NON-ENERGY REVENUES
NUCLEAR

1.0 PURPOSE

This evidence describes OPG's non-energy revenue derived from its nuclear operations; the regulatory treatment of these revenues; and the forecast of the nuclear non-energy revenues for the test period.

2.0 OVERVIEW

Actual and planned nuclear non-energy revenues (net of related costs) for the period 2013–2021 are presented in Ex. G2-1-1 Table 1. The forecast of nuclear non-energy revenues for the test period is included as an offset in the calculation of OPG's revenue requirement. No change is proposed in the regulatory treatment for nuclear non-energy revenues.

As more fully described in section 3.1.1, OPG is considering a proposed new initiative to produce Cobalt-60 at Darlington. The initiative presents operational and financial risks to OPG and if it proceeds, OPG will seek revenue sharing for Cobalt 60 revenues in a future application.

Bridge and test years' nuclear non-energy revenues trend lower than historical periods though a modest increase in demand for heavy water is reflected in higher forecasted heavy water sales revenues for 2016 and 2017. After 2017, OPG's inventory of heavy water will be exhausted and OPG forecasts no revenues from heavy water sales for 2018 to 2021 (See Ex. G2-1-1 Table 1).

Differences between forecast and actual revenues associated with ancillary services are recorded in the Ancillary Services Net Revenue Variance Account – Nuclear Sub Account. (See Ex. H1-1-1).

3.0 NUCLEAR NON-ENERGY REVENUE SOURCES

3.1 Isotope Sales

3.1.1 Cobalt-60

Cobalt-60 is a critically important medical isotope used for radiation therapy; sterilization of medical equipment; food irradiation and specialized industrial uses. OPG currently produces Cobalt-60 at Pickering B (Units 6, 7 and 8) for use in the sterilization of surgical and medical supplies. OPG sells Cobalt-60 to Nordion (Canada) Inc. (“Nordion”) under a long term agreement.

OPG is not proposing any change to the treatment of revenues from Cobalt-60 production at Pickering. Total revenues from Cobalt-60 sales over the period 2016-2021 are shown in Ex. G2-1-1 Table 1. Electricity generating activities take precedence over Cobalt-60 processing. Cobalt-60 harvesting is tied to the outage schedule of the Pickering units. This results in fluctuating annual revenues and variances between actual and planned revenues.

Sales volumes are constrained by OPG’s ability to produce Cobalt-60. The direct costs and other support costs for this activity are discussed in section 4 below. Cobalt-60 production and its associated revenues would cease with the closure of Pickering planned for 2024.

3.1.1.1 Cobalt-60 Production at Darlington

OPG and Nordion are examining a new opportunity to develop the capability to produce Cobalt-60 at Darlington after Pickering ceases operation. The conversion of the Darlington units to enable production of Cobalt-60 will be most cost effective over the full Darlington refurbishment period.

The conversion will impose additional operational and financial risks to OPG and will require Nordion to make a significant investment by installing equipment to produce Cobalt-60. These additional risks include ensuring ongoing worker safety; maintaining production and outage schedules; regulatory compliance; and revenue variances due to a potential for outage extensions to enable harvesting Cobalt-60.

If OPG and Nordion proceed with this opportunity, production of Cobalt-60 at Darlington would not begin until after the current test period. As a result of the incremental risks OPG faces in introducing Cobalt 60 production at Darlington, OPG will, at its next payment amounts application, propose a revenue sharing of the net revenues it earns from any Cobalt-60 produced at Darlington.

3.1.2 Tritium Sales

Tritium is a by-product of electricity generation using CANDU (Canadian Deuterium Uranium) technology. It is produced by the irradiation of heavy water. In order to stay within the specified limits, and to lower radiation exposure to workers and the environment, tritium is removed from the heavy water via the Darlington Tritium Removal Facility (“TRF”).

OPG has entered into short-term contracts to sell the tritium to government-approved and licensed organizations. Commercial use of tritium includes safety and security products like land-mine markers and emergency exit signs, tritium labeled chemicals for medical research and research into future power sources.

Tritium sales have been relatively stable over time, with some variation due to competition, fluctuating demand and variations in the value of the Canadian dollar. Planned total revenues from isotope sales over the test period are shown in Ex. G2-1-1 Table 1. The direct costs and other support costs are described in Section 4 below.

3.2. Heavy Water Sales and Processing

Heavy water is a manufactured product required for CANDU reactor operations. Heavy water is required as a moderator for sustaining a nuclear reaction and as a heat transport medium in a CANDU nuclear reactor.

3.2.1 Heavy Water Sales

OPG seeks opportunities to sell surplus quantities of heavy water from its heavy water inventory. Surplus quantities are defined as those quantities of heavy water not required to meet OPG’s current and future needs. OPG expects to have surplus heavy water available for sale up to 2017 when OPG's inventory will be depleted. As determined by the OEB in EB-2010-0008, revenues (less costs) from heavy water sales are to be shared on a 50-50 basis between OPG and ratepayers. OPG proposes that this treatment continue unchanged during the test period.

3.2.2 <u>Heavy Water Processing</u>

Heavy water processing is primarily comprised of tritium removal (detritiation) at the TRF. The bulk of the heavy water processing revenue is earned from the provision of detritiation services to Bruce Power. Opportunities for providing detritiation services to others are limited because of storage and capacity restrictions at the TRF.

Provision of detritiation services is affected by a station's ability to ship water to the TRF and the availability of the TRF, which fluctuates according to its maintenance cycle. TRF outages follow a three year cycle, with the first year requiring a long outage (six months), the second year requiring a shorter one (three months) and the third year requiring no outage at all. As a result, revenues fluctuate from year to year.

On occasion, OPG is able to lease/loan small quantities of heavy water to third parties; revenues from these transactions are also recorded under "heavy water services". Planned total revenues for heavy water sales and processing over the test period are summarized in Ex. G2-1-1 Table 1. Cost of goods sold and other support costs are described in section 4 below.

3.3 Helium-3

In EB-2013-0321, OPG included a forecast for $4M of revenue in 2015 from the sale of Helium-3. A change in customer requirements resulted in no sales of Helium-3. OPG's test period forecast does not include revenue for sales of Helium-3.

3.4 Ancillary Services

OPG's nuclear assets are able to supply the IESO with reactive support and voltage control. Reactive support service allows the IESO to maintain the reactive power levels required by the IESO-controlled grid. Voltage control service allows the IESO to maintain voltage levels required by the IESO-controlled grid.

OPG and the IESO negotiated an extension to the existing Reactive Support and Voltage Control Service Agreement effective January 1, 2013 to May 31, 2016. OPG's expectation for the plan period is that a new contract will be negotiated with terms and conditions similar to those in the existing contract; hence the forecast is based on 2015 values with an allowance for inflation.

4.0 OPERATING COSTS OF NUCLEAR NON-ENERGY BUSINESSES

The operating costs of the nuclear non-energy business are made up of direct costs (costs directly associated with producing or generating the product or service) and other support costs (costs associated with sales, administration and other overheads). The direct costs of the nuclear non-energy business are shown in Ex. G2-1-1 Table 1 on an aggregated basis. Other support costs are included in Base OM&A (Ex. F2-2-1 Table 1 Nuclear Support Divisions either under Inspection and Maintenance Services or under Commercial Services).

4.1 Cobalt-60

The direct costs for Cobalt-60 production include installation, removal, processing, storage, and packaging of Cobalt-60. Under the Amended and Restated Used Fuel Waste and Cobalt-60 Agreement between Bruce Power and OPG, Bruce Power makes payments to OPG to assume liability for the interim storage and future disposal of Bruce Power's spent Cobalt-60. The revenues associated with Cobalt-60 are included in Isotope Sales and are set out in Ex. G2-1-1 Table 1.

Other support costs for Cobalt-60 are included in OPG OM&A and represent an allocation of the Isotopes Sales Group support costs including a portion of labour costs related to sales and administration.

4.2 Tritium Sales

The direct costs for the tritium sales program are primarily Canadian Nuclear Laboratories dispensing fees, packaging, and shipping costs. The product itself is a pure by-product of the detritiation process and no production cost is attached to what is sold.

Other support costs for the tritium sales program are included as OM&A and represent an allocation of the Isotopes Sales Group support costs including a portion of labour costs related to sales and administration.

4.3 Heavy Water Sales

The direct costs for heavy water sales include labour for handling, testing, loading, unloading, and packaging; the cost of containers, and transportation costs. OPG proposes that 50 per cent of the related costs from the sale of surplus heavy water continue to be included in the determination of the revenue requirement in accordance with the OEB's decision in EB-2010-0008.

4.4 Heavy Water Processing

Direct costs for heavy water processing services are for estimated incremental direct labour costs attached to processing heavy water for Bruce Power at the TRF and direct labour (e.g., handling, testing, packaging) and other costs (e.g., shipping) attached to the provision of other services (e.g., loans, swaps, upgrading) to third parties.

"Other support costs" for heavy water detritiation processing services relate to sales and support staff dedicated to serving this market, all of which is included in OPG OM&A (i.e., Commercial Services see Ex. F2-2-1 Table 1).

Numbers may not add due to rounding.

Table 1
Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NGD-Related Revenues:									
1	**Heavy Water Sales & Processing**	28.2	21.5	24.9	18.0	25.4	[redacted]	[redacted]	[redacted]	[redacted]
2	**Isotope Sales (Cobalt 60 + Tritium)**	7.0	12.7	13.5	12.6	12.6	[redacted]	[redacted]	[redacted]	[redacted]
3	**Inspection & Maintenance Services**	0.0	0.4	0.0	0.0	0.0	[redacted]	[redacted]	[redacted]	[redacted]
4	**Helium-3 Sales**	0.0	0.0	0.0	0.0	0.0	[redacted]	[redacted]	[redacted]	[redacted]
5	**Total NGD-Related Revenues** (lines 1 through 4)	35.2	34.6	38.4	30.6	38.0	28.7	28.7	28.7	28.7
6	**NGD-Related Direct Costs**	5.9	5.9	6.7	8.3	8.1	8.6	7.9	8.5	7.8
7	**NGD-Related Contribution Margin** (line 5 - line 6)	29.3	28.7	31.6	22.3	29.9	20.1	20.8	20.2	21.0
8	**Ancillary Services**	1.7	2.4	1.5	1.8	1.8	1.8	1.9	1.9	2.0
9	**Other**	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total** (line 7 + line 8 + line 9)	31.0	31.2	33.2	24.1	31.7	22.0	22.7	22.2	22.9

COMPARISON OF NON-ENERGY REVENUES
NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of nuclear non-energy revenues.

