Board Staff Interrogatory #042

Ref: Ex. F1-T1-S1, pages 18-22

Issue Number: 6.2
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's regulated hydroelectric facilities reasonable?

Interrogatory

The results of the Navigant Consulting OM&A unit energy cost benchmarking are summarized in Chart 4 on page 18. The application provides several reasons why the unit cost for SAB PGS is much higher than the other hydroelectric facilities. For example, the application notes on page 22 *"In addition to its role in pumping water for use during peak periods (which is typical for PGS's), Sir Adam Beck PGS is used to: 1) control the cross-over elevation of the Sir Adam Beck canals, 2) assist in automatic generation control, and 3) provide for flexibility and optimization of operations at the Sir Adam Beck complex."* However, between 2006 and 2008, the unit cost almost doubled (increased from 47.1 to 81.2 cents/kWh) and is consistently in the 4th quartile (ranging from 22.1 to 81.1 cents) amongst the other PGS comparators. Board staff considered that the rising unit cost may be due to addressing the issue of increased SBG but staff understands from the May 2009 IESO 18-month Outlook report that SBG events became a prominent issue following the benchmarking period, in early 2009.

a) Please explain why the unit cost almost doubled between 2006 and 2008.
b) The application appears to suggest that none of the other 15 PGS comparators in the Navigant results provide functions beyond pumping water for use during peak periods, with references to the SAB PGS being "unique". For example, do none of the other PGS units provide other functions such as Automatic Generation Control?
c) Is OPG able to provide a listing of those 15 PGS comparators (with or without their respective unit costs)? If so, please provide the list.
d) On page 16 it notes that, since March 2009, the "*operational performance has been excellent*" in relation to SAB PGS. What has the unit cost been since March 2009?

Response

a) The Sir Adam Beck Pump Generating Station ("SAB PGS") unit energy costs increased by 72 per cent between 2006 and 2008, rising from $47.1/MWh to $81.2/MWh.

The primary reason for this significant increase was the unusually large volume of maintenance and repair work required in 2008 relative to 2006. There was more than twice the number of outage days in 2008 as compared to 2006. The majority of these outage days were for troubleshooting and base maintenance related to the SAB PGS-6 runner failure. The increased staff required to support these outages and the materials

and equipment required to carry out temporary repairs resulted in the significant cost increases.

The SAB PGS unit energy costs were also negatively affected by changes in exchange rates. Navigant Consulting applies exchange rates to OPG's Canadian dollar costs. From 2006 – 2008, the Canadian dollar appreciated by approximately 10.3 per cent versus the U.S. dollar.

In general terms (i.e., not necessarily with respect to 2006 versus 2008), the SAB PGS costs are high compared to other pump-generating plants for the following reasons:

- With a capacity of 174 MW and a head of only 24.4 metres, SAB PGS is the smallest of all 15 peer group plants. The average plant size and head, excluding SAB PGS, is 942 MW and 243 metres, respectively. As such, the SAB PGS does not have the economies of scale associated with these comparators. SAB PGS is included in the benchmarking with these larger plants because there is not enough similarly-sized pump-generating plant data to form a more representative peer group.

- SAB PGS has an inherently low generation-to-pump cycle efficiency of about 50 per cent, as further detailed in the next bullet. Some peer group plants operate as high as 70 - 80 per cent cycle efficiency. The higher efficiencies of the peer group increase their generation output, thus lowering their unit energy costs.

