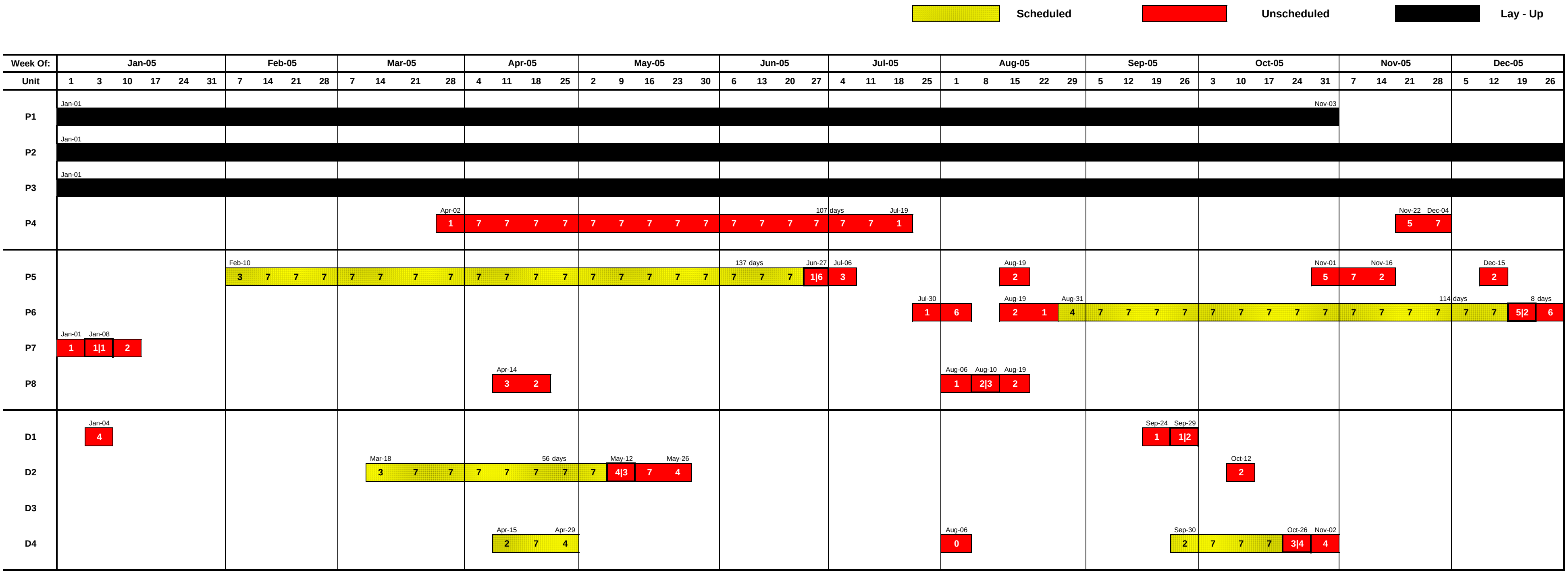
- 63.0 day delay in the commissioning, from lay-up, of Pickering A Unit 1.
- Worse than budgeted FLR performance of Pickering A, resulting in forced losses equivalent to 60.1 days more than the business plan target.
- 32 more days than business plan target outage days needed to complete planned outage work at Darlington.

The above losses were partially off-set by:

- Deferral of the Pickering A Unit 4 outage (66.2 days) to 2006.
- 12 fewer than planned business plan targeted outage days to complete planned outage work at Pickering B.
- Better than planned FLR performance at Pickering B (52.0 days lower than business plan target) and Darlington (46 days lower than business plan target).

LIST OF ATTACHMENTS

2005 Outage Results
OPG Nuclear



APPENDIX A

Outage Schedule 2005

Chart 1 attached to this Appendix A provides a visual display of scheduled and unscheduled outage start dates, end dates, and duration for 2005.

The following is provided to assist in a review of the information set out in the tables:

Scheduled outages include planned outages and unbudgeted planned outages. These terms are defined in E2-1-1.

Unscheduled outages include forced outages, and forced extensions of planned outages. These terms are also defined in E2-1-1.

Pickering A units 1, 2 and 3 are shown in lay-up mode until, in the case of unit 1, the unit was returned to service in November, 2005.

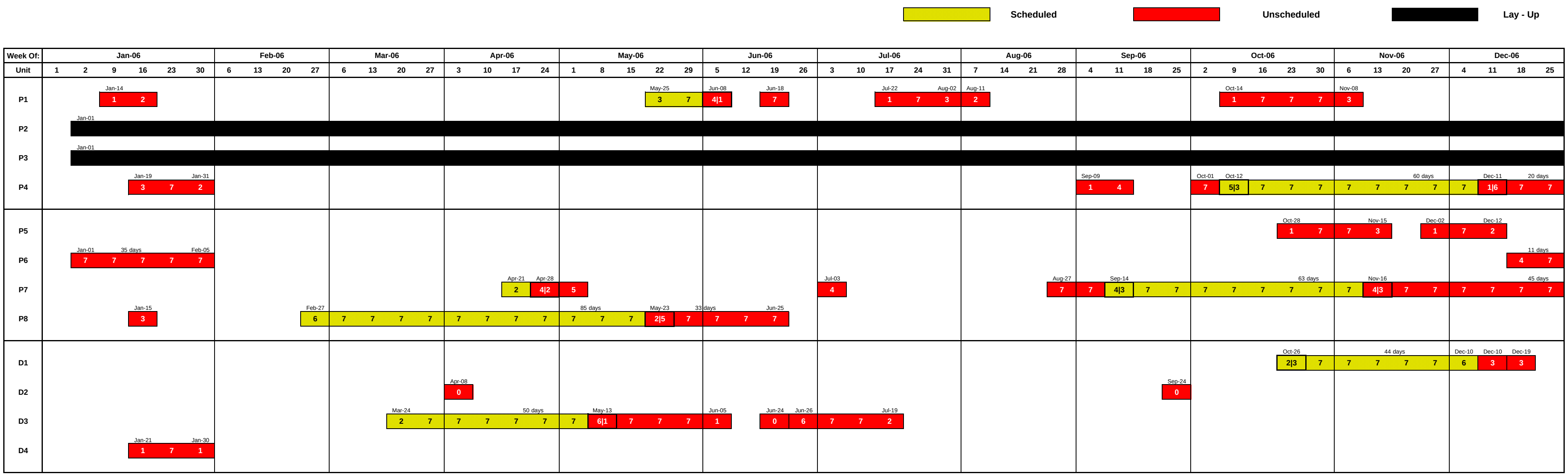
The first vertical column in the charts refers to the various nuclear units by station. Units P1, P2, P3 and P4 refer to Pickering A, units P5, P6, P7 and P8 refer to Pickering B units. The Darlington units are referenced as D1, D2, D3 and D4.

