PRODUCTION FORECAST AND METHODOLOGY – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides the production forecast for the regulated hydroelectric facilities and a description of the methodology used to derive the forecast.

2.0 OVERVIEW

The regulated hydroelectric production for the years 2010 to 2015 is presented in Ex. E1-1-1 Table 1. OPG is seeking approval of a test period production forecast of 64.1 TWh (31.4 TWh in 2014, and 32.7 TWh in 2015) for the regulated hydroelectric facilities. Of this total, 39.3 TWh (19.1 TWh in 2014, and 20.2 TWh in 2015) is related to the Niagara Plant Group and R.H. Saunders, and 24.8 TWh (12.4 TWh in 2014, and 12.5 TWh in 2015) is related to the newly regulated hydroelectric facilities. Annual changes in production are mostly due to actual or forecast changes in water availability, though an increase in production starting in mid-2013 is related to the Niagara Tunnel Project. Forecast monthly production data for the test period are presented in Ex. E1-1-1 Table 2.

Differences between forecast and actual production that are due to changes in water conditions are captured in the Hydroelectric Water Conditions Variance Account. (See Ex. H1-1-1).

The methodology used to determine the Niagara Plant Group and R. H. Saunders production forecasts is the same as that approved by the OEB in EB-2010-0008. Brief descriptions are presented in Sections 3.2 to 3.4. The forecast methodology for the newly regulated stations are presented in Section 3.5. A brief description of outage planning for the regulated hydroelectric facilities is presented in Section 4.0.

3.0 REGULATED HYDROELECTRIC PRODUCTION FORECAST

3.1 Forecast Methodology

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

Computer models are used to derive production forecasts for the six previously regulated hydroelectric facilities and twenty-one of the forty-eight newly regulated hydroelectric plants. Forecast monthly water flows, generating unit efficiency ratings, and planned outage information are used to convert forecast water availability into forecast energy production. The remaining twenty-seven newly regulated hydroelectric plants (25 Central Hydro Plant Group stations, plus Indian Chute GS and Matabitchuan GS in the Northeast Plant Group) are small stations (capacity up to 10 MW), for which computerized modeling is not available. Average historical production is used as the production forecast for these stations.

There are no deductions made for Surplus Baseload Generation (SBG) in this application, as per the OEB's Decision with Reasons in EB-2010-0008. Instead, as per the Decision, a variance account has been established to deal with SBG. Please see Exhibits E1-2-1 and H1-3-1 for additional information.

3.2 Niagara River Flow and Production Forecast

The Hydrological Response Model for the Great Lakes (developed by the Great Lakes Environmental Research Laboratory – GLERL) and the Advanced Hydrological Prediction System (adapted by GLERL for the Great Lakes system) are used by OPG to derive a forecast of monthly average water levels and outflows for Lake Erie for the next 24 months. Minor adjustments are applied to the forecast of monthly Lake Erie outflows to determine the Grass Island Pool inflow forecast (i.e. the section of the Niagara River immediately above Niagara Falls where water is diverted to the hydropower plants). These minor adjustments account for seasonal variations in local inflows and flow reductions due to ice or weed retardation effects. Beyond 24 months, the flow forecasts trend back towards historical monthly median flows.

The forecast Grass Island Pool inflows are input to the Niagara Utilization Model which uses generating unit efficiency ratings and planned unit outage information to calculate the monthly energy production for the Sir Adam Beck plants. These values are adjusted for losses primarily associated with electrical system operational requirements (e.g., automatic generation control, operating reserve, condense-mode operations, and system constraints), based on an assessment of historical model performance.

OPG has estimated the long-term incremental energy production from the Niagara Tunnel Project (NTP). This "average case" estimate has recently been revised from the 1.6 TWh indicated in the NTP Business Case to 1.5 TWh[1]. The revision is due to some minor refinements in the modeling.

The 2013-2015 Business Plan energy production forecasts included in this application were prepared assuming the new Niagara tunnel in-service in August 2013.

3.3 DeCew Falls Diversion Flow and Production Forecast

Water is diverted from the Welland Seaway Canal and routed to the DeCew Falls plants to generate electricity. Forecasts of monthly DeCew diversion flows are prepared based on historical diversion flows, and consideration of planned Seaway Canal maintenance, planned unit outages at the DeCew plants, and flow constraints during major scheduled rowing regatta events held downstream of the plants.

The forecast DeCew diversion flows are used with DeCew Falls unit availability information and generating unit efficiency ratings to calculate the monthly energy production forecast for the DeCew Falls stations.

[1] The long-term average production number is an estimate of the incremental energy from the Niagara Tunnel based on historical information about water availability, and the operation of water control facilities on the Niagara River and OPG's Sir Adam Beck complex. The 2005 figure was 1.555 TWh and the current figure is 1.472 TWh, a difference of 0.083 TWh or about 5%.

3.4 St. Lawrence River Flow and Saunders Production Forecast

Lake Ontario and the St. Lawrence River outflows and levels are regulated by the International St. Lawrence River Board of Control (“ISLRBC”). “Regulation Plan 1958-D” has been used by the ISLRBC to provide artificial control of the outflows and levels of Lake Ontario since 1963. The ISLRBC has the authority to deviate from the approved plan under specific conditions. An alternative regulation plan 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.

Forecast monthly Lake Ontario outflows and levels are derived from applications based on the Regulation Plan 1958-D model and, if necessary, adjustments applied to reflect ISLRBC authorized deviations from plan. These forecast flows and levels are utilized for up to six months in the forecast period; thereafter, monthly flows are projected consistent with trends predicted by the Niagara River flow forecast.

The forecast St. Lawrence River flow is used with R. H. Saunders unit availability information and generating unit efficiency ratings to calculate the monthly energy production forecast for the R. H. Saunders station.

3.5 Production Forecast for the Newly Regulated Hydro Plants

Water availability on the watersheds of the newly regulated plants can change quickly in response to significant precipitation events. Consequently, long-term flow forecasting is not undertaken for these rivers. Instead, historical median monthly flows are used as the basis for determining the monthly energy production forecasts.

Energy production forecasts for twenty-one of the newly regulated hydroelectric plants, located on nine river systems (Ottawa, Madawaska, Montreal, Abitibi, Aguasabon, Nipigon, Kamanistikwia, English and Winnipeg Rivers) (See Appendix 1), are produced using computer models that convert water availability to forecast energy production using generating unit efficiency ratings and planned outage information.

Energy production forecasts for the other twenty-seven small newly regulated hydroelectric stations (25 Central Hydro Plant Group stations located on ten river systems: Beaver, Mississippi, Muskoka, Otonabee, Rideau, Severn, South, Sturgeon, Trent, and Wanapitei Rivers, plus Indian Chute GS on the Montreal River and Matabitchuan GS on the Matabitchuan River in the Northeast Plant Group) (See Appendix 2), are based on historical mean monthly production values, adjusted to account for planned outages. These small stations account for only 5 percent of the total production from the newly regulated hydroelectric facilities and less than 2 percent of total production from all regulated hydroelectric facilities. Development of computer models to forecast production for these twenty-seven small stations is unwarranted. OPG proposes to exclude these 27 small stations from the Hydroelectric Water Conditions Variance Account. (See Ex. H1-1-1).

Ottawa River flow may be augmented at times with water diverted from Quebec to the Ottawa River basin upstream of Lake Temiskaming (referred to as the “Cabonga diversion”). The production forecasts for the four Ottawa River plants are based on historical median flow data that includes the Cabonga diversion flow. OPG benefits from additional energy produced at the four plants due to the Cabonga water. By agreement, a portion of the additional energy generated is returned to Hydro Quebec (“Cabonga payback”). Cabonga payback typically amounts to less than one percent of total production from the Ottawa River plants. In addition, OPG shares in operation, maintenance and project refurbishment costs associated with Hydro Quebec’s facilities that enable the Cabonga diversion. (See Ex. F1-4-1, Section 4, Hydro Quebec – Dozois Agreement.)

4.0 OUTAGE PLANNING

Outage planning for OPG’s hydroelectric generating stations is unchanged from EB-2010-0008 and continues to be based on the streamlined reliability-centered maintenance philosophy as described in Ex. F1-1-1.

Outages are generally planned to conduct:

- Major overhaul, rehabilitation or upgrade work
- Preventative maintenance

- Condition based maintenance
- Inspection and testing

The normal cyclical patterns of river flow within a year are considered when scheduling outages in order to minimize the spilling of water. Generating unit availability is determined from the planned outage schedule and included in the energy production forecast.

Major overhaul and rehabilitation work is planned, in addition to regularly scheduled maintenance outages, at Niagara Plant Group facilities and a number of the newly regulated plants during 2014 and 2015. (See Ex. D1-1-2 and F1-3-1).

APPENDIX 1

NEWLY REGULATED STATIONS WITH MODELED PRODUCTION FORECASTS

River System	Station
Madawaska	Mountain Chute
	Barrett Chute
	Calabogie
	Stewartville
	Arnprior
Ottawa	Otto Holden
	Des Joachims
	Chenaux
	Chats Falls
Abitibi	Abitibi Canyon
	Otter Rapids
Montreal	Lower Notch
Nipigon	Pine Portage
	Cameron Falls
	Alexander
Aguasabon	Aguasabon
Kamanistikwia	Silver Falls
	Kakabeka Falls
English	Manitou Falls
	Caribou Falls
Winnipeg	Whitedog Falls

APPENDIX 2

NEWLY REGULATED STATIONS WITHOUT MODELED PRODUCTION FORECASTS

River System	Station
Montreal	Indian Chute
Matabitchuan	Matabitchuan
Mississippi	High Falls
Rideau	Merrickville
Otonabee	Lakefield Auburn
Trent	Seymour Ranney Falls Hagues Reach Meyersburg Sills Island Frankford Sidney
Beaver	Eugenia Falls
Muskoka	Trethewey Hanna Chute South Falls Ragged Rapids Big Eddy
Severn	Big Chute
South	Elliot Chute Bingham Chute Nipissing
Sturgeon	Crystal Falls
Wanapitei	Stinson Conistion McVittie

Numbers may not add due to rounding.

Table 1

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

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Budget	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	12.2	12.7	13.5
2	**Saunders GS**[1]	6.5	6.9	6.5	6.2	6.3	6.7
3	**Sub total**	18.9	19.5	18.5	18.4	19.1	20.2
	Newly Regulated Hydroelectric:						
4	**Ottawa-St. Lawrence Plant Group**[2]	4.7	5.7	5.1	5.7	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	2.5	2.5	2.5
7	**Northwest Plant Group**	3.4	3.3	3.3	3.8	3.8	3.8
8	**Sub total**	10.0	11.5	10.9	12.4	12.4	12.5
9	**Total**	28.9	31.0	29.4	30.9	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.

Numbers may not add due to rounding.

Table 2
Monthly Production - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric (TWh)
Test Period

Line No.	Prescribed Facility	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	2014 Plan:													
	Niagara Plant Group and Saunders GS:													
1	**Niagara Plant Group**	1.2	1.0	1.2	1.0	1.1	1.0	1.0	1.0	0.9	1.0	1.1	1.2	12.7
2	**Saunders GS**[1]	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	6.3
3	**Subtotal**	1.7	1.5	1.7	1.5	1.6	1.6	1.6	1.5	1.4	1.5	1.6	1.8	19.1
	Newly Regulated Hydroelectric:													
4	**Ottawa-St. Lawrence Plant Group**[2]	0.6	0.5	0.5	0.6	0.7	0.5	0.4	0.3	0.3	0.4	0.5	0.6	5.7
5	**Central Hydro Plant Group**	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
6	**Northeast Plant Group**	0.2	0.2	0.2	0.3	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.5
7	**Northwest Plant Group**	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	3.8
8	**Subtotal**	1.1	1.0	1.1	1.2	1.4	1.1	0.9	0.8	0.7	0.9	1.0	1.1	12.4
9	**Total**	2.8	2.5	2.8	2.7	3.0	2.6	2.5	2.3	2.2	2.5	2.6	2.9	31.4
	2015 Plan:													
	Niagara Plant Group and Saunders GS:													
10	**Niagara Plant Group**	1.2	1.1	1.2	1.1	1.2	1.1	1.1	1.1	1.0	1.1	1.2	1.3	13.5
11	**Saunders GS**[1]	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	6.7
12	**Subtotal**	1.7	1.6	1.8	1.6	1.8	1.7	1.7	1.7	1.6	1.6	1.7	1.8	20.2
	Newly Regulated Hydroelectric:													
13	**Ottawa-St. Lawrence Plant Group**[2]	0.6	0.5	0.5	0.6	0.7	0.5	0.4	0.3	0.3	0.4	0.5	0.5	5.7
14	**Central Hydro Plant Group**	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5
15	**Northeast Plant Group**	0.2	0.2	0.2	0.3	0.4	0.2	0.2	0.2	0.1	0.2	0.2	0.2	2.5
16	**Northwest Plant Group**	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	3.8
17	**Subtotal**	1.1	1.0	1.1	1.2	1.4	1.1	0.9	0.8	0.7	1.0	1.0	1.1	12.5
18	**Total**	2.9	2.6	2.9	2.9	3.2	2.8	2.6	2.4	2.3	2.6	2.7	2.9	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.

COMPARISON OF PRODUCTION FORECAST – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of regulated hydroelectric production forecasts for 2010 - 2015. This evidence supports the approval of the regulated hydroelectric production forecast presented in Ex. E1-1-1.

2.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2015 Plan vs. 2014 Plan

The total regulated hydroelectric production forecast for 2015 is four per cent (1.2 TWh) higher than the forecast plan for 2014 (Ex. E1-1-2 Table 1).

Total production from the Niagara Plant Group and Saunders is forecast to increase by six percent (1.2 TWh) primarily due to higher flows forecast for the Niagara and St. Lawrence Rivers in the 2015 Plan. The annual means of monthly flows forecast for 2015 were five to seven per cent higher than those forecast in the 2014 Plan.

The production forecast plans for the newly regulated hydro plants were similar for the two years.

2014 Plan vs. 2013 Budget

The total regulated hydroelectric production plan for 2014 is two per cent (0.6 TWh) higher than the 2013 Budget (Ex. E1-1-2 Table 1).