2.0 OVERVIEW

This evidence supports the approvals OPG is seeking with respect to non-energy revenues from its nuclear facilities. Exhibit G2-1-2 Table 1 presents year-over-year comparisons of nuclear non-energy revenues.

3.0 PERIOD-OVER-PERIOD CHANGES - TEST YEARS

2017 Plan versus 2016 Budget

Planned nuclear non-energy revenue for 2017 is $31.7M, an increase of $7.6M over 2016 budgeted nuclear non-energy revenue, primarily due to higher revenues from heavy water sales and processing.

2018 Plan versus 2017 Plan

Planned nuclear non-energy revenue for 2018 is $22.0M, a decrease of $9.7M over 2017 planned nuclear non-energy revenue, primarily due to OPG's exit from the sale of surplus heavy water due to the depletion of inventory and marginally higher direct costs offset slightly by increased ancillary services revenues due to inflation.

2019 Plan versus 2018 Plan

Planned nuclear non-energy revenue for 2019 is $22.7M, an increase of $0.7M over 2018 planned nuclear non-energy revenue, primarily due to marginally higher direct costs offset slightly by increased ancillary services revenues due to inflation.

2020 Plan versus 2019 Plan

Planned nuclear non-energy revenue for 2020 is $22.2M, a decrease of $0.6M over 2019 planned nuclear non-energy revenue, primarily due to marginally higher direct costs offset slightly by increased ancillary services revenues due to inflation.

2021 Plan versus 2020 Plan

Planned nuclear non-energy revenue for 2021 is $22.9M, an increase of $0.8M over 2020 planned nuclear non-energy revenue, primarily due to increased ancillary services revenue as a result of inflation.

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE YEAR

2016 Budget versus 2015 Actual

Budgeted nuclear non-energy revenue for 2016 is $24.1M, a decrease of $9.1M over 2015 actual nuclear non-energy revenue, primarily due to lower revenues from heavy water sales and processing as a result of an unplanned outage of the Darlington Tritium Removal Facility (“DTRF”) limiting processing services as well as increased competition for isotope sales offset slightly by increased ancillary services revenues.

5.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL YEARS

2015 Actual versus 2015 OEB Approved

Actual nuclear non-energy revenue for 2015 is $33.2M, a decrease of $4.5M over 2015 OEB Approved nuclear non-energy revenues, reflecting the OEB adjustment to the total approved nuclear non-energy revenues, no sales of Helium 3 and slightly lower revenues from ancillary services offset by higher revenues from sales of heavy water and processing services and isotopes.

2015 Actual versus 2014 Actual

Actual nuclear non-energy revenue for 2015 is $33.2M, an increase of $1.9M over 2014 Actual nuclear non-energy revenue, primarily due to higher revenues from sales of heavy water and processing services and isotopes offset by slightly higher direct costs and slightly lower revenues from the sale of ancillary services.

2014 Actual versus 2014 OEB Approved

Actual nuclear non-energy revenue for 2014 is $31.2M, a decrease of $6.4M over 2014 OEB Approved nuclear non-energy revenue reflecting the OEB adjustment to the total approved nuclear non-energy revenues, lower revenues from heavy water sales and processing due to high customer inventory, competition and reduced performance of the DTRF offset by slightly higher revenues from isotope sales and ancillary services.

2014 Actual versus 2013 Actual

Actual nuclear non-energy revenue for 2014 is $31.2M, a decrease of $0.2M over 2013 actual nuclear non-energy revenue primarily due to lower revenues from heavy water sales due to competition offset by higher revenues from isotope sales and slightly higher sales of ancillary services.

2013 Actual versus 2013 Budget

Actual nuclear non-energy revenue for 2013 is $31.0M, an increase of $7.3M over 2013 budgeted nuclear non-energy revenue, primarily due to higher demand for heavy water as customers anticipated OPG’s exit from the market and unplanned heavy water services projects in France and Japan offset by lower isotope sales revenue due to operational issues that delayed planned shipments.

Numbers may not add due to rounding.

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

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved[1]	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved[1]	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	NGD-Related Revenues:											
1	**Heavy Water Sales & Processing[2]**	17.8	10.4	28.2	(6.7)	27.4	(5.9)	21.5	3.4	15.4	9.5	24.9
2	**Isotope Sales (Cobalt 60 + Tritium)**	11.1	(4.1)	7.0	5.7	11.6	1.1	12.7	0.8	11.9	1.6	13.5
3	**Inspection & Maintenance Services**	0.0	0.0	0.0	0.4	0.0	0.4	0.4	(0.4)	0.0	0.0	0.0
4	**Helium-3 Sales**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	(4.0)	0.0
5	**Total NGD-Related Revenues** (lines 1 through 4)	29.0	6.2	35.2	(0.6)	39.0	(4.4)	34.6	3.8	31.3	7.1	38.4
6	**NGD-Related Direct Costs**	7.2	(1.3)	5.9	0.0	6.8	(0.9)	5.9	0.8	7.8	(1.1)	6.7
7	**NGD-Related Contribution Margin** (line 5 - line 6)	21.7	7.6	29.3	(0.6)	32.2	(3.5)	28.7	2.9	23.5	8.1	31.6
8	**Ancillary Services[3]**	1.9	(0.2)	1.7	0.7	1.9	0.5	2.4	(0.9)	1.9	(0.4)	1.5
9	**Other**	0.1	(0.1)	0.0	0.1	0.1	0.0	0.1	(0.1)	0.1	(0.1)	0.0
10	**Adjustment[1]**	0.0	0.0	0.0	0.0	3.4	(3.4)	0.0	0.0	12.1	(12.1)	0.0
11	**Total** (line 7 + line 8 + line 9 + line 10)	23.7	7.3	31.0	0.2	37.6	(6.4)	31.2	1.9	37.6	(4.5)	33.2

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	NGD-Related Revenues:											
12	**Heavy Water Sales & Processing[2]**	24.9	(6.9)	18.0	7.4	25.4	[redacted]					
13	**Isotope Sales (Cobalt 60 + Tritium)**	13.5	(0.9)	12.6	0.0	12.6						
14	**Inspection & Maintenance Services**	0.0	0.0	0.0	0.0	0.0						
15	**Helium-3 Sales**	0.0	0.0	0.0	0.0	0.0						
16	**Total NGD-Related Revenues** (lines 12 through 15)	38.4	(7.8)	30.6	7.5	38.0	(9.3)	28.7	0.0	28.7	0.0	28.7
17	**NGD-Related Direct Costs**	6.7	1.5	8.3	(0.1)	8.1	0.4	8.6	(0.7)	7.9	0.6	8.5
18	**NGD-Related Contribution Margin** (line 16 - line 17)	31.6	(9.3)	22.3	7.6	29.9	(9.7)	20.1	0.7	20.8	(0.6)	20.2
19	**Ancillary Services[3]**	1.5	0.2	1.8	0.0	1.8	0.0	1.8	0.0	1.9	0.0	1.9
20	**Other**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Total** (line 18 + line 19 + line 20)	33.2	(9.1)	24.1	7.6	31.7	(9.7)	22.0	0.7	22.7	(0.6)	22.2

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
	NGD-Related Revenues:			
22	**Heavy Water Sales & Processing[2]**	[redacted]		
23	**Isotope Sales (Cobalt 60 + Tritium)**			
24	**Inspection & Maintenance Services**			
25	**Helium-3 Sales**			
26	**Total NGD-Related Revenues** (lines 22 through 25)	28.7	0.0	28.7
27	**NGD-Related Direct Costs**	8.5	(0.7)	7.8
28	**NGD-Related Contribution Margin** (line 26 - line 27)	20.2	0.7	21.0
29	**Ancillary Services[3]**	1.9	0.0	2.0
30	**Other**	0.0	0.0	0.0
31	**Total** (line 28 + line 29 + line 30)	22.2	0.8	22.9

Notes:

1 OEB Approved 2014 and 2015 total Nuclear Other Revenues are $37.6M per EB-2013-0321 Decision with Reasons, p. 66. OEB Approved adjustments were applied to the 2014 Plan and 2015 Plan Total Nuclear Other Revenue amounts shown in EB-2013-0321 Decision with Reasons, Table 17 (p. 65).

2 Starting in 2011, Other Revenues included in the determination of the revenue requirement are adjusted for sharing of 50 percent of forecasted net revenue from sales of heavy water per the OEB Decision in EB-2010-0008 and continued per OEB Decision in EB-2013-0321.

Table to Note 2 - 50% Share of Net Revenues from Heavy Water Sales ($M)

Line No.		2013 Actual	2014 Actual	2015 Actual	2016 Plan	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1a	50% Share of Net Revenues from Heavy Water Sales	[redacted]								

3 Ancillary Services related to the nuclear facilities are discussed in Ex. G2-1-1.

BRUCE GENERATING STATIONS – REVENUES AND COSTS

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce lease agreement and associated agreements (collectively "Bruce Lease") and the related costs incurred by OPG with respect to the Bruce Nuclear Generating Stations.

2.0 OVERVIEW

OPG leases the Bruce A (Units 1-4) and Bruce B (Units 5-8) Nuclear Generating Stations and associated lands and facilities to Bruce Power L.P. ("Bruce Power"). The Bruce lease agreement sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power, including lease payments.