The first horizontal row in the charts, designated “week of”, shows the first day of each week of each month of the year for all 52 weeks. For example, by reference to April 2005, April 4 was the first day in the first complete week in April 2005. The next full week commenced April 11. The days that include April 1-3 are captured in the table in the 7 days of the week starting March 28.

Outage duration is also depicted on each chart visually and by start/end date and by number of days during the outage. For example, by reference to Chart 1, Darlington Unit 2 had a scheduled (i.e. planned) outage in the spring of 2005 that commenced in the morning of March

18, 2005 and ended May 12, 2005 for a total of 56 days. As well, this unit experienced a forced extension of the planned outage that commenced on May 12, 2005 and ended May 26, 2005 for a total of 14 days. The total duration was 70 days.

2006 Outage Results
OPG Nuclear



APPENDIX B

Outage Schedule 2006

Chart 1 attached to this Appendix B provides a visual display of scheduled and unscheduled outage start dates, end dates, and duration for 2006.

The following is provided to assist in a review of the information set out in the tables:

Scheduled outages include planned outages and unbudgeted planned outages. These terms are defined in E2-1-1.

Unscheduled outages include forced outages, and forced extensions of planned outages. These terms are also defined in E2-1-1.

Pickering A units 1 and 2 are shown in lay-up mode.

The first vertical column in the charts refers to the various nuclear units by station. Units P1, P2, P3 and P4 refer to Pickering A units. Units P5, P6, P7 and P8 refer to Pickering B units. The Darlington units are referenced as D1, D2, D3 and D4

The first horizontal row in the charts, designated “week of”, shows the first day of each week of each month of the year for all 52 weeks. For example by reference to April 2006, April 3 was the first day in the first complete week in April 2006. The next full week commenced April 10th. The days that include April 1-2 are captured in the table in the 7 days of the week starting March 27th.

Outage duration is also depicted on each chart visually and by start/end date and by number of days during the outage.

Darlington	2005						
Planned Outages & Extensions	**Outage Type**	**Start Date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Outage Scope / Description**	**Management Action to Prevent Recurrence**
D2	PO	18-Mar	12-May	55.5	1.24	Outage scope included Feeder inspections/replacements/CIGARS/Boilers/Turbine inspections/SDS2.	Not applicable
	FEPO	12-May	27-May	14.4	0.32	FEPO due to installation problems with Single Fuel Channel Replacement.	Investigation completed. Procedures were enhanced for future installations to address results of investigation. The enhancements to the procedure were verified by the succesful completion of 2007 Pickering B fall outage .
D4	PO	15-Apr	29-Apr	13.3	0.3	Unbudgeted Planned Outage. An additional unbudgeted planned outage was added to the 2005 schedule after completion of the 2005 business plan in order to complete Moisture Separator Reheater Inspection and Repair . Without this outage, continued operation would have resulted in significant reduction in the life of the low pressure turbine blade, bundles and casing with increased risk of material damage in the future	Regular inspections carried out as part of subsequent planned outages to minimize potential for unbudgeted planned outages.
	PO	30-Sep	26-Oct	26	0.58	Critical Path of planned outage included SDS 1/2, Turbines, Electrical and Feeder Inspection	Not applicable
	FEPO	26-Oct	2-Nov	7.9	0.18	During routine periodic inspection program on the Heat Transport System, inspections discovered some crack indications in the bleed condenser nozzles.	Discovery work. As a precaution, the outage scope was increased to include inspections of all the large nozzles in the bleed condenser.Inspections added to subsequent forced and planned outage schedules.
Forced Outages	**Outage Type**	**Start Date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Description**	**Management Action to Prevent Recurrence**
D1	FO	4-Jan	9-Jan	4.5	0.1	Loss of Low Pressure Service Water to the unit. During maintenance on the LPSW strainer backwash system, the strainers became plugged, and water supply pressure fell. Operators reponded to this event as per procedure by shutting down the reactor and turbine and re-establishing cooling water flow.	Screen house rehab project team was put together and all screen houses have been overhauled. Upgrades are being assessed to deal with changing lake conditions.
	FO	24-Sep	26-Sep	2	0.05	A problem with the Unit 1 fuelling unit was detected by Fuel Handling operators and as a result, fuelling was unable to continue and Unit 1 was shutdown	Material conditions evaluated and repairs completed. Procedures reviewed and revised based on investigation of failure.
	FO	29-Sep	1-Oct	2.1	0.05	Unit 1 was pre-emptively shut down for screen wash system repair. Excess silt and algae caused the circulating water screens to become plugged	Screen house rehab project team was put together and all screen houses have been overhauled. Upgrades are being assessed to deal with changing lake conditions.
D2	FO	12-Oct	14-Oct	2.2	0.05	During ground fault troubleshooting, a Unit 2 reactor setback occurred on low deaerator level.	Discovery item. Lessons learned from investigation have been incorporated into troubleshhoting procedures for future planned outages.

