Board Staff Interrogatory #059

Ref: Exh E1-1-2 page 1 and Exh N1-1-1 page 16

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

Total production from the Niagara Plant Group ("NPG") and Saunders is forecast to increase by 5.2 percent (1.0 TWh) primarily due to higher flows forecast for the Niagara and St. Lawrence Rivers in the 2015 Plan.

a) In the last 10 years how many times has the actual annual production from NPG and Saunders increased by 5% or more year-to-year?
b) For the last 10 years what has been the deviation of actual annual production from forecast production in both absolute and percentage terms?
c) What are the specific meteorological factors that lead to the forecast of increased flow rates for the Niagara and St. Lawrence Rivers?
d) Precipitation and evaporation are specifically mentioned as significant factors affecting the availability of water. Over the last 10 years what has been the trend change in both of these factors?

Response

There is an error in the preamble to this question (lines 10 - 12 above). The 1.0 TWh (5%) increase applies to the 2014 Plan, not the 2015 Plan. The 2015 Plan increased by 0.8 TWh (4%).

a) Actual production from NPG and Saunders combined has not increased by 5% or more from year-to-year during the last ten years (2004 to 2013). The maximum increase from year-to-year during this period was 4.2%. Actual production decreased by more than 5% from year-to-year on one occasion.

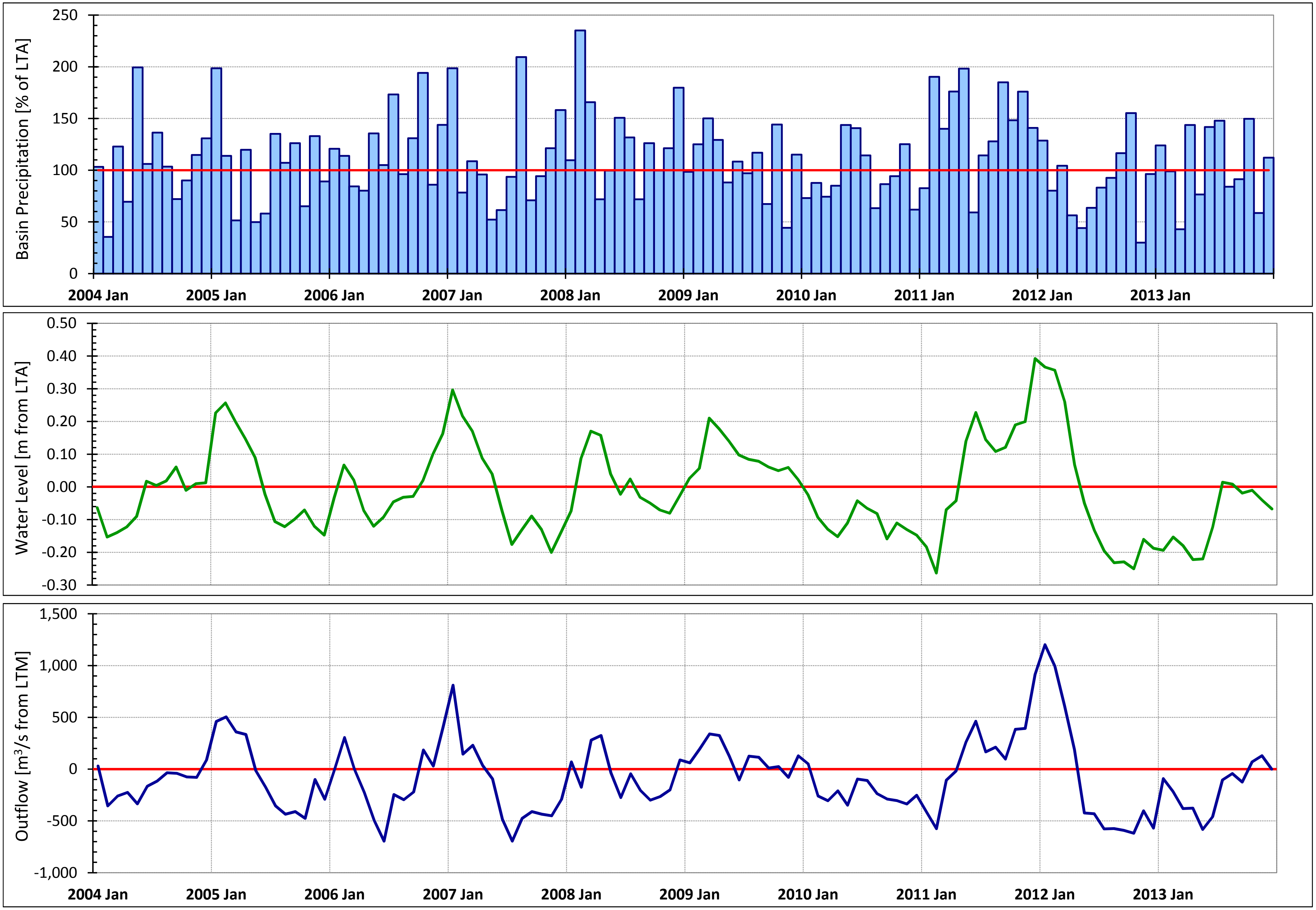
b) The deviations between actual production and forecast plan production (NPG and Saunders combined) for the years from 2005 - 2013 are summarized in the following table.

Year	Actual TWh - Forecast TWh	% Difference
2005	-0.012	-0.1%
2006	0.674	3.7%
2007	0.731	4.0%
2008	1.570	8.7%
2009	0.896	4.8%
2010	-0.566	-2.9%
2011	-0.316	-1.6%
2012	-1.350	-6.8%
2013	0.441	2.4%

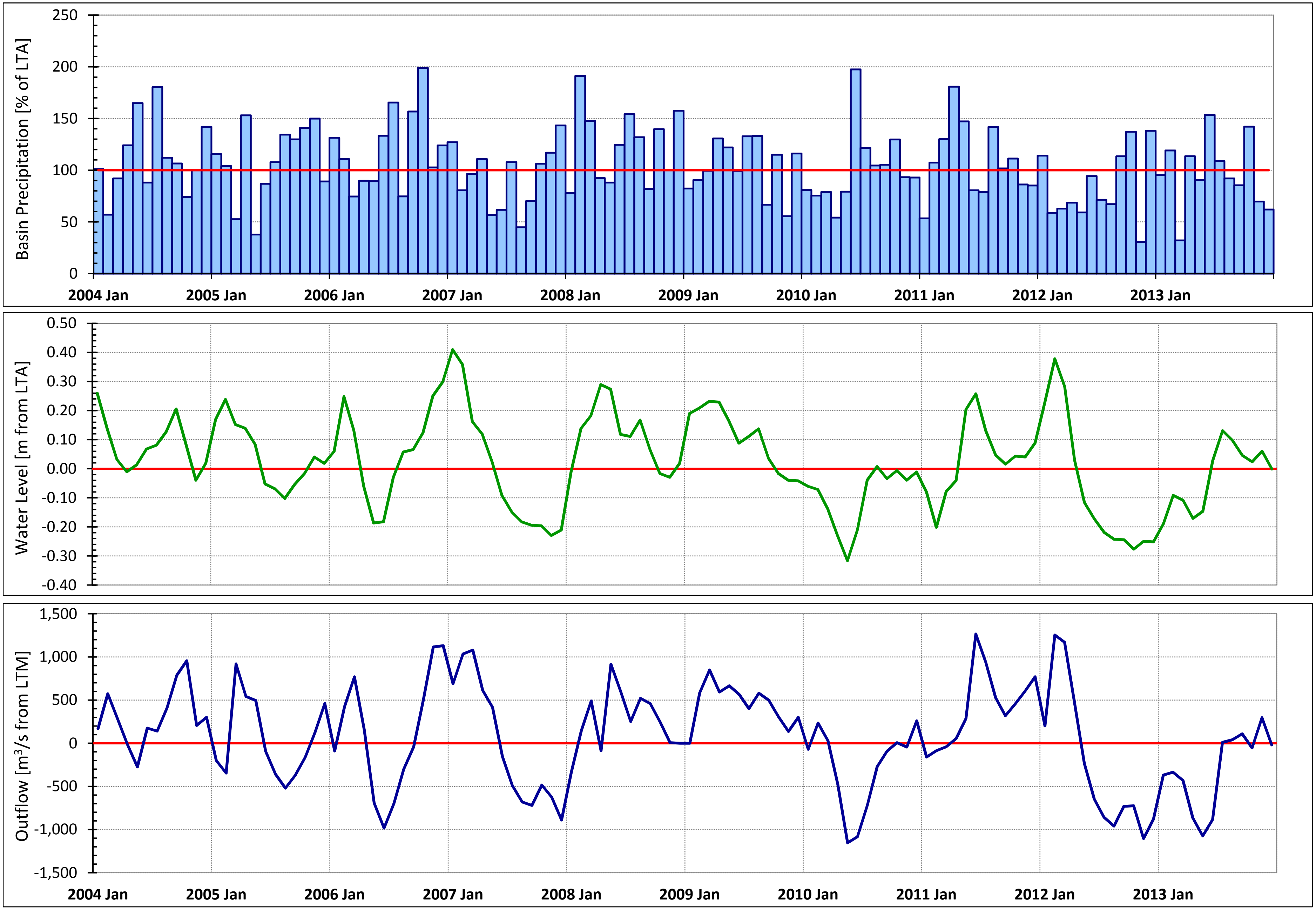
c) The primary meteorological factors that result in changes to the flow rates for the Niagara and St. Lawrence Rivers are precipitation and temperature. Combined, they influence the natural runoff across the entire Great Lakes basin, resulting in higher or lower lake levels. These changes in level ultimately lead to changes in outflow (i.e., the higher the level, the greater the outflow). Precipitation, either rain or snow, changes the amount of new water that is available to a basin, and the timing of the water supply. Temperature affects the type of precipitation (rain or snow) and evaporation. For example, colder winters result in greater ice cover on the Great Lakes, and subsequently, less evaporation. On the shorter term, wind can also affect lake levels and outflows. Strong winds blowing towards the outlet of a lake can cause the level at the outlet to increase substantially, thereby increasing outflow. Strong winds, coupled with warm, sunny weather, can also result in sublimation of snowpack, reducing the potential water available to the basin. They can also increase evaporation during the open water period.

d) Over the last ten years, there has not been a significant trend in precipitation for either Lake Erie or Lake Ontario. The graphs in Attachment 1 show the historical precipitation from 2004 - 2013 and the corresponding deviation from the average water level of the lakes for this period. Graphs of the resultant outflow deviation are also shown. For each graph, a line representing the long-term historical average is also included. While basin precipitation has been close to average over the past ten years, it has been above and below average on a random basis. Forecasts are based on recent conditions and trends. The flow forecast prepared in 2012 for the energy production plan was undertaken during a period of low water levels. The forecast undertaken in 2013 followed a wet summer that had resulted in lake levels recovering to average and the resultant average outflow. Evaporation data is not specifically reported by either the Canadian or USA government agencies monitoring and forecasting Great Lakes hydrology, but is recognized to have an impact on water supply.

Lake Erie - Niagara River Monthly Hydrology: 2004-2013 relative to 1926-2013



Lake Ontario - St. Lawrence River Monthly Hydrology: 2004-2013 relative to 1926-2013



Board Staff Interrogatory #060

Ref: Exh E1-1-1 pages 2 - 8

Issue Number: 5.1
Issue: Production Forecast
Regulated Hydroelectric
Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

Twenty-seven of the newly regulated facilities use average historical production as their production forecast.

a) Is this an average monthly production forecast for each station or for the aggregate output of all 27 stations?
b) How many observations are included in the average calculation? Is the calculation a simple average or a weighted average that would give greater (or lesser) weight to more recent observations?
c) In preparing the production forecasts for these 27 stations, does OPG apply any adjustments to the monthly averages of actual production to account for trends in meteorological conditions?

Response

a) It is an average monthly production forecast for each station.

b) For most stations, annual average production is based on over 40 years of data (since 1967). For stations where station rehabilitation or upgrades have been undertaken, the station annual average is determined based on production for those years following completion of the upgrade/rehabilitation.

   The station monthly production forecast is calculated as a weighted average, as follows:
   - Monthly aggregate production for the 27 stations is divided by the annual aggregate production for the 27 stations to yield the monthly distribution of annual aggregate production for each year since 2000 (expressed as a percentage of annual aggregate production).
   - These monthly percentages (from 2000 on) are averaged and the resulting average monthly percentages are applied to the long-term annual average production for each station (>40 yrs as per above) to calculate the station monthly production forecast.
   - Adjustments are then applied to the monthly station production to account for any major planned outages.

c) No.

AMPCO Interrogatory #022

Ref: Exhibit E1, Tab 1, Schedule 1, Production Forecast Regulated Hydroelectric

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

a) Page 3 – OPG indicates monthly energy production forecasts for the Sir Adam Beck plants are adjusted for losses based on an assessment of historical model performance. Please explain more fully how losses are accounted for and provide any calculations.

b) Page 3 – With respect to the long-term average incremental energy production from the Niagara Tunnel Project, please provide a breakdown and TWh impact of the specific factors that contribute to the difference between the 2005 figure of 1.555 TWh and the current figure of 1.472 TWH, a difference of 0.083 TWh or 5%.

c) Page 4 – OPG indicates an alternative regulation plan to Regulation Plan 1958-D is currently under review by the International Joint Commission and is expected to be implemented in 2014, if approved. Electricity production is not expected to be significantly affected under the proposed alternative plan.

   Please provide an update on the status of the alternative plan and when it will be approved and implemented in 2014 (if approved). Please discuss the likelihood of the alternative plan being approved.

   Please discuss the differences/deviations between the alternative plan and the existing plan.

   Please explain why production is not expected to be significantly affected under the proposed alternative plan.

Response

a) A number of steps are repeated on a monthly basis in order to continually assess model performance. The energy forecast model is rerun for the previous month using actual data for all applicable input variables. Output from this run is a “hindcast” of the monthly gross energy production (i.e., the best forecast that could have been achieved if all of the input variables had been perfectly forecast). The model error is then calculated as the difference between the hindcast gross energy value and the actual net energy production. An assessment is made of the hindcast and actual production values to determine if there are any untypical biases that would render the subsequent model error inappropriate for the purpose of future forecast adjustments. Examples of untypical biases encountered in recent history include the PGS reservoir drawdown/outage and the impact of extensive SBG (large amounts or long duration) on production. If the number is free of any untypical biases, it is used to update a five year rolling average of the monthly model error.

b) A number of changes were made to the modeling of long-term incremental energy production from the Niagara Tunnel Project between 2005 and 2013.