In addition, OPG and Bruce Power have entered into a number of associated agreements for the provision of services by OPG to Bruce Power or by Bruce Power to OPG. These agreements include the Amended and Restated Used Fuel Waste and Cobalt-60 Agreement ("Used Fuel Agreement"), the Amended and Restated Low and Intermediate Level Waste Agreement ("L&ILW Agreement"), and the Amended and Restated Bruce Site Services Agreement.

For the test period, the net amounts of Bruce Lease revenues and costs are forecast to be ($66.1)M for 2017, ($74.3)M for 2018, ($85.9)M for 2019, ($82.1)M for 2020 and ($93.1)M for 2021 as shown in Ex. G2-2-1 Table 1. In accordance with O. Reg. 53/05 and the OEB's previous findings, these net amounts are applied towards the nuclear revenue requirement. Specifically, sections 6(2)9 and 6(2)10 of 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. These revenues and costs are subject to the Bruce Lease Net Revenues Variance Account.

On December 3, 2015, the Province announced that an updated contract had been executed between the Independent Electricity System Operator ("IESO") and Bruce Power to enable the refurbishment of Bruce Units 3-8 (the Amended and Restated Bruce Power Refurbishment Implementation Agreement or "ARBPRIA").[1] In support of these planned refurbishments, an amended Bruce lease agreement was executed by OPG and Bruce Power on December 4, 2015 ("2015 Amendment") that extended the lease period in line with the estimated post-refurbishment end-of-life ("EOL") dates of the Bruce units. The negotiated amendments to the Bruce Lease cover several other areas including base rent, supplemental rent, low and intermediate level waste ("L&ILW") management fees, and related provisions that serve to limit OPG's financial risk exposure over the term of the lease.

The 2015 Amendment resulted from negotiations undertaken by OPG and Bruce Power in the context of the IESO and the Province's need to fully consider the economics of Bruce Power's proposed refurbishment of the Bruce units, which provided an opportunity for certain aspects of the lease arrangements between OPG and Bruce Power to be reassessed.

Key changes to the Bruce Lease resulting from the negotiations included:

- Extension of the lease renewal term by approximately 20 years;
- Elimination of the derivative liability embedded in the lease agreement;
- Changes in the supplemental rent and L&ILW management fees to align them more closely with the costs of managing used fuel and L&ILW generated by the Bruce units as determined under the Ontario Nuclear Funds Agreement ("ONFA"); and
- Provisions that serve to limit OPG's financial risk exposure over the term of the lease related to changes in nuclear used fuel and waste management costs arising from future updates to the ONFA reference plan.

[1] https://news.ontario.ca/mei/en/2015/12/ontario-commits-to-future-in-nuclear-energy.html

As in EB-2014-0370, EB-2013-0321, EB-2012-0002 and EB-2010-0008, the treatment of revenues and costs associated with the Bruce lease agreement and associated agreements are based on the OEB's decision in EB-2007-0905. The methodology for assigning and allocating revenues and costs to the Bruce facilities and under the Bruce Lease is unchanged from that applied in EB-2013-0321 and EB-2010-0008, and reflected in EB-2014-0370 and EB-2012-0002 through the disposition of the Bruce Lease Net Revenues Variance Account. As discussed in EB-2010-0008, this methodology was previously independently reviewed and found to be appropriate by Black & Veatch Corporation Inc.[2]

Historically, Bruce Lease net revenues have typically been positive and have reduced the nuclear revenue requirement. While Bruce Lease net revenues are largely stable over 2016-2021, beginning in 2016 the net revenues are currently projected to be negative (i.e., net costs) and therefore increase the nuclear revenue requirement. The forecast decrease in net revenues in 2016-2021 relative to 2015, excluding the impact of the derivative embedded in the Bruce lease agreement, is primarily due to the impact on OPG's nuclear asset retirement obligation ("ARO") and related asset retirement costs ("ARC") of extending the EOL dates of the Bruce units in line with the ARBPRIA, effective December 31, 2015. As discussed in Ex. C2-1-1 and detailed in Ex. C2-1-1 Tables 5 and 6, the estimated impact of these changes is a decrease to the forecast Bruce Lease net revenues of approximately \$69.9M in 2016, \$72.0M in 2017, \$73.5M in 2018, \$75.5M in 2019, \$120.7M in 2020 and \$121.7M in 2021.[3]

Section 3 discusses the key changes to the agreements between OPG and Bruce Power. Section 4 considers the resulting revenue implications and trends. Section 5 considers OPG's costs associated with the Bruce facilities. A year-by-year presentation of Bruce Lease revenues and costs for 2013 to 2021 is provided in sections 4.5 and 5.10, respectively.

[2] EB-2010-0008 Ex .G2-2-1, section 3.0
[3] With respect to the total nuclear revenue requirement, the impact of the December 31, 2015 changes in nuclear station EOL dates and ARO related to the Bruce facilities is partly offset by reductions in the nuclear liability costs for the prescribed nuclear facilities resulting from these changes, as detailed in Ex. C2-1-1

3.0 CHANGES TO BRUCE LEASE AGREEMENT AND ASSOCIATED AGREEMENTS

The following summarizes the key aspects of the 2015 Amendment that affect OPG's revenues and/or serve to limit OPG's financial risk exposure:

1. Lease Term: The maximum term of the lease has been extended by 21 years from December 31, 2043 to December 31, 2064, such that Bruce Power now has options to renew the lease for additional consecutive renewal periods for up to 46 years after the expiry of the initial lease term on December 31, 2018. OPG's test period forecasts assume that Bruce Power will exercise its options to renew the lease.

2. Base Rent: The 2015 Amendment increased base rent payments payable by Bruce Power for the renewal terms commencing in 2019 from effectively \$16M per year[4] to \$16M per year plus annual escalation by the Consumer Price Index (Ontario) ("CPI").[5] As part of the amendment process, the parties acknowledged that the renewal term payments are generally intended to cover the executory costs being incurred by OPG in connection with the lease, such as property taxes for the Bruce site (discussed in section 5.2) and Bruce Lease contract management oversight and administration costs (discussed in section 5.0). The provision for CPI escalation increases the economic value of future base rent payments over the life of the lease. The accounting implications of these changes are discussed in section 4.1.1. The amendment did not affect the existing annual base rent amounts prescribed in the lease agreement for the initial lease term to December 31, 2018.

3. Supplemental Rent: The 2015 Amendment aligned the supplemental rent with the prevailing ONFA-based estimate of OPG's lifecycle costs to manage Bruce Power's used fuel generated after 2015 for which OPG is responsible under the Used Fuel Agreement. Effective January 1, 2016, stipulated dollar amounts of supplemental rent previously payable by Bruce Power for each Bruce unit are replaced with a single average per fuel

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[4] As shown in EB-2013-0321 Ex. L-1.3-17 SEC-019, Attachment 2.

[5] The 2015 Amendment also aligned the base rent payment for the first renewal term, for one year in 2019, with the effective annual amounts for subsequent renewal terms, by reducing it from \$32M to \$16M.

bundle cost rate (for all Bruce units), based on ONFA estimates and subject to annual CPI escalation. Accordingly, supplemental rent will now vary each period with the number of fuel bundles discharged by Bruce Power into the irradiated fuel bays.

While the above change has the effect of reducing supplemental rent revenue in the shorter term starting in 2016, it allows the supplemental rent to be aligned, for the remainder of the extended lease term, with prevailing estimates of OPG's lifecycle costs of managing Bruce Power's used fuel waste generated after 2015 as determined through future ONFA reference plan update processes. Any resulting future adjustments to the ONFA-based estimated costs per bundle for used fuel generated after 2015 will now trigger a cumulative true-up of supplemental rent calculated retroactively to January 1, 2016.[6] The true-up amount will be payable (or refundable) over the remaining expected life of the longest running Bruce unit, less five years. This mechanism provides certain protection against potential cost changes arising from future ONFA reference plan updates during the extended term of the lease and replaces the previous terms of the agreement that provided OPG with a single opportunity to adjust, through negotiations, Bruce Power's used fuel fees for the full renewal period of the lease.

The 2015 Amendment also eliminated the requirement for OPG to provide Bruce Power with a partial supplemental rent rebate going forward. Prior to the amendment, supplemental rent was dependent on the Hourly Ontario Energy Price ("HOEP"). As discussed in EB-2013-0321, EB-2012-0002 and EB-2010-0008, a provision in the lease agreement required OPG to provide Bruce Power with a partial rebate of the supplemental rent payments for the Bruce units not subject to the original Bruce Power Refurbishment Implementation Agreement (i.e. Bruce B units) in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") fell below $30/MWh.

[6] The cost rate in effect in 2016 was derived from the approved 2012 ONFA Reference Plan and will be subject to a future true up adjustment based on cost estimates from the 2017 ONFA Reference Plan update process, which is in progress as of the date of this Application.

The 2015 Amendment eliminated the rebate provision effective December 4, 2015. As a result, the fair value of the derivative liability established in accordance with GAAP to account for the conditional reduction to supplemental rent payments in the future ("Bruce Derivative") was fully reversed by the end of 2015. The liability had a fair value of approximately $299M prior to reversal (approximately $224M after tax).[7] As discussed in section 4.1.2, the reversal of the Bruce Derivative triggered a corresponding reduction in the amount recorded as recoverable from ratepayers in the Derivative Sub-Account of the Bruce Lease Net Revenues Variance Account ("Derivative Sub-Account"). In accordance with the approved methodology for recovering the balance of the Derivative Sub-Account, OPG expects this amount would have otherwise been payable by ratepayers over 2016 to 2019 as the annual rent rebate became payable by OPG.