- While SAB PGS is primarily used for peaking generation, it also supports the control of the water supply to the Sir Adam Beck complex (diversion control), and provides: voltage support (reactive power), operating reserve, and Automatic Generation Control ("AGC"). Diversion control is accomplished through the SAB PGS by either generating or pumping in order to maintain the crossover elevation upstream of the Sir Adam Beck I and II Generating Station forebays. Maintaining the crossover elevation is critical to controlling and optimizing the diversion of water to these stations. The units at the SAB PGS can be required to make several quick changes in input/output flow per minute in order to maintain the correct crossover elevation. This type of constantly changing operation means that the SAB PGS units are very seldom operated at or near efficiency. The provision of ancillary services (i.e., operating reserve and AGC), while valuable to the power system, reduces the energy generated and increases the unit energy cost for this station.

b) OPG does not have specific information from Navigant Consulting detailing the provision of ancillary services by the peer group plants. However, from discussions with other pump-generation station owners, OPG is aware of no other plant in North America that is subject to the frequency and depth of manoeuvring that is experienced at SAB PGS. For example, Raccoon Mountain (Tennessee Valley Authority) is a 1,650 MW plant that provides very limited AGC and no reactive support service. Carters (Army Corps of Engineers) is a 591 MW plant which does not provide AGC or reactive support service.

c) The pumped-generating station comparators that were included in the 2009 (2008 data) Navigant Benchmarking study are listed in Table 1. Unit energy costs for SAB PGS and the 14 peer group plants selected by Navigant are shown in Table 2. Due to legal and confidentiality requirements, the information is presented in a coded format. Study participants are required to avoid linking the unit energy costs with the specific stations. Furthermore, it should be noted that most of the cost and energy information for the other stations in the study date back to prior years and have been adjusted and escalated to 2008 dollars. Therefore, they may no longer reflect their most current unit energy costs.

Table 1:
Pump-Generating Stations in 2009 Navigant Benchmarking

Company	Station Group Name
California Dept. of Water Resources	Gianelli GS
Exelon Power	Muddy Run
Guangzhou Pumped Storage Power Station	Guangzhou Pumped Storage
Iberdrola	La Muela
Iberdrola	Villarino
Los Angeles Dept. of Water & Power	Castaio Pump
New York Power Authority	Blenheim-Gilboa
New York Power Authority	Lewiston
Ontario Power Generation	Sir Adam Beck PGS
Scottish Power	Cruachan
Southern California Edison	Big Creek Pumped Storage
Tennessee Valley Authority	Raccoon Mountain
U.S. Army Corps of Engineers (ASE – Mobile)	Carters
U.S. Bureau of Reclamation	Grand Coulee (Pump Storage)
Virginia Power	Bath City

Table 2:
Pump-Generating Station Data in Navigant Benchmaking

Plant Code	Data (Year)	Plant Size (MW)	Head (m)	OM&A Cost (2008 USD/MWh)
04UF	2004	2,400	535.0	5.3
95DP	1995	2,100	330.0	5.0
08QV	2008	1,653	317.0	3.7
96SI	1996	1,272	304.8	14.0
01RE	2001	550	105.2	14.3
08PE	2008	1,072	137.0	6.1
02MB	2002	1,040	334.9	19.2
93ZD	1993	810	N/A	8.0
93OY	1993	621	N/A	14.7
93GI	1993	420	N/A	18.4
04SZ	2004	402	88.4	26.6
02DK	2002	336	22.9	26.3
08OA	2008	314	105.5	39.4
94KE	1994	207	396.0	4.5
SAB PGS	2008	174	24.4	81.1

d) The statement in the evidence on page 16 (lines 14-15) was made with reference to SAB PGS Unit 6's environmental and operational performance since it returned to service in March 2009. OPG does not track unit energy costs for individual hydroelectric units and thus cannot provide costs specific to Unit 6.

Board Staff Interrogatory #043

Ref: Ex. F1-T1-S1, page 16, and Attachment 1, pages 10 and 34

Issue Number: 6.2
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's regulated hydroelectric facilities reasonable?