Total production from the Niagara Plant Group and Saunders is forecast to increase by three percent (0.6 TWh). Forecast production by the Niagara plants for 2014 is 0.5 TWh more than 2013 Budget production. The forecasted increase is mostly due to the Niagara Tunnel which was assumed to come into service in August 2013. The Niagara River flow forecast for 2014 is only marginally higher (less than one per cent) than that forecast in the 2013 Budget. Forecast production for R.H. Saunders for 2014 is 0.1 TWh more than the 2013 Budget as the St. Lawrence River flow forecast for 2014 is about two per cent higher than that forecast in the 2013 Budget.

The production forecast plans for the newly regulated hydro plants were similar for the two years.

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2013 Budget vs. 2012 Actual

The total regulated hydroelectric production budget for 2013 is five per cent (1.5 TWh) higher than actual production for 2012 (Ex. E1-1-2 Table 1). There was essentially no change in total production expected from Niagara and R.H. Saunders as production increases forecast for the Niagara Plant Group for 2013 are offset by production reductions forecast for R. H. Saunders. The increase in production forecast for 2013 is primarily attributable to the newly regulated hydro plants.

Forecast production by the newly regulated hydro plants in 2013 is 1.6 TWh more than actual production achieved in 2012. Production from these plants was lower than normal in 2012. Annual mean flows for 2012 were generally below normal and ranked as lower quartile for several river systems. Surplus baseload generation likely inhibited production at some sites as well.

R. H. Saunders budget production for 2013 is forecast to be 0.3 TWh lower than 2012 production due to a decrease in the St. Lawrence River flow forecast for 2013. The annual mean of forecast monthly flows for 2013 is five per cent lower than the 2012 annual mean flow.

The annual mean of Niagara River monthly flows forecast for the 2013 budget is eight per cent lower than the 2012 annual mean flow. However, 2013 budget production for the Beck plants is forecast to increase by 0.2 TWh over 2012 actual production, based on the Business Plan assumption that the new tunnel would be placed in-service by August 2013. Budget production for DeCew Falls for 2013 is forecast to increase by almost 0.1 TWh over

2012 actual production. Production at DeCew Falls was curtailed during the fall of 2012 due to extended unit outages at Decew Falls NF23 and operational strategies to manage Niagara flow entitlement (Beck and DeCew).

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2012 Actual vs. 2012 Board Approved

The total regulated hydroelectric production during 2012 was nine per cent (2.9 TWh) below the 2012 Plan (Ex. E1-1-2 Table 1). Production from the Niagara Plant Group and R. H. Saunders was 1.4 TWh below plan while production by the newly regulated hydro plants was 1.6 TWh below plan.

Production at the Sir Adam Beck plants was 0.7 TWh below plan for 2012 due to lower Niagara River flow (2 per cent below forecast plan flow) and production losses associated with surplus baseload generation (See Ex. E1-2-1). Production at DeCew Falls was 0.2 TWh below plan. Production at DeCew Falls was curtailed during the fall of 2012 due to extended unit outages at Decew Falls NF23 and operational strategies to manage Niagara flow entitlement (Beck and DeCew). Production at R. H. Saunders was 0.4 TWh below plan during 2012 due to lower St. Lawrence River flow. The annual mean of St. Lawrence River flow for 2012 was eight per cent lower than the annual mean of the forecast plan flow.

The variance in production by the newly regulated hydro plants (1.6 TWh) is generally attributable to below normal flow in 2012. The annual mean flow for several river systems ranked as lower quartile. Production at some stations may have been inhibited by surplus baseload generation as well.

2012 Actual vs. 2011 Actual

The total regulated hydroelectric production for 2012 was five per cent (1.7 TWh) lower than actual production achieved in 2011 (Ex. E1-1-2 Table 1). Production during 2012 was 0.7 TWh lower for the Niagara Plant Group, 0.4 TWh lower at R. H. Saunders, and 0.6 TWh lower for the newly regulated hydro plants.

Production decreased by 0.5 TWh at the Sir Adam Beck plants during 2012 due to lower Niagara River flow and an increase in production losses due to surplus baseload generation (See Ex. E1-2-1). The annual mean flow for 2012 for the Niagara River was four per cent lower than that for 2011. Production at DeCew Falls during 2012 was almost 0.2 TWh lower than 2011. Production at DeCew Falls was curtailed during the fall of 2012 due to extended unit outages at Decew Falls NF23 and operational strategies to manage Niagara flow entitlement (Beck and DeCew). The production decrease of 0.4 TWh at R. H. Saunders was due to lower St. Lawrence River flow. The annual mean of St. Lawrence River flow for 2012 was nine per cent lower than the annual mean flow for 2011.

The production decrease of 0.6 TWh for the newly regulated hydro plants in 2012 was attributable to lower production from plants located in the eastern part of the Province. Production from the Madawaska River plants in 2012 was 28 percent (0.3 TWh) lower than in 2011 and production from the Ottawa River plants decreased by seven per cent (0.3 TWh), primarily due to lower river flow. Annual mean flows for the Madawaska and Ottawa Rivers were lower in 2012 than 2011, with the Madawaska River mean flow ranking as lower decile.

2011 Actual vs. 2011 Board Approved

The total regulated hydroelectric production during 2011 was 4 per cent (1.3 TWh) below the 2011 Plan. Total production from the Niagara Plant Group and R. H. Saunders was 0.3 TWh below plan while production from the newly regulated hydro plants was 0.9 TWh below plan.

Production at the Sir Adam Beck plants during 2011 was slightly lower (0.2 TWh) than the 2011 Plan, although the annual mean Niagara River flow for 2011 was marginally higher (one per cent) than the annual mean of the forecast plan flow. Production was below plan in January and February, when actual flow was lower than forecast, and in April and May, when production losses increased due to surplus baseload generation. R.H. Saunders production during 2011 was 0.1 TWh lower than the 2011 Plan. The annual mean St. Lawrence River flow for 2011 was very similar to the annual mean of the forecast plan flow for 2011. Simultaneous outages of multiple units for replacement of transformer and unit protection and control equipment impacted production at R. H. Saunders during 2011. As a result of these outages, increased St. Lawrence water transactions occurred with NYPA in 2011.

Production from the newly regulated hydro plants during 2011 was 0.9 TWh below plan with the variance occurring primarily in the Northeast and Northwest. Generally, river flows in the Northeast and Northwest were below normal in 2011, with annual mean flows for several river systems ranking as lower quartile. River flows in the eastern part of the Province during 2011 were about normal.

2011 Actual vs. 2010 Actual

The total regulated hydroelectric production for 2011 was 7 per cent (2.1 TWh) greater than 2010 production (Ex. E1-1-2, Table 1). Production by the Niagara Plant Group and R. H. Saunders accounted for 0.6 TWh of the increase, while production from the newly regulated hydro plants increased by 1.5 TWh from 2010 - 2011.

Production at the Sir Adam Beck plants was similar for the two years, although the annual mean Niagara River flow for 2011 was seven per cent higher than the mean for 2010. Production during January and February 2011 was lower than the output during the same months in 2010 due to lower flow, whereas production from July to October in 2011 was greater than the output during the same months of 2010 due to higher flow. Production was similar for the two years for the months of November and December, although Niagara River flow during these months was much higher in 2011 than 2010. Insufficient water conveyance capacity limited additional production increases at the Sir Adam Beck plants when Niagara River flow was high, because the extra water could not be conveyed to the plants. Production during 2011 was also inhibited due to surplus baseload generation, particularly during the months of April and May. (See Ex. E1-2-1). Production at DeCew Falls increased by 0.1 TWh in 2011, as the four generating units at DeCew Falls ND1 returned to service following completion of penstock replacement. DeCew Falls ND1 was out of service for all of 2010. The 0.4 TWh increase in production at R. H. Saunders during 2011 was attributable to higher St. Lawrence River flow. The annual mean St. Lawrence River flow for 2011 was 10 per cent higher than the annual mean for 2010. Simultaneous outages of multiple units for replacement of transformer and unit protection and control equipment at R. H. Saunders inhibited additional increases in production during 2011. Increased St. Lawrence water transactions occurred with NYPA in 2011 as a result of these outages.

Production from the newly regulated hydro plants increased by 1.5 TWh in 2011 compared to 2010. Production from the Ottawa River plants accounted for 1.0 TWh of the increase as Ottawa River flow returned to normal after being well below normal in 2010. The annual mean Ottawa River flow for 2010 ranked as lower decile. Production from the Northeast plants increased by 0.6 TWh in 2011 over 2010, as river flows, although still below normal, increased from the very low levels experienced in 2010. The annual mean flow for the Abitibi River in 2010 was the lowest recorded in the past 50 years, while the annual mean for the Montreal River for 2010 ranked as lower decile.

2010 Actual vs. 2010 Budget

The total regulated hydroelectric production for 2010 was nine per cent (2.8 TWh) lower than the 2010 budget forecast prepared in 2009.

Niagara Plant Group production was similar to budget, while R. H. Saunders production was 0.4 TWh below budget due to St. Lawrence River flow being eight per cent lower than the 2010 Budget forecast.

Production from the newly regulated hydro plants was 2.4 TWh below budget as dry conditions existed throughout much of the Province in 2010. Annual mean flow for many of the river systems ranked as lower decile for 2010.

Numbers may not add due to rounding.

Table 1

Comparison of Production Forecast - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric (TWh)

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	Niagara Plant Group	12.4	0.0	12.4	0.2	12.9	(0.2)	12.6	(0.7)	11.9
2	Saunders GS[1]	6.9	(0.4)	6.5	0.4	7.0	(0.1)	6.9	(0.4)	6.5
3	Sub total	19.3	(0.4)	18.9	0.6	19.8	(0.3)	19.5	(1.0)	18.5
	Newly Regulated Hydroelectric:									
4	Ottawa-St. Lawrence Plant Group[2]	5.7	(1.0)	4.7	1.0	5.7	0.0	5.7	(0.6)	5.1
5	Central Hydro Plant Group	0.5	(0.0)	0.5	0.0	0.5	(0.0)	0.5	(0.1)	0.4
6	Northeast Plant Group	2.4	(1.0)	1.4	0.6	2.5	(0.5)	2.0	(0.0)	2.0
7	Northwest Plant Group	3.8	(0.4)	3.4	(0.1)	3.8	(0.5)	3.3	0.1	3.3
8	Sub total	12.4	(2.4)	10.0	1.5	12.5	(0.9)	11.5	(0.6)	10.9
9	Total	31.7	(2.8)	28.9	2.1	32.3	(1.3)	31.0	(1.7)	29.4

Line No.	Prescribed Facility	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
10	Niagara Plant Group	12.9	(0.9)	11.9	0.3	12.2	0.5	12.7	0.8	13.5
11	Saunders GS[1]	7.0	(0.4)	6.5	(0.3)	6.2	0.1	6.3	0.4	6.7
12	Sub total	19.8	(1.4)	18.5	(0.0)	18.4	0.6	19.1	1.2	20.2
	Newly Regulated Hydroelectric:									
13	Ottawa-St. Lawrence Plant Group[2]	5.7	(0.6)	5.1	0.5	5.7	0.0	5.7	0.0	5.7
14	Central Hydro Plant Group	0.5	(0.1)	0.4	0.1	0.5	(0.1)	0.4	0.1	0.5
15	Northeast Plant Group	2.5	(0.5)	2.0	0.5	2.5	(0.0)	2.5	(0.0)	2.5
16	Northwest Plant Group	3.8	(0.4)	3.3	0.5	3.8	(0.0)	3.8	0.0	3.8
17	Sub total	12.5	(1.6)	10.9	1.6	12.4	(0.1)	12.4	0.1	12.5
18	Total	32.3	(2.9)	29.4	1.5	30.9	0.6	31.4	1.2	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.

HYDROELECTRIC INCENTIVE MECHANISM AND SURPLUS BASELOAD GENERATION

1.0 PURPOSE

This evidence describes OPG's proposed treatment of Surplus Baseload Generation ("SBG") during the test period and explains OPG's proposed Enhanced Hydroelectric Incentive Mechanism ("eHIM").

2.0 OVERVIEW

OPG's operation of the Sir Adam Beck Pump Generating Station ("PGS") under the Hydroelectric Incentive Mechanism ("HIM") reduces SBG spill to the maximum extent possible and provides a consumer benefit through reduced consumer costs. In order to address an unintended interaction between HIM and the SBG Variance Account, a modification to the HIM, or enhanced HIM ("eHIM"), is proposed. Compared to the alternatives considered, eHIM is the best choice and is proposed for both the existing regulated and the newly regulated hydroelectric facilities.

The evidence is organized as follows:

- Section 3.0 addresses the methodology for determining entries in the SBG Variance Account;
- Section 4.0 addresses the usage of the Pump Generating Station (PGS) during periods of SBG;
- Section 5.0 addresses the proposed enhanced incentive payment mechanism;
- Section 6.0 addresses the proposed payment mechanism for the test period;
- Attachment 1 presents a review of the proposed eHIM prepared by Cliff Hamal of Navigant Economics.

3.0 METHODOLOGY FOR DETERMINING ENTRIES INTO THE SBG VARIANCE ACCOUNT

3.1 Overview

In EB-2010-0008, the OEB established the Hydroelectric Surplus Baseload Generation Variance Account to capture the financial impacts of forgone production at OPG's hydroelectric facilities due to SBG spill. Entries in the account are calculated by multiplying the foregone production volume due to SBG spill (in MWh) by the approved regulated hydroelectric payment amount, net of the avoided Gross Revenue Charge (GRC) costs. OPG is seeking to clear the 2013 year end forecasted balance in the SBG Variance Account (See Ex. H1-1-1).

SBG spill occurs at Sir Adam Beck (SAB), and at other regulated hydroelectric facilities, including many that are newly regulated. OPG is proposing to extend the SBG Variance Account to include the newly regulated hydroelectric facilities with modeled production forecasts(See Ex. E1-1-1, Appendix 1).