4. <u>Low & Intermediate Level Waste Management Revenues</u>: Effective January 1, 2016, the volumetric fees payable by Bruce Power for OPG's L&ILW storage and disposal services have been aligned with the prevailing estimate of OPG's lifecycle costs associated with managing Bruce Power's L&ILW (excluding non-routine refurbishment waste) generated after 2015. Similar to used fuel fees (i.e. supplemental rent), the costs are determined through the ONFA reference plan update process and are subject to annual CPI escalation. Any resulting future adjustments to the ONFA-based L&ILW management costs during the lease term for waste generated after 2015 will now trigger a cumulative true-up of the fees calculated retroactively to January 1, 2016.[8] The true-up amount is payable (or refundable) over the expected remaining life of the longest running Bruce unit, less five years. Similar to used fuel fees, this mechanism provides certain protection against potential cost changes arising from future ONFA reference plan updates over the extended term of the lease and replace the previous terms of the agreement that provided OPG with a single opportunity to adjust, through negotiations, Bruce Power's L&ILW fees for the full lease renewal period. The above changes increase OPG's revenues from providing L&ILW management services to Bruce Power starting in 2016.

[7] The value of the Bruce Derivative reversed in December 2015 can be found in OPG's 2015 audited consolidated financial statements at Ex. A2-1-1, Att. 3, pp. 158-159
[8] Ibid.

4.0 BRUCE LEASE REVENUES

The forecast test period Bruce Lease revenues are $251.1M for 2017, $246.5M for 2018, $245.0M for 2019, $257.4M for 2020 and $223.6M for 2021. Actual Bruce Lease revenues earned by OPG during the 2013-2015 period and forecast to be earned during the 2016-2021 period are summarized in Ex. G2-2-1 Table 2. As in EB-2013-0321, EB-2012-0002 and EB-2010-0008, OPG derives revenues from the Bruce lease agreement and associated agreements, which are described in Sections 4.1 to 4.4 below.

4.1 Bruce Lease Agreement Revenues

As in EB-2013-0321 and EB-2010-0008, revenues from the Bruce lease agreement consist of amortization of a fixed amount of initial deferred rent ($12.1M per year) to the end of 2018, base rent and supplemental rent. Base rent is discussed in Section 4.1.1 and supplemental rent is discussed in Section 4.1.2.

4.1.1 <u>Base Rent Revenue</u>

The Bruce lease contains base rent payments that are preset for each year of the initial lease term up to the end of 2018. These are $88M for 2016, $90M for 2017 and $92M for 2018.[9] As discussed in section 3.0, pursuant to the 2015 Amendment, the renewal term payments starting in 2019 are effectively $16M per year, subject to CPI escalation, and are generally intended to cover the executory costs being incurred by OPG in connection with the lease.[10] As these ongoing costs are also being incurred by OPG currently (i.e. not only during the renewal term), a portion of the annual base rent payments in the 2016-2018 period is also attributed to executory costs, by de-escalating the renewal term amount.

As per the OEB's direction in EB-2007-0905, OPG continues to determine lease revenue in accordance with GAAP for non-regulated businesses. This requires the application of a straight-line basis to determine lease revenue by dividing the total expected base rent

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[9] As shown in EB-2013-0321 Ex. L-1.3-17 SEC-019, Att. 2, first column.

[10] Prior to the 2015 Amendment, there was insufficient evidence to characterize, for accounting purposes, a portion of base rent payments as being intended as reimbursement of executory costs.

revenues, excluding any payments intended to cover the lessor's executory costs, by the number of years in the expected lease term determined for accounting purposes. As the full amount of base rent starting in 2019 is now considered to be on account of executory costs, only the base rent payment to the end of 2018 (excluding the portion attributable to executory costs) are subject to the straight line calculation. The portion of the lease payments for executory costs is generally recognized as revenue on the same basis as the costs.

As a result of the significant change in the lease from the 2015 Amendment, US GAAP required the expected lease term to be reassessed for accounting purposes. In line with the ARBPRIA and the 2015 Amendment, the expected lease term for accounting purposes has been extended from December 2036[11] to December 2064, effective January 1, 2016.

Based on the above, starting in 2016, annual base rent revenue consists of a fixed straight-line revenue amount and the portion of the base rent payments attributed to executory costs. The resulting forecast base rent revenue in accordance with US GAAP ranges from $24.2M in 2016 to $25.7M in 2021, compared to the straight line revenue of $38.7M in 2015. This reduction is a timing difference that reflects the longer lease term used to determine the amount of straight-line base rent revenue. As noted in Section 3.0, the 2015 Amendment did not result in changes to the existing base rent amounts payable over the remainder of the initial lease term to the end of 2018 (and increased the economic value of future base rent payments through incorporation of CPI-based adjustments during the renewal term).

Base rent revenue amounts and their calculations are set out in Ex. G2-2-1 Table 2.

4.1.2 <u>Supplemental Rent Revenue, Including Bruce Derivative</u>

As discussed in Section 3.0, effective January 1, 2016, the monthly supplemental rent payable to OPG in addition to base rent represents the volume-based fee for managing Bruce Power's used fuel. Supplemental rent revenue (excluding the impact of the Bruce Derivative) is generally recognized on a cash basis for financial accounting purposes because it is not a fixed amount. Prior to 2016, the supplemental rent was contingent on the

[11] As discussed at EB-2010-0008 Ex. G2-2-1, p. 3.

number and operational state of the Bruce units. Starting in 2016, it is contingent on the number of fuel bundles discharged by Bruce Power into the irradiated fuel bays.

As discussed in section 3.0, the 2015 Amendment removed the HOEP-triggered provision for a conditional partial supplemental rent rebate by OPG to Bruce Power, as of December 4, 2015. As a result, the Bruce Derivative for periods after December 3, 2015 was reversed from OPG's 2015 financial statements in accordance with GAAP. The resulting increase in 2015 Bruce Lease revenues triggered a credit entry of approximately $299M (approximately $224M after tax) in the Derivative Sub-Account. This credit entry reversed amounts previously recorded in the account as recoverable from ratepayers in the future (i.e. over the 2016-2019 period as the rent rebate became payable by OPG).[12] There will be no further impacts on Bruce Lease net revenues from the Bruce Derivative starting in 2016, which eliminates OPG's and ratepayers' future exposure to this obligation.

By the end of 2016, OPG expects the Derivative Sub-Account to have a credit balance of $68.6M, as shown in Ex. H1-2-1, Table 2, line 6, col. (c). The credit largely represents the amount that the OEB authorized to be collected for the Bruce Derivative for the post-December 3, 2015 period through the EB-2014-0370 rate riders.[13] OPG proposes to return this amount to ratepayers over the 2017-2018 period as part of its deferral and variance account clearance proposal set out in Ex. H1-2-1.

The impacts of the Bruce Derivative (including its reversal) on Bruce Lease net revenues for the 2013-2015 period are presented separately in Ex. G2-2-1 Tables 1-3 and Tables 5-6.

[12] Ex. H1-1-1 Table 12, line 10 shows a credit entry of $168.7M for the Bruce Derivative in 2015. This entry is the net amount of the following: a credit entry (after tax) of $224.0M for the Bruce Derivative reversal in December 2015, and debit entries from earlier in the year of approximately $55.4M (after tax) representing increases in the fair value of the Bruce Derivative due to increases in probability-weighted expectations of Average HOEP falling below $30/MWh.

[13] For the period from January 1, 2015 to December 3, 2015, the supplemental rent rebate was triggered and subsequently paid by OPG, on a pro-rated basis, in accordance with the terms of the lease agreement in effect prior to the 2015 Amendment.

4.2 Used Fuel Waste and Cobalt-60 Agreement Revenues

Under the Used Fuel Agreement, OPG remains responsible for managing Bruce Power's used nuclear fuel waste by providing interim storage and long-term disposal services for the used fuel generated at the Bruce stations. OPG also accepts the liability for the interim storage and future disposal of Bruce Power's spent cobalt-60 and, in return, receives payments from Bruce Power. As set out in Ex. G2-2-1 Table 2, these revenues are about $0.5M per year during the test period. Revenues for cobalt-60 storage and disposal services are recorded as the services are provided.

4.3 Low and Intermediate Level Waste Agreement Revenues

Under the L&ILW Agreement, OPG continues to manage the low and intermediate level radioactive waste received from Bruce Power.[14] In return for these services, Bruce Power pays OPG a volumetric, cost-based fee as discussed in section 3.0. OPG is required to maintain the capacity to accept all of the L&ILW received from Bruce Power.[15] Revenues under this agreement continue to be recorded as the services are provided. As set out in Ex. G2-2-1 Table 2 and discussed in section 4.5, L&ILW services revenues increase from $4.0M in 2015 to an average of $31.6M per year during the test period.

4.4 Bruce Site Services Agreement Revenues

This agreement, as amended, provides for various support and maintenance services that are provided by OPG to Bruce Power, and by Bruce Power to OPG, on a cost recovery basis. The services contemplated by this agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power. OPG's site services revenues are set out in Ex. G2-2-1 Table 2 and are approximately $0.7M per year during the test period. The related costs are discussed in Section 5.0 below.

4.5 Comparison of Revenues

A comparison of revenues from the Bruce Lease for the 2013 to 2021 period is provided in Ex. G2-2-1 Table 3. Overall, total non-derivative revenue declines from an average of

[14] Excluding non-routine refurbishment waste
[15] Ibid

approximately $263M per year in the 2013-2015 historical period to an average of approximately $245M per year in the test period. This chiefly reflects a decrease in the base rent revenue recognized for accounting purposes in accordance with US GAAP, and the full amortization of the initial deferred rent at $12.1M per year by the end of 2018,[16] as originally scheduled.[17] Relative to the 2013-2015 period, the higher L&ILW management services revenues and the lower supplemental rent revenues over the test period, both reflecting the 2015 Amendment, are largely offsetting.

