AMPCO Interrogatory #177

Interrogatory

Reference: Ex G2 T1 S1 Table 1

a) Please provide the forecast amounts for the years 2016 to 2019.

b) Please explain the increase in Heavy Water Sales & Processing in 2017.

c) Please explain the decrease in Isotope Sales (Cobalt 60 + Tritium) in 2017.

Response

a) Please see Ex. G2-1-2, Table 1a. The 2016 to 2019 forecast amounts are reflected in the 2016 Budget and 2017 to 2019 OEB-approved columns.

b) Actual nuclear non-energy revenues for heavy water sales and processing for 2017 were $43.1M compared to 2016 actual revenues of $18.9M, an increase of $24.2M. This increase was primarily due to strong operational performance of the Tritium Removal Facility ("TRF") in 2017 increasing heavy water processing revenues, whereas revenues from heavy water processing in 2016 was significantly lower due to the extension of the TRF outage from 2015. Offsetting the increased heavy water processing was a reduction in heavy water sales in 2017 versus 2016 (Ex. G2-1-2, p. 5).

c) Actual nuclear non-energy revenues for isotope sales for 2017 were $2.0M compared to 2016 actual revenues of $14.0M, a decrease of $12.0M. The reduced isotope revenue was due to there being no harvesting of Cobalt-60 at Pickering in 2017 as outage schedules were shifted over 2016 to 2018 (Ex. G2-1-2, p. 5).

CCC Interrogatory #52

Interrogatory

Reference: Exhibit G2/T1/S1/pp. 1-3

OPG currently produces Cobalt -16 at Pickering (Units 6,7 and 8) for use in the sterilization of surgical and medical supplies. How are the revenue forecasts derived and how are they treated in the IR plan? Why has the forecast been redacted? What relief is OPG seeking through this Application regarding the production of Cobalt-60 at Darlington? Please explain why Total Non-Energy Revenues are so much higher in 2024 and 2026 relative to 2022?

Response

As in prior OPG payment amounts proceedings, Pickering Cobalt-60 revenue forecasts are based on estimated volumes associated with the timing of each harvest and also reflect the price at which OPG sells Cobalt-60 to Nordion (Canada) Inc. ("Nordion") under a long-term agreement. Forecasted non-energy revenue from Cobalt-60 production at Pickering is included as an offset in the calculation of OPG's revenue requirement (Ex. G2-1-1, p. 1).

The forecast has been redacted as it contains commercially sensitive information. The confidential treatment of this type of information was granted by the OEB in previous OPG payment amounts applications and has been granted in this application on the same basis.

OPG is not seeking any relief in this Application regarding the production of Cobalt-60 at Darlington. As discussed at Ex. G2-2-1, Section 3.1.1.1, while OPG is moving forward with the opportunity to produce Cobalt-60 at Darlington, subject to CNSC approval, the first harvest and associated revenues and related operating costs will not occur until after the end of the IR Term. No revenue, operating costs or capital in-service amounts for Cobalt-60 production at Darlington are included in the proposed revenue requirements in this Application.

Total non-energy revenues are higher in 2024 relative to 2022 primarily due to increased heavy water processing in 2024 as a result of an expected increase in tritium removal facility ("TRF") availability compared to 2022, plus one unit at Pickering is expected to harvest Cobalt-60 in 2024, compared to none in 2022, resulting in increased Cobalt-60 sales.

Total non-energy revenues are higher in 2026 relative to 2022 primarily due to increased heavy water processing and Cobalt-60 sales. Increased heavy water processing in 2026 is due to an expected increase in TRF availability. Cobalt-60 will be harvested in 2026 following the planned shutdown of Pickering at the end of 2025 (Ex. G2-1-2, p. 2).

CCC Interrogatory #53

Interrogatory

Reference: Exhibit G2/T1/S1/pp. 1-3

With respect to Heavy Water sales please provide the forecast and actual amounts for the period 2017-2021.

Response

Chart 1 provides the forecast and actual amounts for non-tritiated heavy water sales in 2017 to 2021.