OPG has determined that the present structure of the hydroelectric incentive mechanism results in unintended payments to OPG when SBG spill occurs. As a result, and based on the analysis described in Section 5.2, OPG is proposing changes in the operation of the SBG Variance Account, effective January 1, 2014, as an integral component of eHIM. The proposed changes to the account are described in Section 6.1

3.2 Determination of SBG Spill

In its Decision with Reasons in EB-2010-0008, the OEB suggested that OPG approach the IESO for assistance in the calculation of SBG spill. In 2011, OPG approached the IESO for this assistance and was advised by the IESO that it does not have a reporting framework to identify SBG production losses and was therefore unable to assist OPG. As a result, OPG developed its own methodology for calculating the foregone production associated with SBG spill.

Hydroelectric production planning is based upon the objective of achieving total utilization of the available water or ("stream flow"). However, several market, operational and production capability constraints, described below, inhibit the complete utilization of the available stream flow. As a result, spill occurs.

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 (i.e., IESO dispatch constraints: market or transmission system); and
- contractual obligations (e.g., AGC).

Therefore, to calculate the foregone production due to SBG spill, OPG starts with the total volume of spill and subtracts the volume of spill due to these four components. The remaining spill volume is identified as potential SBG spill. From this potential spill volume, 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. These volumes have been calculated to be 76.5 GWh for March through December 2011 and 116.9 GWh for 2012. SBG spill volume for 2013 is projected to be 178.0 GWh.

When SBG occurs, it has the effect of significantly depressing market prices. Therefore, SBG conditions are deemed to be present when the prevailing market price falls below a price threshold representing the marginal cost of generation for OPG's regulated hydroelectric facilities. This threshold is based on a plant's Gross Revenue Charge (GRC) which represents the minimum offer price for generation that would allow OPG to cover its cost of GRC on its production.

In practice, there is some minor variability around the SBG price threshold used at some of the hydroelectric facilities. This is because OPG needs to create small differences between the generation offers from its various units to achieve an orderly dispatch and meet operational requirements at its hydroelectric facilities.

4.0 USE OF SAB PGS DURING SBG CONDITIONS

4.1 Overview

In its Decision with Reasons in EB-2010-0008, the OEB indicated that it expects OPG to use the SAB Pump Generating Station ("PGS") to the maximum extent possible to mitigate the cost to ratepayers in the SBG Variance Account. OPG operates the PGS taking into consideration market price signals, the availability of the PGS, the capacity of the PGS reservoir, and hydrological limitations. By following market price signals for PGS deployment, OPG is able to minimize SBG spill to mitigate the cost to ratepayers of entries into the SBG Variance Account and substantially reduce consumer costs, as described in Section 5.1.

Table 1 shows the extent to which PGS pump was used to reduce SBG spill at SAB.

Table 1: PGS usage and SBG spill
March 1, 2011 to July 31, 2013

	Number of hours	Percentage hours
Total SBG spill hours	2,604	100%
<u>During SBG hours only:</u>		
Hours where PGS was pumping	1,556	60%
<u>Hours where PGS was not pumping</u>		
Due to constraints	883	34%
Missed opportunities	165	6%

During the period March 1, 2011 to July 31, 2013, there were 2,604 hours when SBG spill occurred at SAB. Of these hours, OPG operated the PGS in 1,556 hours or 60 per cent of the total SBG spill hours.

There was no PGS pump operation in the remaining 1,048 hours or 40 per cent of the total SBG spill hours. Of these 1,048 hours, the PGS was not pumping for 883 hours (34 per cent of the total SBG hours) due to constraints such as: insufficient available pumping capacity; insufficient storage in the reservoir; uneconomic off to on-peak price differentials; and prevailing hydrological conditions.

There was no PGS pump operation in 165 hours, or 6 per cent of the time, where there were no constraints that would have prevented pumping. These few hours represent missed opportunities: periods where the PGS was available and could have been deployed to mitigate SBG spill but was not. Use of the PGS is based on anticipated on-peak prices several hours in the future and as a result, misreading future on-peak prices can cause such missed opportunities. Given the dynamic nature of pricing in the Ontario market, missing just 6 per cent of the SBG spill hours represents very good performance by OPG and is evidence that OPG is maximizing the use of the PGS to mitigate the impact of SBG.

5.0 THE HYDROELECTRIC INCENTIVE MECHANISM

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-2012-0002 Payment Amounts Order, the OEB set the threshold for 2013 at $13M. Between March 1, 2011 and December 31, 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. Resulting entries into the HIM Variance Account are discussed in ex. H1-1-1.

In the Board's Decision with reasons for EB-2010-0008 (p.148), OPG was directed to revisit the structure of the Hydroelectric Incentive Mechanism ("HIM"). OPG was also directed to provide a more comprehensive analysis of the benefits of the HIM for ratepayers, an analysis of the interaction between HIM and SBG, and an assessment of potential alternative approaches within the context of expected conditions in the contracted and traded markets.

5.1 Consumer Benefits of the HIM

The purpose of the HIM is to provide OPG with an incentive to operate its regulated hydroelectric facilities in a way that benefits consumers. Presently, this takes the form of payments to OPG to incent it to time-shift generation from periods of low market price to periods of high market price. This, in turn, provides a benefit by reducing customer costs. OPG's assessment of consumer benefits from the HIM concluded that economic time-shifting its regulated hydroelectric substantially reduces consumer costs. OPG's findings are based on analysis that accounts for the market effects by time shifting: the displacement by hydroelectric production of more expensive generation (i.e., on-peak gas); increases in GRC payments for additional on-peak generation at the regulated hydroelectric facilities; and higher exporter payments[1] made to the IESO for off-peak exports that result in reduced incremental costs to ratepayers.

Table 2 shows OPG's forecast of changes in ratepayer costs arising from the three factors above for the test period. Negative values represent an *increase* in customer costs while positive values represent a *reduction* in customer costs. These figures represent 'all-in' customer costs including changes in Global Adjustment payments.

[1] Sales of exports in the off-peak are typically made from contracted generation sources with contract prices that are independent of market prices. These volumes are effectively "take or pay". The consumer benefit arises from increasing the off-peak price for export sales so as to generate additional revenues that, in turn, reduce Global Adjustment payments by consumers.

Table 2: Forecast Change in Customer Costs Arising from Economic Time-shifting		
Customer cost Changes in M$	**2014**	**2015**
Reduction in payments to gas-fired generators	30	27
Increased GRC costs	(16)	(15)
Increase in export revenues	22	24
Total reduction in customer costs	**36**	**36**

As shown in Table 2, economic time-shifting, even when the impacts of the Global Adjustment are included, reduces ratepayers' costs as cheaper hydroelectric generation displaces more costly gas-fired generation. Additionally, increased amounts paid to the IESO for export sales also reduce ratepayers' costs.

5.2 Interaction between HIM and SBG

The incentive component of HIM is calculated as the sum of all hourly differences between the actual hourly production and the monthly average production priced at the prevailing market price (i.e. Hourly Ontario Energy Price or "HOEP") for a given month. When the hourly output is greater than the monthly average, OPG is credited for that incremental energy at HOEP. Conversely, when the hourly output is less than the monthly average, HIM is reduced for that decremental energy at HOEP.

Since the total hourly production in excess of the monthly average is equal to that below the monthly average, HIM is positive only when the production in excess of the monthly average has a higher market value than the production below the monthly average.

SBG conditions that result in production curtailments typically occur in low priced, off peak periods. When SBG spill is avoided through PGS deployment or time shifting the stored water is shifted to a higher value time period and incentive payments are appropriately awarded. While the monthly average production is unchanged, the incentive payments are based on the quantity of energy moved at a value that represents the market price differential.

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.

These two points may be best illustrated by the example shown in Table 3.

Table 3: Example of the Interaction Between SBG and the HIM (assuming 100 MW of Water Available for Use in Each Hour)

	Case 1: Spill avoided			Case 2: Spill not avoided			
Period	Output MW	Spill MW	HIM $	Output MW	Spill MW	HIM $	HOEP $/MWh
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**	

In this example, SBG conditions are present in the low-valued periods 1 through 5. In Case 1, spill is avoided through time-shifting the energy from the low-priced periods 1 through 5 to the higher valued periods 6 through 10. As a result, an incentive payment totaling $2,500 is generated. In Case 2, the SBG conditions result in spill in periods 1 through 5. Since spill occurs, no energy can be time-shifted to the higher-valued periods 6 through 10. Nonetheless, an incentive payment of $1,250 is still generated as the SBG spill gives rise to the appearance of time-shifting.

In Case 1, as there is no SBG spill, there is no entry into the SBG Variance Account. In Case 2 however, the SBG-related spill in periods 1 through 5 gives rise to an entry into the SBG Variance Account. The SBG Variance Account entry in Case 2 is appropriate as the overall production in Case 2 is 250 MW lower than Case 1.

As the intent of the HIM is to reward time-shifting, the HIM payment in Case 1 is appropriate as time-shifting occurred. However, in Case 2, the HIM payment is unintended as no time-shifting occurred.

In order to eliminate this unintended consequence, OPG is proposing an enhanced Hydroelectric Incentive Mechanism ("eHIM") that eliminates the potential for incentive payments that produce no value for ratepayers. This alternative is described in greater detail in Section 6.

5.3 Alternative Incentive Mechanisms

Three alternatives to the current HIM incentive mechanism were assessed by OPG and reviewed by Mr. Cliff Hamal of Navigant Economics: the enhanced Hydroelectric Incentive Mechanism ("eHIM"); a modified version of the Hydroelectric Baseload Forecast ("eHBF") mechanism (used during the 2005 – 2008 period); and an Incentive Mechanism (IM) based on a fixed market price exposure.

The eHIM is essentially identical to the existing HIM payment mechanism and SBG Variance Account with the addition of an adjustment to the incentive mechanism to remove the effects of SBG. Under the proposed adjustment, all induced incentive revenues arising from SBG-related spill would be removed from the SBG Variance Account (as discussed in Section 5.2). OPG proposes to adopt eHIM for the test period. Further implementation information is found in Section 6.

The eHBF modifies the Hydroelectric Baseload Forecast ("HBF") mechanism used from June 2005 to November 2008. The HBF incentive payment was based on a quantity of generation in excess of a predetermined volume of electricity that was priced at HOEP. The predetermined volume of electricity was an unchanging amount for all hours. Under the eHBF, the predetermined quantity of electricity would vary hourly commensurate with seasonal and daily variations in available flows. Therefore, the volume of generation exposed to market prices is more uniform across all hours. As a result, the quantity of electricity that could be time-shifted would earn incentive revenues at the prevailing market rate.

The incentive mechanism (IM) based on a fixed market price exposure is similar to some current electricity supply contracts in the Ontario market. This mechanism is conceptually the simplest of all alternatives since the incentive payment is a fixed percentage (i.e., five per cent for the purpose of this analysis) of actual output that is paid at HOEP.

Each alternative facilitates economic time-shifting decisions on the basis of prevailing market prices. For the purpose of this assessment, the use of generation facilities under each alternative, for any given set of market prices, is assumed to be the same.

Along with HIM, each alternative was assessed and evaluated on the basis of the *correlation* between the annual volume of water time-shifted and the amount of incentive revenue generated. An appropriately designed incentive mechanism would have a strong positive correlation between the amount of time-shifting and the level of incentive revenues.
Additionally, the volatility of each alternative was analyzed. As incentive revenues are funded by ratepayers based on a portion of the ratepayer savings achieved through time-shifting, an incentive payment that exhibits low volatility ensures an appropriate balance between ratepayer value and the incentive revenues provided to OPG. An incentive scheme that exhibits a high volatility could result in incentive revenues that exceed the ratepayer cost savings.

With respect to the correlation between the amount of time-shifting and the amount of incentive revenues, all payment mechanisms except for IM, exhibit some degree of positive correlation. The strongest correlations are found in the HIM and eHIM approaches followed by the eHBF mechanism. With respect to the degree of volatility in the incentive revenues, all payment mechanisms, except for eHBF exhibit approximately the same degree of volatility. The volatility in the HIM, eHIM and IM are similar but the volatility in incentive revenues under the eHBF scheme is much, much higher.

This assessment of the payment mechanisms is summarized in Table 4.

Table 4: Assessment of Alternative Payment Mechanisms

Alternative	Correlation between incentive payout and amount of time shifting (High is preferable)	Volatility in incentive payout (Low is preferable)
HIM	High	Low
eHIM	High	Low
eHBF	High	High
IM	Low	Low

Based on this assessment, the HIM and eHIM are preferable to both the eHBF, due to much lower volatility in incentive payouts, and the IM due to better correlation between the amount of the incentive payout and the amount of time-shifting. Owing to its better ability to deal with SBG spill, OPG proposes the eHIM be used over the test period. This is discussed in Section 6 and supported in the accompanying testimony of Cliff Hamal of Navigant Economics (E1-2-1, Attachment 1).

6.0 PROPOSED NEW INCENTIVE MECHANISM

6.1 Design of Incentive Payments and SBG Variance Account

As a result of the assessment shown in Section 5.3 and the supporting testimony of Cliff Hamal of Navigant Economics (E1-2-1, Attachment 1), OPG proposes adopting the eHIM for the existing regulated hydroelectric facilities and the newly regulated hydroelectric facilities listed in Ex. E1-1-1, Appendix 1. The eHIM is identical to the existing HIM and SBG Variance Account except that under the eHIM the entries in the SBG Variance Account would be adjusted to remove incentive revenues arising from SBG spill. The enhanced mechanism provides greater transparency and fairness while continuing to provide the correct market drivers to incent OPG's plant operations in a way that directly benefits ratepayers.

6.2 Incentive Revenue Sharing and Implementation

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 adjustment quantity is known as the 'X-factor'.

The proposed eHIM formula, consisting of HIM and SBG variance account adjustments combined with the revenue sharing mechanism is:

Monthly IESO Payment[2]	= Regulated payment +
	+ Incentive payment
where	
Regulated Payment	= (MW_{avg} × Regulated rate × No of hours in month)
Incentive Payment	= 'X factor' × $\sum [(MW_i - MW_{avg}) \times HOEP_i]$

[2] OPG notes that many of the newly regulated hydroelectric stations are not connected directly to the IESO-controlled grid but are instead embedded at the distribution level. As the IESO does not currently have access to production data for these stations for settlement purposes, OPG will work with the IESO and the distributor to develop a settlement solution to enable implementation of this proposal.