The fluctuations in services revenue over 2013-2021 reflect an increase in L&ILW management services revenues as a result of modifications to the L&ILW Agreement fee structure effective January 1, 2016 as described in section 3.0, as well as differences in volumes of L&ILW received or forecast to be received from Bruce Power. Reflecting this, L&ILW management services revenues increase from $4.0M in 2015 to $32.3M in 2016 and average approximately $31.6M over the test period. Differences in waste volumes were the main reason for actual services revenue being below budget in 2013 and below the OEB-approved amounts in 2014 and 2015. As noted in previous proceedings, OPG projects revenues under the L&ILW Agreement based on information received from Bruce Power regarding forecasted L&ILW volumes. Actual waste volumes received are affected by the operations of the Bruce units, including the impact of any waste volume reduction initiatives implemented by Bruce Power, and are not under OPG's control. Lower site services revenue in 2015 compared to other years and the OEB-approved amount include a timing difference related to billings that is expected to be caught up in 2016.

As discussed in Section 4.1.1, base rent revenue is expected to decrease from $38.7M per year over the 2013-2015 period to $24.2M in 2016, due to timing differences arising from the longer expected lease term applied starting in 2016 to recognize revenue on a straight line basis. Base rent revenue increases modestly starting in 2017 as forecast executory costs escalate at an assumed CPI rate of 2% per year.

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[16] As shown in EB-2013-0321 Ex. L-1.3-17 SEC-019, Attachment 2.
[17] The amount and timing of initial deferred rent amortization were not affected by the 2015 Amendment

Supplemental rent revenue is largely stable over the 2013-2015 period.[18] It then decreases from $210.5M in 2015 to $167.6M in 2016, chiefly reflecting the restructuring of supplemental rent payments to align with ONFA-based lifecycle used fuel management cost estimates as discussed in section 3.0. Supplemental rent revenue averages approximately $182M over the test period, with year-over-year fluctuations largely reflecting information received from Bruce Power regarding the forecasted number of used fuel bundles. The relatively higher projected supplemental rent revenue of $200.7M in 2020 reflects an estimate of the fuel bundles assumed to be discharged during the defueling of the first reactor scheduled to undergo refurbishment under the ARBPRIA. The supplemental rent revenue over the test period reflects CPI-based increases per the terms of the 2015 Amendment.

The 2013 budget and the 2014 and 2015 OEB-approved amounts did not include a forecast financial impact associated with the Bruce Derivative. Excluding the Bruce Derivative, the actual supplemental rent revenue in the historical period was generally consistent with the budget (2013) and OEB-approved amounts (2014 and 2015). The impact on actual Bruce Lease revenue of changes in the fair value of the Bruce Derivative in 2013 and 2014 primarily reflected net changes in the probability-weighted expectations of future Average HOEP falling below $30/MWh and was recorded in the Derivative Sub-Account. In 2015, the impact of the Bruce Derivative was a net increase in revenue of $224.9M, of which $298.7M represented the reversal of the embedded derivative liability in December 2015 following the 2015 Amendment as discussed in section 4.1.2, and the remainder was due to increases in the probability-weighted expectations of future Average HOEP falling below $30/MWh recognized in 2015 prior to the reversal of the liability.

5.0 BRUCE LEASE COSTS

The Bruce Lease costs forecast to be incurred by OPG for the test period are $317.3M for 2017, $320.9M for 2018, $330.8M for 2019, $339.5M for 2020 and $316.8M for 2021. Actual Bruce Lease costs incurred by OPG for the 2013 to 2015 period and forecast to be incurred for the 2016 to 2021 period are summarized in Ex. G2-2-1 Table 1 and are further detailed in

[18] Excluding the impact of changes in the value of the Bruce Derivative

Ex. G2-2-1 Table 5. The costs incurred by OPG with respect to the Bruce Nuclear Generating Stations presented in this Application are consistent with those presented in EB-2014-0370, EB-2013-0321, EB-2012-0002 and EB-2010-0008. Certain relatively minor costs incurred by OPG with respect to the Bruce stations, including for services provided under the Amended and Restated Bruce Site Services Agreement and for contract management oversight and administration, continue to be reflected in other aspects of the nuclear revenue requirement and do not form part of the Bruce Lease net revenues.

5.1 Depreciation

Depreciation is calculated on the fixed assets owned by OPG at the Bruce site and leased to Bruce Power. These fixed assets include the associated ARC discussed in Ex. C2-1-1 and shown in Ex. C2-1-1 Table 3. OPG applied the same methodology and depreciation policy as in previous proceedings, also summarized in Ex. F4-1-1, to derive the depreciation expense for 2013 to 2021. The average depreciation forecast for the 2016 to 2021 period is $100.7M per year, based on the closing 2015 Bruce fixed asset balances. The continuity of Bruce fixed asset balances for 2013 to 2021 is presented in Ex. G2-2-1 Table 4.[19]

5.2 Property Tax

Pursuant to the provisions of the Bruce lease agreement, OPG continues to pay the property taxes for the Bruce site as a whole. OPG manages the annual tax assessment process and payments of municipal property taxes to the Municipality of Kincardine and payments-in-lieu of property tax to the Ontario Electricity Financial Corporation, as described in Ex. F4-2-1, Section 6.0. The average forecast property tax cost is $13.8M per year during the test period.

5.3 Accretion

Accretion expense represents the growth in the present value based ARO due to the passage of time. The forecast accretion expense for 2016 to 2021 is derived by reference to the December 31, 2015 ARO balance attributed to the Bruce stations as reflected in OPG's

[19] There are no additions to the Bruce fixed assets as any such additions, except for accounting changes to ARC, are not recorded in OPG's accounting records and are the property of Bruce Power.

2015 audited consolidated financial statements, using the same methodology as in previous proceedings. The recovery methodology for OPG's nuclear liability costs, including accretion expense, is discussed in further detail in Ex. C2-1-1. The continuity schedule for the Bruce ARO is presented in Ex. C2-1-1 Table 3. The average accretion expense is forecast at $574.2M per year during the test period.

5.4 Earnings on Nuclear Segregated Funds

OPG includes the portion of earnings from investments in the nuclear segregated funds attributed to the Bruce stations as a negative cost associated with these stations. These funds are maintained by OPG in accordance with the ONFA to provide funding for the long-term programs of the nuclear liabilities. Discussed further in Ex. C2-1-1, the segregated fund earnings form part of the OEB-approved methodology for recovery of costs associated with OPG's nuclear liabilities for the Bruce assets. The forecast fund earnings for the 2016 to 2021 period are determined using the same methodology as in previous proceedings, by reference to the actual closing balance of the funds attributable to the Bruce stations as reflected in OPG's 2015 audited consolidated financial statements. The continuity schedule for the Bruce portion of the segregated funds is presented in Ex. C2-1-1 Table 3. The average forecast earnings on the segregated funds are $435.4M per year during the test period.

5.5 Used Fuel Storage and Disposal Expenses

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with the storage and disposal of incremental used nuclear fuel produced at the OPG-owned nuclear stations, including the stations on lease to Bruce Power. These costs are included as expenses related to the applicable nuclear assets in the period incurred and are presented as part of the nuclear fuel expense in OPG's consolidated financial statements.[20] The average used fuel storage and disposal expense is forecast at $72.6M per year during the test period.

[20] OPG's costs associated with the cobalt-60 services provided to Bruce Power are presented as part of the costs associated with the nuclear non-energy businesses in Ex. G2-1-1.

5.6 Waste Management Variable Expenses and Facilities Removal Costs

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with managing the low level and intermediate level radioactive nuclear waste produced at the OPG-owned nuclear facilities, including the stations on lease to Bruce Power. Facilities removal costs incurred by OPG to meet its obligations under the Bruce Lease are also included in this category of expenses. The average waste management variable expense and facilities removal costs are forecast at $2.8M per year during the test period.

5.7 Interest

Interest related to the Bruce assets represents an allocation of OPG's actual/forecast corporate-wide accounting interest expense after attributing project-specific interest to appropriate business units. As in previous proceedings, the allocation is based on a historical proportion of the average net book value of the fixed assets leased to Bruce Power relative to the total average net book value of OPG's in-service fixed assets (including intangible assets and excluding in-service assets financed by project-specific debt). The average forecast interest expense is $24.9M per year during the test period.

5.8 Current Income Taxes

In calculating current income taxes for the Bruce assets for the historical, bridge and test periods, OPG is following the methodology approved by the OEB in EB-2010-0008 and applied in EB-2013-0321. In particular, current income taxes for the Bruce assets continue to be calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. The amount of taxes is determined by applying the enacted statutory tax rates to taxable income. Taxable income is computed by making adjustments, in accordance with applicable legislation, to the Bruce stand-alone accounting earnings before tax (i.e. the difference between Bruce Lease revenues and Bruce Lease costs) determined in accordance with GAAP, for items with different accounting and tax treatment. The adjustments in 2013 to 2021 are consistent with those presented in EB-2014-0370, EB-2013-0321, EB-2012-0002 and EB-2010-0008. The derivation of actual (2013-2015) and forecast (2016-2021) taxable income and current tax expense is shown in Ex. G2-2-1 Tables 7 and 8.

Tax losses associated with the Bruce assets on a stand-alone basis that arose in prior periods, on or after April 1, 2008, were carried forward, as in EB-2013-0321 and EB-2010-0008, and fully utilized by the end of 2014. The benefit of tax losses forecast to arise in the 2017-2021 test period is realized by carrying them back to reduce taxable income of preceding test period years. The resulting reduction in current income tax expense is reflected in the year in which the loss arises, in accordance with GAAP for non-regulated businesses. The average current income tax expense is forecast at $6.9M per year during the test period.