Chart 1: Heavy Water Sales 2017-2021 (at 100% Prior to Revenue Sharing)

$M	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
OEB-Approved[1]	[redacted]					
Actual [2]	[redacted]					

[1] Includes adjustments for heavy water sales per partial settlement as described in EB-2016-0152 Decision, Ex. O, p. 11.
[2] Amount shown for 2021 is 2021 Budget.

Energy Probe Interrogatory #65

Interrogatory

References:
Exhibit G2, Tab 1 Schedule 1 Table 1; Exhibit G2 Tab 1 Schedule 2 Tables 1&2

a) Why are Other Revenues Nuclear increasing in the 2021-2026 period?

b) Is there an increase in volume of Heavy Water and Isotope sales, or are the prices forecast to increase? If the latter. what does OPG do to mitigate market risks and support its Other Revenue forecast?

Response

a) While nuclear non-energy revenues are forecasted to increase from 2021 to 2026, they fluctuate over the IR term, mainly based on the forecasted timing of Cobalt-60 harvesting at Pickering, which is constrained by operational outages, and based on the impact of tritium removal facility's ("TRF") production schedule on heavy water processing (Ex. G2-1-1, p. 1). The main driver for the overall increase in nuclear non-energy revenues is the increase in forecast heavy water processing revenue due to the availability of additional volumes and a higher unit price from the provision of detritiation services to Bruce Power (Ex. G2-1-1, p. 4).

b) As noted above, there is an expected increase in heavy water processing volume during the IR term. Sales volumes for Cobalt-60 are dependent on the Cobalt-60 harvesting schedule. No sales of non-tritiated heavy water are expected over the IR term (Ex. G2-1-1, p. 4). The volume of tritium sales is expected to be stable over the IR term.

Long-term contracts help mitigate market risks associated with nuclear non-energy revenues. The majority of each type of revenue is supported by long-term contracts with a single customer.

SEC Interrogatory #153

Interrogatory

Reference: G2-1-2-1a

Please update Table 1a to include 2020 actuals.

Response

See Attachment 1.

Numbers may not add due to rounding.

Table 1a
Comparison of Other Revenues - Nuclear ($M) 2016-2021

Line No.	Business Unit	2016 Budget	(c)-(a) Change	2016 Actual	(g)-(c) Change	2017 OEB Approved	(g)-(e) Change	2017 Actual	(k)-(g) Change	2018 OEB Approved	(k)-(i) Change	2018 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Non-energy Revenues:											
1	**Heavy Water Sales & Processing**[1]	18.0	0.9	18.9	24.2	31.5	11.6	43.1	(11.7)	17.4	14.0	31.4
2	**Isotope Sales (Cobalt 60 + Tritium)**	12.6	1.4	14.0	(12.0)	12.6	(10.6)	2.0	14.1	12.6	3.5	16.1
3	**Total Non-energy Revenues** (line 1 + line 2)	30.6	2.3	32.9	12.2	44.1	1.0	45.1	2.4	30.0	17.5	47.5
4	**Non-energy Direct Costs**	8.3	(1.8)	6.5	(1.0)	8.1	(2.6)	5.5	0.6	8.6	(2.5)	6.1
5	**Non-energy Contribution Margin** (line 3 - line 4)	22.3	4.1	26.4	13.2	36.0	3.6	39.6	1.8	21.4	20.0	41.4
6	**Ancillary Services**	1.8	(0.6)	1.2	(0.2)	1.8	(0.8)	1.0	0.6	1.8	(0.2)	1.6
7	**Total** (line 5 + line 6)	24.1	3.5	27.6	13.0	37.8	2.8	40.6	2.4	23.3	19.8	43.0