- An updated version of the energy model was used in the 2013 runs
  - Characteristics of units upgraded since 2005 are reflected in the updated model
  - Automated Generation Control ("AGC") capability was added to the model
  - The 2005 assessment utilized a maximum pre-third tunnel diversion value, while the 2013 model allowed both the two and three tunnel diversion profiles to be driven by the Grass Island Pool ("GIP") and cross-over elevations and the Niagara diversion equation (including seasonal flow reductions)
  - Seasonal flow reduction values were increased to better represent conditions that had been experienced in recent years
  - Actual monthly Lake Ontario water level data was used in the 2013 analysis in place of long-term monthly average values
  - While a single average GIP leakage level was used for the entire year in the 2005 model, the recent analysis assumed different leakage level values for tourist season and non-tourist season
- The current methodology uses daily Niagara River flow data from 1926 - 2010; the 2005 methodology used 12 monthly mean flow values (one average value for each month) calculated using 1926 - 2002 data
  - Additional data (2003 - 2010) was available for use
- Daily flow data was used in the 2013 modeling while mean monthly data was used in 2005
  - Changes were made to the cycling regime of the PGS and the GIP to better reflect conditions that were being experienced
- Foregone water transactions
  - The reduction due to foregone water transfers was increased to reflect recent experience

While all of these factors combined to contribute to the change of 0.083 TWh, it is difficult to attribute an exact contribution to most of the modeling changes. The change in the foregone water transactions had the greatest impact, accounting for 0.036 TWh or approximately 43% of the change.

c) The IJC invited public comment on its proposed new regulation plan during the summer of 2013. Input that was received is currently being reviewed, with the expectation that a decision on the plan will be made in 2014. The IJC are very committed to updating the current regulation plan. However, there remain some interest groups that are still strongly opposed to the new plan. Passage of the plan will require support from Provincial, State and Federal Governments.

The objective of the new plan, known as Plan 2014, is to return the Lake Ontario-St. Lawrence River System to a more natural hydrologic regime, while limiting impacts on other interests. Plan 2014 will maintain more natural seasonal level and flow hydrographs on the lake and river. Environmental conditions (e.g., diversity, productivity and sustainability of species sensitive to water level fluctuations) will be enhanced, while trying to maintain benefits to recreational boating. Flood and low water protection on the lower St. Lawrence River will be comparable to the current plan, and benefits to municipal water intakes, commercial navigation and hydropower interests will be maintained as much as possible. Adaptive management will also be a key component of the new plan.

Hydropower production is not expected to be significantly affected by the new plan because in the longer term, the amount of water passing through the system remains approximately the same.

AMPCO Interrogatory #023

Ref: Exhibit N1, Tab 1, Schedule 1, Impact Statement

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

Preamble: The evidence indicates the updated (increased) previously regulated hydroelectric production forecast for 2014 and 2015 is a result of higher flows forecast for the Niagara and St. Lawrence Rivers.

a) Page 16 -Please explain the cause of the higher flows in 2014 and 2015 and provide the annual TWh impact associated with each cause.

b) Please provide the monthly production in 2013 related to the NTP.

c) Attachment 4, Page 4 – OPG's 2014-2016 Business Plan – Under Key Planning Assumptions, OPG provides a hydroelectric production forecast broken down by previously and newly regulated hydroelectric for forecast 2013 and business plan 2014 to 2016. AMPCO notes the amounts shown on Page 4 of the 2014-2016 Business Plan for 2014 and 2015 for previously regulated hydroelectric differ from the amounts updated in the Impact Statement (Pages 16-17). Similarly, the amounts for newly regulated hydro shown on Page 4 of the 2014-2016 Business Plan for 2014 and 2015 differ from the amounts shown in Table 1 at Exhibit E1, Tab 1, Schedule 1. Please explain these variances.

d) Attachment 4, Page 4 – OPG's 2014-2016 Business Plan – Under Key Planning Assumptions, OPG provides a hydroelectric production forecast that includes 2016. Please explain the 2016 forecast compared to 2015 plan.

Response

a) Flow forecasts are based on recent conditions and trends. The flow forecast prepared in 2012 for the 2014 and 2015 energy production plans was undertaken during a period of low water levels and lower lake outflows, whereas the flow forecast undertaken in 2013 followed a wet summer that resulted in lake levels recovering to average and subsequently higher lake outflows. The 2013 flow forecasts for 2014 and 2015 were 5 to 6 per cent higher for the Niagara River than the 2012 forecast and 3 to 4 per cent higher for the St. Lawrence River. The production forecast for Niagara increased by almost 0.9 TWh for 2014 and 0.6 TWh for 2015. The production forecast for Saunders increased by about 0.2 TWh for each of the two years.

b) Estimated monthly production attributable to NTP:

NTP Incremental Production (GWh)	
Mar-13	58.0
Apr-13	38.2
May-13	33.4
Jun-13	37.0
Jul-13	61.2
Aug-13	61.9
Sep-13	34.9
Oct-13	37.5
Nov-13	27.8
Dec-13	74.8

c) For both the previously regulated and newly regulated hydroelectric facilities, plan production totals presented in the Application represent total forecast production with no reduction for forecast surplus baseload generation (“SBG”). The production totals presented in the referenced Business Plan table (Ex. N1-1-1, Attachment 4, page 4) include forecast SBG reductions.

d) OPG declines to respond to this request as 2016 is beyond the test period of this application, and as such, is irrelevant to the determination of payment amounts for the test period.

AMPCO Interrogatory #024

Ref: Exhibit E1, Tab 1, Schedule 2, Comparison of Production Forecast, Regulated Hydroelectric

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

a) Page 1 – Please provide the actual total regulated hydroelectric production for 2013 and provide an explanation for 2014 plan (updated) compared to 2013 actual.

b) Page 2 – Please provide a period-over-period changes explanation for 2013 actual compared to 2012 actual.

c) Page 4 – Please explain the reason for lower river flow in 2012 resulting in lower than normal production in 2012.

Response

a) Actual production data for 2013 is shown in a revised Ex. E1-1-1 Table 1 included in the response to LPMA Interrogatory #5.

b) See response to Board Staff Interrogatory #2.

c) Spring freshet occurred earlier than normal in 2012 due to warm temperatures in March. Below normal precipitation in the lower Great Lakes basin and eastern part of the Province through the spring and summer of 2012 resulted in lower river flow.

LPMA Interrogatory #005

Ref: Exhibit E1, Tab 1, Schedule 1

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

Please update Table 1 to reflect actual production in 2013.

Response

See revised E1-1-1 Table 1 below.

Table 1 (Revised for 2013 Actuals)

Production Trend - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric (TWh)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	Niagara Plant Group	12.4	12.6	11.9	12.4	12.7	13.5
2	Saunders GS[1]	6.5	6.9	6.5	6.5	6.3	6.7
3	Sub total	18.9	19.5	18.5	18.9	19.1	20.2
	Newly Regulated Hydroelectric:						
4	Ottawa-St. Lawrence Plant Group[2]	4.7	5.7	5.1	6.3	5.7	5.7
5	Central Hydro Plant Group	0.5	0.5	0.4	0.5	0.4	0.5
6	Northeast Plant Group	1.4	2.0	2.0	2.3	2.5	2.5
7	Northwest Plant Group	3.4	3.3	3.3	3.4	3.8	3.8
8	Sub total	10.0	11.5	10.9	12.5	12.4	12.5
9	Total	28.9	31.0	29.4	31.3	31.4	32.7

Notes:
1 Saunders values represent total station production (including energy delivered to HQ).
2 Ottawa-St. Lawrence PG values are for the balance of the Plant Group, i.e. Saunders GS production is excluded.

PWU Interrogatory #008

Ref: Exh N1-1-1, Page 1, Lines 24-25

> The change in the previously regulated production forecast reflects an increase in water availability resulting in an overall increase of 1.8 TWh over the test period.

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

a) What is the basis for the significant increase in water availability? Where is the evidence located?

Response

a) The increase is attributable to higher forecast flows for the Niagara and St. Lawrence Rivers for 2014 and 2015. (Refer to Section 2.3.2, Exhibit N1, Tab 1, Schedule 1, pages 16 and 17.) Flow forecasts are based on recent conditions and trends. The flow forecast prepared in 2012 for the 2014 and 2015 energy production plans was undertaken during a period of low water levels and lower lake outflows, whereas the flow forecast undertaken in 2013 followed a wet summer that resulted in lake levels recovering to average and subsequently higher lake outflows.

SJ Interrogatory #001

Ref:

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

OPG operate many run-of-the river power generation stations in Eastern Ontario. They collectively generate about 1819 megawatts of power but by using exergy storage they could continue to supply the 1819 MW of power to their normal clients but could at the same time deliver up to an additional 36,000MW of power in thermal form, all of it coming from energy sources that are not presently employed. The distributed storage sites would be able to heat most of the buildings in Eastern Ontario without drawing power during the peak demand periods. The principles are outlined in a paper presented to KEGS at NRCan which is available here.

How much are the capacity factors of these power stations reduced by the inability to match the power supply with the demand vs. the reduction caused by low water flow?

Response

The capacity factors of hydroelectric stations are generally determined by water availability (i.e., natural water inflows). As can be seen in Ex. E1-1-1, Table 2, lines 4 and 13, the production and inflows for the generating stations on the Ottawa and Madawaska Rivers vary seasonally, with a high during the spring freshet and a low during dry summer months. Hydroelectric stations are typically designed with a maximum capacity sufficient to capture most of the statistically high inflows. Therefore, under normal operating conditions, there is little or no unutilized water.

Board Staff Interrogatory #061

Ref: Exh E1-2-1 pages 8&9

Issue Number: 5.3
Issue: Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

Interrogatory

OPG states: "When SBG spill cannot be avoided, because the water cannot be time-shifted or stored, it is irrevocably lost. As a result, the monthly average production falls. The SBG spill, which lowers the monthly average production, is compensated for by an entry in the SBG variance account. However, the resulting production profile, reduced by the SBG spill volume also generates incentive payments under the HIM. This is an unintended consequence of interaction between the HIM and SBG Variance Account."

The problem of "unintended" compensation appears to be "double counting" for foregone generation from SBG conditions arising when the monthly production average is reduced by the volume of SBG.

a) To negate this impact, is it not possible to add in the amount of SBG generation foregone to the actual production to get an "average monthly production compensated for SBG" for operating the HIM?
b) Is there a qualitative or quantitative difference between the adjustment above and OPG's proposal: "…induced incentive revenues arising from SBG-related spill should be removed from the SBG Variance Account."?

Response

a) Yes, it is possible to do so. However, doing so would substantially complicate the existing IESO and OPG settlements processes as the IESO does not know the volume or hourly resolution of OPG's SBG spill. By having the IESO perform these calculations, additional financial reporting and settlements processes would need to be developed by both OPG and the IESO.

b) As described in Ex E1-2-1, page 13, the proposed Incentive Payment Adjustment explicitly determines, and corrects for, the impact of SBG spill on the HIM valuation. The Incentive Payment Adjustment calculated by OPG provides the identical outcome as the methodology suggested in the question part a), while not further complicating the existing settlements processes.

Board Staff Interrogatory #062

Ref: Exh E1-2-1 page 13

Issue Number: 5.3
Issue: Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

Interrogatory

OPG proposes to eliminate the revenue requirement adjustment associated with the incentive revenues, claiming that the value to the customer, i.e., reduced payments to natural gas generators and higher export revenues, accrue to consumers simultaneously with the incentive payments accruing to OPG.

The benefits that OPG identifies are “general system benefits” that arise from the impact on the market of incremental PGS generation being available during peak, or higher, demand periods. This is not the same as increased revenues arising from selling incremental energy above a threshold of average generation that is shifted from low price periods to higher price periods. These are real revenues, incremental to the general system impacts, and a portion should be returned to consumers by reducing OPG’s revenue requirement in the future.

OPGs regulated hydroelectric assets operate in a price guaranteed, low risk environment. The HIM is intended to encourage OPG to operate the PGS as if it was transacting in an open, competitive market with corresponding risks and rewards. OPG risks and loses nothing if they miscalculate and operate the PGS inappropriately, yet consumers will lose the potential “general system benefits” identified by OPG.

In exchange for the security of a guaranteed price, is it not appropriate that OPG share the direct rewards of operating outside that low risk environment by a reduced revenue requirement in the future? If not, please explain why not.

Response

OPG disagrees with Board Staff’s characterization that the consumer benefits arising from OPG time-shifting PGS generation are simply “general system benefits” and, by implication, are not legitimate financial benefits to Ontario consumers. OPG’s forecast of changes in consumer costs arising from time shifting PGS generation (Ex. D1-2-1, Table 2, page 7) yields significant consumer benefits that, in the absence of time-shifting, represent additional costs to Ontario consumers. The existence of these benefits and the approach used by OPG to calculate them were validated by Cliff Hamal of Navigant Economics, at Ex. E1-2-1 Attachment 1.

Further, Board Staff is incorrect in its assertion that “…OPG risks and loses nothing if OPG miscalculates and operates the PGS inappropriately, while consumers will lose the potential general system benefits”. The HIM is not without risk. Should OPG miscalculate and operate the

PGS uneconomically, it would purchase the difference between the actual energy produced and the hourly volume at market prices, potentially resulting in a negative incentive payment to OPG. Additionally, uneconomic PGS operations will result in financial losses to OPG if the incremental costs associated with pumping are not recovered.

OPG agrees that it should share with ratepayers the rewards from the incentive mechanism and its proposal does just that – only not through a reduction in future revenue requirements.

Reducing OPG's revenue requirement based on an expectation of future incentive payments is inappropriate for the following reasons:

- A reduction in the revenue requirement based on a forecast of incentive payments will financially penalize OPG should persistent market conditions beyond OPG's control result in reduced opportunities to time-shift.
- A reduction in the revenue requirement introduces temporal inequities whereby benefits attributable to time-shifting are awarded to consumers prior to OPG realizing any benefits. The generation of consumer costs and the attendant value of time shifting delivered to the consumer, occur simultaneously under OPG's proposal (Ex. E1-2-1, page 13).

IESO Interrogatory #001

Ref: *Overall Use of the Beck PGS and Newly Regulated Hydroelectric Facilities*
Exhibit E1 Tab 2 Schedule 1 Section 4.0 page 4 lines 10-12

Issue Number: 5.3
Issue: Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

Interrogatory

In this section, OPG discusses the operation of the PGS during SBG conditions. Specifically, OPG states:

> *OPG operates the PGS taking into consideration market price signals, the availability of the PGS, the capacity of the PGS reservoir, and hydrological limitations.*

The IESO is looking to better understand how OPG's strategies to operate the PGS and the newly regulated hydroelectric facilities in an economically efficient manner are influenced by market price signals.

(a) How do the expectations of price spreads affect OPG's operational strategy for the PGS and the newly regulated hydroelectric facilities? Specifically, in 2013, what was the expected on- and off-peak price spreads that would induce a pumping decision for the PGS and, for the newly regulated hydroelectric facilities, induce a decision to generate or not generate?

(b) How have these expected price spreads compared to the actual price spreads that materialized over the 2013 time period?

Response

a) OPG's operating strategy with respect to time shifting the PGS is economic deployment of the unit based on short run market conditions, including expected price spreads, as described in detail in EB-2010-0008, Ex. E1-2-1, section 3.0. Time shifting at Newly Regulated facilities is also based on economic deployment using the same short run market conditions. The customer benefit accruing from this operational strategy for Previously Regulated and Newly Regulated facilities is described in Ex. E1-2-1, section 4.

   OPG does not have expected on/off peak price spreads that would induce time shifting at PGS and the Newly Regulated facilities.

   The question infers there is a single parameter, price spreads, that induces time shifting, (i.e., a decision to generate or not). This is not the case. Expectations of on and off peak price spreads are an important criterion used along with a number of other factors, including operational considerations, environmental considerations, safety, equipment protection requirements, transmission and system constraints and the intrinsic assessment of risk due to uncertainty in each of these criteria. Furthermore, hydroelectric facilities operate in a competitive market administered by the IESO. OPG's assessment may be that time shifting will occur but ultimately, actual dispatch outcome is controlled by the IESO using additional factors unknown to OPG.

b) For the reasons discussed in part a), OPG does not have on/off price spreads for 2013 that induce time shifting. Therefore there is no basis for comparison to actual price spreads.