Monthly SBG Variance Account Entry	= Spill compensation
	+ Incentive payment adjustment
where	
Spill Compensation	$= MW_{SBGavg} \times$ (Regulated rate – GRC) × No of hours in month)
Incentive Payment Adjustment	= ‘X factor’ × $\sum [(MW_{SBGi} - MW_{SBGavg}) \times HOEP_i$

The ‘X factor’ appearing in the Incentive Payment and Incentive Payment Adjustment formulae is established such that the net incentive retained by OPG is equal to one-half the customer cost reduction shown in Table 2. In this manner the benefits arising from time-shifting of energy are shared equally between the customer and OPG as shown in Table 5 below.

Table 5: Expected Payments and Adjustments

M$	2014	2015
‘X’ factor	35%	31%
Incentive payment	27	30
Incentive payment adjustment	(9)	(12)
eHIM	18	18

Furthermore, OPG proposes to eliminate the revenue requirement adjustment, that no offset attributed to incentive revenue be applied to the revenue requirement based on an expectation of future incentive revenues. The generation of incentive payments for OPG, and the attendant value delivered to the customer, occur simultaneously. As a result, there is no difference in the timing between the customer cost savings and OPG’s incentive payments. As a result, there is no need for a revenue requirement offset.

Given these proposed changes described above, the need for a HIM Variance Account is eliminated. (Refer Exhibit H1-1-1).

Under the proposed eHIM, OPG anticipates incentive payments totaling $27M in 2014 and $30M in 2015. Furthermore, OPG anticipates incentive payment adjustments in the SBG Variance Account of ($14M) and ($19M) in 2014 and 2015 respectively (See Ex. H1-1-1).

LIST OF ATTACHMENTS

Attachment 1:	Testimony of Cliff Hamal, Review of Proposed Hydroelectric Incentive Mechanism.

REVIEW OF PROPOSED HYDROELECTRIC INCENTIVE MECHANISM

1.0 EXECUTIVE SUMMARY

I, Cliff Hamal, have been asked by Ontario Power Generation, Inc. (OPG) to offer an opinion on the reasonableness of its proposed incentive mechanism to promote the efficient dispatch of hydroelectric generation resources. My review is, in part, a response the Ontario Energy Board (Board) request for a more comprehensive analysis of the interaction of the incentive mechanism with surplus baseload generation (SBG), the benefits for ratepayers, and an assessment of potential alternatives.[1]

The existing Hydroelectric Incentive Mechanism (HIM) was approved by the Board in EB2010-0008, and builds on prior incentives. Going forward, OPG proposes a new calculation it calls the enhanced Hydroelectric Incentive Mechanism (eHIM), with the enhancement involving adjusting for the effect of hydroelectric spill associated with SBG. The proposal calls for a new approach to sharing the benefits associated with the eHIM calculation and also expands the coverage of the incentive mechanism to include the hydroelectric generation that is seeking regulated cost-of-service compensation as part of this rate filing.

The eHIM proposal and supporting analysis is presented in evidence Exhibit E1-2-1. This includes a description of the incentive mechanism, the results of modeling its expected benefits and an assessment of alternatives. I have reviewed that material, conducted a review of the underlying analysis and engaged in detailed conversations with OPG analysts into the mechanics of the associated modeling. My review addresses three issues specifically raised in the Board's Decision: the interaction between the mechanism and SBG, the benefits of the incentive mechanism to ratepayers, and an assessment of alternative approaches for providing incentives. In conducting my analysis, I have relied on my extensive electricity industry experience, which is detailed in the attached curriculum vitae.

[1] Decision with Reasons, March 10, 2011, EB-2010-0008, p. 148.

I conclude that the eHIM proposal is both reasonable and beneficial. The proposed change eliminates the potential for overcompensation due to interactions during SBG conditions, provides appropriate benefits to ratepayers after payment of the incentive, and is the best option in light of expected future conditions in the Ontario market.

2.0 THE eHIM PROPOSAL

Under its regulatory framework, OPG is paid a fixed amount for each MWh of hydroelectric generation; this is a strong incentive to maximize generation. This compensation does not give OPG an incentive to shift its hydroelectric output to hours where system energy costs are high and the energy would be of most value to customers. In fact, time-shifting of generation typically involves efficiency loses and therefore reduces OPG's sales volume (MWh) and revenues. Consumers, however, are better served and have reduced costs if generation can be shifted toward hours when it is most needed, generally on-peak periods when prices are highest, even if that results in efficiency losses at the generator and less energy production. Market price in a fully competitive market provides incentives for this shifting. An additional incentive payment in Ontario holds the promise of giving OPG appropriate incentives to dispatch hydro generation in a manner that provides benefits to customers, while working within the hybrid market design and OPG's regulatory framework.

Under the proposal, OPG will receive an annual incentive payment that is based on the eHIM calculation. The eHIM figure is a direct function of the degree to which the weighted average price of hydroelectric deliveries (HOEP times MWh delivered) exceeds the unweighted average price. Thus, the figure reflects the market value associated with shifting electricity production to high-value hours. This was also true of the existing HIM, but under the proposed enhanced calculation, the effects of SBG-induced spill on the incentive payment component are eliminated. The resulting figure is eHIM. The details of this calculation are provided in Exhibit E1-2-1. OPG proposes that its incentive payment be a percentage of the eHIM figure in order to share in the consumer benefits of time-shifting of generation on a 50/50 basis. Also proposed is the elimination of the revenue requirement offset.

The incentive will apply to all regulated hydroelectric generation: the Newly Regulated facilities and those to which HIM had applied in the past. The Newly Regulated hydroelectric facilities are typically dispatchable and have significant ability to store water and shift energy across time. Their operating characteristics contrast with the previously regulated hydroelectric facilities. Among the units historically covered by HIM, the vast majority of storage capacity was associated with the PGS at Beck which can efficiently time-shift hydroelectric generation on a daily basis, but does not provide longer term storage capacity.

The proposal provides incentives to OPG based on HOEP, where that price reflects the need of the system on an hour-by-hour basis. In using a market price to create an incentive, OPG is given a signal that it can directly incorporate into decision making, in real time, to optimize the use of its facilities. Ontario's hybrid market structure involves a variety of different financial structures for the compensation of generation, including contracts and regulation. Regardless of a supplier's regulatory/contract structure, the HOEP provides the best indication of the value of additional generation to the system and the IESO uses HOEP in its dispatch decisions for that reason. For some of the OPA power contracts, it is HOEP that provides the incentive to operate as requested by the IESO, because mismatches between desired and actual production are settled at the HOEP price. HOEP is also central to the pricing of imports and exports. HOEP provides the most appropriate measure of the value of energy in each hour, and therefore it is the best measure of value to use in decision making for the time-shifting of hydroelectric generation across hours and days.

This approach provides a robust incentive under all market conditions. Whether prices are generally high or low, the incentive remains tied to the difference in prices over the hours in which the generation is shifted. The time-shifting might be within a single day, such as is typical for the PGS, or across multiple days for some of the newly-regulated hydroelectric generation. In either case, the incentive is based on the prices in each hour. Thus, if there is a sufficient price-difference to justify shifting from off- to on-peak in a single day, the eHIM mechanism will reward that shifting regardless of prices on other days or whether the overall level of prices was unexpectedly high or low. In addition, the value to customers is associated with the price difference between the periods over which the generation is shifted. Lastly, the eHIM incentive is relative straightforward to calculate. No complications in changing from the HIM to the eHIM approach are expected. The experience with the existing HIM provides added confidence that eHIM can be employed without problems.

3.0 INTERACTION WITH SBG SPILL

The distinguishing change between eHIM and the prior HIM approach is the treatment of SBG-induced spill. Such spill reduces generation during low-priced hours and without the adjustment contained in eHIM would create a positive effect on the incentive mechanism. Since OPG will be made whole for SBG spill through the SBG Variance Account, this increase is unnecessary. Under the proposal, the effect of spill on eHIM is eliminated directly.

It is important to note that OPG still retains the full incentive to shift generation from off-peak to on-peak hours in hours that might otherwise produce SBG-induced spill. That is because of the manner in which the eHIM incentive and the compensation for SBG-induced spill work together. OPG will have a strong incentive to shift generation to on-peak periods to capture the extra compensation from eHIM. It is only if there are residual SBG problems after OPG has done such shifting that it will be asked to spill. When spilling during this situation, OPG is paid the amount it otherwise would have earned through generation for the spilled water, but it will not get an incentive payment. This assures that OPG will give priority to time-shifting generation.

4.0 BENEFITS TO ONTARIO CUSTOMERS

Customer benefits associated with time-shifting of hydroelectric generation come from lower overall payments for electricity. In a fully competitive market, the benefits of reducing on-peak prices would be substantial because customers pay that price, in one form or another, for all on-peak purchases. In Ontario, the situation is much more complicated and benefits are lower because most generators are paid prices that reflect the sum of operating costs and a fixed payment, where that fixed payment is determined through contract terms or through cost-of – service regulation. HOEP plays an important role in providing incentives and in the process of getting payments, but for the most part generators that appropriately follow dispatch instructions are largely indifferent to the level of HOEP.

Customers in Ontario retain some market price exposure, albeit much less than in other markets, that falls primarily in two areas. Customers make payments to cover the cost of fuel, such as natural gas, to generators that face such costs. When hydroelectric generation is shifted into on-peak hours, fossil generation is reduced and the savings in fuel costs gets passed on to consumers. The other source of benefit results from changes in trade in neighboring regions, both the price at which energy is bought and sold and the trading quantities. Customers capture profits from those sales through the market processes; hydroelectric time-shifting will increase those profits by increasing the export price during the off-peak periods when such sales are frequently transacted.

4.1 OPG Calculation of Benefits

OPG has evaluated these effects using a market forecasting model that includes all generation in the province and neighboring regions. Like many production cost models, it determines the lowest-cost means of meeting demand in each hour and allows for trade between regions. The analysis recognizes that in Ontario, most generators are incented to generate on the basis of HOEP, but actual dispatch is determined on a constrained dispatch analysis with congestion payments made as needed. The various OPA contracts and regulated payment mechanisms are also modeled, including the global adjustment. Additionally, the model accounts for the payments made during SBG to resources that curtail generation. I believe it is a reliable modeling tool for this application and is probably the only practical option for such an analysis.

Costs and benefits are estimated by capturing the difference in outcomes in two different scenarios: the base case and the no incentive-hydroelectric case. The base case reflects operations as is presented in the rate case, including hydroelectric spill to manage SBG and dispatch of hydroelectric assets to maximize consumer benefits. In particular, the hydroelectric units are dispatched in a manner that reflects how a competitive firm would operate when fully exposed to the market price. For the conventional hydro units, storage is used to shift production to the higher priced hours, both within the day and across longer periods of time. At the PGS, the model makes dispatch decisions to pump and generate based on an algorithm that considers whether actions taken in a given hour (either pump or generate) will be profitable after all operating costs are incurred. Specifically, the algorithm assumes that PGS pumps when the market price is such that pumping will be profitable if the sales later in the day were at prices that match those of the prior day. It generates using the pumped water if such generation is profitable relative to the pumping cost of the prior evening. This "look-back" approach uses only historical data (i.e., not forecast) that would be available in each hour when pumping and generating decisions would have to be made. In addition, some of the PGS capacity is reserved for the provision of automatic generation control (AGC).

These results are compared to the no incentive-hydro case, which assumes OPG is maximizing its earnings without any hydro incentive. In this scenario PGS is not operated at all, because it reduces the net hydroelectric generation available for sale. The other hydroelectric facilities are operated to maximum production. This is the output level associated with maximum efficiency, at all times. This means that some units are operated 24 hours a day, and others only part of the day but always at maximum efficiency. When only operating for part of the day, the high HOEP hours are selected. The differences between the two scenarios provide the incremental costs and benefits of the eHIM incentive. The results of this analysis are provided in Exhibit E1-2-1 and are summarized in Table 1.

Table 1: Summary Results of OPG's Analysis of eHIM from Exhibit E1		
	2014 M$	2015 M$
Reduction in payments to gas-fired generators	30	27
Increased GRC costs	(16)	(15)
Increase in export revenues	22	24
Total reduction in customer costs	36	36
eHIM calculation, before X factor	51	58
Percentage incentive retained by OPG ('X')	35%	31%
Expected incentive payment to OPG	18	18
Net customer cost reduction (after incentive payment)	18	18

The first item of note in these figures is that the consumer benefits from time-shifting are less than the unadjusted eHIM calculation ($36 million versus $51 million in 2014). Obviously, if OPG were paid the entire eHIM figure, consumers would not benefit from the time shifting. This is the primary driver for OPG's recommendation that it only be paid a fraction of the unadjusted eHIM figure. A major reason for this eHIM being substantially larger than consumer benefits is that the reduction of spill increases the gross revenue charge (GRC) costs. That is a real cost to ratepayers, although, given that the money is paid to the province—effectively taxpayers—this cost has different implications for ratepayers (who are largely taxpayers) than money that might have been paid for fuel or lost through inefficiencies.

Separate from the above calculation of benefits to consumers is the evaluation of costs to OPG. This is provided in the table below. OPG incurs costs for pumping, GRC and non-energy charges, all of which reduce its net benefits from time-shifting hydroelectric generation.

Table 2: OPG costs incurred from time-shifting at PGS		
	2014 M$	2015 M$
Pumping losses	(3)	(3)
PGS GRC costs	(1)	(1)
Pumping non-energy charges	(3)	(3)
Total OPG costs	(7)	(6)
Expected incentive payment to OPG	18	18
Net benefit to OPG from time-shifting hydro generation	11	12

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.

4.2 Thoughts on OPG's Analysis of Benefits and Structure of Incentive

There are a number of positive attributes of the proposed system that should benefit both customers and OPG. The payment is straightforward and easily calculated, making this an easy process to adopt. The payment is also directly tied to performance in the marketplace—if actual shifting of generation from low-priced to high-priced periods is not accomplished, positive eHIM is not generated and no payments are made.

These issues are important to understanding the results of the modeling. No forecast is perfect. In my view, the greatest value in the modeling is the insight it provides into the relationship between benefits, costs, eHIM and HOEP. With the payment based on a modest portion of the calculated eHIM, customers should be assured of positive net benefits from the program. This is shown through the analysis. The analysis also shows that there are significant costs to OPG from time-shifting. Without any incentive mechanism OPG will lose money from time-shifting, surely a counterproductive incentive.