5.9 Deferred Income Taxes

As previously outlined in EB-2013-0321 and EB-2010-0008, deferred income taxes generally represent the amount of tax that will be payable/recoverable in the future upon reversal of temporary differences between the tax basis and the accounting carrying value of items recorded in the current year, including tax losses.[21] In calculating deferred income taxes for the Bruce assets, OPG continues to follow the methodology approved by the OEB in EB-2010-0008 and applied in EB-2013-0321. Specifically, the deferred income tax expense is determined in accordance with financial accounting requirements for unregulated entities. The actual (2013-2015) and forecast (2016-2021) deferred income taxes are calculated on a stand-alone basis using the actual/forecast Bruce Lease revenues and Bruce Lease costs, as shown in Ex. G2-2-1 Tables 7 and 8. This Table 7 separately shows the derivation of income tax impacts associated with the Bruce Derivative. The average forecast deferred income tax expense is ($35.6)M per year during the test period.

5.10 Comparison of Bruce Costs

A comparison of Bruce Lease costs for 2013 to 2021 is set out in Ex. G2-2-1 Table 6.

5.10.1 <u>Depreciation</u>

[21] EB-2013-0321 Ex. G2-2-1, Section 5.9

Depreciation expense was generally stable over the 2013-2015 period. The expense is forecast to decrease slightly in 2016, compared to 2015, and to remain stable thereafter to 2021 as shown in Ex. G2-2-1 Table 4. The relatively small decrease in 2016 reflects the impact of the extension of the estimated average service lives of the Bruce stations, for accounting purposes, effective December 31, 2015, which is largely offset by the impact of the associated increase of $2,747.5M in the Bruce ARC and ARO recorded at the end of 2015 as shown in Ex. G2-2-1 Table 4 and Ex. C2-1-1 Table 3. As discussed in Ex. F4-1-1, the extensions of the Bruce A and Bruce B station service lives aligned OPG's accounting assumptions with estimated post-refurbishment EOL dates for the Bruce units as set out in the ARBPRIA. In particular, the accounting service life of the Bruce B station was extended from the end of 2019 to 2061. The increase in the Bruce ARC and the underlying increase in the Bruce ARO are discussed in Ex. C2-1-1.

Actual depreciation expense for the historical period was generally consistent with the budget for 2013 and OEB-approved amounts for 2014 and 2015.

5.10.2 Property Tax

The property tax expense fluctuates over the 2013-2021 period, ranging from $11.6M in 2013 and 2014 to a forecast of $15.1M in 2021, primarily as a result of differences in municipal property tax rates and changes in property assessment values. Differences in municipal property tax rates also largely account for the variances between actual and budgeted (2013) and OEB-approved amounts (2014 and 2015) in the historical period.

5.10.3 Accretion

Accretion expense of $404.7M in 2015 was $18.0M higher than in 2014 which, in turn, was $17.7M higher than the 2013 accretion expense. These variances were mainly due to the normal growth in the ARO as a result of the passage of time. The actual expense was largely on budget in 2013 and slightly higher than the OEB-approved amounts in 2014 and 2015, including the effect of lower-than-forecast cash expenditures charged against the ARO.

The increase of $2,747.5M in the Bruce ARO at December 31, 2015 is the main driver for the $106.3M forecast increase in the accretion expense to $511.0M in 2016. In 2017 through 2021, the accretion expense is forecast to increase by an average of approximately $17.3M per year, from $531.4M in 2017 to $617.8M in 2021. This is primarily a result of the normal growth in the liability due to the passage of time.

5.10.4 Earnings on Nuclear Segregated Funds

The fluctuations in the Bruce portion of the nuclear segregated fund earnings over the 2013 to 2015 period were largely a function of changes in CPI, which impact the provincially guaranteed rate of return applicable to the majority of the Used Fuel Fund value. As discussed in Ex. C2-1-1, the Province guarantees a return of 3.25% plus the change in the CPI for the portion of the Used Fuel Fund attributed to the first 2.23 million used fuel bundles.

The Bruce portion of segregated fund earnings was largely on budget in 2013, exceeded the OEB-approved amount in 2014, and was below the OEB-approved amount in 2015. The variances in 2014 and 2015 were, in large part, due to fluctuations in the CPI-adjusted rate of return for the guaranteed portion of the Used Fuel Fund.

During 2016 to 2021, both funds are forecast to grow at a rate of 5.15% per annum consistent with the growth rate per the approved 2012 ONFA Reference Plan, with the net effect of the higher fund asset base, contributions pursuant to the current approved contribution schedule and forecast disbursements giving rise to year-over-year increases in fund earnings of approximately $20M. By 2021, fund earnings are forecast to reach $479.8M.

5.10.5 Used Fuel Storage and Disposal Expenses

Actual used fuel storage and disposal variable expenses increased modestly year over year during the historical period and were higher than the budgeted (2013) and OEB-approved amounts (2014 and 2015). The year-over-year increases reflected normal course increases in the per bundle variable cost rates, expressed in present value terms, due to the passage of time, and fluctuations in the number of fuel bundles used by Bruce Power. The variances from the budgeted and OEB-approved amounts were mainly due to differences from the forecasted number of fuel bundles.

Used fuel storage and disposal variable expenses are projected to increase in 2016 over 2015, primarily due to higher variable cost rates reflecting the impact of the year-end 2015 adjustment to the nuclear liabilities, as discussed in Ex. C2-1-1. Over the 2016 to 2021 period, the expenses range from a low of $64.2M in 2021 to a high of $81.7M in 2020, with year-over-year variances primarily driven by changes in the expected volume of fuel bundles based on information provided by Bruce Power.

5.10.6 <u>Waste Management Variable Expenses and Facilities Removal Costs</u>

Actual expenses in this category are higher in 2014 and 2015, compared to the 2013 actual and the 2016 forecast amounts, mainly due to facilities removal costs incurred in 2014 in connection with OPG's contractual obligation under the Bruce Lease to demolish and remove certain buildings and facilities that reside on land leased to Bruce Power, and changes in 2015 to the 2012 cost estimates related to the implementation of new CNSC requirements for certain facilities (Ex. C2-1-1 Table 3, Note 4). The actual expenses were consistent with the budgeted amount in 2013 and the OEB-approved amount in 2015, and were higher than the OEB-approved amount in 2014 on account of the above noted facilities removal costs. The variability in forecast expenses over the test period reflects fluctuations in waste volumes based on information provided by Bruce Power.

5.10.7 <u>Interest</u>

The interest expense associated with the Bruce assets declined over the historical period from $20.2M in 2013 to $15.0M in 2015, reflecting a lower allocation factor and, in 2015, a decline in OPG's non-project specific corporate debt levels. The expense is projected to increase in 2016 and over the test period, mainly due to forecast increases in OPG's non-project specific corporate debt levels over the period.

The actual interest expense attributed to the Bruce assets was higher than budgeted in 2013 and higher than OEB-approved amounts in 2014 and 2015. This was primarily due to a higher allocation factor from the increase in the net book value of the Bruce fixed assets relative to OPG's total fixed assets following the adjustments to ARC at the end of 2012.[22]

5.10.8 Current Income Taxes

The non-derivative portion of current income tax expense was higher in 2014 over 2013, primarily due to lower nuclear segregated fund contributions in 2014 per the currently approved segregated fund contribution schedule, and slightly higher in 2015 over 2014, mainly due to lower nuclear liability cash expenditures in 2015. The historical period expense was largely consistent with budgeted (2013) and OEB-approved (2014 and 2015) amounts.

Forecast current income taxes are an expense of $43.8M in 2016, $38.2M in 2017, $26.3M in 2018 and $9.1M in 2019 and a recovery of $17.7M in 2020 and $21.4M in 2021. Excluding the impact of the Bruce Derivative, this represents a decline in the expense over the test period compared to 2015. This is mainly due to increasing contributions to the nuclear segregated funds per the currently approved contribution schedule, forecast increases in nuclear liability cash expenditures, and lower base rent payments starting in 2019.

The derivative portion of current income taxes for 2013 to 2015 reflects the incidence of the supplemental rent rebate being payable to Bruce Power in a given year.

5.10.9 Deferred Income Taxes

The historical period year-over-year and actual-to-budget or actual-to-OEB-approved amount variability for the non-derivative portion of deferred income taxes reflects variances in nuclear segregated fund earnings and contributions, and nuclear liability cash expenditures. Excluding the impact of the Bruce Derivative in 2015, the deferred income tax credit of $70.5M in 2016 is forecast to be higher than the credit of $63.4M in 2015, primarily due to the projected increase in accretion expense in 2016. The deferred income tax credits are generally projected to decrease over the test period, from a high of $65.0M in 2017 to a low of $9.6M in 2021, reflecting increases in nuclear segregated fund contributions and nuclear liability cash expenditures, and lower base rent payments starting in 2019.

[22] EB-2013-0321 Ex. C2-1-1

The derivative portion of deferred income taxes fluctuated over the 2013-2015 period as a result of changes in the fair value of the Bruce Derivative, the incidence of the rebate being payable to Bruce Power and, in 2015, the reversal of the derivative liability following the 2015 Amendment.

Numbers may not add due to rounding.

Table 1
Bruce Lease Net Revenues ($M)

Line No.	Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Non-Derivative Portion:									
1	**Bruce Lease Revenues**	261.2	262.8	266.1	237.4	251.1	246.5	245.0	257.4	223.6
2	**Bruce Costs**	230.5	191.1	259.0	303.4	317.3	320.9	330.8	339.5	316.8
3	**Bruce Lease Net Revenues**	30.7	71.7	7.1	(66.0)	(66.1)	(74.3)	(85.9)	(82.1)	(93.1)
	Derivative Portion:									
4	**Bruce Lease Revenues**	(32.8)	44.7	224.9	0.0	0.0	0.0	0.0	0.0	0.0
5	**Bruce Costs (Income Tax)**	(8.2)	11.2	56.2	0.0	0.0	0.0	0.0	0.0	0.0
6	**Total Derivative Impact**	(24.6)	33.5	168.7	0.0	0.0	0.0	0.0	0.0	0.0
	Total:									
7	**Bruce Lease Revenues** (line 1 + line 4)	228.4	307.5	491.0	237.4	251.1	246.5	245.0	257.4	223.6
8	**Bruce Costs** (line 2 + line 5)	222.3	202.2	315.2	303.4	317.3	320.9	330.8	339.5	316.8
9	**Bruce Lease Net Revenues** (line 7 - line 8)	6.1	105.3	175.8	(66.0)	(66.1)	(74.3)	(85.9)	(82.1)	(93.1)

Numbers may not add due to rounding.