Board Staff Interrogatory #063

Ref: Exh E1-2-1

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

OPG proposes that the enhanced Hydroelectric Incentive Mechanism ("eHIM") apply to the existing hydroelectric facilities plus the newly regulated hydroelectric facilities.

a) The HIM is associated with the PGS facilities operating in tandem with the SAB GS in that water can be diverted for higher value generation. How does the incentive work for run-of-river units, i.e., Saunders, which is one of the originally prescribed hydroelectric facilities?

b) What is OPG proposing for the newly regulated hydroelectric facilities? Can the newly regulated hydroelectric dams store water in the same way that the PGS can? If so, what is the potential for operating the newly regulated units in this manner?

c) Does OPG intend that all of the newly regulated hydroelectric facilities be considered as potential participants in the eHIM, or just the 21 units listed in Exh E1-1-1 Appendix 1?

Response

a) The incentive payment calculation is applied to run-of-river plants using the formula shown on page 12 of Ex. E1-2-1. As would be expected, incentive payments for run-of-river plants tend to be smaller in comparison to peaking plants due to the lower ability to time-shift production due to the generally limited storage capabilities. Differences in production from hour to hour tend to be very small relative to the output of the entire plant. The Saunders station, which is considered a run-of-river plant, has some small and limited ability to time-shift water that is scheduled one day in advance.

b) OPG is proposing to extend the eHIM to all newly regulated hydroelectric stations with modelled production (See Ex. E1-2-1, pages 11 and 12 and Ex. E1-1-1, Appendix 1). None of the newly regulated plants are pumped storage generation facilities but most of the newly regulated plants have the ability for some water storage and can time-shift water from low to high value periods. While the amount of energy that can be time-shifted changes with changing hydrological conditions, the ability of the newly regulated assets to time-shift water can be considerable.

c) OPG intends just the units listed in Ex. E1-1-1 Appendix 1 participate in eHIM.

CME Interrogatory #007

Ref: Exhibit E1-2-1, Table 3

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

OPG has prepared Table 3 as an example of the interaction between SBG and the existing HIM.

OPG has also identified three alternative incentive mechanisms: the enhanced hydroelectric incentive mechanism ("eHIM"), the modified version of the hydroelectric baseload forecast mechanism ("eHBF") and the incentive mechanism ("IM") based on a fixed market price exposure.

Please reproduce Table 3 for each of these three alternative mechanisms showing the incentive that would be paid for both Case 1 (spill avoided) and Case 2 (spill not avoided). To the extent that additional assumptions have to be included for some or all of the incentive mechanisms, please identify the requisite assumptions.

Response

Shown below are four tables showing illustrative incentive payments under the four alternate payment mechanisms: the current HIM, the proposed eHIM as well as the eHBF and IM incentive mechanisms. All tables are based on the same output in both Case 1 (no SBG spill) and Case 2 (SBG spill).

For illustrative purposes, no sharing of incentive payments are assumed. Furthermore, a ‘Baseline’ MW profile has been added to the eHBF incentive calculation. Under the eHBF mechanism, output in excess of the Baseline profile earns an incentive payment based on HOEP.

Table 1 shows the incentive payment under the current HIM mechanism and is identical to Table 3 as shown in Ex. E1-2-1. This table represents the HIM incentive payment. Note that incentive payments are generated in Case 2 solely due to SBG spill.

Table 1: HIM

	Case 1: Spill avoided			Case 2: Spill not avoided			
Period	Output	Spill	HIM	Output	Spill	HIM	HOEP $/MWh
	MW	MW	$	MW	MW	$	
1	50	0	($500)	50	50	($250)	10
2	50	0	($500)	50	50	($250)	10
3	50	0	($500)	50	50	($250)	10
4	50	0	($500)	50	50	($250)	10
5	50	0	($500)	50	50	($250)	10
6	150	0	$1,000	100	0	$500	20
7	150	0	$1,000	100	0	$500	20
8	150	0	$1,000	100	0	$500	20
9	150	0	$1,000	100	0	$500	20
10	150	0	$1,000	100	0	$500	20
Total	**1,000**		**$2,500**	**750**		**$1,250**	

Table 2 below shows the incentive payment under the eHIM mechanism. Note that, under Case 2, SBG-spill gives rise to an Incentive Payment Adjustment ('Adjust' on the table) which completely offsets the SBG-induced HIM. In other words, the net incentive earned is zero.

Note that there is no Incentive Payment Adjustment in Case 1 because there is no SBG-spill.

Table 2: eHIM

	Case 1: Spill avoided			Case 2: Spill not avoided				
Period	Output	Spill	HIM	Output	Spill	HIM	Adjust	HOEP $/MWh
	MW	MW	$	MW	MW	$	$	
1	50	0	($500)	50	50	($250)	$250	10
2	50	0	($500)	50	50	($250)	$250	10
3	50	0	($500)	50	50	($250)	$250	10
4	50	0	($500)	50	50	($250)	$250	10
5	50	0	($500)	50	50	($250)	$250	10
6	150	0	$1,000	100	0	$500	($500)	20
7	150	0	$1,000	100	0	$500	($500)	20
8	150	0	$1,000	100	0	$500	($500)	20
9	150	0	$1,000	100	0	$500	($500)	20
10	150	0	$1,000	100	0	$500	($500)	20
Total	**1000**		**$2500**	**750**		**$1250**	**($1250)**	

Table 3 below shows the incentive payment under the eHBF mechanism. The rightmost column shows an illustrative ‘Baseline’ in MW: output in excess of this ‘Baseline’ earns an incentive payment at HOEP.

Table 3: eHBF

	Case 1: Spill avoided			Case 2: Spill not avoided				
Period	Output	Spill	HIM	Output	Spill	HIM	HOEP $/MWh	Base Line
	MW	MW	$	MW	MW	$		MW
1	50	0	$250	50	50	$250	10	25
2	50	0	$250	50	50	$250	10	25
3	50	0	$250	50	50	$250	10	25
4	50	0	$250	50	50	$250	10	25
5	50	0	$250	50	50	$250	10	25
6	150	0	$1,500	100	0	$500	20	75
7	150	0	$1,500	100	0	$500	20	75
8	150	0	$1,500	100	0	$500	20	75
9	150	0	$1,500	100	0	$500	20	75
10	150	0	$1,500	100	0	$500	20	75
Total	**1,000**		**$8,750**	**750**		**$3,750**		

Finally, Table 4 shows in the incentive payment under the IM mechanism. Incentive payments are equal to 5% of the total output priced at HOEP.

Table 4: IM

	Case 1: Spill avoided			Case 2: Spill not avoided			
Period	Output	Spill	HIM	Output	Spill	HIM	HOEP $/MWh
	MW	MW	$	MW	MW	$	
1	50	0	$25	50	50	$25	10
2	50	0	$25	50	50	$25	10
3	50	0	$25	50	50	$25	10
4	50	0	$25	50	50	$25	10
5	50	0	$25	50	50	$25	10
6	150	0	$150	100	0	$100	20
7	150	0	$150	100	0	$100	20
8	150	0	$150	100	0	$100	20
9	150	0	$150	100	0	$100	20
10	150	0	$150	100	0	$100	20
Total	**1,000**		**$875**	**750**		**$625**	

IESO Interrogatory #002

Ref: *Proposed Changes to the HIM*
Exhibit E1 Tab 2 Schedule 1

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

OPG proposes to make changes to the hydroelectric incentive mechanism and the incentive revenue sharing between OPG and ratepayers.

(a) Please describe the high-level principles driving the proposed changes to the existing HIM and the incentive revenue sharing, including the role of the X-factor.

Response

In the EB-2010-0008 Decision with Reasons (pages 146 and 147), the Board provided direction and guidance to OPG which formed the basis for some of OPG's proposed changes to the existing HIM and incentive revenue sharing mechanism (see below). The development of the X-factor and the proposal to eliminate the HIM variance account did not directly arise out of the Board's decision in EB-2010-0008.

Specific direction and guidance OPG relied upon to propose changes to the HIM are as follows:

- Direction for OPG to review consumer benefit estimations including Global Adjustment payments;
- A direction to revisit the structure of the HIM in its entirety in the next proceeding;
- A finding that HIM net revenues will be shared equally with the customer (i.e., 50% of the proceeds will be returned to the customer through an offset to the revenue requirement and through the establishment of the HIM variance account);
- The creation of the SBG Variance Account through which OPG can be compensated for SBG-spill;
- Discussion of a possible interaction between the HIM and SBG;
- A requirement to undertake an assessment of potential alternate incentive proposals.

At its highest level, the major difference between the eHIM and the original HIM is the elimination of any interaction between the incentive mechanism and SBG.

In Ex. E1-2-1, OPG describes how it has addressed the Board's directions and has proposed the enhanced HIM (the eHIM) that incorporates changes in the payment mechanism and SBG Variance Account. Furthermore OPG proposes the manner in which the payment mechanism should be implemented introducing the 'X-factor' and the elimination of the HIM Variance account.

IESO Interrogatory #003

Ref: *Alternatives*
Exhibit E1 Tab 2 Schedule 1 Section 5.3

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

In this section, OPG provides a high-level description of alternative incentive mechanisms considered. As the IESO's interest is in ensuring that OPG's assets respond efficiently to market signals, the IESO is looking to better understand how OPG's assets would respond under the various alternatives assessed.

(a) Compared to eHIM, describe how the operation of the previously regulated and newly regulated hydroelectric facilities would differ under each the HIM, eHBF and IM.

Response

The design premise of the proposed eHIM and HIM is identical in that it improves operational drivers by tying all decisions (both operational and financial) regardless of hourly output, to market signals instead of the regulated rate (EB-2007-0905, Ex I1-1-1, page 10).

In the case of the alternate incentive mechanism, OPG did not propose an alternate operational driver during the evaluation of these alternatives but utilized the HIM operating profile to compare each alternative. HIM and eHIM provide the best value to the consumer in terms of the lowest volatility in incentive payout and the highest correlation between amount of time shifting and incentive compared with the alternatives (Ex. E1-2-1, Table 4, page 11). It also provides OPG with a reasonable incentive to optimize the dispatch of hydro facilities and to provide net benefits to customers (Ex. E1-2-1, Attachment 1, page 13).

IESO Interrogatory #004

Ref: *Incentive Revenue Sharing*
Exhibit E1 Tab 2 Schedule 1 Section 6.2 lines 8-9

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

OPG proposes an adjustment to the eHIM net revenue to maintain the 50/50 sharing of net incentive revenues established in EB-2010-0008. The IESO is looking to understand how a different incentive revenue sharing mechanism would affect OPG's operation of their regulated hydroelectric assets.

(a) How would OPG's operation of the previously and newly regulated hydroelectric facilities change if the proposed sharing of net incentive revenues was, for example, 90/10 or 10/90 OPG/ratepayers?

(b) Did OPG contemplate separate incentive revenue sharing mechanisms for the previously regulated hydroelectric facilities and the newly regulated hydroelectric facilities? For example, maintaining a 50/50 incentive revenue sharing mechanism for the previously regulated hydroelectric facilities but introducing a 75/25 or 90/10 incentive revenue sharing mechanism for the newly regulated hydroelectric facilities.
  i. If yes, please explain why this concept was dismissed.
  ii. If no, how would such an incentive sharing mechanism affect OPG's operation of their previously and newly regulated hydroelectric facilities.

Response

a) The higher the level of incentive to OPG, the greater the degree of potential costs and risks that OPG would be willing to assume to time-shift production.

b) No, OPG did not contemplate separate incentive revenue sharing mechanisms for the previously regulated and newly regulated assets.
  i. N/A
  ii. OPG accepted the OEB's decision establishing a 50/50 incentive revenue sharing mechanism and has not undertaken an analysis of how a different level of or a separate incentive revenue sharing mechanism would affect its operation of the previously and newly regulated hydro facilities. However, OPG expects that increases in costs or risks will affect OPG's assessment of time shifting opportunities.

IESO Interrogatory #005

Ref: *X-Factor*
Exhibit E1 Tab 2 Schedule 1 Section 6.2

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

OPG indicates that the purpose of the X-factor is to maintain the 50/50 sharing of cost savings to consumers. The calculation of the X-factor itself is based on an estimated reduction of customer costs of $36 million in each 2014 and 2015. The IESO would like to better understand the effects the estimated reduction of customer costs has on the X-factor.

(a) What happens to the X-factor if the estimated customer cost reduction is less than or greater than $36 million? Is the X-factor a static value or will it be adjusted based on the actual reduction in customer costs?

(b) If actual incentive payments to OPG are less than or greater than the estimated $18 million, how does OPG propose to reconcile this difference?

Response

a) The “X-factor” is established such that the net incentive retained by OPG is equal to one-half of the customer cost reduction (Ex E1-2-1 page 13). A different forecast of customer cost reduction, less than or greater than $36M, would result in a re-calculated X-factor. The “X-factor” is a static value with no adjustment planned throughout the test period.

b) OPG does not propose to reconcile any differences.

PWU Interrogatory #009

Ref:
(a): Exh E1-2-1, Page5

> In EB-2010-0008 Payment Amounts Order, the OEB established the HIM Variance Account to record 50 per cent of HIM net revenues above $10M for the period March through December, 2011 and $14M for calendar year 2012 as a credit to ratepayers. In EB-2012-23 0002 Payment Amounts Order, the OEB set the threshold for 2013 at $13M. Between March 1, 2011 and December31, 2011 actual HIM net revenue was $12.9M. For 2012 actual HIM net revenue was $15.8M. Projected HIM net revenue for 2013 is $8.7M.

(b): Exh E1-2-1, Attachment1, Page8, Lines 3-14

> In the reference, OPG states:
>
> OPG's proposal that its incentive payment be based on a 50/50 sharing of the calculated customer benefit is easily misinterpreted. It does not mean that OPG and customers benefit equally from the time shifting, for two reasons. First, there are substantial costs incurred by OPG in conducting the time-shifting that are not part of the 50/50 sharing calculation—those costs are offset by the incentive payment, leaving OPG with a substantially lower net benefit. Second, the calculation gives zero credit for ratepayer benefits that are likely to accrue from GRC payments to the province. Including consideration of both of those issues allows for a more direct comparison of the benefit-sharing in the proposal. In 2014, customers would achieve $34 million in benefits ($18 million in net cost reductions plus the $16 million in GRC payments) while OPG would benefit by $11 million ($18 million eHIM payment less the incremental costs of$7 million), and as a result customers receive 3 out of every 4 dollars in benefits from the time-shifting of generation.

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

a) What is the reason for the projected decline in Hydroelectric Incentive Mechanism ("HIM") net revenue in 2013? Does OPG have the actual HIM net revenue for 2013?

b) Does the existing HIM formula take into account the cost of time shifting at PGS?

c) Why did the OPG decide not to include in the new calculation referred to as the enhanced Hydroelectric Incentive Mechanism (eHIM) the cost of time shifting incurred by the OPG in determining the 50/50 sharing of net revenue?

Response

a) As shown in Ex. H1-1-1, Table 4, the decline in projected 2013 HIM revenues ($8.7M), relative to 2012 actual ($15.8M), was due to an expected 20% reduction in market price spreads resulting in an expected reduction of greater than 50% in the quantity of energy time-shifted in 2013.