Darlington	2006						
Planned Outages & Extensions	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Outage Scope / Description**	**Management Action to Prevent Recurrence**
D1	PO	27-Oct	10-Dec	44.5	1	Planned outage critical path was three feeder replacements	Not applicable
	FEPO	11-Dec	13-Dec	2.8	0.06	Problems associated with feeder replacement resulted in extension of planned outage	Lessons learned incorporated into D721 feeder replacment program.
D3	PO	23-Mar	13-May	50.5	1.13	Planned outage. Critical path included defuelling, CIGAR inspections, TSS testing, feeder inspections, heat pumps, turbine work and blade inspections	Not applicable
	FEPO	13-May	5-Jun	22.7	0.51	Planned outage was extended by 22.7 days due to fuel handling problems and labour availability during the feeder inspection campaign.	Staffing plan revised for future fuel handling. Modifications were completed on fuelling machine bridges in the unit to eliminate the need for extra panel operators.
Forced Outages	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Description**	**Management Action to Prevent Recurrence**
D1	FO	25-Oct	26-Oct	1.8	0.04	Unit shut down when a shut-off rod clutch card failed. The unit was placed in a safe and stable state and the 27 Oct planned outage commenced shortly thereafter.	Investigation identified fault. All clutch cards on all units upgraded.
	FO	19-Dec	22-Dec	2.6	0.06	During post-outage testing following completion of the Unit 1 planned outage, the unit experienced a turbine generator trip.	Material condition evaluated and repairs completed.
D2	FO	8-Apr	9-Apr	0.2	0.005	Loss of automatic control of the turbine necessitated a brief outage to replace a turbine control computer board.	Material condition evaluated and repairs completed.
	FO	24-Sep	24-Sep	0.4	0.01	A turbine trip on Unit 2 resulted in approx 10 hours of unplanned outage	Material condition evaluated and repairs completed.
D3	FO	24-Jun	24-Jun	0.5	0.01	Turbine tripped on high bearing vibration.	Material condition evaluated and repairs completed.
	FO	26-Jun	19-Jul	22.5	0.5	D3 was forced offline for 22.5 days due to a precautionary decision to inspect for potential heat damage to vault cables after excess temperatures were recorded inside the reactor vault caused by a faulty feeder cabinet door latch.	Preventive maintenance program on feed cabinet doors implemented for future planned and forced outages.
D4	FO	21-Jan	30-Jan	9.1	0.2	D4 was forced out for 9 days to repair a leaking instrument line in the containment collection	Material condition evaluated and repairs completed.

Darlington	2007 January - December						
Planned Outages & Extensions	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Outage Scope / Description**	**Management Action to Prevent Recurrence**
D2	PO	20-Sep-07	19-Nov-07	59.70	1.34	Planned outage critical path was fuel handling	Not applicable
D3	PO	11-May	26-May	16	0.36	Unbudgetted planned outage required to repair leaking PHT pump seals.	Investigation of pump seal failure identified failure mechanism and enhancments incorporated into rebuild procedure to minimize potential for unbudgeted planned outages.
	FEPO	27-May	29-May	2.7	0.06	FEPO was due to a light water steam leak and stuck main turbine value during the start up evolution	Material condition evaluated and repairs completed.
D4	PO	9-Mar	6-May	58.5	1.31	Unit 4 was returned to service on May 6th, 5 days earlier than the BP target of 63.5.	Not applicable
Forced Outages	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Description**	**Management Action to Prevent Recurrence**
D1	FO	29-Jun	3-Jul	4.2	0.09	Unit 1 turbine tripped on an instrumentation fault.	Material condition evaluated and repairs completed. In addition preventative maintenance program reviewed and updated.
	FO	20-Oct-07	20-Oct-07	0.50	0.01	Forced outage required to repair faulty back-up automatic voltage regulator.	Work had been scheduled for spring Darlington planned outage but unit needed to be taken off line for repairs in October 2007.
D4	FO	10-Nov	12-Nov	2.39	0.05	Control adjuster (CA1) dropped fully in core. CCM1 and CCM2 replaced. Poor soldering joints found on CCM1.	Review of failed components traced failure to rework associated with D741 board repairs. Procedure update in place to ensure independent review of repairs.
	FO	13-Nov-07	19-Nov-07	5.28	0.12	Unit shut down as a result of passing RV on gland seal supply line to boiler feed pump.	Problem identified as system configuration problem. Operating manual updated to prevent re-occurrence

Pickering A	**2005**						
Forced Outages	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Description**	**Management Action to Prevent Recurrence**
P4	FO	2-Apr	19-Jul	107.3	1.40	P4 was pro-actively shut down for 107.3 days to allow for inspections on feeder pipe elbows in response to new information on feeder thinning rates on Unit 1.	Governance program for primary heat transfer feeders has been established. It provides roles and responsibilities for feeder aging management. Additionally periodic review of operating experience is being conducted on flow accelerated corrosion, in co-operation with external nuclear industry groups (Candu Operating Group and Electrical Power Research Institute). A feeder maintenance strategy is a component of OPG's ongoing business plans.
	FO	22-Nov	4-Dec	11.8	0.15	P4 was forced offline for 11.8 days due to a primary heat transport pump trip on electrical protection.	Lessons learned from Unit 4 force outage resulted in initiation of a program to replace all coolers in Units 1 and 4, which was completed by early 2007. In addition, reprioritization of primary heat transport coolers will ensure there is periodic inspection and maintenance performed on these coolers. Additionally, a programmatic strategy for operating components beyond the manufacturers recommended end of life has been established and component condition assessments governance has been prepared.

Pickering A		2006					
Planned Outages & Extensions	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Outage Scope / Description**	**Management Action to Prevent Recurrence**
P1	PO	25-May	8-Jun	14.0	0.18	Unit was shut down for unbudgeted planned outage on May 25th. Critical path is replacement of coolers on the heat transport pump motors.	Lessons learned from Nov 22, 2005 forced outage resulted in initiation of a program to replace all coolers in Units 1 & 4, which was completed by early 2007. In addition, reprioritization of primary heat transport coolers will ensure there is periodic inspection and maintenance performed on these coolers. Additionally, a programmatic strategy for operating components beyond the manufacturers recommended end of life has been established and component condition assessments governance has been prepared.
P1	FEPO	8-Jun	9-Jun	0.9	0.01	Delay in returning the unit to service due to a light water steam leak.	Equipment breakdown during start up. Material evaluation and repairs completed.
P4	PO	12-Oct	11-Dec	60.0	0.78	Major scope during planned outage includes: feeder replacements, crack inspections, thickness measurements, boiler tube inpsections and thermal sleeve replacements, fuel channel turbine & generator inspections.	Not applicable
P4	FEPO	12-Dec	31-Dec	20.1	0.26	The unit 4 planned outage was primarily extended due to delays in steam generator repairs and due to the inadvertent release by a third party contractor of purification system resin into the feedwater system.	Steam generator repairs completed. Thermal sleeve contractor rating downgraded. See Appendix C Forced Outage Report and Summary of Corrective Actions Taken, i.e.Resin Inclusion Event
Forced Outages	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Description**	**Management Action to Prevent Recurrence**
P1	FO	14-Jan	17-Jan	3.1	0.04	Unit shutdown due to main output transporter cooling pump failure.	All contactors and relays for all cooling pumps on Units 1 and 4 replaced. Design change to facilitate routine testing of pump power supply. Reviewed & optimized preventive maintenance program.
P1	FO	18-Jun	25-Jun	7.0	0.09	Unit 1 was shut down due to a faulty ribbon cable in the moderator temperature control circuit resulting in loss of moderato cooling.	Equipment break down represented a single point of vulnerability. An OPG fleet initiative is underway that is focusing preventative maintenance on identified single points of vulnerability to prevent reoccurrence.
P1	FO	22-Jul	2-Aug	10.7	0.14	Unit 1 was shut down on July 22nd to address problems with the liquid zone control system.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Pickering A Liquid Zone Control
P1	FO	11-Aug	13-Aug	1.8	0.02	Unit 1 was shut down on August 11th for approximately 48 hours to repair an air conditioning unit in the moderator room.	Material condition evaluated and repairs completed.
P1	FO	14-Oct	8-Nov	25.0	0.33	Unit 1 was shut down to address problems with liquid zZone control system.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Pickering A Liquid Zone Control
P4	FO	19-Jan	31-Jan	11.9	0.16	Unit 4 was taken off line to investigate abnormalities found with the turbine oil supply pressure due to lube oil pump failure.	Investigation determined that during return from system overhaul, main lube oil impeller had been reassembled incorrectly. Equipment
P4	FO	9-Sep	14-Sep	5.0	0.07	Unit 4 was shut down to repair turbine release valves.	Material condition evaluated and repairs completed.
P4	FO	1-Oct	13-Oct	11.7	0.15	Unit 4 was shut down due to address problems with the liquid zone control system.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken, i.e.Pickering A Liquid Zone Control