The modeling assumes that OPG has an incentive to follow market prices, which would be true if OPG were paid the full eHIM amount. But the proposal is based on payments of only about a third of the eHIM figure. Simply put, the proposed structure does not provide as strong an incentive as would be found in an open market, and the incentive is not completely in line with the amount of time-shifting that is assumed to occur. There are two possible implications of this mismatch.

One might assume that OPG's dispatch is based on the market-exposure incentive assumptions, regardless of the sharing detail in the eHIM. As a provincially-owned and regulated entity, it will consider a variety of factors in operating its system, including not only the direct financial incentive, but also the commitment it has made and the need to satisfy the objectives of its shareholder. And while the incentive is reduced by the sharing percentage, it is still sufficient to provide positive benefits after consideration of its incremental costs. Alternatively, one might question that assumption and conclude that OPG's actions more closely match the specific incentive in the shared eHIM approach. If that were true, OPG would do less time-shifting of hydro energy, with the reductions occurring in the hours with the least price benefits. In this instance, while less time-shifting occurs, the benefits to customers are probably very modest in those hours. There does not seem to be much possibility that this result causes any material problem.

This raises the question of whether the sharing percentage is optimal. The approach adopted by OPG, the equal split of the calculated customer benefit, has the advantage of simplicity and apparent fairness. The recommendation appears reasonable as it falls within a range, where the floor would be the lowest level that still provides OPG benefits after considering its incremental costs and the upper end still provides substantial benefits to customers.

5.0 ALTERNATIVE INCENTIVE MECHANISMS

The Board asked that alternative approaches to creating incentives for the dispatch of hydroelectric generation be considered. Exhibit E1 presents and analyzes four options: the proposed eHIM approach, the earlier HIM methodology, an enhanced Hydroelectric Baseload Forecast (eHBF) mechanism and an incentive mechanism (IM) approach. I review each of these alternatives, both as presented by in Exhibit E1 and with modifications, and conclude that the eHIM approach offers significant advantages.

OPG's analysis of the alternatives holds the operations assumptions constant and evaluates how the payments that would be made under the different approaches. Such analyses are important and insightful, but do not give a full understanding of the implications of each approach because they fail to consider the possibility that a different incentive could produce different outcomes. In this case, however, it is relatively straightforward to consider the potential for changes qualitatively, which I do below, and more detailed analysis is unnecessary. In addition, such analysis can be very involved. I do not consider it necessary or cost-effective to conduct such additional analysis in this instance.

5.1 Staying with the HIM alternative

The major difference between the proposed eHIM and the current HIM approaches, as has been discussed, is that under HIM the contribution SBG-spill makes to the HIM value is not subtracted. Thus, HIM calculations are substantially greater. (Absent any SBG spill, and assuming the same sharing factor, the figures would be the same.) Payment of that amount to OPG would exceed the benefits it provides to customers. One alternative might be to apply an even smaller sharing percentage to the HIM figure in order to get the incentive payment to a point that provides net benefits to customers and an incentive to OPG. This would be an inferior option: the outcome would be influenced by the need for spill which falls outside of OPG's control and the incentive to actually time-shift would be diminished because of the lower percentage. The eHIM approach is simply better.

5.2 The IM option

Under the IM (incentive mechanism) option, OPG would be paid a share of what it would be paid if the hydroelectric generation was sold at HOEP. A purely competitive firm would obviously get 100% of the HOEP payment and adjust its output to maximize this revenue. This is a possible alternative from a market perspective, but clearly Ontario has moved away from the purely competitive market approach. Among the problems with this approach is that there are large revenue uncertainties associated with yearly water flow and fossil fuel prices (which drive market prices for electricity). That option is clearly outside of consideration for an incentive mechanism. Under OPG's proposal, the incentive payment would be 5% of hypothetical market revenues, and would come on top of what it is paid in regulated rates. That moves the incentive payment to a range that might be reasonable for the amount of money at risk for an incentive mechanism.

The biggest problem with this approach is that there is no reason to believe that a 5% payment would give the output that is desired. It is simply too weak of an incentive. That competitive approach that is desired corresponds to giving OPG an incentive of 100% of the price difference. This incentive is only one twentieth of that amount, and will rarely offset the increased costs and lost sales volume that will result from efficiency losses from time-shifting. Substantial money will be paid, because payments are made on 5% of all output, but little time-shifting will be incented. In addition, the incentive payment will be heavily influenced by overall water flows and prevailing market prices. These are both independent of OPG's dispatch of the hydro resources, reducing the effectiveness of the payment in providing an incentive.

5.3 The eHBF option

Under the enhanced Hydroelectric Baseload Forecast (eHBF) approach, most of the output would be covered under cost of service ratemaking. Above a certain baseline level, however, generation would be sold at HOEP. As long as marginal sale decisions are made on the basis of HOEP, it provides the competitive-market incentive for time shifting that is desired. Thus, this option could provide the incentives for dispatch that are very similar to that for a competitive firm.

The challenge in implementing eHBF lies in establishing the baseline amounts and then evaluating whether the amount paid would be cost-effective in providing the desired outcome. I think the difficulties in both of these areas are insurmountable.

OPG proposes that the baseline amount be set using a statistical analysis based on data over the past five years. The hourly baseline amount is equal to the volume for that particular hour that corresponds to the 5th percentile of output. The idea is to choose a benchmark value for each hour that will be below actual levels 19 out of 20 times. The "extra" generation above this level is then sold at HOEP, with OPG benefiting from its ability to shift the generation to higher priced hours. The process of setting the hourly baseline amounts is critical. If it is too high, insufficient generation is subject to HOEP to provide an appropriate incentive. Too low, and the mechanism can produce a windfall to OPG. While five years of hourly data involves more than 40,000 data points, this is not a random sample and all hours are not interchangeable. There is still only one data point for each hour. And there are lots of reasons why there could be variations, based on high-stream-flow years, unusual patterns of dispatch due to market conditions, timing of spring run-off and disturbances in the electric system that result in unexpected hydro demands. And in any event, if stream flow is unexpectedly high or low in the year when the incentive is being used, it will not provide the appropriate incentive. Customers and OPG are reasonably protected from the consequences of outlier variations in stream flow under cost-of-service regulation, but that advantage would be lost under this approach. This approach can also result in unexpected levels of payments due to changes in market prices having nothing to do with the dispatch of hydro resources.

In short, this is a messy, complicated alternative that could result in large changes in the amount of money paid to OPG for reasons having nothing to do with hydro dispatch and an having nothing to do with customer benefits. It is an inferior alternative.

6.0 SUMMARY AND CONCLUSION

I conclude that the eHIM proposal offers the best potential to provide OPG with a reasonable incentive to optimize the dispatch of hydro facilities and to provide net benefits to customers after considering the incentive payment. The incentive is robust from the perspective of OPG in that it provides a sufficiently strong signal under a wide range of market conditions. It is likewise robust from customers' perspective in that there will be net benefits after considering the incentive payment under a similarly wide range of market conditions. The flexibility inherent in the incentive mechanism can accommodate the range of market outcomes better than a static command-and-control approach. Despite focused effort, I have been unable to develop a better alternative approach.

Curriculum Vitae

Cliff W. Hamal

Managing Director & Principal

SUMMARY

Cliff Hamal specializes in economic issues in the electric power and related industries. For over 30 years he has been involved in a wide variety of engagements, as an economic consultant since 1989 and in technical roles involving power system operations in prior years. Mr. Hamal brings to each assignment a deep understanding of the industry, its operations, and the dynamics of its markets. He approaches each engagement openly, allowing the unique circumstances of each situation to determine the analyses and methodologies most likely to provide insights into the relevant issues. He particularly enjoys unique challenges that require tailored solutions. His clients have included vertically integrated electric utilities, unregulated electric generation companies, load serving entities, fuel and pipeline companies, equipment suppliers, a debt rating agency, a hedge fund and the US Department of Justice. He has provided testimony in cases before the Federal Energy Regulatory Commission, federal courts, state public utility commissions, arbitrators and the Ontario Energy Board.

TOPICAL SURVEY OF PRIOR ENGAGEMENTS

Market Design

Support electricity market development, including analysis of rules, development of modifications, evaluation of likely participant behavior, and assessment of strategic implications. Analyze capacity markets and provide recommendations for their development and evolution. Review dispatch algorithms to determine how subtle changes could affect market prices and efficiencies. Develop market rules that address the potential exercise of market power during periods of congestion.

Competitive Strategy

Assess investment opportunities in electricity generation market. Evaluate a new merchant transmission project with unique technical challenges. Analyze the potential for repowering a generation facility. Assist in the establishment of a power marketing organization and the development of its business strategy. Model a large generation portfolio and evaluate divestiture options. Evaluate business opportunities and public policy options for equipment suppliers.

Power Purchase Agreements

Negotiate and renegotiate power purchase agreements. Evaluate contract pricing terms in light of changed market circumstances. Review implications of "good faith" terms on specific circumstances related to changed market circumstances. Review whether changes to force majeure provisions could lower energy costs. Analyze the value of a power contract to assess employee compensation claims.

Investment Analysis

Evaluate the value of power generation facilities for a potential buyer. Analyze partnership opportunities related to projects in development. Evaluate strategic alternatives for managing spent nuclear fuel in the U.S. Evaluate price forecasts and revenue projections for project-financed investments to support credit ratings by Standard & Poor's. Evaluate investment opportunities at existing facilities related to repowering, pollution control upgrades, and other modifications.

Environmental Strategy

Analyze implications of cap-and-trade and carbon tax climate change initiatives. Investigate strategic implications of changing environmental regulations. Provide a comprehensive analysis of the effect on the U.S. economy of policies targeting technologies considered favorable for the environment. Evaluate pollution control equipment upgrades and fuel switching options related to meeting emission standards. Consider implications of new environmental regulations on asset values.

Market Power Analysis

Evaluate market power issues in energy, capacity and ancillary services markets. Evaluate the implication of mergers and asset acquisitions on market power before the Federal Energy Regulatory Commission and the US Department of Justice. Prepare market based rate applications using FERC's market screen and Appendix A methodologies. Evaluate claims of antitrust violations under the Clayton Act.

Market Participant Behavior

Evaluate participant behavior in markets, including bidding patterns and generation unit availability. Analyze participant behavior in real-time, day-ahead, and longer-term energy markets. Evaluate claims of inappropriate market behavior by generators. Evaluate the behavior of a financial participant in energy and financial transmission rights (FTR) markets. Evaluate ancillary services markets regarding the implications of different market structures on participant behavior. Analyze the potential for specific trades to influence reported market prices.

Economic Testimony

Testify regarding damages in cases involving breach of contract. Testify on power contracting issues. Opine on market design issues. Testify regarding cost responsibilities for must run generation in a dispute centering on changes in the electricity market structure. Testify regarding electricity price forecasts. Serve as an arbitrator in an insurance claim matter involving the value of lost electricity generation.

PROFESSIONAL HISTORY

Since 2011	Navigant Economics	1996-2010	LECG
	1200 19th Street, NW, Suite 850	1995-1996	The Tesla Group, Inc.
	Washington, DC 20036	1993-1994	JFG Associates, Inc.
	Direct: 202.481.8303	1989-1993	Putnam, Hayes and Bartlett, Inc.
	Main: 202.973.2400	1983-1989	Westinghouse Electric Corporation
	Fax: 202.973.2401	1981-1983	General Electric Corporation
	cliff.hamal@naviganteconomics.com	1980-1981	Trinidad Lines and Marine Transport Line

EDUCATION

MS (with Distinction), Industrial Administration, Carnegie Mellon University, 1989.

BS (with Honors), Marine Engineering and Marine Transportation, U.S. Merchant Marine Academy, 1980.

TESTIMONY

On behalf of the Association of Power Producers of Ontario, before the Ontario Energy Board, October 1, 2012 and February 25-26, 2013, in the rate proceeding of Hydro One Networks, Inc., EB-2012-031. Subject: Evaluation of export tariff rates.

On behalf of Montana Alberta Tie Ltd. (a subsidiary of Enbridge Inc.), before the Alberta Utilities Commission, June 15 and September 18 and 19, 2012, Proceeding 1633. Subject: The Alberta Electric System Operator's rule modification, Section 203.6, concerning transmission rights following the addition of a merchant transmission interconnection.

On behalf of Ontario Power Generation, Inc., before the Ontario Superior Court of Justice, Canada, August 26, 2011, February 9, 10 and 13, 2012, Court File No.: 03-CV-252820CMZ. Subject: Review of Mishkeegogamang's claim for damages from electricity sales.

On behalf of PacifiCorp, before the U.S. District Court for the District of Oregon, February 22, 2011, Docket No. 09-1012-HZ. Subject: Dispute over pricing in a power purchase agreement concerning generation, transmission, ancillary services and power in the form of hydroelectric pondage.

On behalf of H.Q. Energy Services (U.S.) Inc., before the Federal Energy Regulatory Commission (FERC), September 1, 2010, Docket nos. ER010-787-000, EL10-50-000 and EL10-57-000. Subject: Changes in the forward capacity market in New England.

On behalf of the Narragansett Electric Company (National Grid), before the Rhode Island Public Utilities Commission, December 9, 2009 and March 9, 2010, Docket no. 4111, regarding the Town of New Shoreham Project. Subject: Power price review relevant to the Deepwater offshore wind project.

On behalf of Ontario Power Generation, Inc., before an arbiter under the Canadian Arbitration Act, in 2009, regarding a confidential matter.

On behalf of Ontario Power Generation Energy Trading, Inc., before the FERC, June 19, 2009 (filed June 23, 2009), Docket no. ER08-580-002. Subject: Market power evaluation for market based rate application for the Midwest ISO market.

On behalf of COALSALES II, L.L.C., before the U.S. District Court for the Northern District of Florida, Pensacola Division, August 19, 2008, December 11, 2008 and February 16, 2010, Docket no. 3:06 CV 270/MCR/MD, in the matter of Gulf Power Company v. COALSALES II, L.L.C. Subject: Damages analysis associated with a claimed breach of a coal sales agreement.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated August 4, 2008, Docket no. 04-0033C, in the matter of Consolidated Edison Company v. The United States of America. Subject: Analysis of sale prices of coal and nuclear generation units.