   Actual 2013 HIM revenues were $18.1M as shown in Ex. L-9.1-17 SEC-132, Attachment 1, Table 4, line 1.

b) No, the current approved HIM formula as shown in EB-2010-0008, Ex. I1-1-1, page 11, does not take into account PGS time shifting costs.

c) OPG did not consider changing the fundamental characteristics of the currently approved HIM formula, to potentially include other formula elements or components such as PGS time shifting costs, when developing the eHIM proposal. As described in Ex. E1-2-1, section 5.3, HIM and eHIM are the preferred incentive mechanisms to provide the consumer benefit as described in Ex. E1-2-1, section 5.1.

SEC Interrogatory #069

Ref:
[E1-2-1/p.11]

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

Please provide a full calculation of the results of each of the HIM, eHIM, eHBF, and IM using the actual water flows and production for 2013, on the assumption in each case that the mechanism had applied in 2013 to both the previously regulated and the newly regulated facilities. Please provide a breakdown for each mechanism of the results for each of the previously regulated and newly regulated facilities separately. Please confirm that the Applicant's expert, Mr. Hamel, did not test any of the mechanisms against actual data for 2013 and any prior year.

Response

The table below summarizes the net incentive revenues based on actual 2013 production and market prices for the four alternative payment methods described in Ex. E1-2-1 pages 9 through 11 for the previously regulated hydroelectric facilities only. Calculation of the eHIM net incentive requires hourly SBG spill figures which are not available for the newly regulated facilities (Ex. L-9.7-1 Staff 195), thus OPG cannot provide a comparison with other payment mechanisms.

The incentive revenues in the table do not incorporate any sharing mechanism with the consumer, as described in Ex. E1-2-1 section 6.2. OPG would retain a portion of the incentive revenues shown in the table to the equivalent of a 50% share of the consumer benefit.

Table: 2013 Net Incentives Generated by the Previously Regulated Hydroelectric Assets

Payment Method	M$
HIM	18.1
eHIM	10.0
eHBF	99.2
IM	24.6

OPG can confirm that Mr. Ham<u>a</u>l's analysis was completed prior to the end of 2013 and has not been updated with 2013 actuals.

SEC Interrogatory #070

Ref: E1-2-1/p.3

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

Please explain how the "total volume of spill" is calculated, and how each of the components listed is calculated.

Response

As stated in Ex. E1-2-1, page 3:

There are several components of spill which are due to circumstances other than SBG for which volumes are calculated:

- water conveyance constraints (e.g., SAB GS tunnel capacity constraints)
- production capability constraints (e.g., unit outages; operating regulatory requirements etc.)
- market constraints (e.g., IESO dispatch constraints: market or transmission system)
- contractual obligations (e.g., AGC)

The methodology for spill reporting is described in Ex. E1-2-1, page 3, lines 15 - 16 and is further described below:

1. OPG Starts with the Total Volume of Spill
   The total volume of spill at the Sir Adam Beck station is obtained from the Niagara River Control Centre ("NRCC") which manages the joint works at Niagara (Ex. A1-4-2) on behalf of both OPG and the New York Power Authority ("NYPA"), to ensure that the terms of the 1950 Niagara Treaty and the International Niagara Board of Control's ("INBC") Directive for the Grass Island Pool are met.

   The total volume of spill at the newly regulated facilities is calculated based on actual water elevations and flow management of the spill facilities that divert water around, rather than through, the facility.

2. Subtract the volume of spill for things other than SBG
   (Ref: the four spill components listed above)

   a. Estimate spill attributable to conveyance limitations
      Water conveyance limitations pertain specifically to the physical geometry and hydraulic characteristics of the tunnels at Sir Adam Beck. Water conveyance limitations are based

on actual water elevations obtained from the NRCC. Due to storage capability, there are no equivalent limitations at the newly regulated facilities.

b. Estimate spill attributable to production capability constraints
Production capability constraints refer to restrictions in maximum station turbine flows attributable to headwater and tailwater elevations and unit outages.

c. Estimate spill attributable to market constraints
Market constraints refer to limitations in electrical production due to system restrictions. These constraints are computed together with the impact of contractual obligations whenever applicable to the station based on a comparison of IESO-issued market scheduled production quantities and station actual production.

d. Estimate spill attributable to contractual obligations
Contractual obligations refer to limitations in electrical production arising from the provision of ancillary services such as Regulation Service ("AGC").

3. Potential SBG Spill
The remaining spill volume, after Step 2 above, is identified as potential SBG spill.

4. SBG Spill
From the potential spill volume (Step 3 above) OPG excludes spill that occurs when the Ontario market price is above the level of the Gross Revenue Charge ("GRC"). The volume of spill remaining after this adjustment is the foregone production due to SBG and is used in calculating entries into the SBG Variance Account.

SEC Interrogatory #071

Ref:
[E1-2-1/p.4]

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory
Please confirm that the PGS can be used to reduce SBG spill at all of the Applicant's hydroelectric facilities. Please describe how pumping activity is co-ordinated with load following activities of the newly regulated hydroelectric facilities.

Response

OPG cannot confirm that use of the PGS will reduce SBG spill at all OPG hydroelectric facilities (Ex. E1-2-1, Section 4). In addition to the prevailing SBG conditions, local hydrological and transmission conditions; asset capabilities; public and employee safety; and environmental considerations; will determine the actual amount of SBG spill, if any, at OPG's other hydroelectric facilities.

OPG notes that there is no load following service in the IESO-administered market.

SEC Interrogatory #072

Ref: E1-2-1/p.13

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

Please confirm that the "X-factor" is a fixed amount based on a forecast of SBG in each of 2014 and 2015. Please confirm that the Applicant does not intend to adjust the X factor for actual SBG in those years.

Response

The 'X-factor' is not based on a forecast of SBG. There is no intention to adjust the 'X-factor' for actual SBG.

The determination of the "X-factor" is explained in Ex. L-5.4-11 IESO-005.

SEC Interrogatory #073

Ref: E1-2-1/p.14

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

Please explain why the proposed eHIM (as well as the previous HIM), is based on monthly averages, rather than weekly, annual, or some other period. Please confirm that the amount of the incentive payment should be the same, regardless of the period over which the incentive payment and volatility is measured. Please provide calculations showing the derivation of the figures of $27 million for 2014, and $30 million for 2015, and alternate calculations using weekly and annual periods as the basis for the incentive.

Response

Since their implementation in 2005, the incentive mechanisms have been settled using a monthly averaging period for production consistent with the monthly IESO billing and settlements processes. The proposed eHIM is also settled on a monthly average for production. No other averaging periods were considered.

OPG confirms the amount of the incentive payment under the proposed eHIM and payment sharing mechanism is the same (i.e., $18M), regardless of the period over which the incentive payment and volatility is measured.

In Table 1 below, OPG provides the results of the calculations showing the derivation of the figures of $27M for 2014, and $30M for 2015, and compares them to the results of the alternate calculations that use weekly and annual average production periods as the basis for the incentive.

The formulas used for the calculation of the incentive payment and the incentive payment adjustment are set out in evidence (Ex. E1-2-1, pp. 12 - 13) and are reproduced as follows:

Calculation of Incentive Payment

Incentive payment $= \text{'X factor'} \times \Sigma\, [(MW_i - MW_{avg}) \times HOEP_i]$

Calculation of Incentive Payment Adjustment

Incentive Payment Adjustment $= \text{'X factor'} \times \Sigma\, [(MWSBGi - MWSBGavg) \times HOEPi]$

Table 1: Incentive Payments and Adjustments Using Different Averaging Periods (All values in M$ unless otherwise noted)						
Averaging period	**Monthly**	**Monthly**	**Weekly**	**Weekly**	**Annual**	**Annual**
Year	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**
Forecast of Incentive Payment ***(a)***	78	96	71	85	76	96
Forecast of Incentive Payment Adjustment due to SBG ***(b)***	(27)	(38)	(21)	(31)	(28)	(38)
'X' factor ***(c)***	35%	31%	36%	34%	38%	32%
Forecast of Incentive Payment with X Factor Applied ***(d) = (a) * (c)***	27	30	26	29	29	31
Forecast of Incentive Payment Adjustment with X Factor Applied ***(e) = (b) * (c)***	(9)	(12)	(8)	(11)	(11)	(12)
eHIM ***(f) = (d) + (e)***	18	18	18	18	18	18

As shown in Table 1, the application of the X-factor results in an identical incentive payment under eHIM regardless of which average production period is applied to the calculation.

VECC Interrogatory #004

Ref: E1-2-1

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

a) Please confirm that for the period 2011-2013, the existing approved HIM applied to the Sir Adam Beck Pump Generating Station (SAB PGS) facility. If unable to so confirm, please provide a list of any other generating plants that attracted HIM payments over this period.

b) Please provide OPG's views as to what is the intended purpose of a PGS facility.

c) Does OPG require an extra incentive to use plant that is included in rate base for the purpose for which it was intended?

d) Please confirm that, prior to receiving an incentive, OPG operated the PGS for supply shifting, from low demand periods to high demand periods.

e) Please provide historical operating data, similar to that provided in Table 1 on page 4 of the referenced exhibit for the SAB PGS in all years prior to 2011 for which comparative data is available.

f) Please provide the original cost of the SAB PGS facility when it first went into service.

g) Please explain why, per page 5 of the referenced exhibit (and also in H1-1-1, Table 4), 2013 net revenues fell to $8.7M.

h) Had the proposed eHIM been in effect for 2011-2013, what would have been the direct dollar benefit to ratepayers for each of those years?

i) Please confirm that under the proposed eHIM, OPG will realize higher net revenues than had it continued under the current HIM; if unable to so confirm, please explain.

j) Please explain how OPG's goal to be "the low cost generator" in Ontario is furthered by increasing its revenues, ceteris paribus.

Response

a) Not confirmed. For the period March 2011 to 2013, the HIM applied to all of the previously regulated hydroelectric facilities including the PGS as shown in Ex. A1-4-2, Chart 1.

b) The PGS facility is described in detail in EB-2010-0008, Ex. A1-4-2, section 2.1.3. It is reproduced below.

> The Sir Adam Beck Pump Generating Station ("PGS") consists of six mixed-flow variable pitch reversible pump-turbines. The station was designed and built for integrated operation with the other two Sir Adam Beck plants and is generally used to pump and store water during off-peak periods for use during peak periods. During off-peak periods, the station pumps water from the cross-over location of the Sir Adam Beck open cut canals into a large man-made storage reservoir. During peak demand periods it generates electricity from water stored in the reservoir and discharges water back into the Sir Adam Beck I and Sir Adam Beck II open-cut canals at the cross-over location. The discharged water is then used by Sir Adam Beck I and Sir Adam Beck II.
>
> The station also assists in providing automatic generation control ("AGC") and operating reserve ("OR") at the Beck complex, as well as controlling the amount of water diverted from the Niagara River to the Beck complex by controlling the cross-over elevation.

c) No. However, as described in Ex E1-2-1, section 5.1, the purpose of the HIM is to provide OPG with an incentive to time shift production at its regulated hydroelectric facilities in a way that benefits consumers. Please also see VECC IR #37 (L-14-37, part d) in EB-2010-0008 for additional information on the need for an incentive.

d) OPG confirms prior to regulation in 2005, OPG and its predecessor Ontario Hydro, operated PGS consistent with its stated design intent as described in part b) above, using the prevailing economic paradigm, i.e., de-regulated/competitive market post 2002, regulated/centrally planned system pre-2002, which governed the facility at the time. Since regulation in 2005 (Ref EB-2007-0905 Ex.I1-1-1, page 3), OPG has received a financial incentive to provide hydroelectric peaking supply.

e) Comparative data prior to March 2011 is not available as the methodology to report SBG spill was developed and implemented following the EB-2010-0008 Decision with Reasons to establish the SBG Variance Account.

f) The gross asset value of SAB Pump Generating Station as of December 2013 was approximately $155M including the value of the reservoir. The original cost of the facility is not relevant to the setting of payment amounts for 2014 - 2015.

g) See Ex. L-5.4-15 PWU-009, part a).

h) OPG cannot calculate the customer benefit for these prior periods.

i) Not confirmed. Net incentive payments received will be significantly lower under eHIM relative to the current HIM. As per Ex E1-2-1, Table 5 the net incentive payment under eHIM, would be $18M in 2014 and $18M in 2015. The equivalent net incentive payments under the HIM would be approximately $39M in 2014 and $48M in 2015.

j) Please refer to Ex. A1-3-1, pages 4 - 5 ("Proposed Payment Amounts and Riders") which describes how OPG remains the low cost generator of choice in Ontario.

Board Staff Interrogatory #064

Ref: Exh N1-1-1 pages 12 - 13

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

OPG submitted a revised production forecast (2014-2016 Business Plan, dated November 14, 2013) with significant reductions in production for 2014 (-0.6 TWh) and 2015 (-2.0 TWh) compared to the originally filed forecast (2013-2015 Business Plan, dated May 16, 2013).

These reductions are entirely the result of an increase in planned outage days; a 10.6% increase in 2014 and 22.9% increase in 2015. OPG's explanation for these increases notes the complexity of planned maintenance outages and the historical performance of nine consecutive years of actual generation being lower than forecast.

a) What did OPG specifically discover in the six month period between these two forecasts to justify such a significant increase in planned outages?

b) Why make these adjustments now, all at once, if the evidence over the previous nine years indicated a systemic bias for over forecasting production?

Response

a) A senior management review is typically conducted in Q3 of the business planning year. A senior management review of the business planning assumptions underpinning the generation plan occurred in Q3 2013 as part of the 2014-2016 business planning process.

As indicated in Ex. N1-1-1 page 13, the outcome of that review was that senior management directed the generation staff to reassess the generation plan. This direction was driven by a concern that the 2014-2016 forecast was overstating generation based on OPG's historical performance from 2005-2012 where actual generation has been lower than forecast in each year. Senior management was also aware that the Q3 2013 production forecast was indicating that production would again be below OPG's 2012-2014 budget as well as significantly below the generation forecast underpinning OPG's approved rates, resulting in a sizable revenue deficiency.

Exhibit N1-1-1 page 12-13 describes in detail the changes in the number of planned outage days made in the 2014-2016 generation plan resulting from this review. The VBO planned outage scope was revisited because of its complexity and additional scope. The reassessment identified a decision to add 39 additional planned outage days to the Darlington VBO for the reasons set out in Ex. N1-1-1 page 12-13. With the history of planned outages experiencing forced extension of planned outage days, additional allowances were also added to the schedule of planned outage durations at Darlington and Pickering.

Other factors that resulted in changes from this reassessment were to add additional planned outage days for an unanticipated 23 day mid cycle planned Unit 5 outage to address pressure tube to calandria tube gap issues, a shift of the 2013 Unit 4 outage into 2014 and a decision to add an additional 28 day mid-cycle outage in 2015 to focus on preventative maintenance to improve reliability and reduce FLR.

b) In its Decision for Reasons EB-2007-0905, the Board noted at page 174 that it believes "OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast"

The 2014-2016 generation plan represents OPG's most complete and accurate forecast of nuclear production for 2014 and 2015 and consistent with the Board's EB-2007-0905 Decision, should be the basis for deriving rates for 2014 and 2015. An approach that would delay implementing these adjustments will result in overstating 2014 /15 generation production, resulting in revenue shortfall and reducing OPG's allowed rate of return.

Board Staff Interrogatory #65

Ref: Exh N1-1-1 page 14

Issue Number: 5.5
Issue: Production Forecast
Nuclear
Is the proposed nuclear production forecast appropriate?

Interrogatory

OPG lists the detailed changes in the Pickering N.G.S. planned outage schedule.

a) Why the 2013 Unit 4 was planned outage deferred to January 2014?
b) Board staff notes that this deferral cascades into other planned outages for 2015 and 2016. What is the nature of the "additional scope" that resulted in an additional seven days of outage in 2014?
c) An additional 28 day 2015 mid-cycle reduction was added to the 2014-2016 BP.