Pickering A		**2007 January - December**					
Planned Outages & Extensions	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Outage Scope / Description**	**Management Action to Prevent Recurrence**
P4	FEPO	1-Jan	19-Feb	49.2	0.64	The Unit 4 Dec 12 2006 forced extension to planned outage continued into 2007 as a result of problems with an adjuster rod broken cable.	Procedures improved and reinforcement of procedural use and adherance as a learning tool for the stations
P1	PO	16-Oct	21-Dec	65.1	0.85	Planned outage critical path was feeder inspections	Not applicable
P1	FEPO	21-Dec	31-Dec	11.0	0.14	Planned outage extended due to delays in completion of heat transport maintenance work and a shutdown cooling pump failure that prevented progression of outage.	Delays in heat transport maintenance work due to incorrect parts. Future outages will include a more comprehensive configuration management review for work on or near critical path. Several days also lost due to an unforseen failure of a SDC pump. No further management action required for this equipment failure.
Forced Outages	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Description**	**Management Action to Prevent Recurrence**
P1	FO	11-Mar	23-Mar	11.9	0.16	Unit 1 was shut down to repair a crack in a welded joint in the low pressure service water supply line to the moderator heat exchanger.	Failed welded joint occurred due to vibration fatigue. Material condition evaluated and repairs completed.
	FO	5-Jun	16-Oct	133.33	1.73	Units 1 and 4 were shut down when it was discovered that the configuration of Unit 3 Class III inter-station transfer bus (ISTB) power supplies could result in the unavailability of certian control power should a steam line break occur. In addition LZC problems extended the outage.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Pickering A Electrical Supply System and the Pickering A Liquid Zone Control system.
P4	FO	15-Apr	29-Apr	14.2	0.19	Unit 4 was taken off-line to replace heat transport system (HTS) post-accident temperature monitoring detectors (RTDs). While preparing to return the unit to service, a high HTS leakage to collection was discovered. During troubleshooting, a low heat transport pressure transient occurred, resulting in a reactor trip.	Material conditon evaluated, problem with RTDs determined as design error. RTDs were replaced. Lessons learned include increased focus going forward on improving design human performance. On HTS leakage, material condition evaluated and cuase of leakage repaired. On reactor trip which was human performance related, actions taken on coaching re adherence to procedures.
	FO	4-Jun	4-Oct	121.57	1.58	Units 1 and 4 were shut down when it was discovered that the configuration of Unit 3 Class III inter-station transfer bus (ISTB) power supplies could result in the unavailability of certain control power should a steam line break occur.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Pickering A Electrical Supply System.
	FO	5-Oct	13-Oct	8.09	0.11	Unit shutdown due to spurious safety system trip.	This unplanned safety system trip occurred due to the shutdown system operating as intended. No further management action required.

Pickering B 2005

Planned Outages & Extensions	Outage Type	Start Date	End Date	Duration (days)	Generation Loss (TWh)	Outage Scope / Description	Management Action to Prevent Recurrence
P5	PO	10-Feb-05	27-Jun-05	137.0	1.78	Critical path work during planned outage was through fuel channel and boiler inspections.	Not applicable
	FEPO	27-Jun-05	06-Jul-05	9.0	0.12	Planned outage was forced extended by 9 days due to light water leak in the shutdown cooling heat exchanger anda hydrogen gas leak into the stator cooling water system in the generator.	Corrective actions include development of a preventive maintenance task to pressure/vacuum test the generator stator winding/end core cooling for leaks and improving the thoroughness of inspections on this equipment during future planned outages.
P6	PO	31-Aug-05	23-Dec-05	114.0	1.48	Critical path work during planned outage was through fuel channel, boiler and turbine inspections. There was a reduction of 14 days to the planned outage by way of a deferred start-date due to a change in outage duration related to a universal delivery machine installation and a single fuel channel replacement	Not applicable
	FEPO	23-Dec-05	01-Jan-06	8.4	0.11	Force extension of planned outage due to shutdown cooling pump 4 mechanical pump seal replacements. Also planned outage was extended (into 2006) to remove materials left inadvertently in steam generator following maintenance.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Shutdown SDC Seal Performance. Efforts to improve performance re foreign material exclusion (FME) are focused on human performance improvement. Recent FME initiatives at OPG include specialized FME training for maintenance; FME benchmarking to best-in-industry and revising procedures as required.