Interrogatory

As noted in the application and referenced in the interrogatory above, the Navigant benchmarking results show the unit cost of the SAB PGS almost doubled and the SAB PGS provides many important functions in the Ontario electricity market. The summary report prepared by Elenchus, in relation to OPG's stakeholder consultation meetings (in November 2007) prior to the previous payments application, notes that the SAB PGS is over half a century old and is relatively inefficient, with about a 50% efficiency loss when water is pumped (i.e., for each MWh used to pump water, 0.5 MWh is generated) and that efficiency loss is attributable to the age of the equipment. The application also notes on page 16 that the unit had to be *"dismantled and shipped to the manufacturer's facility in Montreal"* and the repairs *"took over ten months"*. In Attachment 1 (p. 34), which is page 13 of the Business Plan, it further identifies *"• SAB PGS Unit rehabilitation on G2-5 planned for 2011-2014. PGS Unit transformers also scheduled for replacement 2009-11. Unit breakers and governors planned for replacement 2011-13."* Attachment 1 (p.10) further notes OPG has conducted a *"preliminary review of expansion of the existing Sir Adam Beck PGS reservoir".*

a) Given all of the above, please explain if OPG has investigated a full replacement of the PGS equipment. If not, please explain why. If so, what is the estimated cost of a full replacement?

b) Please identify the total estimated cost of all of the recent and planned material investments in relation to the SAB PGS (i.e., dismantling and shipping to the manufacturer's facility, rehabilitation, transformer replacements, breaker and governor replacements, etc.).

c) What efficiency improvement could likely be achieved with state-of-the-art equipment?

d) Please also elaborate on the results of the preliminary review of SAB PGS expansion.

Response

a) At this time, OPG has not performed a complete investigation nor prepared a detailed cost estimate for replacing the six units at Sir Adam Beck Pump Generating Station ("SAB PGS"). OPG has initiated a Plant Condition Assessment ("PCA") study for the

PGS. The PCA study is expected to be completed by December 2010. The PCA study will be followed by a Life Cycle Plan to be completed by December 2011. Estimates for the replacement of PGS equipment will be developed as part of the Life Cycle Plan study.

b) PGS investments (i.e. capital and OM&A projects) over the 2010 - 2014 approved business planning ("BP") period total $31.4 M. The major projects are:
- PGS Unit overhauls (OM&A: $9.1 M of $15.0 M total quoted in F1-3-1 Table 1 is within the BP period)
- Transformer Replacements (Capital: $6.9 M of $7.2 M Total quoted in D1-1-2 Table 2 is within the BP period)
- 13.8kV Breaker Replacement (Capital: $5.9 M as quoted in D1-1-2 Table 2 is in the BP period)
- Governor Replacements (Capital: $5.6 M as quoted in D1-1-2 Table 2 is in the BP period)
- The balance of $3.9 M is composed of small projects under $5 M.

c) OPG estimates that it would likely be able to achieve up to a 5 per cent increase in cycle efficiency (combining both pumping and generation operation efficiencies) with state of the art pumping and generating equipment at SAB PGS. As explained in L-01-042, the unique operating circumstances of the SAB PGS limit the opportunities for efficiency improvements generally and, in particular, would make it very difficult to justify the installation of new pump-turbines.

d) The preliminary review referenced in the Business Plan Presentation considered the following options: expanding the footprint of the reservoir, deepening the reservoir, and increasing the dyke elevation. While the reservoir volume increases under the individual options can be as high as 27 per cent, a combination of options could result in volume increases of over 40 per cent.

VECC Interrogatory #010

Ref: Ex. F1-T1-S1, page 5

Issue Number: 6.2
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Interrogatory

a) Please provide a simple worked example to show how the EFOR index is calculated.

b) Please confirm that the accident severity rate is defined as the number of days lost by employees injured on the job per 200,000 hours worked.

Response

a) The Equivalent Forced Outage Rate ("EFOR") shows the rate (in per cent) that a unit is not available due to forced events. Forced events are unplanned events that require a unit to be removed from service, in whole or in part.

A simple worked example is provided below for a generator which during a given year spent the following amounts of time in the following states:

- Service Hours (Operating) – 5,000 hrs
- Reserve Shutdown (Available but not Operating) – 1,760 hrs
- Forced outages – 250 hrs
- Planned or Maintenance outages – 1,750 hrs
- (The total hours per year is 8,760)

If there are no deratings (see discussion below), the EFOR for the above example would be equal to 250 divided by the sum of 250 and 5,000 which is 4.76 per cent.