   OPG notes that "…starting in 2012, OPG began implementing short duration, mid-cycle planned outages (i.e., an additional planned outage within the two year cycle) for Pickering Units 1 and 4 to focus on preventative maintenance and to lessen the risk of future forced outages thereby improving reliability and reducing the FLR."

   i. Board staff notes that OPG indicates that this practice started in 2012. Why was this practice not included in the 2013-2015 Business Plan production forecast?
   ii. Is there a material difference between outage days attributed to FLR versus planned outages? If so, describe these differences and how the materiality is calculated.
   iii. Is one form of outage more costly to accommodate than the other? If so, based on previous experience with FLRs and planned outages what is the net difference in scalable costs, i.e., costs per day of outage?
   iv. Is there a performance metric for FLRs that is a component for determining individual compensation or bonuses for OPG staff? Is there a comparable performance metric for achieving, or exceeding, the planned outage schedule?

d) Based on historical performance over the 2005 to 2013 period that showed an average annual forced extension of 82.5 days to planned outages at Pickering, OPG increased allowances for planned outages by a total of 28.6 days over the two year test period. How did OPG determine that an average annual outage of 14.3 days was justified when average annual forced extension of outages over the selected comparison period are nearly six times that rate?

Response

a) As explained in Exx N1-1-1, page 14 (2nd bullet), the 2013 Unit 4 planned outage was deferred from October 2013 to January, 2014. It was deferred because:

- Unit 4 outage activities were severely restricted due to the presence of a 350,000 Rem/h radioactive hot spot in the Boiler Room. Removal of the hot spot required additional time for the development of remote tooling that would not have been available in time for an October outage start. The hot spot was removed event free in January of this year.

- There were key work activities during the outage for which critical parts would not be available due to extended delivery times. The deferral of the outage allowed for a significant improvement in parts availability.

b) Each outage has unique requirements and scope to be completed during the planned outage period. The Unit 4 outage that was moved from 2013 has a planned duration of 85.3 days whereas the Unit 1 outage that was displaced from the fall of 2014 to the spring of 2015 has a planned duration of 78.3 days. The net effect of moving these two outages is an additional 7 days of work in 2014.

c)

i) This practice was included in the 2013 - 2015 Business Plan as there was one mid-cycle outage in 2013 and another in 2014. The additional mid-cycle outage in 2014 and in 2015 were added to address preventative maintenance concerns to reduce future forced outages, to achieve OPG's 2016 targeted improvement in FLR to 5.0%.

ii) No. However, OPG does not budget for forced outages.

iii) Planned outages are undertaken with the use of incremental resources whereas forced outages are typically managed using existing base resources. It is difficult to provide a specific answer as the nature of the issue which necessitated the forced outage will significantly influence the costs, specifically whether the issue can be corrected without the need for an injection of incremental resources.

iv) Yes, the compensation package is based on total generation which is impacted by forced loss rate and achieving planned outage schedule. Station management is also compensated on achieving or bettering FLR and PO targets.

d) The increase in the allowance for planned outages was less (more aggressive) than historical performance related to FEPO Days based on the business planning initiatives (i.e., Fuel Handling Reliability Project) that are expected to ensure OPG planned outages are completed on budget.

Board Staff Interrogatory #066

Ref: Exh N1-1-1 pages 15-23

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

The revised Darlington production forecast reduced output by 1.6 TWh total for 2014-15 compared to the 2013-2015 Business Plan forecast.

0.28 TWh of this lower production is related to higher lake water temperatures that reduce condenser efficiency.

a) How are these lake water temperatures forecast?

b) Is there a historical correlation to lake water temperatures and Niagara and St. Lawrence River flows? If so, what is that correlation?

Response

a) Lake water temperatures are not forecast. The forecast of reduced production due to higher lake water temperatures is based on historical production data.

b) OPG has not done this analysis and therefore cannot conclude if a correlation exists.

Board Staff Interrogatory #67

Ref: Exh N1-1-1 pages 15-23

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Planned outage days for Darlington are increased by a total of 61.9 days, with 93% (57.6 days) of the outage occurring in 2015. 39 additional planned outage days are added because of an increase in the vacuum building outage ("VBO") scope.

a) What factors were involved in changing the planning for VBO outages from the 2013-2015 Business Plan to the current plan?
b) In Exh E2-1-1, page 6, OPG states that it is seeking regulatory approval (presumably from the CNSC) to eliminate the station containment outages going forward and that this strategy of moving forward the VBO to 2015 is part of that regulatory plan.
   i. How critical is CNSC approval to the outage plans?
   ii. When will OPG know if they are successful with this strategy?
   iii. If regulatory approval is not obtained, what is OPG's plan to accommodate this scenario?
c) On page 15, the evidence contains the following statement: "….the 2015 VBO eliminates the need for the 2021 VBO, reducing the complexity and resource demands during the Darlington Refurbishment Project." To support this statement, did OPG prepare any analysis of the cost and benefits of moving the VBO forward to 2015?

Response

a) Please see the response to Ex. 05.5-17 SEC-074.

b)
   i. CNSC approval is required to change the frequency of the SCO as the requirement for the SCO is documented in the Darlington License Condition Handbook/Darlington Power Operating License.

   ii. During the SCO that has been combined with the VBO, OPG will complete the required testing to demonstrate future SCO's are not required. It is anticipated that the results will support OPG's request to the CNSC to eliminate the need for any future SCO outages.

   iii. Darlington submitted a request to the CNSC for approval to eliminate the 2021 SCO. If regulatory approval is not obtained, OPG will perform additional inspections or analysis to confirm to the CNSC that future SCO's are not required.

c) A high level summary was prepared which established a positive payback to implementing a 12 year VBO/SCO cycle for the life of the plant compared to a 12 year VBO/6 year SCO cycle. Also, eliminating the VBO/SCO in 2021 will have a benefit when Darlington is scheduled to have two units in refurbishment by reducing complexity and resource demands.

AMPCO Interrogatory #025

Ref: Exhibit N1, Tab 1, Schedule 1 Page 13 Impact Statement

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Preamble: OPG indicates that as part of the 2014-2016 Business Plan review its senior management directed generation staff to reassess the plan based on OPG's historical performance (i;e; actual generation has been lower than forecast over the past nine years including 2013).

i) Please provide production data and variance explanations for the years 2005 to 2007.

ii) When did OPG's senior management direct generation staff to reassess the plan? Please provide the typical timing frequency of this review.

Response

i) The production data for 2005 to 2007 is shown in the following table in TWh. This was discussed in previous OEB hearings.

	2005	2006	2007
Actual (TWh)	45.0	46.9	44.2
Forecast (TWh)	45.2	49.4	49.9
Variance (TWh)	-0.2	-2.5	-5.7

2005 Variance – The actual production was 0.2 TWh below forecasted production. The variance was mainly due to a Pickering Unit 4 forced outage to allow for feeder inspections based on Pickering Unit 1 feeder inspection results.

2006 Variance – The actual production was 2.5 TWh below forecasted production. The variance was mainly due to 141.5 days of Pickering forced extensions to planned outages for unexpected heat transport system work and boiler repairs.

2007 Variance – The actual production was 5.7 TWh below forecasted production. The variance was mainly due to major unforeseen events such as testing and modification required to upgrade the in-station transfer bus (Pickering Unit 1 & 4) and resin found in the Pickering demineralized water supply (Pickering Units 5-8) which originated from a vendor water treatment plant.

ii) A senior management business planning review is typically conducted in Q3 of the business planning year. A senior management review occurred in Q3 2013 as part of the 2014-2016 business planning process

AMPCO Interrogatory #026

Ref: Exhibit N1, Tab 1, Schedule 1 Page 14

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Preamble: OPG indicates its generation plan includes allowances and the increase of 28.6 outage days
(0.3 TWh) proposed in the Impact Statement is based on an assessment of historical performance which showed that over the 2005 to 2013 period the average annual forced extension to planned outages at Pickering was 82.5 days.

a) Please provide the 2005 to 2013 data.
b) Please provide the average forced extension to planned outages in TWh.
c) Please confirm the allowance in outage days and TWh included in the original nuclear production forecast for Pickering.

Response

During a review of the forced extension to planned outage ("FEPO") days for Pickering, a discrepancy was found in the Impact Statement EB-2012-0321 Ex. N1-1-1, page 14, line 26. The average FEPO days from 2005 - 2013 is 72.6 days, not 82.5 days. The average production loss due to FEPO days for Pickering is correct in the Impact Statement (~0.87TWh).

a) The actual forced extensions to planned outage days for Pickering are provided below:

PN	2005	2006	2007	2008	2009	2010	2011	2012	2013
FEPO Days	17.5	141.5	128.4	19.7	60.2	21.5	70.7	26.2	167.6

b) The production loss in TWh due to actual forced extensions to planned outage days for Pickering are provided below:

PN	2005	2006	2007	2008	2009	2010	2011	2012	2013
TWh due to FEPO days	0.22	1.75	1.59	0.24	0.75	0.27	0.88	0.32	2.08

c) The 2013 -2 015 Business Plan has a nuclear fleet level allowance for Pickering planned outages in 2014 and 2015 of 73.4 days. he equivalent TWh is 0.91 TWh.

AMPCO Interrogatory #027

Ref: Exhibit N1, Tab 1, Schedule 1 Page 16

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Preamble: OPG indicates the reassessment increased the allowance for Darlington planned outages by a total of 22.0 outage days (0.49 TWh) based on an assessment of historical performance over the period was 0.24 TWh. The average annual forced extension to planned outages at Pickering was 82.5 days.
a) Please provide the 2005 to 2013 data.
b) Please provide the average forced extension to planned outages in days.
c) Please confirm the allowance in outage days and TWh included in the original nuclear production forecast for Darlington.

Response

During the review of the forced extension to planned outage ("FEPO") days for Darlington, a discrepancy was found in the Impact Statement EB-2012-0321 Ex. N1-1-1, page 16, line 5. The increase in the allowance for Darlington planned outages was 22.0 outage days (or 0.46 TWh) over the test period, not 0.49 TWh.

a) The production loss due to actual forced extension to planned outages for Darlington are provided below:

DN	2005	2006	2007	2008	2009	2010	2011	2012	2013
TWh	0.47	0.54	0.06	0.00	0.25	0.29	0.00	0.00	0.84

b) The actual forced extension to planned outage ("FEPO") days for Darlington are provided below. The average FEPO days for Darlington over 2005 - 2013 is 12.9 days per year or 25.8 days over a two year period. The adjustment of 22 days for Darlington is less than the average of 25.8 days over the two year period.

DN	2005	2006	2007	2008	2009	2010	2011	2012	2013
FEPO Days	22.3	25.5	2.7	0.0	11.9	13.9	0.0	0.0	39.8

c) The 2013 - 2015 Business Plan has a nuclear fleet level allowance for Darlington planned outages in 2014 and 2015 of 23.7 days. The equivalent TWh is 0.50 TWh.

AMPCO Interrogatory #028

Ref: Exhibit E2, Tab 1, Schedule 1, Table 2

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Preamble: Table 2 provides monthly nuclear production forecasts for 2014 and 2015 for Darlington NGS and Pickering NGS.

a) Please recast the table to show monthly nuclear production budgeted vs. actuals for the years 2010 to 2013 separately for Darlington, Pickering A and Pickering B.

Response

a) 2010 Monthly Actual Net Output vs. Forecasted (TWh).

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PNGS A - Actual	0.32	0.58	0.57	0.29	0.02	0.36	0.30	0.43	0.72	0.74	0.63	0.58
PNGS B - Actual	1.46	1.37	1.52	0.63	0.13	1.07	1.21	1.34	1.35	1.09	1.10	1.43
PNGS - Actual	1.79	1.95	2.09	0.92	0.14	1.43	1.51	1.77	2.07	1.82	1.73	2.01
DNGS - Actual	2.61	1.65	1.94	2.12	2.60	2.36	2.55	1.90	2.02	1.93	2.27	2.60
PNGS A - Budgeted	0.66	0.59	0.66	0.27	0.00	0.25	0.33	0.62	0.63	0.66	0.63	0.66
PNGS B - Budgeted	1.44	1.30	1.44	0.64	0.00	0.89	1.32	1.44	1.28	1.08	1.05	1.17
PNGS - Budgeted	2.10	1.90	2.10	0.91	0.00	1.14	1.65	2.06	1.91	1.74	1.68	1.82
DNGS - Budgeted	2.55	1.81	1.91	2.26	2.55	2.47	2.55	2.55	2.03	1.91	2.06	2.55

2011 Monthly Actual Net Output vs. Forecasted (TWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PNGS A - Actual	0.70	0.64	0.19	0.68	0.75	0.20	0.42	0.73	0.61	0.38	0.37	0.37
PNGS B - Actual	1.41	1.09	1.15	1.10	1.14	0.99	1.03	1.34	1.08	1.00	0.99	1.32
PNGS - Actual	2.11	1.73	1.34	1.79	1.89	1.18	1.45	2.07	1.70	1.38	1.35	1.69
DNGS - Actual	2.62	2.36	2.45	1.88	2.19	2.50	2.52	2.52	2.29	2.57	2.51	2.55
PNGS A - Budgeted	0.63	0.57	0.63	0.61	0.63	0.61	0.63	0.63	0.51	0.31	0.30	0.52

PNGS B - Budgeted	1.38	1.01	1.03	1.00	1.04	1.33	1.38	1.38	1.05	1.03	1.00	1.16

2012 Monthly Actual Net Output vs. Forecasted (TWh)

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
PNGS - Actual	1.85	1.70	1.60	1.63	1.76	1.83	1.97	2.16	1.77	1.31	1.47	1.61
DNGS - Actual	2.48	2.41	2.40	1.87	2.20	2.41	2.45	2.47	1.98	2.57	2.49	2.58
PNGS - Budgeted	1.97	1.59	1.72	1.67	1.94	2.01	2.08	2.08	1.63	1.40	1.35	1.65
DNGS - Budgeted	2.56	2.40	2.37	1.85	1.91	2.40	2.51	2.51	2.43	2.56	2.48	2.56

2013 Monthly Actual Net Output vs. Forecasted (TWh)

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
PNGS - Actual	1.86	1.70	1.68	1.50	1.55	1.34	1.55	1.81	1.64	1.63	1.77	1.59
DNGS - Actual	2.58	1.81	1.94	1.86	2.23	2.40	2.54	2.27	1.74	1.81	1.88	2.00
PNGS - Budgeted	2.09	1.81	1.80	1.67	1.72	1.86	2.07	2.07	1.66	1.48	1.36	1.51
DNGS - Budgeted	2.56	1.79	1.91	2.26	2.56	2.42	2.50	2.50	1.89	1.91	2.04	2.56

AMPCO Interrogatory #029

Ref: Exhibit E2, Tab 1, Schedule 1, Table 2

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please compare OPG's nuclear production actuals for 2010 to 2013 compared to the IESO reported actuals for the same years and explain any variances.

Response

Given that no reference was made to a specific IESO published report, OPG is unable to provide a comparison of its nuclear production actual results against IESO reported production figures for the 2010 to 2013 period.

The IESO does publish hourly generation quantities for most plants, but this data is from analogue operational meters which show a slightly different result than the digital revenue meters used by OPG to report nuclear production actuals. The revenue meters form the basis for settling OPG's regulated rate payments with the IESO.