On behalf of Ontario Power Generation Energy Trading, Inc., before the FERC, June 19, 2008 (filed June 27, 2008), Docket no. ER08-580-001. Subject: Market power evaluation for market based rate application for the New York ISO market.

In a non-public investigation before the FERC, June 3, 2008, in response to a request for information. Subject: Analysis of financial transmission right (FTR) trading activity.

On behalf of the Ameren Energy Marketing Company, before the FERC, June 12, 2007 (filed June 18, 2007), Docket no. EL07-47-000. Subject: Review and comment on the economic issues raised in a complaint by the Illinois Attorney General concerning the September 2006 auction used to procure wholesale electricity supplies in Illinois.

On behalf of the Narragansett Electric Company, before the U.S. District Court for the District of Massachusetts, Central Division, May 18, 2007, and June 11, 2007, Docket no. C.A. No. 05-40076, in the matter of TransCanada Power Marketing, LTD v. Narragansett Electric Company. Subject: Review of pricing issues in a wholesale power contract and pricing issues in electricity power contracting more generally.

On behalf of The Association of Power Producers of Ontario (APPrO), before the Ontario Energy Board, March 9, 2007, Docket no. MR-0031-R00. Subject: Evaluation of a proposed change in the pricing algorithm in the Ontario electricity market, with the change related to how generator ramp rates are considered in setting prices.

On behalf of American Electric Power Service Corporation, before the FERC, January 29, 2007, Docket no. EC07-56-000. Subject: Evaluation of the competitive effects of the acquisition of the Lawrenceburg Electric Generation Station.

On behalf of American Electric Power Service Corporation, before the FERC, January 19, 2007, Docket no. EC07-49-000. Subject: Evaluation of the competitive effects of the acquisition of the Darby Electric Generation Station.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated June 29, 2006, testimony on October 12 and 16, 2007, and declaration dated September 17, 2008, Docket no. 00-697-C, in the matter of Wisconsin Electric Power Company v. The United States of America. Subject: Evaluation of decisions made by the utility in managing spent nuclear fuel at the Point Beach Nuclear Power Plant.

On behalf of Reliant Energy Services, Inc., before the U.S. Superior Court of California for the County of San Diego, May 25, 2006, in the matter of Jerry Egger, et al., v. Reliant Energy Services, Inc. et al., Wholesale Electricity Antitrust Cases I and II. JCCP Case Nos. 4204 and 4205. Subject: Analysis of purchases made by Montana-based utilities in California markets.

On behalf of The United Illuminating Company, before the FERC, January 20, 2006 and February 28, 2006, Docket no. EL05-76-001. Subject: Evaluation of issues in a contract dispute involving cost responsibilities for reliability must-run generators.

On behalf of Reliant Energy Services, Inc. and four individuals, before the U.S. District Court for the Northern District of California, San Francisco Division, October 7, 2005, Docket no. CR 04-0125 VRW, in the matter of United States of America v. Reliant Energy Services, Inc. et al. Designated as an expert in case involving claims of price manipulation and a criminal violation of the Commodity Exchange Act. Subject: The operation of the California electricity market, price artificiality, and the behavior of market participants.

On behalf of American Electric Power Service Corporation, et al, before FERC, September 8, 2005, Docket no. EC05-134-000. Subject: Evaluation of the market power implications of the acquisition of Reliant Energy's Ceredo generation station with respect to capacity and ancillary service markets.

On behalf of Niagara Mohawk Power Corporation, et al, before FERC, July 19, 2005, Docket no. ER96-2585, et al. Subject: Market-based ratemaking application for National Grid USA affiliated companies.

On behalf of American Electric Power Service Corporation, et al, before FERC, June 24, 2005, Docket no. EC05-98-000. Subject: Evaluation of market power implications of the acquisition of the PSEG Waterford generation unit with respect to capacity and ancillary services markets.

On behalf of Ontario Energy Trading International Corp., and Ontario Power Generation, Inc., before the FERC, April 11, 2005, Docket no. ER02-1021-000. Subject: Evaluation of the potential for market power in U.S. markets using pivotal supplier and market share screens.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated November 22, 2004, testimony on March 28, 2005 and April 1, 2005, Docket no. 98-488C, in the matter of

Sacramento Municipal Utility District v. The United States of America. Subject: Review of the damages claim made by SMUD associated with alleged breach of contract for the disposal of spent nuclear fuel.

On behalf of National Grid USA, before FERC, November 4, 2004 (revised November 19, 2004), January 10, 2005, January 28, 2005, March 14, 2005, and March 17, 2005, Docket no. ER03-563-030. Subject: Review of the locational capacity market proposal filed by ISO New England with consideration given to market design, participant behavior, the mechanics of implementing the market, and the cost of new generation capacity.

On behalf of Reliant Energy Services, Inc. and four individuals, before the U.S. District Court for the Northern District of California, San Francisco Division, December 10, 2004, Docket no. CR 04-0125 VRW, in the matter of United States of America v. Reliant Energy Services, Inc. et al. Subject: Review of a report concerning the market effects of certain bidding actions by Reliant on California electricity markets in the summer of 2000.

On behalf of New England Power Co. before FERC, December 24, 2003, March 9, 2004, and April 15, 2004, Docket no. EL03-37-000. Subject: Evaluation of the electricity price forecast used for setting a contract termination charge, as well as the determination of variable costs and generation asset sale prices.

On behalf of Koch Power, Inc., before the Harris County, Texas District Court, Cause no. 2001-48858, in the Matter of Tim Beverick v. Koch Power, Inc., provided testimony summary on August 25, 2003. Subject: Evaluation of the potential for savings under a renegotiated power purchase agreement and the contributions of certain individuals to the renegotiation process.

On behalf of Reliant Energy Services, Inc. before the FERC, April 16, 2003, Docket no. EL03-59-000. Subject: Evaluation of the implications of certain trades of forward energy contracts on the overall electricity market.

On behalf of Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. before the FERC, March 3, 2003, with rebuttal March 20, 2003, Docket nos. EL00-95-069 and EL00-98-058. Subject: Investigation into alleged manipulative practices by market participants in the California electricity markets in the 2000-2001 timeframe.

On behalf of Ontario Energy Trading International Corp., and Ontario Power Generation, Inc. subsidiary, before the FERC, February 14, 2002, Docket no. ER02-1021-000. Subject: Evaluation of the potential for market power in U.S. markets.

On behalf of The New Power Company before the FERC, July 13, 2001 (filed July 17, 2001), Docket no. EL01-105-000. Subject: Evaluation of the capacity credit market in PJM, primarily focusing on market power issues.

On behalf of National Grid USA before the FERC, January 16, 2001, Docket no. EL00-62-005 and EL00-62-013. Subject: Analysis of the incentives for new generation facilities in New England, and in particular the role of the $8.75/kw-month installed capacity deficiency charge.

On behalf of Oklahoma Gas & Electric before the Arkansas Public Service Commission, November 30, 2000, Docket no. 00-326-U. Subject: Analysis of OG&E's potential market power in a restructured, retail open-access environment.

On behalf of National Grid USA and TransCanada OSP Holdings, LTD before the FERC, August 7, 2000, Docket no. EC00-122. Subject: Analysis of the competitive effects of the proposed acquisition of interests in the Ocean State Power generation facility by TransCanada.

On behalf of Central Illinois Light Company and the AES Corporation before the FERC, February 19, 1999, Docket no. EC99-40. Subject: Analysis of competitive effects of the proposed acquisition of Central Illinois Light Company by the AES Corporation.

On behalf of Public Service Electric & Gas Co., before the United States District Court for the Eastern District of Pennsylvania, Docket no. 96-CV1705, in the Matter of Delmarva Power & Light Company and PECO Energy Company v. Public Service Enterprise Group, Inc. and Public Service Electric and Gas Co., March 28, 1997. Subject: Replacement power costs associated with the multi-year forced outage of the Salem Nuclear Station.

SPEECHES & PAPERS

"Solving the Electricity Capacity Market Puzzle: The BiCap Approach," the seminal paper presenting a new market design and incorporated into a website dedicated to capacity market developments, www.BiCapApproach.com, initiated July 4, 2013.

"Realities in the Pricing of Power in Ontario," in the session, "Realistic options for getting to truer and more effective price signals," as part of APPrO 2012, Toronto, Canada, November 7, 2012.

"Opportunities in Spent Nuclear Fuel Consolidation," as part of a workshop sponsored by the United States Nuclear Infrastructure Council, Baltimore, MD, May 31, 2012.

"How can an economist help with complicated technical and political issues?" in the session, "Spent Nuclear Fuel Storage and Repository Options," for the Institute of Nuclear Materials Management Spent Fuel Workshop XXVII, Arlington, VA, February 2, 2012.

"Five Thoughts on Evolutionary Change," in the session, "Market Evolution in the Context of the Electricity Market Forum Road Map and the Post-Election Environment," APPrO 2011, Toronto, Canada, November 16, 2011.

"Spent Nuclear Fuel Management: How centralized interim storage can expand options and reduce costs," with Julie M. Carey and Christopher L. Ring. A study conducted for the Blue Ribbon Commission on America's Nuclear Future, May 16, 2011.

"Nine Trends to Watch in the Renewable Transformation," with Julie M. Carey. *Dialogue*, United States Association for Energy Economics, Volume 18, Number 3 - 2010.

"Capacity Market Design Fundamentals." Workshop for EUCI's conference, "Capacity Resources: Issues and Market Dynamics," Baltimore, MD, October 27, 2010.

"The Impact of Transmission Expansion and New Renewable Generation on the Evolution of FTR Markets." Panel moderated for EUCI's conference, "Financial Transmission Rights: Trends and Trajectory," Arlington, VA, July 19, 2010.

"Managing FTR Credit Risk." Panel moderated for EUCI's conference, "Financial Transmission Rights: Where Are We Now?" Washington, DC, July 28, 2009.

"Credit Coverage Requirements for FTR and Virtual Bidding." Session moderated for EUCI's conference, "Unsecured Credit: Is it the right policy for RTOs/ISOs?" Alexandria, Virginia, April 29, 2009.

"Force Majeure Risk and Ontario Power Authority's Power Contracts." Whitepaper with Julie M. Carey, on behalf of the Ontario Power Authority, March 31, 2008.

"Financial Accommodation for Force Majeure Events." Whitepaper with Julie M. Carey, on behalf of Ontario Power Authority, January 21, 2008.

"Market Design Choices for Ancillary Services Products," with Cleve Tyler. Presented at the EUCI Ancillary Services Conference, Minneapolis, Minnesota, September 12, 2007.

"Cost-Benefit Analysis In the Evaluation of Market Rule Changes: Comments on MR-00332-R00." Whitepaper on behalf of Ontario Power Generation, Inc., July 12, 2007.

"Adopting a Ramp Charge to Improve Performance of the Ontario Market." Whitepaper with Arun Sharma, on behalf of The Association of Power Producers of Ontario (APPrO), June 21, 2006.

"Shifting Regulatory Oversight of Utility Mergers," with Cleve Tyler, *Innovating for Transformation*, The Energy and Utilities Project, Volume 6, 2006, page 37.

"Allocation of Emission Allowances for the Regional Greenhouse Gas Initiative." Whitepaper regarding an initiative under consideration in mid-Atlantic and Northeastern regions of the United States, written with Alan Madian, September 20, 2005.

"Toward a Capacity Demand Curve Market," with Julie Murphy, *Innovation for the Future*, The Energy and Utilities Project, Volume 5, 2005, page 46.

"LICAP Key Issues." Presented to Commissioners and staff of the Massachusetts Department of Telecommunications and Energy, Boston, Massachusetts, March 28, 2005.
"Market Power Screens." Presented at the Electric Power Supply Association (EPSA) Annual Fall Membership Meeting, Washington, DC, November 10, 2004.

"Ancillary Service Pricing Dynamics." Presented at the EUCI Ancillary Service Conference, Westminster, Colorado, March 13, 2003.

"California's Electricity Markets: Structure, Crisis, and Needed Reforms." Contributor, January 16, 2003.

"Capacity Payment Schedules: A Workable Approach for Resource Adequacy." Presented to the Energy Bar Association, Washington, D.C., December 12, 2002.

"Power Market Panel." Speaker in the Standard & Poor's 2002 Project, Power & Energy Credit Conference, New York, New York, November 13, 2002.

"Market-Based Pricing of Ancillary Services: Market Design Choices, Consequences and Performance." Presented at the EUCI Ancillary Services Conference, Atlanta, Georgia, September 27, 2002.

"Ancillary Service Market Performance During the Summer of 2002." Presented at the EUCI Ancillary Services Conference, Atlanta, Georgia, September 26, 2002.

"Revenue and Risk from the Lender's Perspective." Presented at the Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

"Preparing for Antitrust Scrutiny." Panel discussion at the Utility Mergers & Acquisitions Conference, Washington, D.C., July 15, 1998.

"Perspectives of Investors and Developers." Presented at the American Education Institute Conference on Power Contracts in affiliation with the United States Energy Association to the Romanian Electric Authority, Washington, D.C., March 19, 1997.

"Risk and Risk Management in Electricity Markets." Presented at the Electric Load Aggregation Conference, Washington, D.C., November 18, 1996.

"Developing Firm Plans During Uncertain Times: Anticipating Change." Presented during a session titled "Integrated Resource Planning and Demand Side Management After Federal Endorsement," to the Institute of Public Utilities, Williamsburg, Virginia, December 15, 1992.

Numerous speeches and training programs regarding nuclear power plant operations, accident analysis, nuclear engineering and related subjects were given to operators and technical engineering personnel from power plants around the world, 1984-1986.

AFFILIATIONS AND PROFESSIONAL QUALIFICATIONS

Member, International Association for Energy Economics.

Member, Non-Attorney Professional, Energy Bar Association.

Mr. Hamal has held U.S. Nuclear Regulatory Commission certification as Senior Reactor Operator; U.S. Department of Energy qualifications as Nuclear Plant Engineer and Nuclear Engineer Officer of the Watch; and U.S. Coast Guard licenses as Third Assistant Engineer and Third Mate.