Table 2
Bruce Lease Revenues ($M)

Line No.	Revenue Source	2013 Actual[1]	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Site Services (OPG to Bruce Power)**	0.6	0.5	0.2	0.7	0.7	0.7	0.7	0.7	0.7
2	**Low & Intermediate Level Waste Services**	5.3	3.7	4.0	32.3	28.9	32.5	31.2	30.0	35.5
3	**Cobalt-60**	0.6	0.6	0.7	0.5	0.5	0.5	0.5	0.5	0.5
4	**Total Services Revenue**	6.6	4.9	4.9	33.5	30.1	33.7	32.4	31.2	36.7
5	**Fixed (Base) Rent[2,3]**	38.7	38.7	38.7	24.2	24.5	24.8	25.1	25.4	25.7
6	**Supplemental Rent - Non-Derivative Portion**	203.8	207.2	210.5	167.6	184.5	176.0	187.5	200.7	161.2
7	**Amortization of Initial Deferred Rent**	12.1	12.1	12.1	12.1	12.1	12.1	0.0	0.0	0.0
8	**Total Non-Derivative Rent Revenue**	254.6	257.9	261.3	203.9	221.0	212.8	212.6	226.1	186.9
9	**Total Non-Derivative Revenue** (line 4 + line 8)	261.2	262.8	266.1	237.4	251.1	246.5	245.0	257.4	223.6
10	**Supplemental Rent - Derivative Portion[4]**	(32.8)	44.7	224.9	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Revenue** (line 9 + line 10)	228.4	307.5	491.0	237.4	251.1	246.5	245.0	257.4	223.6

Note:
1 2013 Actual from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 36.
2 2013-2015 amounts represent straight-line revenue amounts calculated as shown in EB-2013-0321 Ex. L-1.3-17 SEC-018, Chart 3.
3 As discussed in Ex. G2-2-1, section 4.1.1, 2016-2021 amounts comprise: 1) reimbursement of OPG's executory costs and 2) a straight-line revenue amount of $9.1M. The full amount of base rent payments starting in 2019, subject to CPI escalation, is attributed to executory cost reimbursement ($16.0M for 2019, $16.3M for 2020, $16.6M for 2021). For 2016-2018, the executory cost component is determined by deescalating, at an assumed CPI rate of 2.0%, the 2019 base rent payment, yielding $15.1M for 2016, $15.4M for 2017 and $15.7M for 2018.
The straight-line revenue amount of $9.1M is calculated as the sum below, divided by the remaining expected lease term for accounting purposes of 49 years (from the end of 2015 to the end of 2064): Dec. 31, 2015 deferred base rent revenue balance of $222.1M (from EB-2013-0321 Ex. L-1.3-17 SEC-019, Att. 2, last column), plus 2016-2018 base rent payments of $88.0M, $90.0M and $92.0M respectively (from EB-2013-0321 Ex. L-1.3-17 SEC-019, Att. 2, first column), less corresponding portion of 2016-2018 base rent payments attributed to executory costs per above.
4 As discussed in Ex. G2-2-1, section 4.1.2, the derivative embedded in the Bruce lease agreement was reversed in 2015 following the December 2015 amendments to the agreement, which included the removal of the supplemental rent rebate provision giving rise to the embedded derivative.

Numbers may not add due to rounding.

Table 3
Comparison of Bruce Lease Revenues ($M)

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Site Services (OPG to Bruce Power)**	0.7	(0.0)	0.6	(0.1)	0.7	(0.1)	0.5	(0.3)	0.7	(0.4)	0.2
2	**Low & Intermediate Level Waste Services**	17.0	(11.7)	5.3	(1.6)	14.8	(11.1)	3.7	0.2	17.2	(13.2)	4.0
3	**Cobalt-60**	0.5	0.1	0.6	(0.1)	0.5	0.0	0.6	0.1	0.5	0.1	0.7
4	**Total Services Revenue**	18.2	(11.6)	6.6	(1.7)	16.0	(11.1)	4.9	(0.0)	18.4	(13.5)	4.9
5	**Fixed (Base) Rent**	38.7	(0.0)	38.7	0.0	38.7	(0.0)	38.7	(0.0)	38.7	(0.0)	38.7
6	**Supplemental Rent - Non-Derivative Portion**	206.7	(2.8)	203.8	3.3	207.9	(0.7)	207.2	3.3	212.0	(1.5)	210.5
7	**Amortization of Initial Deferred Rent**	12.1	0.0	12.1	0.0	12.1	0.0	12.1	0.0	12.1	0.0	12.1
8	**Total Non-Derivative Rent Revenue**	257.4	(2.8)	254.6	3.3	258.6	(0.7)	257.9	3.3	262.8	(1.5)	261.3
9	**Total Non-Derivative Revenue** (line 4 + line 8)	275.6	(14.4)	261.2	1.6	274.6	(11.8)	262.8	3.3	281.2	(15.0)	266.1
10	**Supplemental Rent - Derivative Portion**	0.0	(32.8)	(32.8)	77.5	0.0	44.7	44.7	180.2	0.0	224.9	224.9
11	**Total Revenue** (line 9 + line 10)	275.6	(47.2)	228.4	79.1	274.6	32.9	307.5	183.5	281.2	209.8	491.0

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
12	**Site Services (OPG to Bruce Power)**	0.2	0.4	0.7	0.0	0.7	0.0	0.7	0.0	0.7	0.0	0.7
13	**Low & Intermediate Level Waste Services**	4.0	28.3	32.3	(3.4)	28.9	3.6	32.5	(1.3)	31.2	(1.1)	30.0
14	**Cobalt-60**	0.7	(0.1)	0.5	0.0	0.5	0.0	0.5	0.0	0.5	0.0	0.5
15	**Total Services Revenue**	4.9	28.6	33.5	(3.4)	30.1	3.6	33.7	(1.3)	32.4	(1.1)	31.2
16	**Fixed (Base) Rent**	38.7	(14.5)	24.2	0.3	24.5	0.3	24.8	0.3	25.1	0.3	25.4
17	**Supplemental Rent - Non-Derivative Portion**	210.5	(42.9)	167.6	16.9	184.5	(8.5)	176.0	11.5	187.5	13.2	200.7
18	**Amortization of Initial Deferred Rent**	12.1	(0.0)	12.1	0.0	12.1	0.0	12.1	(12.1)	0.0	0.0	0.0
19	**Total Non-Derivative Rent Revenue**	261.3	(57.4)	203.9	17.2	221.0	(8.2)	212.8	(0.3)	212.6	13.6	226.1
20	**Total Non-Derivative Revenue** (line 15 + line 19)	266.1	(28.8)	237.4	13.8	251.1	(4.6)	246.5	(1.6)	245.0	12.4	257.4
21	**Supplemental Rent - Derivative Portion**	224.9	(224.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	**Total Revenue** (line 20 + line 21)	491.0	(253.7)	237.4	13.8	251.1	(4.6)	246.5	(1.6)	245.0	12.4	257.4

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
23	**Site Services (OPG to Bruce Power)**	0.7	0.0	0.7
24	**Low & Intermediate Level Waste Services**	30.0	5.5	35.5
25	**Cobalt-60**	0.5	0.0	0.5
26	**Total Services Revenue**	31.2	5.5	36.7
27	**Fixed (Base) Rent**	25.4	0.3	25.7
28	**Supplemental Rent - Non-Derivative Portion**	200.7	(39.6)	161.2
29	**Amortization of Initial Deferred Rent**	0.0	0.0	0.0
30	**Total Non-Derivative Rent Revenue**	226.1	(39.2)	186.9
31	**Total Non-Derivative Revenue** (line 26 + line 30)	257.4	(33.7)	223.6
32	**Supplemental Rent - Derivative Portion**	0.0	0.0	0.0
33	**Total Revenue** (line 31 + line 32)	257.4	(33.7)	223.6

Numbers may not add due to rounding.

Table 4

Bruce Net Fixed Assets[1] ($M)

Line No.	Item	2013 Actual[2]	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Opening Net Book Value**	1,963.4	1,858.9	1,754.9	4,399.6	4,298.7	4,197.9	4,097.1	3,996.3	3,895.6
2	**Add: Nuclear Liabilities Adjustment[3]**	0.0	0.0	2,747.5	0.0	0.0	0.0	0.0	0.0	0.0
3	**Add: Additions**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Less: Depreciation**	104.5	104.0	102.9	100.9	100.8	100.8	100.8	100.7	100.7
5	**Closing Net Book Value**	1,858.9	1,754.9	4,399.6	4,298.7	4,197.9	4,097.1	3,996.3	3,895.6	3,794.9

Notes:

1 Includes asset retirement costs presented in Ex. C2-1-1 Table 3.

2 2013 Actual from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 37.

3 Represents change in asset retirement costs effective December 31, 2015, as shown at Ex. C2-1-1 Table 3, line 8, col. (c).