AMPCO Interrogatory #030

Ref: Exhibit E2, Tab 1, Schedule 1 Page 3

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please provide the equivalent TWh for the following outages that OPG has accounted for in its test period production forecast:

- Darlington Vacuum Building Outage in 2015
- Pickering Unit #1 mid-cycle planned outage of 20 days
- Pickering's forecast Forced Loss rate of 7.8% in 2014 and 5.5% in 2015
- Darlington's Forced Loss Rate of 1.3% in 2014 and 1.0% in 2015

Response

- Darlington Vacuum Building Outage in 2015:
  The Darlington Unit 3 planned outage overlaps with the Darlington VBO. The impact of the VBO on the Unit 3 planned outage is 7.2 days

  Unit 1 – 47.5 days
  Unit 2 – 51.5 days
  Unit 3 – 7.2 days
  Unit 4 – 50.8 days
  Total = 157.0 days (3.31 TWh)

- Pickering Unit #1 mid-cycle planned outage of 20 days:
  0.25 TWh in 2014

- Pickering's forecast Forced Loss rate of 7.8% in 2014 and 5.5% in 2015:
  1.82 TWh in 2014
  1.29 TWh in 2015

- Darlington's Forced Loss Rate of 1.3% in 2014 and 1.0% in 2015:
  The 2014 forced loss rate is actually 1.25% (i.e., was rounded to 1.3%), which is 0.31 TWh. The comparable figure for 2015 is 0.27 TWh.

AMPCO Interrogatory #031

Ref: Exhibit N1, Tab 1, Schedule 1, Page 14

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Preamble: OPG indicates that the updated production forecast for Pickering for 2014 and 2015 in the 2014-2016 Business Plan shows a 1.0 TWh reduction in generation compared to the 2013-2015 Business Plan, due to an increase of 86.6 planned outage days over the two-year period:

Please provide the equivalent TWh for the following:
-Pickering Unit #5 additional 23 day mid-cycle outage in 2014
-Deferral of 2013 Pickering Unit #4 outage to January 2014
-Deferral of 2015 Unit #4 outage to 2016
-Additional 28 day 2015 mid-cycle outage to support 2016 targeted reduction in FLR to 5%.

Response

- Pickering Unit #5 additional 23 day mid-cycle outage in 2014:
  0.28 TWh in 2014

- Deferral of 2013 Pickering Unit #4 outage to January 2014:
  1.05 TWh in 2014

- Deferral of 2015 Unit #4 outage to 2016:
  0.98 TWh in 2015

- Additional 28 day 2015 mid-cycle outage to support 2016 targeted reduction in FLR to 5%:
  0.35 TWh in 2015

AMPCO Interrogatory #032

Ref: Exhibit N1, Tab 1, Schedule 1, Page 15

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Preamble: OPG indicates that the updated production forecast for Darlington for 2014 and 2015 in the 2014-2016 Business Plan shows a 1.6 TWh reduction in generation compared to the 2013-2015 Business Plan, due to an increase of 61.9 planned outage days over the two-year period:

Please provide the equivalent TWh for the following:

a) 39 additional planned outage days for VBO in 2015

Response

a) The 39.0 additional planned outage days is equivalent to 0.83 TWh.

AMPCO Interrogatory #033

Ref: Exhibit N1, Tab 1, Schedule 1, Page 16

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

a) Please confirm the total allowances in the production forecast for 2014 and 2015 separately for Darlington and Pickering.

Response

a) The 2014 - 2016 Business Plan has a nuclear fleet level allowance for Pickering planned outages in 2014 and 2015 of 102.8 days. The equivalent TWh is 1.27 TWh.

The 2014 - 2016 Business Plan has a nuclear fleet level allowance for Darlington planned outages in 2014 and 2015 of 23.7 days. The equivalent TWh is 0.50 TWh.

LPMA Interrogatory #006

Ref: Exhibit E2, Tab 1, Schedule 1

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please update Charts 1 & 2 to reflect actual production figures for 2013.

Response

Please see updated Charts 1 and 2.

Chart 1 – Updated for Actual 2013 production

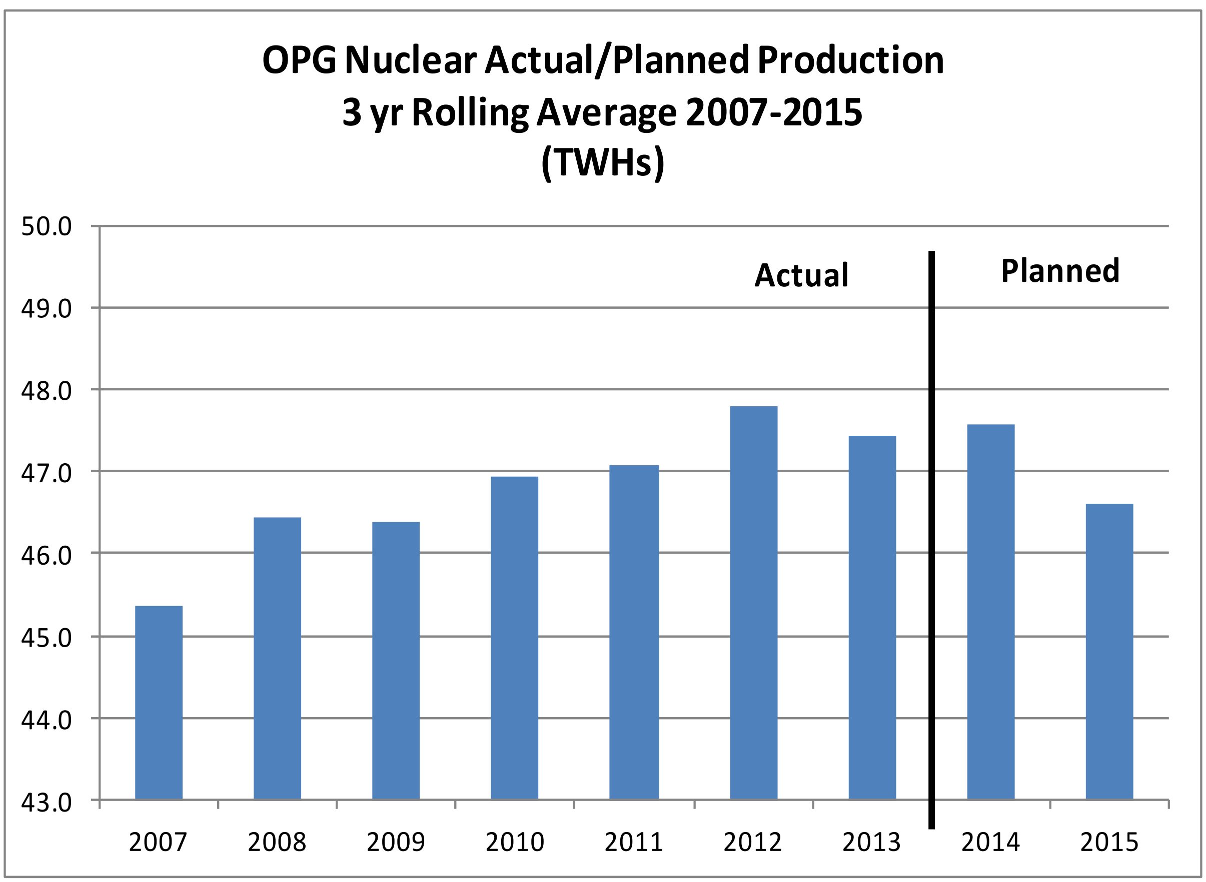


Chart 2 – Updated for Actual 2013 Production

OPG Nuclear Production Variances and Revenue Impact

	2008	2009	2010	2011	2012	2013	Average
Actual /Forecast - TWh (1)	48.2	46.8	45.8	48.6	49.0	44.7	
Board Approved - TWh (2)	51.4	49.9	50.7	50.4	51.5	51.0	
Variance -TWh	3.2	3.1	4.9	1.8	2.5	6.3	3.6
Revenue Impact - $M (3)	-159.9	-154.9	-242.4	-87.3	-121.3	-305.7	-178.6

[1] All amounts are actual

[2] 2010 is average of 2008 and 2009 Board Approved; 2013 is average of 2011 and 2012 Board Approved

[3] Board Approved rates of $52.98/Mwh 2008-10 and $51.52/Mhw 2011-13 less fuel

PWU Interrogatory #010

Ref:
(a): Exh N1-1-1, Pages 14, line 29-page 15, line 8:

> The Darlington production forecast for 2014 and 2015 in the 2014-2016 Business Plan has a 1.6 TWh reduction in generation compared to the 2013 -2015 Business Plan.
>
> This is due to:
> - A reduction of 0.28 TWh to reflect the expectation of higher lake water temperatures than assumed in the 2013 -2015 Business Plan. Higher lake water temperatures lower generation output due to reduced condenser efficiency.
> - A 61.9 day increase in planned outage days...

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

a) Please confirm if the 61.9 day increase in planned outage days is responsible for a 1.32 TWh reduction in production forecast -the balance of the 1.6 TWh reduction after taking into account the 0.28 TWh reduction attributable to the expectation of higher water temperature?

b) If question a)is confirmed, please also confirm if, of the 1.32TWh reduction due to the 61.9 day increase in planned outage days, 0.83TWh is attributable to the Vacuum Building Outage ("VBO") and 0.49TWh is attributable to increased allowances for Darlington planned outages by 22 days?

Response

a) Yes, the 61.9 planned outage day increase for Darlington is responsible for a 1.32 TWh reduction in the production forecast. Losses due to lake water temperature account for a 0.28 TWh reduction.

b) Yes. 22.9 days (0.49 TWh) are attributed to Darlington planned outages (Unit 1 outage in 2014 and Unit 3 outage in 2015) and 39.0 days (0.83 TWh) are attributed to the Darlington VBO/SCO.

PWU Interrogatory #011

Ref:
(a): Exh E2-1-1, Page 5, Lines 18-25

> Planned outages consist of a combination of "routine" inspection and maintenance activities and "non-routine" activities specific to a particular outage. Examples of routine activities would be preventive maintenance, feeder inspections and water lancing of steam generators. Non-routine activities include corrective and deficient maintenance, and replacements or modifications to the equipment or plant configuration that can only be done when the unit is shut down. The majority of work in an outage typically is routine preventative maintenance and inspection activities while the remaining work is non-routine breakdown maintenance and modifications.

(b): Exh F2-4-1, Page 1, Lines 12-17

> Actual and forecast outage OM&A costs over the period 2010 -2015 primarily reflect:
> - ...
> - ...
> - The addition of mid-cycle outages for Pickering Units 1 and 4 over the period 2012-2014 to accelerate reliability work execution

(c): Exh N1-1-1, Page14, Lines 8-14

> - The 2013 Unit 4 outage was deferred to January 2014. This resulted in the timing of all future Unit 1 and 4 planned outages being similarly deferred (e.g., the 2014 Unit 1 outage is deferred to 2015; and, the 2015 Unit 4 outage is deferred until 2016). The deferral of the 2013 Unit 4 fall outage into 2014 results in an additional seven planned outage days over the test period due to additional scope.
> - An additional 28 day 2015 mid-cycle outage has been added to the 2014 — 2016 Business Plan in support of OPG's 2016 targeted reduction in FLR to 5.0 percent...

(d): Exh F2-1-1, Attachment 2: 2013-2015 Nuclear Business Plan, May 16, 2013, page 11, Pickering 2013-2015 Equipment Reliability Plan.

> - Pickering Nuclear FLR performance does not meet expectations, in particular Units 1, 4, and 8.

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

a) Please describe routine and non-routine works to be performed during mid-cycle planned outages at Pickering Units 1 and 4 over the period 2014-2015 to accelerate reliability work execution.

b) Ref (c) set out that an additional 28 day mid-cycle outage schedule for 2015 has been added to the 2014-2016 Business Plan in support of OPG's 2016 targeted reduction in FLR to 5.0 per cent. In what unit this outage will be performed? Please describe non-routine works, if any, that OPG will perform during this outage?

c) As per Ref (d), Pickering Nuclear FLR performance does not meet expectations, in particular Units 1, 4, 8. Please explain why OPG has not implemented mid-cycle planned outages for Pickering Unit 8?

Response

a) Pickering units are on a 2-year planned outage cycle. Pickering Units 1 and 4 however were not consistently achieving two year runs and were subject to forced outages to address equipment problems as they occurred. A proposal was developed to take mid-cycle outages on Pickering Units 1 and 4 to proactively repair equipment and perform preventive maintenance, thereby allowing the units to run “more predictably”. The proposal was approved in the 2012 - 2014 Business Plan.

   Routine work is preventative and predictive maintenance and occurs at a set frequency. For example, critical valve diagnostics, pump seal replacements, crane inspections and radiation detector testing.

   Non-routine work is one-time fixes such as the replacement of obsolete or defective parts, modification to systems or components, or discovery work based on inspections from a prior outage.

b) The 28 day mid-cycle outage in 2015 will be performed on Unit 4. Routine and non-routine work will be scoped into the outage as part of outage planning in 2014.

   The scoping process for determining non-routine work for the mid-cycle outages consists of the following:
   - Review of ready to execute reliability type work
   - Review of unit equipment reliability challenges
   - Review of outstanding inspections and preventive maintenance work that can be used to improve unit predictability/reliability

   Based on the above, the mid-cycle outage scope of non-routine work will be then determined.

b) As part of the Pickering Units 5 - 8 Continued Operations project, additional outage days were included in the 2011 - 2014 planned outages to achieve the same goal of improved unit reliability as the mid-cycle outages. For this reason, no mid-cycle outage has been planned for Unit 8.

PWU Interrogatory #012

Ref: Exh. E2-1-2, page3, lines 20-23:

> The higher actual production for 2012 relative to 2011 actual production is primarily due to:
>
> • A 1.0 percent decline (i.e. improvement) in the combined nuclear FLR in the 2012 (4.6 percent improvement for Pickering, partially offset by a 1.7 percent increase for Darlington).

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

a) Please provide the reasons for the 1.7 percent FLR increase for Darlington in 2012?

Response

In 2011, Darlington units had 3.9 Forced Outage ("FO") days and 4.3 equivalent days of Forced Derates, for a total of 8.2 FLR days and a 0.59% FLR.

In 2012, Darlington units had 22.0 FO days and 10.3 equivalent days of Forced Derates, for a total of 32.3 FLR days and a 2.31% FLR.

The largest contributor to FO days was a pump failure on Darlington Unit 1, followed by forced outages on Darlington Unit 2 for boiler feedwater repairs and a spurious shutdown system trip. The largest contributor to Forced Derates was a reactor power reduction on Darlington Unit 2 due to a vertical flux detector failure and derates related to condenser cooling water system maintenance.

SEC Interrogatory #074

Ref: N1-1-1/p.12

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

At the reference OPG states "*OPG's senior management directed generation planning staff to reassess the plan based on OPG's historical performance in which significant production forecast variances have occurred (i.e., actual generation has been lower than forecast over the past nine years including 2013)*." Please provide data and analysis which Senior Management reviewed in making their determination that the original outage forecast should be reviewed. Please also provide all e-mails between senior management (or their offices) and generation planning staff in respect to the request to revisit the forecast.