August 2013

PRODUCTION FORECAST AND METHODOLOGY – NUCLEAR

1.0 PURPOSE

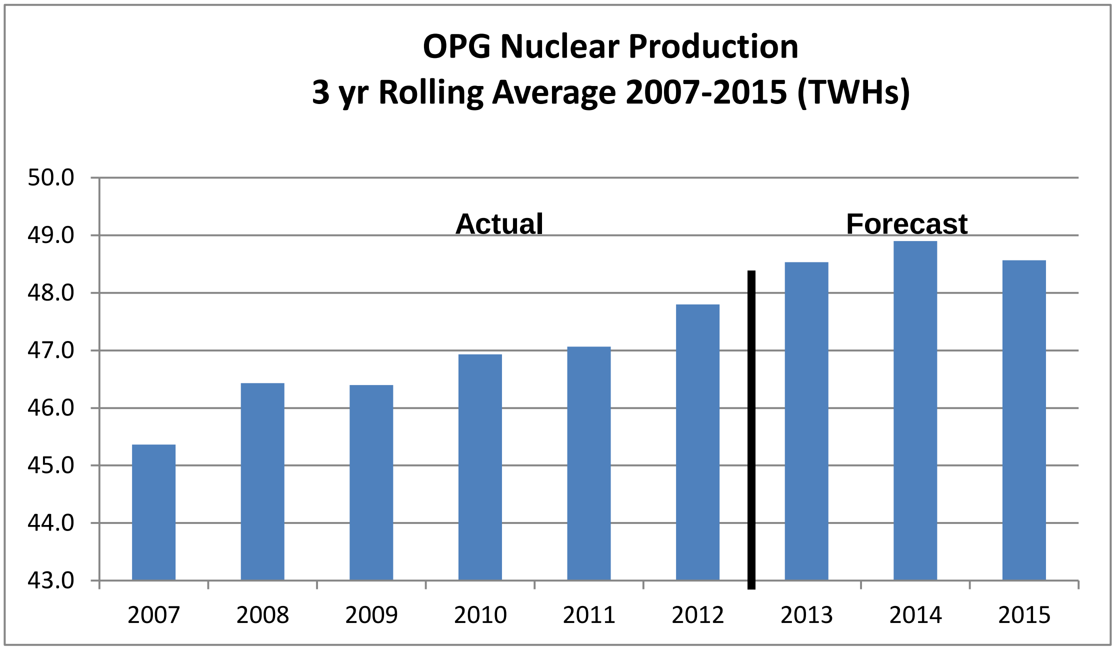
This evidence provides the production forecast for the nuclear facilities and a description of the methodology used to derive the forecast.

2.0 OVERVIEW

OPG is seeking approval of a nuclear production forecast of 49.7 TWh in 2014 and 48.0 TWh in 2015 for a total of 97.7 TWh during the test period. The nuclear production forecast for the years 2010 - 2015 is presented in Ex. E2-1-1 Table 1. A monthly nuclear production forecast for 2014 - 2015 is presented in Ex. E2-1-1 Table 2.

Nuclear production (3 year rolling average) over the period 2007 - 2015 is trending higher (see Chart 1) reflecting the success of OPG initiatives to improve planned outage execution and to reduce the number of forced outages by improving plant equipment reliability. Reliability improvement is addressed in the discussion of OPG's gap closure initiatives in the Benchmark and Business Planning evidence (Ex. F2-1-1).

Chart 1



Despite the upward trend in nuclear production, prior OEB approved nuclear production forecasts have historically projected greater generation than actual, as shown in Chart 2 below. The average production shortfall has been -3.1TWh from 2008 to 2013 resulting in a negative revenue impact of $151.9M annually over the same period. While OPG has used the same methodology (described in Section 3 below) to forecast nuclear production as that approved by the OEB in EB-2010-0008, the forecast reflects a change in OPG's performance expectations. OPG's projected FLR, planned outage days and Generation Losses[1] reflect reasonable and achievable targets that will improve forecast accuracy and avoid substantial production forecast variances as has occurred in the past.

[1] see Attachment 1 Glossary of Outage and Generation Performance Term for definitions

Chart 2

OPG Nuclear Production Variance and Revenue Impact

Chart 4; revised

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	48	
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	3.0	3.1
Revenue Impact - $M (3)	-159.9	-154.9	-242.4	-87.3	-121.3	-145.6	-151.9

(1) All amounts are actual with exception that 2013 is OPG Budget production forecast
(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

The test period production forecast takes into account the following:

- Darlington will execute a Vacuum Building Outage (VBO) in 2015 in which all 4 units will be shutdown. The 2015 VBO eliminates a scheduled 4 unit shutdown Station Containment Outage (SCO) in 2015.
- A mid-cycle planned outage of 20 days on Pickering Units 1 in 2014 to focus on preventative maintenance and lessen the risk of future forced outages.
- An extended scope and duration for the planned outages at Pickering Units 5-8 as a result of the Pickering Continued Operations initiative (see Ex F2-2-3) equivalent to 0.5 TWh.
- Pickering's forecast FLR for 2014 is 7.8 per cent and 5.5 per cent in 2015. Pickering's FLR is trending lower (Pickering's actual FLR was 9.3 per cent in 2010, 11.6 per cent in 2011 and 7.0 per cent in 2012 as set out in Ex. E2-1-2, Table 1) reflecting expectations of improved performance due to reliability improvements.
- Darlington's forced loss rate (FLR) is 1.3 per cent in 2014 and 1.0 per cent in 2015.

- OPG has retained the 0.5 TWh allowance for major unforeseen events approved by the OEB[2] in EB-2010-0008 and has included this allowance in its production forecast.

3.0 NUCLEAR PRODUCTION PLANNING PROCESS

3.1 Methodology

Nuclear facilities are designed as base load generators. OPG's annual nuclear production forecast is equal to the sum of the nuclear generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages, forced production losses (i.e., unplanned outages and unplanned derates, as these terms are defined in Attachment 1) and corrections for sources of Generation losses (i.e., lake temperature, grid losses, consumption (station service) as defined in Attachment 1).

OPG's nuclear planning process has not changed since EB-2010-0008 and is focused on establishing annual planned outage schedules and on calculating variances to planned generation due to forced production losses. Outage durations are determined based on the scope of work defined for each outage while considering recent benchmarking efforts and the nuclear commitment to continuous improvement. The objective is to establish a realistic and accurate annual nuclear production forecast based on the Nuclear Generation and Outage Plan, with the following deliverables:

- A planned outage schedule for all stations that includes unit outage start dates, end dates, and durations, as well as a summary of major elements comprising the scope of work that will be executed during each outage.
- Operational reliability targets such as unit capability factor and the level of forced production losses represented by the forced loss rate ("FLR").
- Generation forecasts in terawatt-hours ("TWh") for individual nuclear units and an aggregated forecast for each station.

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[2] EB-2010-0008 Decision with Reasons, p. 39

The Nuclear Generation and Outage Plan is approved as part of the OPG business planning process. As discussed at Ex. F2-4-1, outage resource requirements and cost estimates for the outage OM&A budget are also tied to the Nuclear Generation and Outage Plan.

3. 1.1 Planned Outage Schedule

OPG's planned outage schedule identifies the number of days required for inspections and maintenance activities to ensure continued safe, reliable and long-term operation. The planned outage scheduled is prepared in accordance with OPG's aging and life cycle management programs and in compliance with OPG's nuclear operating licenses issued by the Canadian Nuclear Safety Commission ("CNSC").

Planned outages are complex, involving many OPG divisions and individuals working together. Outages require focus, expertise, high levels of coordination and a level of detail that exceeds major construction projects (due to regulatory complexity and constraints in work execution). The planned outage schedule also incorporates "lessons learned" from recent OPG outages and operating experience outside OPG.

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.

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

For the test period, there is a single unit planned outage at Darlington in both 2014 and 2015. In addition, there is a VBO in which all 4 units will be shut down A station-wide 4 unit station VBO is required by the regulator every 12 years and a Station Containment Outage ("SCO") every 6 years. A SCO also requires that all 4 units be shut down, but for a shorter duration. A Darlington VBO was last conducted in 2009. The next planned VBO that was scheduled for 2021 has been moved forward to 2015, eliminating the need for a scheduled SCO in 2015 and a VBO in 2021. OPG is seeking regulatory approval to eliminate the need for SCO's going forward. This will shift these 4 unit station outages from a 6 year cycle to a 12 year cycle. This change will result in savings in the number of outage days in 2021 and beyond and will also reduce the complexity and resource demands during the Darlington Refurbishment Project.

The 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.

The outage durations include a station level allowance for uncertainty related to potential discovery work and a nuclear fleet level allowance under the control of the Chief Nuclear Officer to address risks to the completion of the outage on schedule, risks that could emerge from fleet aging issues, or the complexity in fleet level activities (e.g., availability of Inspection Maintenance Service resources to service multiple outages).

3. 1.2 Forced Loss Rate (FLR)

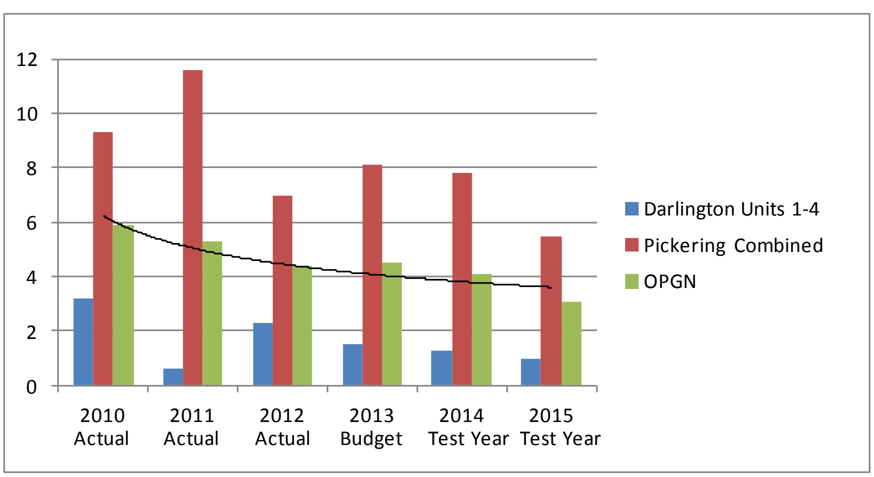
Variances to planned generation result from forced production losses (i.e., unplanned outages and derates). OPG projects FLR targets that reflect the risk of forced production losses at Darlington and Pickering. The FLR targets are based on the plants' historical performance, any known improvements or plant material condition issues, and initiatives to improve equipment reliability.

Darlington’s forecast FLR for 2014 is 1.3 per cent and for 2015 it is 1.0 per cent (Ex. E2-1-2, Table 1). Darlington’s FLR has been trending lower since 2010 when Darlington’s FLR was 3.2 per cent mainly due to a forced outage caused by the fuel handling system. Darlington’s forced outage performance is close to top quartile (calculated on a 3–year rolling average basis) for the most recent period (Ex F2-1-1, Attachment 2, 2012 Nuclear Benchmarking Report).

Pickering’s forecast FLR for 2014 is 7.8 per cent and 5.5 per cent in 2015 (Ex. E2-1-2, Table 1) Pickering’s FLR is also trending lower (Pickering's actual FLR was 9.3 per cent in 2010, 11.6 per cent in 2011 and 7.0 per cent in 2012) reflecting improved performance due to reliability improvements. Mid-cycle planned outages of 20 days were introduced at Pickering Units 1 and 4 starting in 2012 to allow for additional preventative maintenance which will lessen the risk of future forced outages. Another major initiative at Pickering is the 2013 - 2015 Equipment Reliability Plan to ensure Pickering’s availability during Darlington refurbishment (see gap closure initiatives in the Nuclear Benchmarking and Business Plan evidence Ex. F2-1-1).

Chart 3 presents historical and forecast FLR for the nuclear facilities for the period 2010 - 2015.Chart 3

OPG Nuclear FLR (2010-2015)



LIST OF ATTACHMENTS

ATTACHMENT 1

GLOSSARY OF OUTAGE AND GENERATION PERFORMANCE TERMS

Consumption Losses: The electrical service energy consumed by a station and used to supply the electrical load for ancillary equipment and related on-site processes.

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

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

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

Forced Loss Rate ("FLR"): FLR is a WANO indicator of performance reliability. FLR is a measure of the percentage of energy generation that a plant is not supplying to the electrical grid during non-planned outage periods, because of forced production losses, i. e, and forced outages or unplanned derates. This indicator excludes forced production losses due to high lake water temperatures, and forced extensions to planned outages.

Forced Outage: a forced outage is an unplanned electricity system component failure (e.g., immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed completely from service immediately and, per WANO industry performance reporting guidelines, for which OPG did not provide at least 28 days advance notice to the IESO for the start of the outage.

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

Generation losses: Represent the total generation losses that are outside of the control of plant management losses and are equal to the sum of **“**Consumption” + “Grid” + “Lake Temperature losses”.

Grid Losses: Generation losses due to a reduction in electrical power generation because the grid is unable to accept the available power (due to a problem outside of the station boundary) or because of demand limitations.

Lake Temperature Losses: High lake water temperature losses result when reduced condenser efficiency results in lower generation output

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

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

Maximum Continuous Rating: The design, or demonstrated higher, maximum power of a unit operating continuously in MWs.

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

Unbudgeted Planned Outages: An unbudgeted planned outage is an emergent outage that was not included in the approved integrated nuclear outage and generation plan that underpins the business plan, but which OPG had sufficient time to notify the IESO at least 28 days prior to the start date. Although unbudgeted, this allows the outage to be categorized as 'planned' for performance reporting purposes as per WANO industry guidelines.

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

Numbers may not add due to rounding.

Table 1
Production Forecast Trend - Nuclear (TWh)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Darlington NGS**	26.5	29.0	28.3	26.9	28.4	26.1
2	**Pickering NGS**	19.2	19.7	20.7	21.1	21.3	21.9
3	**Total**	45.8	48.6	49.0	48.0	49.7	48.0

Numbers may not add due to rounding.