Line No.	Business Unit	2018 Actual	(e)-(a) Change	2019 OEB Approved	(e)-(c) Change	2019 Actual	(i)-(e) Change	2020 OEB Approved	(i)-(g) Change	2020 Actual	(k)-(i) Change	2021 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Non-energy Revenues:											
8	**Heavy Water Sales & Processing**[1]	31.4	(21.7)	16.6	(6.9)	9.7	27.9	16.7	20.9	37.6	[redacted]	[redacted]
9	**Isotope Sales (Cobalt 60 + Tritium)**	16.1	(6.7)	13.6	(4.2)	9.4	(4.4)	13.6	(8.6)	5.0	[redacted]	[redacted]
10	**Total Non-energy Revenues** (line 8 + line 9)	47.5	(28.4)	30.2	(11.1)	19.1	23.5	30.3	12.3	42.6	(4.8)	37.8
11	**Non-energy Direct Costs**	6.1	0.0	7.9	(1.8)	6.1	1.0	8.5	(1.4)	7.1	1.2	8.3
12	**Non-energy Contribution Margin** (line 10 - line 11)	41.4	(28.4)	22.3	(9.3)	13.0	22.5	21.8	13.7	35.5	(6.0)	29.5
13	**Ancillary Services**	1.6	4.2	1.9	3.9	5.8	0.9	1.9	4.8	6.7	(1.8)	4.9
14	**Total** (line 12 + line 13)	43.0	(24.2)	24.2	(5.4)	18.8	23.4	23.8	18.4	42.2	(7.8)	34.4

Notes:

1 EB-2016-0152 heavy water sales reflect adjustments of $6.1M in 2017; $1.3M in 2018; $1.5M in 2019; $1.6M in 2020 and $1.7M in 2021 per partial settlement as described in EB-2016-0152 Decision Exhibit O page 11 of 17. The 2016-2020 Actuals are total amounts unadjusted for sharing.

VECC Interrogatory #36

Interrogatory

Reference:
Exhibit G2-01-01, Table 1, G2-01-02, Table 2a

a) Please confirm that 2019 actuals are meant to be redacted.
b) During the 2017-2021 period, other than for the year 2019, OPG has underestimated Other Revenues. Please explain what changes the Utility has made to its forecasting methodologies to more accurately estimate other revenues?

Response

a) The 2019 actual non-energy revenues were not meant to be redacted. See Ex. L-A1-02-Staff-002 for unredacted 2019 and 2020 actual non-energy revenues.

b) OPG provided an appropriate forecast of nuclear other revenues in EB-2016-0152, in line with the underpinning business plan. Actual non-energy revenues were higher than OEB-approved amounts in 2017, 2018 and 2020, were less in 2019, and are forecast to be higher in 2021. Detailed explanations of variances can be found at Ex. G2-1-2.

   The main area of increased revenues compared to OEB-approved amounts was heavy water sales and processing. Heavy water sales are estimated to be zero in the future as the sales pool has zero inventory of non-tritiated heavy water available for sale (Ex. G2-1-1), and therefore no forecasting methodology change is necessary nor applicable.

   OPG has not changed its forecasting methodology for heavy water processing for the IR term as it continues to reflect the best available information at the time that the forecast is set. Actual heavy water processing revenues are mainly impacted by the timing of the tritium removal facility's ("TRF") production schedule, which may change over the five-year IR term after the plan has been finalized based on operational factors and outage requirements (Ex. G2-1-1, p. 1). For example, TRF availability resulted in lower heavy water processing revenue in 2018 and 2019 compared to OEB-approved amounts (Ex. G2-1-2, p. 4), followed by increased heavy water processing revenue in 2020 compared to OEB-approved (as noted at Ex. L-A1-02-Staff-002).

Energy Probe Interrogatory #66

Interrogatory

References:
Exhibit G2, Tab 2, Schedule 1, Page 2, and Table 1, and Table 2

Preamble: "Sections 6(2)9 and 6(2)10 of the O. Reg. 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations, and that any revenues earned from the Bruce Lease in excess of costs be used to offset the nuclear payment amounts."

a) Please discuss why Bruce Lease Net revenues are significantly reduced in 2022?

b) Why is the Bruce Lease a losing financial proposition for OPG and ratepayers?

c) Please provide a schedule showing the total increase in Net Costs and the Total Loss projected for 2020-2026.

d) If costs continue to increase, why should not the Lease Amount be increased to a break-even proposition?

e) Provide all relevant factors resulting in the Lease losses: legislative, lease terms, and other factors driving the loss and preventing an increase in the Lease amount.