Forced Outages	Outage Type	Start Date	End Date	Duration (days)	Generation Loss (TWh)	Description	Management Action to Prevent Recurrence
P5	FO	01-Nov-05	16-Nov-05	14.3	0.19	Unit forced outage to investigate intermittent noise coming from Low Pressure Turbine No. 3.	Investigation completed and minor equipment defects were repaired. The frequency and intensity of noise events were significantly reduced but not eliminated. Unit returned to service with enhanced monitoring in place. Turbine overhaul in subsequent outage corrected problem completely.
	FO	15-Dec-05	17-Dec-05	2.1	0.03	Turbine trip caused by turbine control hydraulic system filters plugging, while the standby system was out of service for a planned inspection.	Investigation completed and procedures reviewed and revised to eliminate cause of failure.
	FO	19-Aug-05	20-Aug-05	1.8	0.02	Multi-unit shutdown (see below) due to high influx of algae into screen house.	Iinvestigation completed on muti-unit outage including effectiveness of screenhouse modifications, operating strategies, design review of screen house. Lessons learned implemented and various actions undertaken to prevent recurrence,e.g. install lake condition monitoring in order to develop an understanding of algae behaviour, determine the optimal response strategy to a debris run event, install meteorological data showing the precursors to algae runs at Pickering.

Forced Outages	Outage Type	Start Date	End Date	Duration (days)	Generation Loss (TWh)	Description	Management Action to Prevent Recurrence
P6	FO	30-Jul-05	05-Aug-05	6.5	0.08	Forced Outage due to high primary heat transport leakage to collection. Emergency coolant injection system MV52 replaced.	Investigation determined that leakage was packing failure and equipment was repaired. Performance maintenance review conducted to ensure maintenance frequency is appropriate.
P6	FO	19-Aug-05	22-Aug-05	2.9	0.04	Multi-unit shutdown due to high influx of algae into screen house.	Investigation completed on muti-unit outage including effectiveness of screenhouse modifications, operating strategies, design review of screen house. Lessons learned implemented and various actions undertaken to prevent recurrence,e.g. install lake condition monitoring in order to develop an understanding of algae behaviour, determine the optimal response strategy to a debris run event, install meteorological data showing the precursors to algae runs at Pickering.
P7	FO	01-Jan-05	02-Jan-05	1.6	0.02	Forced outage continues due to full stream heavy water leak from shutdown cooling pump 4.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - SDC Pump Seals
P7	FO	08-Jan-05	10-Jan-05	2.6	0.03	Turbine trip on loss of excitation due to AVR power supply fault.	Investigation determined that the AVR power supply problems caused the AVR to fail off. An electronic card was repaired. Failure mode of card was inspected to prevent recurrence.
P8	FO	14-Apr-05	20-Apr-05	5.5	0.07	Unit forced out due to failure of bleed condenser spray control valve CV113.	Process equipment failure. Material condition evaluated and repairs conducted.
P8	FO	06-Aug-05	09-Aug-05	3.2	0.04	Reactor trip during SDS2 maintenance.	Investigation completed and attributed to human performance (i.e. incorrect application of correct component verification). Procedures revised, inappropriate employee behaviours addressed, enhanced field training implemented and the Human Performance Working Committee were requested to develop and implement new relevant processes.
P8	FO	10-Aug-05	12-Aug-05	2.9	0.04	During re-start from forced outage, Unit 8 turbine generator tripped at 28% due to loss of excitation.	Investigation conducted and identified vulnerabilities with field breakers. Maintenance checks, inspections and cleaning were conducted to improve reliability of field breakers. Implemented improved preventive maintenance processes for all units.
P8	FO	19-Aug-05	21-Aug-05	2.1	0.03	Multi-unit shutdown due to high influx of algae into screen house.	Investigation completed on muti-unit outage including effectiveness of screenhouse modifications, operating strategies, design review of screen house. Lessons learned implemented and various actions undertaken to prevent recurrence, e.g. install lake condition monitoring in order to develop an understanding of algae behavior, determine the optimal response strategy to a debris run event, install meteorological data showing the precursors to algae runs at Pickering.

Pickering B 2006

Planned Outages & Extensions	Outage Type	Start date	End Date	Duration (days)	Generation Loss (TWh)	Outage Scope / Description	Management Action to Prevent Recurrence
P6	FEPO	01-Jan-06	05-Feb-06	35.4	0.46	Continuation of forced extension (of Aug 2005 planned outage) to remove materials left inadvertently in steam generator following maintenance.	Efforts to improve performance re foreign material exclusion (FME) are focused on human performance improvement. Recent FME initiatives at OPG include specialized FME training for maintenance; FME benchmarking to best-in-industry and revising procedures as required.
P7	PO	21-Apr-06	28-Apr-06	6.5	0.08	Unbudgeted planned outage required for maintenance on stuck shutdown cooling system inlet valve MV4, and bleed circuit CV104 repair.	Investigation completed and cause of failure determined. Maintenance procedures revised for future outages to capture lessons learned.
	PO	14-Sep-06	16-Nov-06	63.0	0.82	Planned Outage for SLAR, heat transport system valve maintenance, service water outage, and reactor face work.	Not applicable
	FEPO	28-Apr-06	05-May-06	7.1	0.09	Extension due to primary heat transport D2O leakage to collection. Critical path is through repair of main circuit and ECI valves.	Investigation completed and cause of failure determined to be failed packing in two MV's. The MV's were repacked and returned to service. Extent of condition evaluated for other MVs and no further action was recommended at the time; subsequently proactive packing of critical MV's was scoped into future planned outages.
	FEPO	16-Nov-06	01-Jan-07	45.3	0.59	P7 planned outage was extended by 45.3 days in 2006. The extension was necessary to complete service water system maintenance and replace shutdown cooling pumps seals The outage was further extended due to steam generator chemistry issues arising from the inadvertent release by a third party contractor of feedwater purification system resin into the demineralized water supply.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Resin Inclusion Event and Improved SDC Seal Performance.
P8	PO	27-Feb-06	23-May-06	85.0	1.10	Critical path work during planned outage was through fuel channel, boiler and turbine inspections and maintenance.	Not applicable
	FEPO	23-May-06	25-Jun-06	32.6	0.42	The P8 planned outage was extended by 32.6 days primarily due to primary heat transport pump seal failure, replacement of shutdown cooling pump seals and problems with heat transport pressure control, and resource availability due to concurrent unit 7outage.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Primary Heat Transport Pumps and Improved SDC Seal Performance.
Forced Outages	**Outage Type**	**Start date**	**End Date**	**Duration (days)**	**Generation Loss (TWh)**	**Description**	**Management Action to Prevent Recurrence**
P5	FO	28-Oct-06	15-Nov-06	17.5	0.23	Forced outage due to high levels of combustible gasses in the main output transformer.	Investigation determined problem with defective high voltage lead and third party forensic analysis supported evaluation. Extent of condition evaluated and no further actions were required.
	FO	02-Dec-06	12-Dec-06	9.5	0.12	P5 was forced offline for 9 days due to primary heat transport pump seal failure	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Primary Heat Transport Pumps.
P6	FO	20-Dec-06	01-Jan-07	11.5	0.15	P6 was forced offline for 11 days in 2006 due to the inadvertent introduction by a third party contractor of purification system resin into the feedwater system treatment plant.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Resin Inclusion Event.
P7	FO	27-Aug-06	14-Sep-06	18.2	0.26	P 7 was forced offline for 18 days as a response to increasing primary heat transport leakage to the containment collection system.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Primary Heat Transport Pumps.
	FO	03-Jul-06	07-Jul-06	3.5	0.05	Boiler level transient due to failed level controller	Investigation determined problem to be faulty level controller. Extent of condition evaluation completed by plant design with result that all analog controllers have been replaced with digital in all units.
P8	FO	15-Jan-06	18-Jan-06	3.5	0.05	Unit transient occurred caused by turbine runback	Investigation completed and various actions implemented to prevent recurrence, e.g. maintenance procedures were revised to incorporate improved diagnostics methods, and implemented a major procedure revision for troubleshooting critical equipment.