A derating is when a unit is only partially available: for example, a 100 MW unit that can only generate 80 MW of power. In such a case, additional forced derate time is added to the equivalent forced outage time. For this example, a 5 day derating on an operating unit would count as one equivalent outage day (i.e., 5 days times 20 per cent derating). This equivalent outage day (24 hours) would be added to the forced outage hours (in the numerator) in the simple example above.

A derating can also occur during Reserve Shutdown hours. In the case of a derating during reserve shutdown, the 100 MW unit derated to 80 MW for five days while available but not operating would have the equivalent 24 outage hours added to both the forced outage hours (in the numerator) and the service hours (in the denominator) in the above simple example of EFOR.

Witness Panel: Hydroelectric

The EFOR calculation methodology is defined in the Generating Availability Data System Reporting Instructions issued by the North American Reliability Council ("NERC").

b) Confirmed.

VECC Interrogatory #011

Ref: Ex. F1-T1-S1, pages 5, 10, and 11

Issue Number: 6.2
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Interrogatory

Please provide specific details regarding the construction of the environmental performance index.

Response

The Environmental Performance Index ("EPI") is described in Ex. F1-T1-S1, pages 5, 10, and 11. The EPI is normally produced annually at the plant group level. The components of the EPI target are shown in the sample calculation below, which is representative of the components in an actual index.

2010 Environmental Performance Index (EPI) – Sample Calculation

Category	Performance Measure	Threshold (0.5)	Target (1.0)	Max. (1.5)	Weighting (%)	Actual	Score
Spills	Category A Spill	0	0	0	Meet	0	Meet
	Category B Spill	0	0	0	Meet	0	Meet
	Category C Spill	2	1	0	25%	1	25%
Regulatory Compliance	Major Regulatory Infractions	0	0	0	Meet	0	Meet
	Moderate Regulatory Infractions	2	1	0	35%	0	53%
Internal Energy Efficiency (IEE)	Energy Efficiency Projects Completed	1 runner upgrade	1 runner upgrade; 1 transformer replacement	2 runner upgrades; 1 transformer replacement	40%	1 runner upgrade	20%
TOTAL					**100%**		**98%**

VECC Interrogatory #012

Ref: Ex. F1-T1-S1, pages 6 and 7, and Chart 1

Issue Number: 6.2

Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Interrogatory

Regarding the EFOR targets and actual as shown on Chart 1, please provide the comparable CEA and EUCG average and median results for 2007, 2008, and 2009. Also, please explain how the targets for future years are set.

Response

The comparable results are presented in the tables below. The 2009 data from Canadian Electrical Association ("CEA") and Electric Utility Cost Group ("EUCG") is not currently available.

Table 1
Average Equivalent Forced Outage Rate (%)

Name of Station/Grouping	2007	2008	2009
CEA Excluding OPG	3.25	N/A	N/A
EUCG Excluding OPG	5.77	6.17	N/A
OPG	1.80	1.50	1.00

Table 2
Median Equivalent Forced Outage Rate (%)

Name of Station/Grouping	2007	2008	2009
CEA Excluding OPG	Not Available (CEA may make it available in 2011)		
EUCG Excluding OPG (median by plant, ~210 plants)	0.61	0.85	N/A
OPG (median by unit, 5 regulated plants = 49 units)[1]	0.03	0.02	0.01

[1] The sample of OPG five regulated plants is statistically insufficiently representative to calculate the median by plant.

Witness Panel: Hydroelectric

In general, Equivalent Forced Outage Rate ("EFOR") targets are set based on plant historical performance. An average EFOR is calculated for the last ten years after rejecting the two most extreme numbers (i.e., minimum and maximum years) leaving eight data points. Continuous improvement or other factors may be added to the targets subject to the discretion of the Executive Management Team. However, since recent EFOR targets have been at historical lows, they have received little or no adjustment.