Response

a) The primary driver of the reduction in Bruce Lease net revenues between 2021 and 2022 is a decrease in low and intermediate level waste services revenue received from Bruce Power in return for managing said waste materials. As noted at Ex. G2-2-1, Section 3.5, OPG projects revenues under the L&ILW Agreement based on waste volume projections received from Bruce Power, which drives variability in forecasted levels of revenue. Additionally, as noted at that evidence, the revenue forecast for 2021 includes incremental revenue under a Supplemental Waste Agreement related to the Bruce Unit 6 Major Component Replacement and is therefore higher than in other years.

b) OPG applies Bruce Lease net revenues to the revenue requirement for OPG's prescribed nuclear assets in accordance with sections 6(9) and 6(10) of O. Reg. 53/05. To the extent the Bruce Lease net revenues are positive, applying them against the nuclear revenue requirement reduces it. If the Bruce Lease net revenues are negative, their application to the nuclear revenue requirement serves to increase it. This treatment was indicated in the OEB's EB-2007-0905 Decision with Reasons:

> When OPG earns a profit (measured in accordance with GAAP) on its Bruce activities, the Board's approach calls for all of that profit to be used to reduce the payment amounts for Pickering and Darlington. […] If OPG were to incur a loss on its Bruce activities, which could happen if there are significant increases in the Bruce nuclear liabilities in the future, that loss would increase the payment amounts for the prescribed assets under the Board's approach. (p. 111)

As noted at Ex. G2-2-1, p. 6, the fluctuations in revenues from the Bruce Lease over the period are driven primarily by variability in low and intermediate level waste volumes and fuel bundles being discharged from the Bruce reactors, including impacts arising from the refurbishment of these units. These revenues are determined in accordance with the terms of the Bruce lease and associated agreements. The cost levels are primarily driven by the application of financial accounting requirements to calculate component expenses associated with OPG's nuclear liabilities related to the Bruce facilities (as described in Ex. C2-1-1), including changes to these liabilities recorded over time. Together, these factors result in the forecast amount of Bruce Lease net revenues applied to the nuclear revenue requirements in this application.

c) Refer to Attachment 1, which is presented in the form of Ex. G2-2-1, Table 1, as updated for 2020 actual results, with columns added to provide total values over the 2020-2026 period and the change in the values as between 2020 and 2026.

d) and e)

Refer to part b). OPG declines to provide the further requested information on the basis of relevance. Further details of the Bruce Lease agreement are not relevant to the issues in this application for reasons set out in the OEB's decision in EB-2007-0905 (Decision with Reasons, pp. 99-106) where the OEB held, among other things, that the Bruce Lease is an unregulated commercial contract and that "[t]he Board has no authority to set or review the terms of the lease between OPG and Bruce Power." (p. 99).

Numbers may not add due to rounding.

Table 1
Bruce Lease Net Revenues ($M)

Line No.	Item	2020 Actual	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan	Total (2020-2026)	Change From 2020 to 2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (a) to (g)	(i) = (g) - (a)
	Bruce Lease Net Revenues:									
1	**Bruce Lease Revenues**	218.2	212.1	185.7	217.6	203.7	218.4	221.0	1,476.8	2.8
2	**Bruce Costs**	230.1	233.2	231.3	256.3	251.9	264.9	259.3	1,727.0	29.2
3	**Bruce Lease Net Revenues** (line 1 - line 2)	(11.9)	(21.1)	(45.6)	(38.7)	(48.1)	(46.5)	(38.3)	(250.2)	(26.4)

OAPPA Interrogatory #9

Interrogatory

Reference:
Exhibit G2-2-1, Table 1 provides that net revenues from the Bruce Power Lease are forecast to be negative for the duration of the IR (2022-2026), for a total gross loss of $217 million which is expected to be reclaimed from Ontario's ratepayers. OAPPA understood from EB-2016-0152 that the principal reason for this loss was precipitated by the extension of the December 2015 amendment to the Bruce Power Lease Agreement, extending the term to 2061 and to consequently increasing the Accretion expense. It was also understood that the 2015 Amendment removed OPG's material obligations specific to OPG payment obligations specific to HOEP settlements.

a) Please provide an annual estimate of the avoided HOEP to contract rate settlement payments that would have occurred during the IR had the pre-2015 obligation persisted.
b) Please provide a detailed explanation as to how the annual Accretion expenses are determined during the IR period.