Pickering B 2007 January - December

Planned Outages & Extensions	Outage Type	Start date	End Date	Duration (days)	Generation Loss (TWh)	Outage Scope / Description	Management Action to Prevent Recurrence
P5	PO	02-Apr-07	11-Jun-07	69.4	0.90	Planned outage for Fuel Channel inspections, High Pressure Service Water outage, and Heat Transport Low level Drain State maintenance.	Not applicable
	FEPO	11-Jun-07	05-Jul-07	24.7	0.32	Forced extension of the planned outage due to site electrical system test failure. During this forced extension, additional work included SDC pump seal changes, and primary heat transport pump seal replacement.	Investigation completed and repairs made to site electrical system. A number of actions implemented on maintenance and installation procedures, testing procedures, and design parameters, including, for future outages,improving response to test failures by assembling troubleshooting team in advance of test. See Appendix C Forced Outage Report and Summary of Corrective Actions Taken, i.e.Primary Heat Transport Pumps and Improved SDC Seal Performance.
P6	PO	10-Sep-07	12-Nov-07	62.4	0.81	Planned outage for feeders and boiler inspections, single fuel channel replacement, high pressure service water outage, and auxiliary power system commissioning.	Not applicable
	FEPO	12-Nov-07	27-Nov-07	15.6	0.20	Forced extension to the planned outage due to unanticpated electrical equipment deficiencies, SDC heat exchanger leak repair liquid zone control troubleshooting and repairs.	Investigation completed, and repairs made to affected systems and components.
P7	FEPO	01-Jan-07	28-Jan-07	28.0	0.36	Continuation of Nov 2006 force extension of Unit 7 planned outage due to resin ingress and recovery activities.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken, i.e.Resin Intrusion Event.

Forced Outages	Outage Type	Start date	End Date	Duration (days)	Generation Loss (TWh)	Description	Management Action to Prevent Recurrence
P5	FO	28-Jan-07	14-Feb-07	16.9	0.22	Forced outage as unit transient due to partial loss of Class II power, resulting in SDS1 and 2 trips.	Investigation conducted and actions implemented. Based on Original Equipment Manufacture input, field modifications implemented to prevent recurrence.
	FO	19-Jul-07	01-Aug-07	13.1	0.17	Unit forced outage to repair shutdown cooling pump seals.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken, i.e, Improved SDC Seal Performance.
	FO	09-Aug-07	12-Aug-07	3.4	0.04	Forced outage due to high influx of algae.	OPG experienced a multi-unit outage in 2005 due to a high influx of algae (see Unit P5 FO August 2005). After this most recent event, an investigation was conducted and immediate concerns addressed. Given the unprecedented level of algae in 2007, the 2005 corrective action plan is being further enhanced to improve organizational readiness for algae intrusion events
	FO	01-Dec-07	04-Dec-07	2.7	0.03	Forced outage due to turbine trip during testing.	The trip is associated with obsolescence issues (solenoid valves replacement required). A strategy to do the test at low power or to take short planned outages to replace the solenoid valves is being prepared.
P6	FO	01-Jan-07	13-Jan-07	12.5	0.16	Continuation of Dec 2006 force outage of unit 6 due to resin ingress and recovery activities.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken, i.e.Resin Intrusion Event.
P7	FO	14-Mar-07	23-Mar-07	9.1	0.12	Unit forced outage due to severe leak on Bleed Condenser Reflux return valve.	Investigation determined problem to be failed weld on NV, repairs conducted. Over the past several years, OPG has taken steps to improve its welding program to provide effective control and management of welding processes. Also on an ongoing basis OPG has procedures to evaluate the quality of legacy welds in all units.
	FO	02-Jun-07	12-Jun-07	9.9	0.13	Force outage due to primary heat transport leakage to follection. Critical path work is through shutdown cooling pump maintenance	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Primary Heat Transport Pumps and Improved SDC Seal Performance.
	FO	23-Sep-07	27-Sep-07	3.8	0.05	Unit forced out due to leak from heat transport main circuit valve.	Investigation completed and condition corrected. A leak mitigation strategy was developed for the station. Also a root cause investigation has been performed to address similar occurences. Other susceptible valves were scoped into the next planned outage.
P8	FO	07-Jan-07	26-Jan-07	19.2	0.25	Unit forced outage for resin ingress and recovery activities.	See Appendix C Forced Outage Report and Summary of Corrective Actions Taken - Resin Intrusion Event.
	FO	15-Aug-07	22-Aug-07	7.0	0.09	Forced outage to repair bleed condenser motorized valve.	Investigation completed and condition corrected by valve repair and repack. No further action required.

APPENDIX C

FORCED OUTAGE REPORT AND SUMMARY OF CORRECTIVE ACTIONS TAKEN

Attachments 1, 2 and 3 to this Appendix provide details (i.e. outage type, start date, end date, duration, generation loss, description of reasons for the outage and corrective actions taken) for 2005, 2006 and 2007 (January - July) as contemplated by the OEB's filing guidelines. OPG has a well-established corrective action program that establishes the processes that ensure that all deficiencies that adversely impact, or may adversely impact plant operations, personnel, nuclear safety, the environment or reliability, are identified and corrected.