Table 2
Monthly Production - Nuclear (TWh)
Test Period

Line No.	Prescribed Facility	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	2014 Plan:													
1	**Darlington NGS**	2.6	2.3	2.6	1.9	1.9	2.0	2.5	2.5	2.4	2.6	2.5	2.6	28.4
2	**Pickering NGS**	2.0	1.6	1.7	1.7	1.9	2.0	2.1	2.1	1.7	1.5	1.4	1.6	21.3
3	**Total**	4.6	3.9	4.3	3.6	3.9	4.0	4.6	4.6	4.1	4.1	3.9	4.2	49.7
	2015 Plan:													
4	**Darlington NGS**	2.6	2.3	2.6	0.2	1.4	1.9	2.5	2.5	2.4	2.6	2.5	2.6	26.1
5	**Pickering NGS**	2.2	1.7	1.8	1.7	1.8	2.1	2.1	2.1	1.6	1.4	1.4	1.9	21.9
6	**Total**	4.7	4.0	4.4	2.0	3.1	4.0	4.6	4.6	4.1	4.0	3.9	4.5	48.0

COMPARISON OF PRODUCTION FORECASTS – NUCLEAR

PURPOSE

This evidence presents year-over-year and budget to actual comparisons of nuclear production forecasts in support of the approval of OPG's nuclear production forecast for the test period.

1.0 OVERVIEW

Variances between actual and forecast production in any year or plan over plan are typically the result of OPG experiencing more or fewer forced outages ("FO") or derates, forced extensions to planned outages ("FEPO"), planned outage days (PO days) or unbudgeted planned outages. Year over year or plan over plan variances may also arise due to station consumption, grid losses and high lake water temperature.

PERIOD-OVER-PERIOD CHANGES – TEST YEARS

2015 Plan versus 2014 Plan

The nuclear production forecast for 2015 of 48.0 TWh is 1.7 TWh lower than the nuclear production forecast for 2014 of 49.7 TWh.

The lower production forecast for 2015 relative to 2014 is due to:

- 105.9 more PO days for the combined nuclear fleet (110.9 more PO days at Darlington and 5.0 less PO days at Pickering). The additional outage days for Darlington are due to a 4 unit Vacuum Building Outage in 2015.
- The lower production is partially offset by a forecast improvement in the combined nuclear FLR of 1.0 per cent (44.4 fewer FO days). Pickering's FLR improves by 2.3 per cent and Darlington's FLR improves by 0.3 per cent. Pickering's forecast FLR improvement reflects an expectation of improved equipment reliability.

2014 Plan versus 2013 Budget

The nuclear production forecast for 2014 of 49.7 TWh is 1.7 TWh higher than the 2013 Budget of 48.0 TWh.

The higher production forecast for 2014 relative to 2013 is due to:

- 77.9 fewer PO days for the combined nuclear fleet (67.3 fewer PO days at Darlington and 10.6 fewer PO days at Pickering). There is a single planned outage scheduled at Darlington in 2014, compared to two in 2013, consistent with the 3 year outage cycle at Darlington
- An improvement in the combined nuclear FLR of 0.3 per cent (10.5 fewer FO days). Pickering's forecast FLR improves by 0.3 per cent and Darlington's FLR improves by 0.3 per cent. Pickering's forecast FLR improvement reflects an expectation of improved equipment reliability due to initiative to improve reliability in an effort to reduce the number of forced outages.

2.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2013 Budget versus 2012 Actual

The nuclear production forecast for 2013 of 48.0 TWh is 1.0 TWh lower than the 2012 Actual of 49.0 TWh.

The lower production forecast for 2013 relative to 2012 Actual is due to 31.9 additional PO days for the combined nuclear fleet (80.7 additional PO days at Darlington offset by 48.8 fewer PO days at Pickering). There are two planned outages scheduled for Darlington in 2013 compared to a single outage scheduled in 2012, consistent with the 36-month outage cycle at Darlington.

The FLR forecast remains constant, as Darlington FLR improves from 2.3 per cent actual to 1.5 per cent forecast, offset by an increase in Pickering FLR from 7.0 per cent actual to 8.1 per cent forecast reflecting historical performance over multiple years.

3.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2012 Actual versus 2012 Board Approved

Actual nuclear production of 49.0 TWh for 2012 is 2.5TWh lower than the 2012 Board Approved forecast of 51.5 TWh. The lower actual production for 2012 relative to the Board Approved 2012 forecast is primarily due to:

- The increase (103.5 days) in PO days for the combined nuclear fleet includes the introduction of a 20-day Pickering Unit 1 mid-cycle outage aimed at improving plant reliability through preventative maintenance to reduce the risk of future forced outages and three unbudgeted planned outages that were not included in the approved nuclear outage and generation plan partly offset by the early completion of the Darlington Unit 3 planned outage.
- A 1.6 per cent increase (26.2 days) in the combined nuclear FLR (2.7 per cent increase at Pickering, 0.8 per cent increase at Darlington).
- There were 26.2 FEPO days for Pickering of which 16.4 FEPO days were due to maintenance required on the Unit 8 west fueling machine and on Unit 4 to complete the pressurizing pump maintenance.

2012 Actual versus 2011 Actual

The nuclear production for 2012 of 49.0 TWh was 0.4 TWh higher than the 2011 actual nuclear production of 48.6 TWh.

The higher actual production for 2012 relative to 2011 actual production is primarily due to:

- A 1.0 per cent decline (i.e. improvement) in the combined nuclear FLR in the 2012 (4.6 per cent improvement for Pickering, partially offset by a 1.7 per cent increase for Darlington).
- There were 70.7 FEPO days for Pickering in 2011 (63.9 FEPO days due to the Pickering Unit 5 planned outage being extended to addressing gadolinium oxalate deposits in the calandria and 6.8 FEPO days due to fuelling machine maintenance on Pickering Unit 4) versus only 26.2 FEPO days in 2012.

Offsetting the above, there were 60.7 additional PO days for the combined nuclear fleet in 2012 versus 2011 (3.4 PO days for Darlington and 57.3 PO days for Pickering). The increase in PO days in 2012 reflects adjustments for historical duration of planned outage performance at Pickering and Darlington as well as the Pickering Unit 1 mid-cycle outage to focus on preventative maintenance and lessen the risk of future forced outages.

2011 Actual versus 2011 Board Approved

The actual nuclear production for 2011 of 48.6 TWh is 1.8 TWh lower than the 2011 Board Approved forecast of 50.4 TWh.

The lower actual production for 2011 relative to the Board Approved 2011 forecast is due to:

- A 2.1 per cent increase (96.6 days) in the combined nuclear forced loss rate ("FLR"). There was a 6.2 per cent increase in the Pickering FLR largely driven by equipment reliability. The largest contributors to unplanned losses were at Pickering Units 1 and 4 which included a steam leak on the turbine system, high condenser vacuum pressure on the heat transport system resulting in a reactor trip, moderator level control valve and system pump seal failures. This was offset by a slight decrease of 0.9 per cent in Darlington's FLR.
- There were 70.7 Forced Extension of Planned Outage ("FEPO") days for Pickering in 2011 (63.9 days due to the Pickering Unit 5 planned outage being extended to addressing gadolinium oxalate deposits in the calandria, and 6.8 days due to fuelling machine maintenance on Pickering Unit 4).

Offsetting the above, there were 17.0 fewer planned outage ("PO") days for the combined nuclear fleet (8.0 fewer actual PO days for Darlington and 9.0 fewer actual PO days for Pickering).

2011 Actual versus 2010 Actual

The actual nuclear production for 2011 of 48.6 TWh is 2.9 TWh higher than the 2010 actual nuclear production of 45.7 TWh.

The higher production for 2011 relative to 2010 is primarily due to:

- A 0.6 per cent decrease (i.e. improvement) in the combined nuclear FLR (2.6 per cent decrease in FLR for Darlington partially offset by a 2.3 per cent increase in FLR for Pickering).
- 62.7 fewer PO days at Darlington in 2011. There was a single planned outage 2011, compared to two planned outages in 2010.
- 13.9 fewer FEPO days at Darlington in 2011 compared to 2010 (2010 FEPO days were due to fuel machine issues).
- 124.3 fewer PO days at Pickering in 2011. In 2010 additional PO days were required for the Pickering Vacuum Building Outage (VBO), partially offset by 49.2 additional FEPO days for Pickering in 2011 due to gadolinium oxalate and fuelling machine issues.

2010 Actual versus 2010 Budget

The actual nuclear production for 2010 of 45.8 TWh is 0.4 TWh lower than the 2010 Budget of 46.2 TWh.

The lower actual production for 2010 relative to the 2010 Budget forecast was due primarily to:

- An increase in the combined nuclear FLR of 2.4 per cent from 3.5 per cent forecast to 5.9 per cent actual. There was a 3.3 per cent increase in Pickering FLR primarily due to a 19.7 per cent FLR for Pickering Units 1 & 4 due to issues regarding Turbines & Auxiliary and Liquid Zone Control systems, and 4.3 per cent FLR for Pickering Units 5-8. There was a 1.5 per cent increase in FLR for Darlington primarily due to Fuel Handling issues. The 2010 Budget forecast of 46.2 TWh included a 2.0 TWh reduction for major unforeseen events.
- There were 35.4 FEPO days in 2010 (13.9 for Darlington Unit 4 defueling delay, and 21.5 for Pickering primarily due to issues during Pickering Unit 1 start-up activities.

Numbers may not add due to rounding.

Table 1
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Darlington NGS									
1	**TWh**	27.8	(1.3)	26.5	2.4	28.9	0.0	29.0	(0.6)	28.3
2	**Unit Capability Factor (%)**	90.3	(2.7)	87.6	7.6	93.9	1.3	95.2	(2.0)	93.2
3	**PO Days**	118.8	4.2	123.0	(62.7)	68.3	(8.0)	60.3	3.4	63.7
4	**FEPO Days**	0.0	13.9	13.9	(13.9)	0.0	0.0	0.0	0.0	0.0
5	**FLR (%)**	1.7	1.5	3.2	(2.6)	1.5	(0.9)	0.6	1.7	2.3
6	**FLR Days Equivalent**	22.5	20.2	42.7	(34.5)	20.9	(12.7)	8.2	24.1	32.3
	Pickering NGS									
7	**TWh**	20.4	(1.1)	19.2	0.4	22.0	(2.3)	19.7	1.0	20.7
8	**Unit Capability Factor (%)**	75.3	(3.6)	71.7	1.7	81.5	(8.1)	73.4	4.4	77.8
9	**PO Days**	436.0	(16.7)	419.3	(124.3)	304.0	(9.0)	295.0	57.3	352.3
10	**FEPO Days**	0.0	21.5	21.5	49.2	0.0	70.7	70.7	(44.5)	26.2
11	**FLR (%)**	6.0	3.3	9.3	2.3	5.4	6.2	11.6	(4.6)	7.0
12	**FLR Days Equivalent**	105.3	55.9	161.2	49.2	101.1	109.3	210.4	(81.5)	128.9
	Totals									
13	**Unit Capability Factor (%)**	83.3	(3.1)	80.2	4.9	88.1	(3.0)	85.1	(0.6)	84.5
14	**PO Days**	554.8	(12.5)	542.3	(187.0)	372.3	(17.0)	355.3	60.7	416.0
15	**FEPO Days**	0.0	35.4	35.4	35.3	0.0	70.7	70.7	(44.5)	26.2
16	**FLR (%)**	3.5	2.4	5.9	(0.6)	3.2	2.1	5.3	(1.0)	4.4
17	**FLR Days Equivalent**	127.8	76.1	203.9	14.7	122.0	96.6	218.6	(57.4)	161.2
18	**TWh**	48.2	(2.4)	45.8	2.8	50.9	(2.3)	48.6	0.4	49.0
19	**Forecast for Major Unforeseen Events**	2.0	(2.0)	0.0	0.0	0.5	(0.5)	0.0	0.0	0.0
20	**Total TWh**	46.2	(0.4)	45.8	2.8	50.4	(1.8)	48.6	0.4	49.0

Line No.	Prescribed Facility	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Darlington NGS									
21	**TWh**	29.0	(0.7)	28.3	(1.4)	26.9	1.5	28.4	(2.3)	26.1
22	**Unit Capability Factor (%)**	94.1	(0.9)	93.2	(4.4)	88.8	4.7	93.5	(7.2)	86.3
23	**PO Days**	65.5	(1.8)	63.7	80.7	144.4	(67.3)	77.1	110.9	188.0
24	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**FLR (%)**	1.5	0.8	2.3	(0.8)	1.5	(0.3)	1.3	(0.3)	1.0
26	**FLR Days Equivalent**	21.0	11.3	32.3	(12.6)	19.7	(5.1)	14.6	(1.9)	12.7
	Pickering NGS									
27	**TWh**	23.0	(2.3)	20.7	0.4	21.1	0.2	21.3	0.6	21.9
28	**Unit Capability Factor (%)**	84.9	(7.1)	77.8	1.4	79.2	0.7	79.9	2.2	82.1
29	**PO Days**	247.0	105.3	352.3	(48.8)	303.5	(10.6)	292.9	(5.0)	287.9
30	**FEPO Days**	0.0	26.2	26.2	(26.2)	0.0	0.0	0.0	0.0	0.0
31	**FLR (%)**	4.3	2.7	7.0	1.1	8.1	(0.3)	7.8	(2.3)	5.5
32	**FLR Days Equivalent**	84.6	44.3	128.9	23.5	152.4	(5.4)	147.0	(42.5)	104.5
	Totals									
33	**Unit Capability Factor (%)**	89.8	(5.3)	84.5	(0.2)	84.3	3.3	87.6	(3.6)	84.0
34	**PO Days**	312.5	103.5	416.0	31.9	447.9	(77.9)	370.0	105.9	475.9
35	**FEPO Days**	0.0	26.2	26.2	(26.2)	0.0	0.0	0.0	0.0	0.0
36	**FLR (%)**	2.8	1.6	4.4	0.1	4.5	(0.4)	4.1	(1.0)	3.1
37	**FLR Days Equivalent**	105.6	55.6	161.2	10.9	172.1	(10.5)	161.6	(44.4)	117.2
38	**TWh**	52.0	(3.0)	49.0	(1.0)	48.0	1.7	49.7	(1.7)	48.0
39	**Forecast for Major Unforeseen Events**	0.5	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	**Total TWh**	51.5	(2.5)	49.0	(1.0)	48.0	1.7	49.7	(1.7)	48.0