EB-2013-0321

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2014.

SCHOOL ENERGY COALITION CROSS-EXAMINATION COMPENDIUM
(Panel 2 – SBG and HIM)

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SEC Interrogatory #070

Ref: E1-2-1/p.3

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

Interrogatory

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

Response

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SEC Interrogatory #071

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

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

Interrogatory

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

Response

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

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

AMPCO Interrogatory #023

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

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

Interrogatory

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

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

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

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

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

Response

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

b) Estimated monthly production attributable to NTP:

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

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

d) As shown in the table below, the forecast production plans for 2015 and 2016, exclusive of forecast SBG reductions [see item (c) above], were very similar.

1

2014-2016 Business Plan Production Forecast (TWh)

Prescribed Facility	**2015 Plan**	(c)-(a) **Change**	**2016 Plan**
	(a)	(b)	(c)
Previously Regulated Hydroelectric:			
Niagara Plant Group	14.1	0.1	14.2
Saunders GS	6.9	0.0	6.9
Sub total	**21.0**	**0.1**	**21.1**
Newly Regulated Hydroelectric:			
Ottawa-St. Lawrence Plant Group	5.7	0.0	5.7
Central Hydro Plant Group	0.5	0.0	0.5
Northeast Plant Group	2.4	0.1	2.5
Northwest Plant Group	3.8	(0.1)	3.8
Sub total	**12.4**	**0.0**	**12.4**
Regulated Hydroelectric Total	**33.5**	**0.1**	**33.5**

2 Note: Numbers may not add due to rounding.
3

OPG Requested Payment Amounts

		Previously Regulated Hydroelectric Facilities														
		2014					2015					2014-2015 Test Period				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
1	Revenue Requirement ($M)	858.0	860.0	866.6	0.0	866.6	879.5	879.8	891.2	0.0	891.2	1,737.5	1,739.7	1,757.8	0.0	1,757.8
2	Forecast Production (TWh)	19.1	20.1	20.1	0.0	20.1	20.2	21.0	21.0	0.0	21.0	39.3	41.1	41.1	0.0	41.1
3	**Requested Payment Amount ($/MWh)**(line 1 / line 2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**44.23**	**42.31**	**42.75**	**-**	**42.75**

		Newly Regulated Hydroelectric Facilities														
		July 1, 2014 - December 31, 2014					2015					July 1, 2014 - 2015 Test Period				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
4	Revenue Requirement[1] ($M)	275.0	277.6	277.3	0.0	277.3	569.7	575.8	575.9	0.0	575.9	844.7	853.4	853.2	0.0	853.2
5	Forecast Production[2] (TWh)	5.5	5.5	5.5	0.0	5.5	12.5	12.5	12.5	0.0	12.5	17.9	17.9	17.9	0.0	17.9
6	**Requested Payment Amount ($/MWh)**(line 4 / line 5)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**47.10**	**47.59**	**47.57**	**-**	**47.57**

		Nuclear Facilities														
		2014					2015					2014-2015 Test Period				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
7	Revenue Requirement ($M)	3,296.0	3,341.4	3,228.5	0.0	3,228.5	3,252.6	3,307.4	3,166.9	0.0	3,166.9	6,548.6	6,648.8	6,395.4	0.0	6,395.4
8	Forecast Production (TWh)	49.7	49.0	48.5	0.0	48.5	48.0	46.1	46.1	0.0	46.1	97.7	95.1	94.6	0.0	94.6
9	**Requested Payment Amount ($/MWh)**(line 7 / line 8)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**67.03**	**69.91**	**67.60**	**-**	**67.60**

		Total Generating Facilities														
		2014					2015					2014-2015 Test Period				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
10	Revenue Requirement ($M)	4,429.0	4,478.9	4,372.5	0.0	4,372.5	4,701.8	4,763.0	4,633.9	0.0	4,633.9	9,130.8	9,130.8	9,006.4	0.0	9,006.4
11	Forecast Production (TWh)	74.2	74.6	74.1	0.0	74.1	80.7	79.6	79.6	0.0	79.6	154.9	154.9	153.7	0.0	153.7
12	**Requested Payment Amount ($/MWh)**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1 Amount represents 50% of 2014 revenue requirement
2 Newly Regulated Hydroelectric Facilities 18 month (July 2014 - December 2015) test period forcast production

Key Planning Assumptions

Production

- Nuclear production ranges from 44.6 to 49.0 TWh/yr over the 2014-2016 period, reflecting the following changes:
  - Fewer outage days in 2014, with one planned outage at Darlington compared to two in 2013
  - The Darlington Vacuum Building Outage (VBO) in 2015 reduces generation by ~3 TWh
  - In 2016, the Pickering Life Management outage and the first Darlington refurbishment outage reduce production by ~3 TWh and ~2 TWh, respectively
- Previously regulated hydroelectric production increases commencing in 2014 due to an expected return to normal water levels
- Newly regulated hydroelectric production decreases by ~0.8 TWh in 2014 due to higher surplus baseload generation
- Contracted hydroelectric production [redacted]
- [redacted]