Response

a) Prior to the amendment effective December 4, 2015, the Bruce Lease Agreement contained a requirement for OPG to provide Bruce Power with a partial supplemental rent rebate for the Bruce units that were not subject to the Bruce Power Refurbishment Implementation Agreement, dependent on the Hourly Ontario Energy Price ("HOEP"). Specifically, the rebate was triggered in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") fell below $30/MWh and at the time applied to the Bruce B units. This provision was eliminated as part of the December 2015 amendment to the Bruce Lease Agreement.

   While OPG has not maintained updated calculations of the specific rebate amount had the Bruce Lease Agreement not been amended, based on information last developed in 2015 and the actual HOEP levels experienced since then, OPG is able to estimate that the rebate for the Bruce B units would have been triggered in each year after 2015, at an average value in the order of $90M per year.

b) As discussed in Ex. C2-1-1, p. 5, line 22 to p. 6, line 24, accretion expense represents the unwinding of the discounting of the nuclear liabilities (referred to as asset retirement obligation or "ARO"), which are determined in present value terms in accordance with US GAAP. As discussed at that evidence, the initial value and each subsequent adjustment to the ARO is calculated using a discount rate determined at the time each such tranche is recorded. In accordance with US GAAP, the discount rate is determined using a credit-adjusted risk free rate (Ex. L-C2-01-Staff-075). The unwinding of the discounting through the accretion expense is calculated on the basis of the underlying discount rates and tranche balances. The ARO is not revalued for changes in the discount rate subsequent to the recording of each tranche.

OAPPA Interrogatory #10

Interrogatory

Reference:
Exhibit G2-2-1, Table 4 reflects a Net Book Value (NBV) for the Bruce Nuclear Facility at the start of the IR period of $2.7527B and a closing NBV of $2.3351B by the end of the IR period, as affected by an annual depreciation expense of ~$69.6M. However, we know that Bruce G6 has started its refurbishment program and will be returned to service in 2023, and there does not appear to be any apparent change in the asset value in 2023 or in the later years of the IR.

a) How is Bruce Power's investment of an estimated $13B being captured in the NBV calculation, depreciation, and associated expenses?
b) If it is not being captured, how is such fundamental change in the investment value of an OPG-owned asset being accounted for?

Response

a) and b)

Bruce Power's investment in the refurbishment of the Bruce facilities is not captured in OPG's net book value for these stations as the costs of the investment are not being borne by OPG. In accordance with US generally accepted accounting principles, OPG's financial statements account for all fixed assets, including the Bruce facilities, at the company's cost (including any asset retirement costs) and report them net of accumulated depreciation.

Board Staff Interrogatory #318

Interrogatory

Reference:
Exhibit G2 / Tab 2 / Schedule 1 / pp. 1, 3

Preamble:

OPG stated that Bruce Power has options to renew the lease to December 31, 2064. OPG's Custom IR term forecasts assume that Bruce Power will exercise its options to renew the lease.

Question(s):

a) Please advise when the Bruce Lease is set to expire.

b) Please advise whether there are any expected changes to the Bruce Lease at the time of the renewal that may impact the Bruce Lease net revenues incorporated as part of OPG's proposed 2022-2026 revenue requirements.

c) Please further explain why the full amount of base rent is considered an executory cost (effective 2019).

d) Please provide the calculation supporting the Bruce Lease base rent revenues for 2022-2026.