As set out in the attachments, there are certain events that have significantly impacted the overall forced losses during the period, specifically:

- Pickering A liquid zone control
- Primary heat transport pumps
- The 2006/2007 resin inclusion event
- Pickering A electrical supply system
- Shutdown cooling (SDC) pump seals

To date, OPG has largely been successful in identifying root causes and has taken aggressive actions in an effort to mitigate reoccurrence. Descriptions of these events along with an overview of OPG's corrective actions are provided below:

<u>Pickering A Liquid Zone Control</u>

The liquid zone control ("LZC") system is the primary reactor power control device in a CANDU reactor. As noted at Ex. F2-T2-S1, while OPG's 10 nuclear units are all heavy water moderated CANDU reactors, they reflect three generations of design philosophy and technology. Pickering A was designed in the 1960's, Pickering B in the 1970's, and Darlington in the 1980's. While the

LZC system at Pickering A represents the first generation of large scale CANDU reactor power control systems, it continues to meet current design standards.

There have been some equipment-related hardware problems detected within the LZC system. These hardware problems have been corrected during forced outages (e.g., failed zone level transmitter, instrument line issues).

In addition, on a number of occasions since 2004, operating staff at Pickering A have observed unexpected variability in system parameters that were inconsistent with today's operating expectations. The ability to see these observations is primarily due to enhanced monitoring equipment installed before the 1997 shutdown.

As a precautionary measure, OPG, in accordance with our Nuclear Safety Policy, shut the reactor down until engineering and maintenance staff could ensure that the reactor power control system was performing within today's operating expectations. This was achieved through a series of technical reviews and investigations. A significant limitation and complicating factor in completing these technical investigations is that the unexpected variability in system parameters is only apparent when the unit is at power. Very limited troubleshooting can be done "at power" due to reactor safety considerations.

Corrective actions taken to date include adding additional instrumentation to aid troubleshooting and upgrading operating procedures to incorporate the lessons learned over the past four years.

In addition, OPG has conducted extensive maintenance on the unit 4 LZC system, replacing or overhauling many of the critical components. This has led to improved performance on this unit This same maintenance work was completed on unit 1 during a fall 2007 outage and is expected to lead to improved unit 1 performance in 2008.

Pickering A LZC is being subjected to an extensive and continuing investigation as OPG seeks to better understand the problems. OPG's goal is to define and evaluate cost effective solutions that will improve the reliability and performance of the LZC.

Primary Heat Transport Pumps

At Pickering B, the main driver of primary heat transport pump performance is the seals on the primary heat transport main circulating pump. These seals fail due to the failure of pins intended to prevent the spinning of the pump bearing housing. OPG has a program, to be completed by 2012, to replace the seals at its Pickering B units based on the age of the seals. New bearing housings fitted with an upgraded design are being installed. The primary heat transport pumps at Pickering A have been inspected and no issues have been found with them.

2006/2007 Resin Inclusion Event

All Pickering B units experienced forced outages or planned outage extensions due to steam generator chemistry issues arising from the inadvertent release of a resin into the demineralized water system in late December 2006. This release was by a third-party contractor and the source of the resin was the feed water purification system. Following this event, OPG implemented a resin cleaning strategy review. Teams from Pickering A and Pickering B were established to investigate the extent of the condition across the two stations. They concluded that a failed internal resin screen and a missing downstream resin trap in the vendor owned and operated water treatment plant led to the resin passing into the demineralized water systems at the stations.

Lessons learned from this investigation are currently being implemented at Pickering B as follows:

- OPG Staff are meeting routinely with the vendor to ensure that appropriate control measures are being taken.
- Daily water treatment plant walk downs are being conducted jointly by OPG staff and the vendor to identify and correct plant deficiencies in a timely manner.
- A project is currently underway to install an extra strainer, shut off valve and enhanced monitoring system on the demineralized water line, downstream of the water treatment plant.
- OPG is working with the nuclear industry, through World Association of Nuclear Operators (“WANO”), to share its experiences with others.

Another key lesson was the need to enhance the focus on asset preservation. To support this, chemistry procedures are being redesigned to be followed by a review and approval for implementation. Also, a workshop for OPG's licensed staff is being planned for late 2007. Furthermore, OPG is reviewing and improving procedures that track vendor quality performance.

<u>Pickering A Electrical Supply System</u>

Pickering units 4 and 1 were shutdown in June 2007 due a discovery that the Pickering inter-station transfer bus was not meeting its design intent. The inter-station transfer bus supplies back-up 600 volt power from Pickering B to Pickering A and is an important safety feature of Pickering A. Field tests had confirmed that the inter-station transfer bus was not able to supply all the emergency loads in terms of voltage drop and current carrying capacity. As a result, a decision was made, in accordance with our Nuclear Safety Policy, to shutdown both units.

Modifications to the design of the inter-station transfer bus were made to increase its ability to supply voltage, increase current carrying capacity and decrease units 2 and 3 loads. In addition, OPG developed comprehensive test plans to validate the performance of the modified inter-station transfer bus.

The modifications included the installation of over six kilometers of new cables. The load reduction involved over 200 discrete non-critical loads on units 2 and 3 (since units 2 and 3 are shut down, these changes can be made with no impact on safety). OPG also conducted extensive reviews (over 300) of other similar designs to ensure no design issues exist.

To minimize the duration of the 2007 inter-station transfer bus forced outage, some limitations were placed on the scope of the modifications. These limitations impose minor outage-related maintenance restrictions on Pickering B and operational restrictions on Pickering A. These restrictions marginally increase the probability of being forced to shut down one or more units or extend an outage in order to maintain safety margins. These restrictions will be removed once additional modifications are installed.

<u>Improve Shutdown Cooling (SDC) Pump Seal Performance:</u>

In response to previous failures of SDC pump seals at Pickering B, a newly designed pump seal was procured from AECL. During 2006 and 2007 the upgraded pump seals were installed in the shutdown cooling pumps on two of the four Pickering B units based on the original equipment manufacturer's recommendation. Unfortunately, the new pump seals have failed as well. An investigation in conjunction with AECL is underway.