Response

The material below summarizes the data and analyses that OPG's Senior Management relied on to reassess the production plan based on historical performance. As explained in the application (Ex. N1-1-1, pp. 13 - 16), Senior Management initiated a review of the forecast as part of the 2014 - 16 Business Plan review process because of the large and persistent gap between forecast and actual production and to ensure that the planned outage days sufficiently recognized the scope and complexity of the planned Station Containment Outage ("SCO")/Vacuum Building Outage ("VBO"). As noted in the evidence (Ex. N1-1-1, page 15), completion of the entire outage scope is crucial to OPG's plan to eliminate the need for the 2021 VBO, which otherwise would have occurred during Darlington Refurbishment.

A Senior Management review is typically conducted in Q3 of the business planning year. A senior management review of the business planning assumptions underpinning the generation plan occurred in Q3 2013 as part of the 2014 - 2016 business planning process.

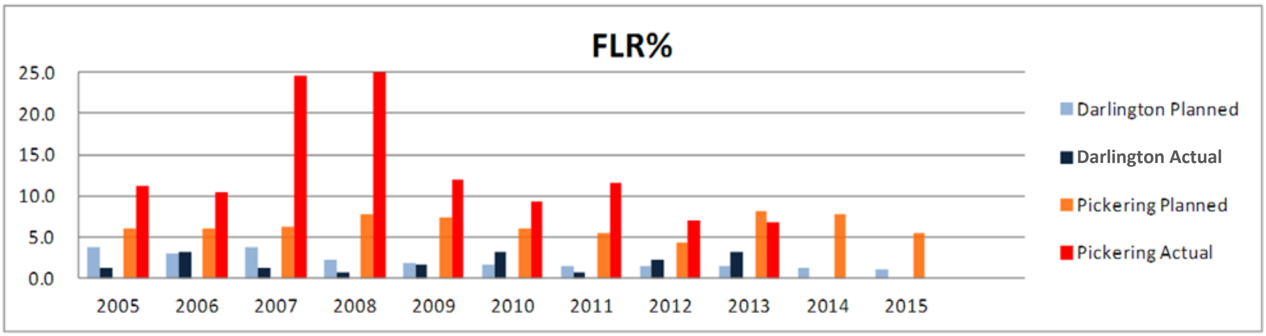
As indicated in Ex N1-1-1. page 13, the outcome of that review was that Senior Management directed the generation staff to reassess the generation plan. This direction was driven by a concern that the 2014 - 2016 forecast was overstating generation based on OPG's historical performance from 2005 - 2012 where actual generation has been lower than forecast in each year. Senior Management was also aware that as of Q3 the 2013 production forecast was indicating that production would again be below OPG's 2012 - 2014 budget as well as significantly below the generation forecast underpinning OPG's approved rates, resulting in a sizable revenue deficiency.

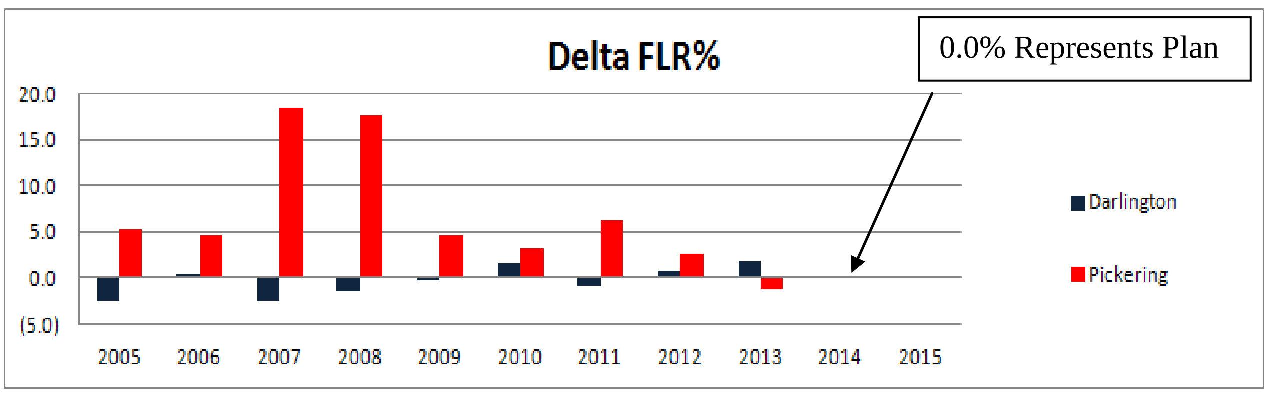
The following historical data was considered by Senior Management as part of the Q3 generation plan review for the outage forecasting process used to support the 2014 - 2016 Business Plan.

- Actual Nuclear production for the last several years has come in significantly below the production forecasts.

- Since 2008, over-forecasting production has resulted in over $900M in lost regulated revenue. See Chart 2 in Ex. E2-1-1

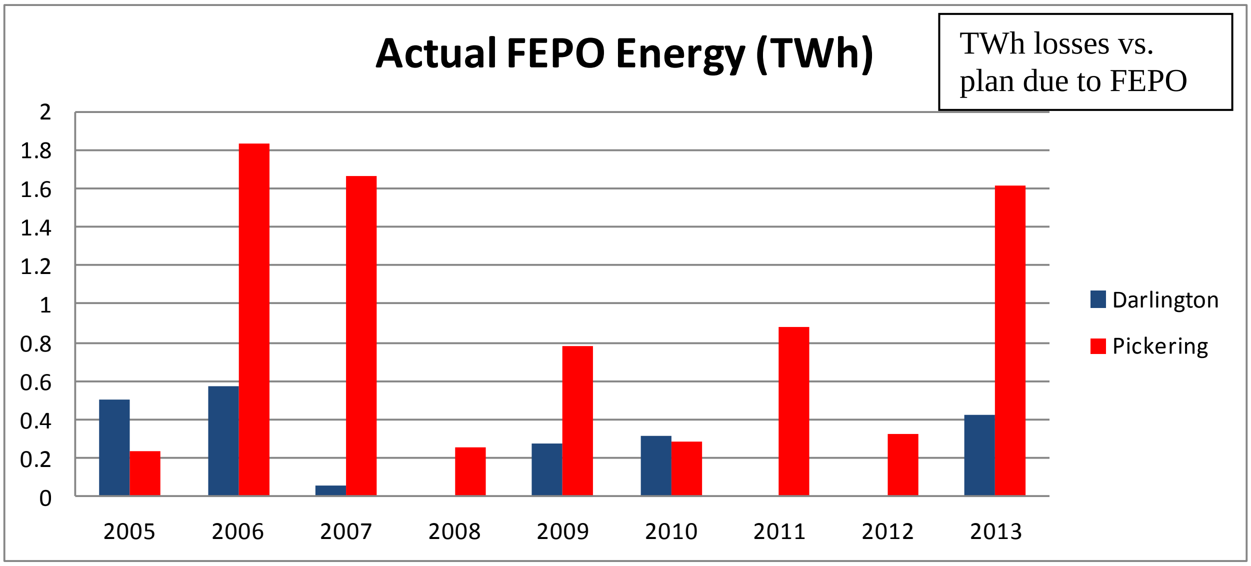
- The following tables review recent nuclear performance versus plan





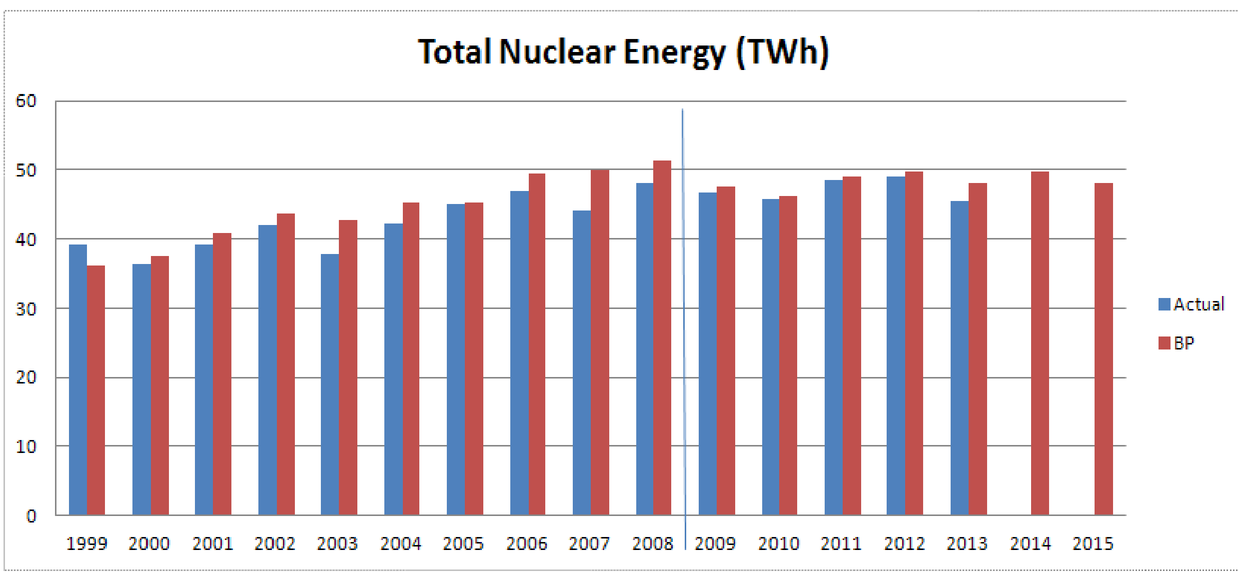
- Actual FLRs have come in well above plan, especially at Pickering

- Average actual FLR from Year 2005 to Year 2013 is 2.0% for Darlington and 13.2% for Pickering



- Average FEPO from 2005 to 2013 for Darlington is 0.24 TWh and for Pickering is 0.87 TWh.

- Average FEPO from 2009 to 2013 for Darlington is 0.20 TWh and for Pickering is 0.78 TWh

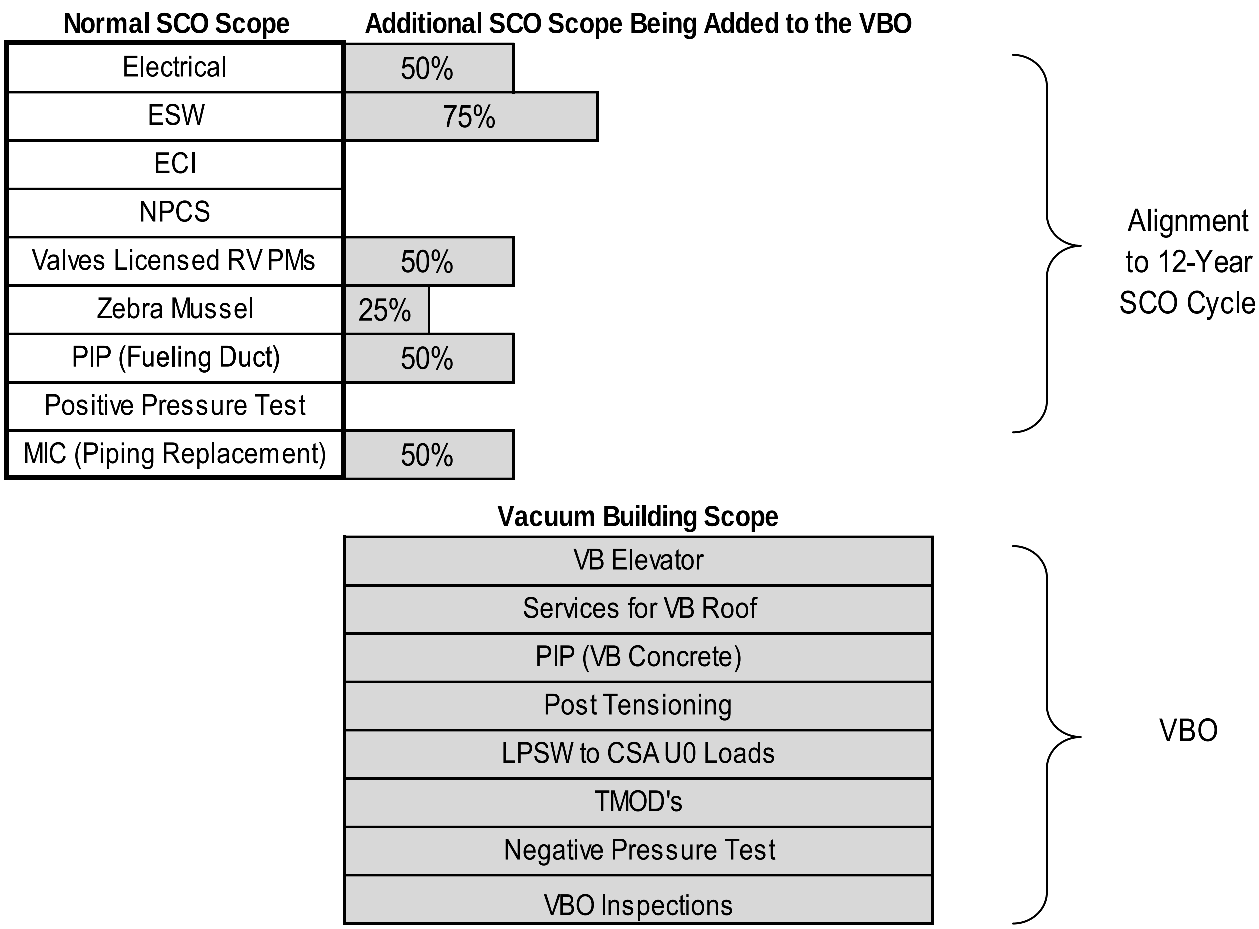


- Average nuclear energy variance from 1999 - 2008 was -2.1 TWh.

- The average nuclear energy variance from 2009 - 2013 was -0.9 TWh (includes 2013 estimated per the July monthly BP update).

In addition the requirements for the 2015 VBO were reviewed by Senior Management prior to making a final determination on the outage forecast, The 2015 VBO differs from previous VBOs in both the amount and complexity of the work to be performed. OPG is aligning the SCO and VBO. As shown in the diagram below, depending on the specific task, 25% to 75% more work will be required. In addition, some tasks will be undertaken for the first time (e.g., the Vacuum Building Pressure Relief Valve seal replacements).

SCO/VBO Scope Changes



SEC Interrogatory #075

Ref: N1-1-1/p14

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please provide the cost-benefit analysis or other economic analysis which was undertaken to support the policy change in 2012 to implement mid-cycle planned outages. Please provide the FLR forecast for 2012.

Response

Pickering units are on a 2 year planned outage cycle. Pickering Units 1 and 4 however were not consistently achieving two year runs and were subject to forced outages to address equipment problems as they occurred. A proposal was developed to take mid-cycle outages on Pickering Units 1 and 4 to proactively repair equipment and perform preventive maintenance, thereby allowing the units to run "more predictably".

The rationale to carry out mid-cycle outages was operational in nature and consequently a formal economic review was not undertaken. The benefits of the proposal were reviewed and approved as part of the 2012 - 2014 Nuclear Business Planning process.

The FLR forecast in the 2012 - 2014 Pickering Business Plan (including Units 5 - 8) was 8.6% in 2012, 8.6% in 2013 and 8.3% in 2014. Table 1 below shows actual and forecast FLR for Unit 1 and Unit 4 over the period 2010 - 2012 which was relied upon in the decision to introduce mid-cycle outages.

	Unit 1	Unit 4
2010 Actual	39.4%	34.7%
2011 Actual	18.0%	29.2%
2012 Budget (2012-2014BP)	16.4%	16.4%

The FLR forecast for the 2013 - 2015 Business Plan was reduced to 8.1% in 2013, 7.8% in 2014, and 5.5% in 2015.