	Forecast	Business Plan		
Production - TWh	2013	2014	2015	2016
Nuclear	45.6	49.0	46.1	44.6
Previously Regulated Hydroelectric	18.9	19.5	20.4	20.2
Newly Regulated Hydroelectric	12.5	11.7	11.9	11.9
Contracted Hydroelectric	[redacted]	[redacted]	[redacted]	[redacted]
Thermal	[redacted]	[redacted]	[redacted]	[redacted]
Total OPG Production	[redacted]	[redacted]	[redacted]	[redacted]

Pension and OPEB Costs

- Pension and OPEB costs reflect the impact of a comprehensive accounting valuation as at December 31, 2013, including updates to mortality and post-retirement medical and dental cost assumptions, and benefit plan membership data
- Pension fund investments are assumed to earn 6.25%/yr. A discount rate of 4.7% is used for valuing pension and other post retirement benefit costs over the 2014-2016 period.

Other

- Nuclear Funds investments are assumed to earn 5.15%/yr over the period
- Pickering units are expected to operate until ~2020
- The Darlington refurbishment execution phase (October 2016 to late 2025) reflects un-lapping of the first and second units
- [redacted]
- The Darlington nuclear new build project is not included in the capital plan, following the Province's announcement

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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

Board Staff Interrogatory #061

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

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

Interrogatory

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

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

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

Response

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

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

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

The Niagara Plant Group facilities (Sir Adam Beck and DeCew Falls) are controlled from a single control centre located at Sir Adam Beck I.

2.2 R.H. Saunders Generating Station

R.H. Saunders Generating Station ("R.H. Saunders") is a 16-unit hydroelectric station on the St. Lawrence River at Cornwall, Ontario. R.H. Saunders is connected to the 16-unit St. Lawrence - Franklin D. Roosevelt Generating Station, which is owned and operated by the New York Power Authority ("NYPA"). Together, the two stations span the entire St. Lawrence River. Associated structures include: the powerhouse, dams, headworks, dykes, bridges, and ice booms. Under a Memorandum of Understanding between OPG and NYPA, OPG and NYPA equally share the costs associated with Joint Works at the St. Lawrence facilities (including the Iroquois Control Dam and Long Sault Dam, headworks, dykes, and the Barnhart Island bridge). A map showing these facilities is provided in Attachment 2.

R.H. Saunders is part of the Ottawa St. Lawrence Plant Group, which includes nine other OPG hydroelectric facilities located on the Ottawa and Madawaska Rivers. R.H. Saunders is operated from a control centre within the station.

Chart 2

Newly Regulated Hydroelectric Facilities General Information

Plant Group	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)	Original Unit In-Service Dates
Ottawa-St.Lawrence Plant Group	Arnprior	2	82	1976-1977
	Barrett Chute	4	176	1942-1968
	Calabogie	2	5	1917
	Mountain Chute	2	170	1967
	Stewartville	5	182	1948-1969
	Chats Falls (OPG owns 4 of 8 units)	4	96	1931-1932
	Chenaux	8	144	1950-1951
	Des Joachims	8	429	1950-1951
	Otto Holden	8	243	1952-1953
Central Hydro	Auburn	3	2	1911-1912

Plant Group	Big Chute	1	10	1909-1919 (rebuilt 1993)
	Big Eddy	2	8	1941
	Bingham Chute	2	1	1923-1924
	Coniston	3	5	1905-1915
	Crystal Falls	4	8	1921
	Elliot Chute	1	2	1929
	Eugenia Falls	3	6	1915-1920
	Frankford	4	3	1913
	Hagues Reach	3	4	1925
	Hanna Chute	1	1	1926
	High Falls	3	3	1920
	Lakefield	1	2	1928
	McVittie	2	3	1912
	Merrickville	2	2	1915-1919
	Meyersberg	3	5	1924
	Nipissing	2	2	1909
	Ragged Rapids	2	8	1938
	Ranney Falls	3	10	1922-1926
	Seymour	5	6	1909
	Sidney	4	4	1911
	Sills Island	2	2	1900
	South Falls	3	4	1916-1925
	Stinson	2	6	1925
	Trethewey Falls	1	1.7	1929
Northeast Plant Group	Abitibi Canyon	5	349	1933-1959
	Otter Rapids	4	182	1961-1963
	Lower Notch	2	274	1971
	Matabitchuan	4	10	1910
	Indian Chute	2	3	1923-1924
Northwest Plant Group	Aguasabon	2	51	1948
	Alexander	5	69	1930-1958
	Cameron Falls	7	92	1920-1958
	Caribou Falls	3	91	1958
	Kakabeka Falls	4	25	1906-1914
	Manitou Falls	5	73	1956-1958
	Pine Portage	4	142	1950-1954
	Silver Falls	1	48	1959
	Whitedog Falls	3	68	1958

2.3 Ottawa-St. Lawrence Plant Group

In addition to R. H. Saunders, the Ottawa-St. Lawrence Plant Group ("OSPG") includes four generating stations on the Ottawa River (Otto Holden, Des Joachims, Chenaux, and Chats

SEC Interrogatory #069

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

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

Interrogatory

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

Response

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

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

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

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

OPG can confirm that Mr. Hamal's analysis was completed prior to the end of 2013 and has not been updated with 2013 actuals.