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit E2
Tab 1
Schedule 2
Table 1

Table 1
Production - Nuclear (TWh)

Line No.	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Budget - Calendar Year Ending December 31, 2005													
1	**Nuclear Total**	4.2	3.6	3.6	3.1	3.7	3.7	4.2	4.0	3.7	3.3	3.7	4.3	45.2
	Actual - Calendar Year Ending December 31, 2005													
2	**Nuclear Total**	4.3	3.9	3.9	2.6	3.2	3.6	4.1	4.1	3.8	3.4	3.9	4.4	45.0
	Budget - Calendar Year Ending December 31, 2006													
3	**Nuclear Total**	4.5	4.2	4.1	3.5	3.8	4.4	4.6	4.6	4.3	3.5	3.4	4.5	49.4
	Actual - Calendar Year Ending December 31, 2006													
4	**Nuclear Total**	4.0	4.3	4.3	3.6	3.7	3.9	4.2	4.6	4.1	3.6	3.0	3.5	46.9
	Budget - Calendar Year Ending December 31, 2007													
5	**Nuclear Total**	4.6	4.2	4.2	3.6	4.1	4.5	4.6	4.6	4.2	3.5	3.4	4.3	49.9
	Actual - Calendar Year Ending December 31, 2007													
6	**Nuclear Total**	3.5	4.0	4.0	3.6	3.9	3.5	3.8	3.7	3.3	3.2	3.2	4.3	44.2
	Plan - Calendar Year Ending December 31, 2008													
7	**Nuclear Total**	4.7	4.2	4.2	3.7	4.0	4.3	4.7	4.7	4.3	4.1	4.0	4.6	**51.4**
	Plan - Calendar Year Ending December 31, 2009													
8	**Nuclear Total**	4.7	4.3	4.4	3.3	2.9	3.9	4.6	4.7	4.4	4.3	3.9	4.5	**49.9**

Numbers may not add due to rounding.

Table 2a
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Darlington NGS									
1	**TWh**	27.8	(0.2)	27.6	(0.6)	27.0	(0.5)	27.5	0.3	27.2
2	**PO Days**	85.6	9.2	94.8	0.2	95.0	(4.8)	99.8	39.3	134.3
3	**FEPO Days**	0.0	22.3	22.3	3.2	25.5	25.5	0.0	(22.8)	2.7
4	**FLR (%)**	4.6	(3.3)	1.3	1.9	3.2	(0.9)	4.1	(2.1)	1.14
5	**FLR Days Equivalent**	63.2	(45.7)	17.5	25.9	43.4	(12.4)	55.8	(18.8)	24.6
	Pickering A NGS									
6	**TWh**	4.0	(0.5)	3.6	2.9	6.4	(0.6)	7.0	(2.8)	3.6
7	**PO Days**	66.2	(66.2)	0.0	74.0	74.0	(3.7)	77.7	(8.9)	65.1
8	**FEPO Days**	0.0	0.0	0.0	21.0	21.0	21.0	0.0	39.2	60.2
9	**FLR (%)**	15.5	14.6	30.1	(12.9)	17.2	5.2	12.0	32.6	49.8
10	**FLR Days Equivalent**	65.2	60.1	125.3	(16.4)	108.9	30.6	78.3	190.7	299.6
	Pickering B NGS									
11	**TWh**	13.4	0.5	13.9	(0.3)	13.5	(1.3)	14.8	(0.2)	13.4
12	**PO Days**	280.5	(29.5)	251.0	(96.5)	154.5	(16.5)	171.0	(22.7)	131.8
13	**FEPO Days**	0.0	17.5	17.5	103.0	120.5	120.5	0.0	(52.2)	68.3
14	**FLR (%)**	9.0	(4.4)	4.6	2.3	6.9	(0.1)	7.0	5.6	12.5
15	**FLR Days Equivalent**	106.1	(52.0)	54.1	30.1	84.2	(6.0)	90.2	75.7	159.9
	Totals									
16	**PO Days**	432.3	(86.5)	345.8	(22.3)	323.5	(25.0)	348.5	7.7	331.2
17	**FEPO Days**	0.0	39.8	39.8	127.2	167.0	167.0	0.0	(35.8)	131.2
18	**FLR (%)**	7.1	(1.7)	5.4	1.0	6.4	0.2	6.2	5.3	11.7
19	**FLR Days Equivalent**	234.5	(37.6)	196.9	39.6	236.5	12.2	224.3	247.6	484.1
20	**Total TWh**	45.2	(0.2)	45.0	1.9	46.9	(2.5)	49.4	(2.7)	44.2

Numbers may not add due to rounding.

Table 2b
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington NGS							
1	**TWh**	26.8	0.4	27.2	1.4	28.6	(2.1)	26.6
2	**PO Days**	131.0	3.3	134.3	(59.2)	75.1	100.3	175.4
3	**FEPO Days**	0.0	2.7	2.7	(2.7)	0.0	0.0	0.0
4	**FLR (%)**	4.1	(3.0)	1.1	1.1	2.24	(0.2)	2.0
5	**FLR Days Equivalent**	54.5	(29.9)	24.6	6.5	31.1	(5.4)	25.7
	Pickering A NGS							
6	**TWh**	7.5	(3.9)	3.6	3.5	7.1	0.2	7.3
7	**PO Days**	66.2	(1.1)	65.1	1.9	67.0	3.0	70.0
8	**FEPO Days**	0.0	60.2	60.2	(60.2)	0.0	0.0	0.0
9	**FLR (%)**	8.0	41.8	49.8	(36.8)	13.0	(3.0)	10.0
10	**FLR Days Equivalent**	53.1	246.5	299.6	(213.2)	86.4	(20.4)	66.0
	Pickering B NGS							
11	**TWh**	15.6	(2.2)	13.4	2.3	15.7	0.3	16.0
12	**PO Days**	121.0	10.8	131.8	(19.8)	112.0	(14.0)	98.0
13	**FEPO Days**	0.0	68.3	68.3	(68.3)	0.0	0.0	0.0
14	**FLR (%)**	6.2	6.3	12.5	(6.3)	6.2	(1.2)	5.0
15	**FLR Days Equivalent**	83.0	76.9	159.9	(76.1)	83.8	(15.7)	68.1
	Totals							
16	**PO Days**	318.2	13.0	331.2	(77.1)	254.1	89.3	343.4
17	**FEPO Days**	0.0	131.2	131.2	(131.2)	0.0	0.0	0.0
18	**FLR (%)**	5.4	6.3	11.7	(6.6)	5.1	(0.9)	4.2
19	**FLR Days Equivalent**	190.6	293.5	484.1	(282.7)	201.4	(41.6)	159.8
20	**Total TWh**	49.9	(5.7)	44.2	7.2	51.4	(1.5)	49.9