SEC Interrogatory #076

Ref: N1-1-1/p15

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

OPG revised the forecast planned outages for Pickering by 28.6 days based on the 2005 to 2013 performance. Please provide the outage average if based on 2008 to 2013 (most recent 5 year period. Please provide a description of the reasons for, and length of, outages for Pickering in each month of 2005 through 2013.

Response

OPG has assumed that the interrogatory is seeking the average number of forced extension to planned outage ("FEPO") days. The total number of outage days per year is variable, and reflects the outage scope based on fitness of service, asset management, and regulatory requirements.

The average number of FEPO days, using the most recent five years of data (2009 - 2013), is 69.2 days per year.

PN	2005	2006	2007	2008	2009	2010	2011	2012	2013
FEPO Days	17.5	141.5	128.4	19.7	60.2	21.5	70.7	26.2	167.6

A description and reasons for each forced extension to a planned outage at Pickering from 2005 to 2013 is provided in the table below:

Item	Month - Year	Unit	FEPO Days	Description
FEPO 2005				
1.	Jun 2005	P5	9.0	Repair of a generator hydrogen leak
2.	Dec 2005	P6	8.4	Replacement of shutdown cooling pump seal
FEPO 2006				
3.	Jun 2006	P1	0.9	Outage delays during unit start-up due to repairs required to a main steam valve and a boiler emergency cooling valve
4.	Dec 2006	P4	20.1	Outage delays due to additional electrical work required for unit start up
5.	Dec 2006	P6	35.4	Boiler inspection and repairs

6.	Apr 2006	P7	7.1	Heat transport D2O leak to collection
7.	May 2006	P7	45.3	Additional service water system work required
8.	May 2006	P8	32.6	Additional work required to support heat transport system pressurization and approach to critical
FEPO 2007				
9.	Dec 2007	P1	11.0	Delays in heat transport work and starting of the service water outage
10.	Jan 2007	P4	49.2	Repair required to reactivity adjuster absorber cable
11.	Jun 2007	P5	24.7	Outage delayed due to site electrical system transfer test and subsequent troubleshooting
12.	Nov 2007	P6	15.6	Repair of shutdown cooling heat exchanger, electrical repair and liquid zone control bubbler headers troubleshooting and repair
13.	Jan 2007	P7	28.0	Recovery activities due to demineralized water supply contaminated with resin
FEPO 2008				
14.	Jan 2008	P1	1.1	Delays in heat transport work and starting of the service water outage
15.	May 2008	P5	5.3	Moderator cover gas chemistry issues
16.	Apr 2008	P8	13.2	Investigation following switchyard ground fault
FEPO 2009				
17.	Mar 2009	P4	32.5	Replacement of shutdown cooling pump seals
18.	Apr 2009	P5	27.7	Shutdown system repair work and electrical maintenance
FEPO 2010				
19.	Jul 2010	P1	12.3	Additional work required to support heat transport system pressurization and approach to critical
20.	May 2010	P7	2.2	Repair of vault air conditioning unit and shutdown system repair work
21.	Jun 2010	P8	7.0	Emergency water supply valve repair
FEPO 2011				
22.	Dec 2011	P4	6.8	Fuelling machine maintenance

23.	May 2011	P5	63.9	Gadolinium oxalate in moderator system
FEPO 2012				
24.	Apr 2012	P1	0.1	Outage delays during unit start-up
25.	Dec 2012	P1	9.8	Heat transport D2O leak to collection
26.	Jun 2012	P4	7.4	Repair to heat transport pressurizing pumps
27.	May 2012	P8	8.9	Additional work required to support heat transport system pressurization and fuelling machine maintenance
FEPO 2013				
28.	Apr 2013	P1	109.7	Lube oil purifier system repair and unit recovery
29.	May 2013	P4	4.5	Steam release valve maintenance and testing
30.	Jun 2013	P5	53.4	Troubleshooting problems with Main Output Transformer

SEC Interrogatory #077

Ref: N1-1-1/p15

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please provide the basis for updating Lake Ontario water temperatures (.28 TWH reductions). Also provide OPG's budget forecasts for the last 5 years for lake temperature forecast and the actual average. Please describe the relationship between lake temperature and generation output (e.g. in terms of temperature vs. output).

Response

The basis for the forecast losses due to high lake water temperature was the trend in actual production losses from 2009 to 2012. The actual production losses due to high lake water temperature ("HLWT") for the period 2009 - 2013 are shown in the table below:

Actual HLWT Production Losses (TWh)					
Station	2009	2010	2011	2012	2013
DN	0.23	0.22	0.23	0.27	0.19
PN	0.08	0.07	0.08	0.13	0.07
Total	**0.30**	**0.28**	**0.32**	**0.40**	**0.26**

OPG's forecast for production losses due to high lake water temperature for the last 5 business plans are summarized in the following charts. Darlington accounted for HLWT as a contributor to FLR in the 2010 - 2014 Business Plan and not as a separate component. However, following a review of past production losses in 2011, OPG determined that it had overstated the production forecast due, in part, to the impact of HLWT and began to separately account for HLWT in the production forecast.

Forecast HLWT Production Losses (TWh) - 2014-2016 BP			
Station/Year	2014	2015	2016
DN	0.34	0.34	0.34
PN	0.06	0.06	0.06
Total	**0.40**	**0.40**	**0.40**

Forecast HLWT Production Losses (TWh) - 2013-2015 BP			
Station/Year	2013	2014	2015
DN	0.20	0.20	0.20
PN	0.06	0.06	0.06
Total	**0.26**	**0.26**	**0.26**

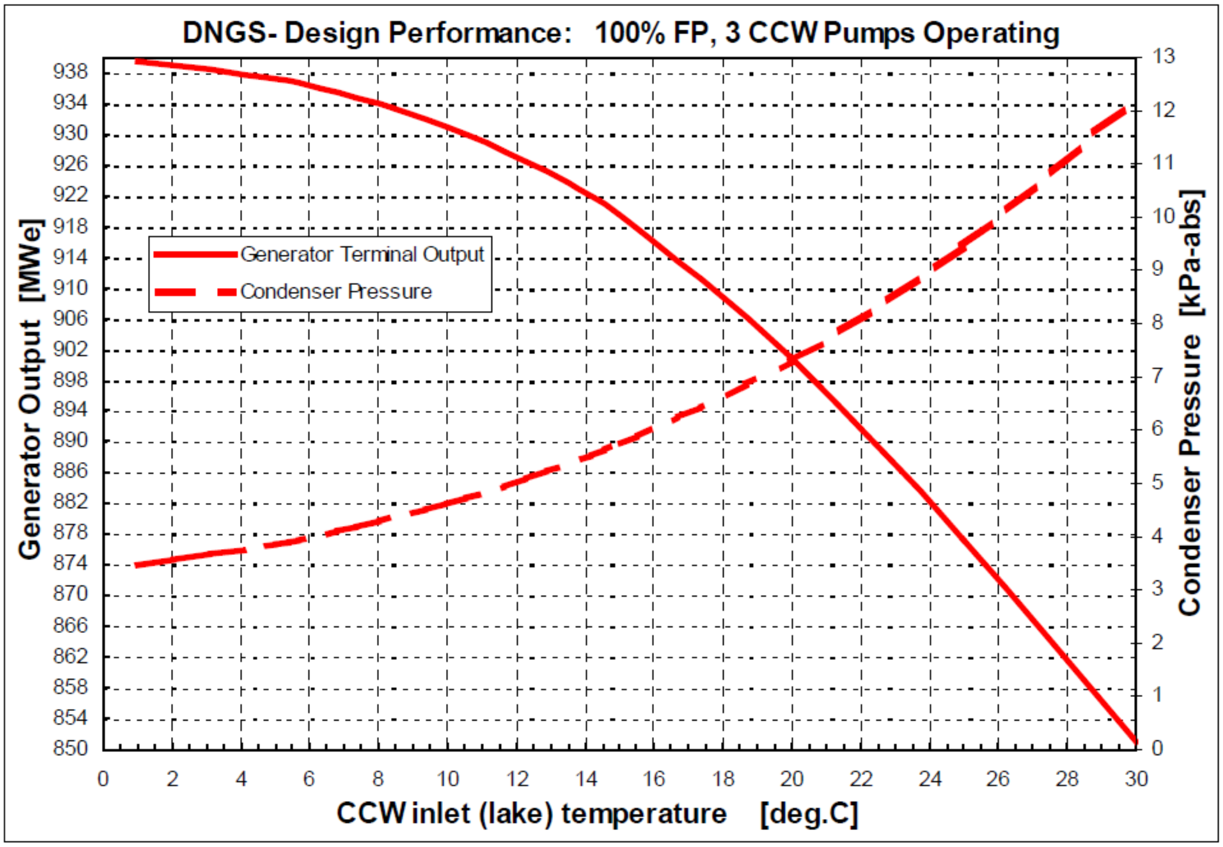
Forecast HLWT Production Losses (TWh) - 2012-2014 BP			
Station/Year	2012	2013	2014
DN	0.20	0.20	0.20
PN	0.06	0.06	0.06
Total	**0.26**	**0.26**	**0.26**

Forecast HLWT Production Losses (TWh) - 2011-2015 BP					
Station/Year	2011	2012	2013	2014	2015
DN	0.15	0.15	0.15	0.15	0.15
PN	0	0	0	0	0
Total	**0.15**	**0.15**	**0.15**	**0.15**	**0.15**

Forecast HLWT Production Losses (TWh) - 2010-2014 BP					
Station/Year	2010	2011	2012	2013	2014
DN	0	0	0	0	0
PN	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**

As lake water temperature rises, so does the condenser temperature and pressure increase which leads to a decrease in generator output. The decrease in generator output is a result in a reduction of thermodynamic efficiency as a result of an increase in condenser pressure. The relationship is shown in the attached graph is similar to what would be seen in any thermal unit (be it nuclear or a conventional unit).

The relationship is shown in the attached graph


DNGS- Design Performance: 100% FP, 3 CCW Pumps Operating
Generator Terminal Output
Condenser Pressure
Generator Output [MWe]
938
934
930
926
922
918
914
910
906
902
898
894
890
886
882
878
874
870
866
862
858
854
850
Condenser Pressure [kPa-abs]
13
12
11
10
9
8
7
6
5
4
3
2
1
0
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30
CCW inlet (lake) temperature [deg.C]

SEC Interrogatory #078

Ref: N1-1-1/p14

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please provide a table showing all the projects for the VBO in the original forecast and, in a separate column, the projects included in the revised forecast. Please explain why any incremental projects cannot be completed concurrently with the originally planned VBO projects.

Response

The initial assessment to determine the forecast 2015 VBO/SCO duration was based on the 2009 VBO scoping strategy/duration. Thereafter, incremental work has been added to the 2015 VBO/SCO scope which introduces greater complexity than was undertaken in the 2009 VBO. Please also see the response to Ex. L-05.5 -17 SEC_074.

Incremental Work	Description	Critical Path Impact
Electrical odd and even bus maintenance	100% increase in scope from the 2009 VBO based on the aging management plan. Extensive temporary modifications are required for alternate supplies. Some of the buses are difficult to inspect and others have not been inspected.	The complexity of integrating odd and even work with other VBO work impacts other critical path work which relies on the electrical buses to be in service.
Emergency Service Water (ESW) piping replacement	Piping replacements based on the aging management plan which requires ESW to be drained below typical VBO level.	The nuclear safety requirement prevents most other work from being executed in parallel.
Emergency Coolant Injection (ECI) valve replacement	50% increase in scope from the 2009 VBO based on the aging management plan and prior inspections.	The nuclear safety requirement prevents most other work from being executed in parallel.

SEC Interrogatory #079

Ref: N1-1-1/p16

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

OPG notes in its revised forecast that it increased the planned outages for Darlington by 22 days based on historical performance between 2005-2013.

(a) Please provide the basis of the original forecast

(b) Please explain what mechanisms have been implemented to reduce forced extensions to planned outages. In particular, please identify contractor penalties and employment performance payments which are associated with planned outage performance.

(c) Please provide the forecast if the years 2008-2013 are used (most recent 5 year historical period).

Response

a) The original Darlington forecast was based on 77.1 planned outage days in 2014 and 188.0 planned outage days in 2015.

b) The following initiatives are underway to help reduce forced extension to planned outages:

- Human Performance Improvement
- Milestone compliance and quality
- Implement Lessons Learned Oversight & Tracking
- Implement Outage models for improved schedule quality
- Parts Improvement Initiative

For contractors, 5% of contractor compensation is tied to planned outage performance. For example, outage extensions caused by a contractor would result in the contractor forfeiting 5% of their compensation, on time outages would result in the contractor being paid out the 5% compensation, whereas a ahead of schedule outage would result in 7.5% contractor compensation.

For OPG employees, performance payment is paid to management and is set by the Annual OPG Corporate and Nuclear Scorecard. The Annual OPG Corporate and Nuclear Scorecard includes a measure for total generation. The performance payment is associated with planned outage performance as total generation is impacted by planned outage performance. Limited outage performance bonuses are paid to unionized workers based on achieving outage performance metrics.

c) The annual average forced extension to planned outages ("FEPO") from 2005 - 2013 is 12.9 days. The average (FEPO) for the most recent 5 years is 13.1 days. Thus the 2014 - 2016 forecast would not change materially if it was based on the most recent 5 years instead of historical performance between 2005 - 2013.

DN	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
FEPO Days	22.3	25.5	2.7	0.0	11.9	13.9	0.0	0.0	39.8

SEC Interrogatory #080

Ref: N1-1-1/p16

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

OPG states that the nuclear fuel bundle cost was reduced in the December update "primarily" as a result of lower forecast production. What if any, other changes were made?

Response

For the year 2015, lower fuel bundle costs (-$7.4M) were affected by lower forecast production and fuel utilization (-$10.2M) offset by the forecast of higher unit prices (+$2.8M).

For the year 2014, lower fuel bundle costs of (-$11.9M) were affected by lower forecast production and fuel utilization (-$4.9M) and a forecast of lower unit prices (-$7.0M).

SEC Interrogatory #081

Ref:
[E2-T1-S1/p.6]

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

OPG states that "[*T]he six Pickering units are on a two year planned outage cycle and therefore Pickering will be subject to 3 planned outages in both 2014 and 2015. In addition there is one mid cycle planned outage in 2014*." Please clarify that the total number of outages for Pickering is 4. What is the difference between the normal planned outage and the mid-cycle planned outage

Response

The following outages are planned for 2014:
Unit 4 – planned outage (85.3 days)
Unit 8 – planned outage (85.7 days)
Unit 7 – planned outage (113.9 days)
Unit 5 – mid-cycle outage (23 days)
Unit 1 – mid-cycle outage (20 days)

The following outages are planned for 2015:
Unit 1 – planned outage (78.8 days)
Unit 5 – planned outage (113.3 days)
Unit 6 – planned outage (119.4 days)
Unit 4 – mid-cycle outage (28 days)

Over the test period, there are 6 planned outages and 3 mid-cycle outages for Pickering.

A normal planned outage for a Pickering Unit occurs every two years and the duration is based on the requirements in OPG's aging and major component life cycle management programs. The major component life cycle management programs must be in compliance with the CNSC's requirements that are part of the station's operating license. The normal planned outage is longer than the mid-cycle outage primarily due to the need to perform major component (fuel channel and feeder pipe) inspections.

A mid-cycle outage is a shorter outage scheduled for Pickering units that provides further opportunities to perform maintenance and improve equipment reliability. These outages are shorter (between 20-30 days) than the normal planned outages. Please also see the response to Ex. L-5.5-15 PWU-11.