Response

a) As noted at Ex. G2-2-1, p. 1, Bruce Power has options to renew the Bruce lease to December 31, 2064. At this time, OPG has received notice from Bruce Power to extend the lease to December 31, 2023. There are 20 subsequent renewal periods available to Bruce Power under the agreement, all but the final one being for 2 years each and the final renewal period being for 3 years. OPG's IR term forecasts assume that Bruce Power will continue to exercise its options to renew the lease.

b) OPG does not expect any changes to the Bruce lease agreement at renewal during the 2022-2026 period that may impact on the Bruce Lease net revenues incorporated into the proposed 2022-2026 revenue requirements.

c) As part of the process to amend the Bruce lease agreement effective in 2015, Bruce Power and OPG explicitly acknowledged that the base rent payments are intended to cover OPG's executory costs such as property tax for the Bruce site.[1] The acknowledgement was made by the parties during the negotiation process but was not formally identified in the text of the amended lease agreement.[2] On this basis, the full amount of base rent payments starting in 2019 is considered to be an executory cost under US GAAP.

d) The requested calculation is shown below.

Chart 1

	Straight line amortization of base rent received from 2016 to 2018 ($M)[3]	**Straight line amortization of base rent received as at Dec 2015 ($M)**[3]	**Executory cost recovery ($M)**	**Total base rent revenue ($M)**
	[A]	*[B]*	*[C]*	*=[A]+[B]+[C]*
Deferred Revenue Balance at Dec 2015		*$222.1M*[4]		
2016-2018 Base Rent Excl. Executory Costs	*$223.9M*[5]			
2022	**4.6**	**4.5**	**17.0**	**26.1**
2023	**4.6**	**4.5**	**17.3**	**26.4**
2024	**4.6**	**4.5**	**17.7**	**26.8**
2025	**4.6**	**4.5**	**18.0**	**27.1**
2026	**4.6**	**4.5**	**18.4**	**27.5**

[1] See also EB-2016-0152, Ex. G2-2-1, p. 4, lines 11-22 and p. 7, lines 19-24.
[2] See also EB-2016-0152, Ex. L-7.2-1 Staff-216.
[3] Deferred revenue balances shown are amortized on a straight-line basis over remaining expected lease term for accounting purposes to end of 2064.
[4] As shown at EB-2013-0321 Ex. L-1.3-17 SEC-019, Att. 2, last column.
[5] As also noted in EB-2016-0152, Ex. G2-2-1, Table 2, Note 3, calculated as *[D] - [E]*, where:
[D] = sum of 2016-2018 base rent payments of $270.0M (i.e. $88.0M + $90.0M + $92.0M)
[E] = sum of executory costs within 2016-2018 base rent payments of $46.2M (i.e. $15.1M + $15.4M + $15.7M), where the annual amounts were determined by de-escalating, at an assumed CPI rate of 2.0%, the 2019 base rent payment.

Board Staff Interrogatory #319

Interrogatory

Reference:
Exhibit G2 / Tab 2 / Schedule 1 / Tables 1, 5
Exhibit F4 / Tab 2 / Schedule 1 / Table 3c

Preamble:

OEB staff notes that OPG included deferred tax (Line 10 at Exhibit G2 / Tab 2 / Schedule 1 / Table 5) in the computation of Bruce costs for the 2016-2026 period. The Bruce net revenues form part of OPG's calculation of regulatory income tax at Exhibit F4 / Tab 2 / Schedule 1 / Table 3c.

OEB staff also notes that OPG's income tax expense for prescribed facilities is based on the taxes payable method (i.e. excludes the impact of deferred taxes).
Question(s):

a) Please provide rationale for departing from the taxes payable method in calculating Bruce net revenues and why it is appropriate to apply a different basis for calculating taxes than the one used for OPG's prescribed facilities.

b) Is OPG aware of any prior OEB decisions where the OEB approved the inclusion of deferred tax impacts in the determination of Bruce net revenues? If so, please provide reference to those decisions.

Response

a) and b)

The deferred income tax method is applied to the Bruce facilities as required by the OEB, as it is the accounting method under generally accepted accounting principles used by unregulated entities. By reference to sections 6(2)9 and 6(2)10 of O. Reg. 53/05, the OEB determined in its EB-2007-0905 Decision with Reasons that OPG's Bruce Lease net revenues are to be calculated on this basis, including income taxes.[1] This approach has been applied consistently in all subsequent OPG proceedings. Further details on the EB-2007-0905 Decision with Reasons in this regard can be found at Ex. C2-1-1, p. 19, lines 8-30.

[1] EB-2007-0905 Decision with Reasons, p. 110.