Table 5
Bruce Costs ($M)

Line No.	Cost Item	2013 Actual[1]	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Depreciation**	104.5	104.0	102.9	100.9	100.8	100.8	100.8	100.7	100.7
2	**Property Tax**	11.6	11.6	12.4	12.0	13.0	13.3	13.6	14.0	15.1
3	**Accretion**	369.0	386.7	404.7	511.0	531.4	552.4	573.9	595.6	617.8
4	**(Earnings) Losses on Segregated Funds**	(337.1)	(411.8)	(338.6)	(379.8)	(395.7)	(413.7)	(432.8)	(454.8)	(479.8)
5	**Used Fuel Storage and Disposal**	54.0	58.9	61.0	65.1	71.4	70.8	74.9	81.7	64.2
6	**Waste Management Variable Expenses and Facilities Removal Costs**	2.8	3.9	4.1	2.5	2.1	2.6	2.4	2.9	4.1
7	**Interest**	20.2	18.6	15.0	18.4	21.1	24.1	26.7	26.8	25.8
8	**Total Costs Before Income Tax**	225.0	171.9	261.4	330.1	344.0	350.4	359.5	366.8	347.8
9	**Income Tax - Current - Non-Derivative Portion**	26.9	56.9	61.0	43.8	38.2	26.3	9.1	(17.7)	(21.4)
10	**Income Tax - Deferred - Non-Derivative Portion**	(21.4)	(37.7)	(63.4)	(70.5)	(65.0)	(55.8)	(37.8)	(9.7)	(9.6)
11	**Total Income Tax - Non-Derivative Portion**	5.5	19.2	(2.4)	(26.7)	(26.8)	(29.5)	(28.6)	(27.4)	(31.0)
12	**Total Non-Derivative Costs** (line 8 + line 11)	230.5	191.1	259.0	303.4	317.3	320.9	330.8	339.5	316.8
13	**Income Tax - Current - Derivative Portion**	(26.9)	(0.6)	(19.2)	0.0	0.0	0.0	0.0	0.0	0.0
14	**Income Tax - Deferred - Derivative Portion**	18.7	11.7	75.4	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Income Tax - Derivative Portion[2]**	(8.2)	11.2	56.2	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Costs** (line 12 + line 15)	222.3	202.2	315.2	303.4	317.3	320.9	330.8	339.5	316.8

Note:
1 2013 Actual from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 36.
2 As discussed in Ex. G2-2-1, section 4.1.2, the derivative embedded in the Bruce lease agreement was reversed in 2015 following the December 2015 amendments to the agreement, which included the removal of the supplemental rent rebate provision giving rise to the embedded derivative.

Table 6
Comparison of Bruce Costs ($M)

Line No.	Business Unit	Note	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Depreciation**		106.8	(2.2)	104.5	(0.6)	106.8	(2.8)	104.0	(1.1)	106.8	(3.9)	102.9
2	**Property Tax**		13.3	(1.7)	11.6	0.1	13.7	(2.1)	11.6	0.8	14.2	(1.8)	12.4
3	**Accretion**	1	367.8	1.2	369.0	17.7	382.9	3.8	386.7	17.9	397.3	7.4	404.7
4	**(Earnings) Losses on Segregated Funds**	2	(330.8)	(6.2)	(337.1)	(74.7)	(347.0)	(64.7)	(411.8)	73.1	(359.8)	21.1	(338.6)
5	**Used Fuel Storage and Disposal**	3	51.6	2.4	54.0	4.9	54.3	4.5	58.9	2.2	56.4	4.6	61.0
6	**Waste Management Variable Expenses and Facilities Removal Costs**	4	2.8	(0.0)	2.8	1.1	2.4	1.5	3.9	0.2	3.8	0.3	4.1
7	**Interest**		12.6	7.6	20.2	(1.6)	13.4	5.2	18.6	(3.6)	13.1	1.9	15.0
8	**Total Costs Before Income Tax**		223.9	1.1	225.0	(53.1)	226.5	(54.6)	171.9	89.5	231.8	29.6	261.4
9	**Income Tax - Current - Non-Derivative Portion**	5	28.5	(1.5)	26.9	30.0	57.1	(0.2)	56.9	4.1	59.1	1.9	61.0
10	**Income Tax - Deferred - Non-Derivative Portion**	6	(19.1)	(2.3)	(21.4)	(16.3)	(48.6)	10.9	(37.7)	(25.7)	(50.3)	(13.0)	(63.4)
11	**Total Income Tax - Non-Derivative Portion**		9.4	(3.9)	5.5	13.7	8.5	10.7	19.2	(21.5)	8.8	(11.2)	(2.4)
12	**Total Non-Derivative Costs** (line 8 + line 11)		233.3	(2.8)	230.5	(39.5)	235.0	(43.9)	191.1	68.0	240.6	18.5	259.0
13	**Income Tax - Current - Derivative Portion**	7	(27.4)	0.5	(26.9)	26.4	(19.8)	19.2	(0.6)	(18.6)	(20.0)	0.8	(19.2)
14	**Income Tax - Deferred - Derivative Portion**	8	27.4	(8.7)	18.7	(7.0)	19.8	(8.1)	11.7	63.6	20.0	55.4	75.4
15	**Total Income Tax - Derivative Portion**		0.0	(8.2)	(8.2)	19.4	0.0	11.2	11.2	45.0	0.0	56.2	56.2
16	**Total Costs** (line 12 + line 15)		233.3	(11.0)	222.3	(20.1)	235.0	(32.7)	202.2	113.0	240.6	74.7	315.2

Line No.	Business Unit	Note	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(c) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
17	**Depreciation**		102.9	(2.0)	100.9	(0.1)	100.8	0.0	100.8	(0.0)	100.8	(0.1)	100.7
18	**Property Tax**		12.4	(0.4)	12.0	1.0	13.0	0.3	13.3	0.3	13.6	0.3	14.0
19	**Accretion**	1	404.7	106.3	511.0	20.4	531.4	21.0	552.4	21.4	573.9	21.7	595.6
20	**(Earnings) Losses on Segregated Funds**	2	(338.6)	(41.1)	(379.8)	(16.0)	(395.7)	(18.0)	(413.7)	(19.1)	(432.8)	(21.9)	(454.8)
21	**Used Fuel Storage and Disposal**	3	61.0	4.1	65.1	6.3	71.4	(0.5)	70.8	4.0	74.9	6.8	81.7
22	**Waste Management Variable Expenses and Facilities Removal Costs**	4	4.1	(1.6)	2.5	(0.4)	2.1	0.5	2.6	(0.2)	2.4	0.5	2.9
23	**Interest**		15.0	3.4	18.4	2.7	21.1	3.0	24.1	2.6	26.7	0.0	26.8
24	**Total Costs Before Income Tax**		261.4	68.7	330.1	13.9	344.0	6.3	350.4	9.1	359.5	7.4	366.8
25	**Income Tax - Current - Non-Derivative Portion**	5	61.0	(17.2)	43.8	(5.6)	38.2	(11.9)	26.3	(17.1)	9.1	(26.8)	(17.7)
26	**Income Tax - Deferred - Non-Derivative Portion**	6	(63.4)	(7.2)	(70.5)	5.6	(65.0)	9.2	(55.8)	18.0	(37.8)	28.1	(9.7)
27	**Total Income Tax - Non-Derivative Portion**		(2.4)	(24.4)	(26.7)	(0.0)	(26.8)	(2.7)	(29.5)	0.9	(28.6)	1.3	(27.4)
28	**Total Non-Derivative Costs** (line 24 + line 27)		259.0	44.3	303.4	13.9	317.3	3.6	320.9	10.0	330.8	8.6	339.5
29													
30	**Income Tax - Current - Derivative Portion**	7	(19.2)	19.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	**Income Tax - Deferred - Derivative Portion**	8	75.4	(75.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	**Total Income Tax - Derivative Portion**		56.2	(56.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	**Total Costs** (line 28 + line 31)		315.2	(11.9)	303.4	13.9	317.3	3.6	320.9	10.0	330.8	8.6	339.5

Line No.	Business Unit	Note	2020 Plan	(c)-(a) Change	2021 Plan
			(a)	(b)	(c)
34	**Depreciation**		100.7	0.0	100.7
35	**Property Tax**		14.0	1.1	15.1
36	**Accretion**	1	595.6	22.2	617.8
37	**(Earnings) Losses on Segregated Funds**	2	(454.8)	(25.0)	(479.8)
38	**Used Fuel Storage and Disposal**	3	81.7	(17.5)	64.2
39	**Waste Management Variable Expenses and Facilities Removal Costs**	4	2.9	1.2	4.1
40	**Interest**		26.8	(1.0)	25.8
41	**Total Costs Before Income Tax**		366.8	(19.0)	347.8
42	**Income Tax - Current - Non-Derivative Portion**	5	(17.7)	(3.7)	(21.4)
43	**Income Tax - Deferred - Non-Derivative Portion**	6	(9.7)	0.1	(9.6)
44	**Total Income Tax - Non-Derivative Portion**		(27.4)	(3.7)	(31.0)
45	**Total Non-Derivative Costs** (line 40 + line 43)		339.5	(22.7)	316.8
46	**Income Tax - Current - Derivative Portion**		0.0	0.0	0.0
47	**Income Tax - Deferred - Derivative Portion**		0.0	0.0	0.0
48	**Total Income Tax - Derivative Portion**		0.0	0.0	0.0
49	**Total Costs** (line 44 + line 47)		339.5	(22.7)	316.8

Notes:
1. 2013 to 2015 Actual, 2016 Budget, 2017 to 2021 Plan from Ex. C2-1-1 Table 3, line 4.
2. 2013 to 2015 Actual, 2016 Budget, 2017 to 2021 Plan from Ex. C2-1-1 Table 3, line 13.
3. 2013 to 2015 Actual, 2016 Budget, 2017 to 2021 Plan from Ex. C2-1-1 Table 3, line 2.
4. 2013 to 2015 Actual, 2016 Budget, 2017 to 2021 Plan from Ex. C2-1-1 Table 3, line 3 plus line 9. 2014 Actual from Ex. C2-1-1 Table 3, line 3 plus facilities removal costs of $2.5M incurred in relation to contractual obligations under the Bruce lease agreement.
5. 2013 to 2015 Actual, 2016 Budget from Ex. G2-2-1 Table 7, line 38. 2017 to 2021 Plan from Ex. G2-2-1 Table 8, line 20.
6. 2013 to 2015 Actual, 2016 Budget from Ex. G2-2-1 Table 7, line 46. 2017 to 2021 Plan from Ex. G2-2-1 Table 8, line 30.
7. 2013 to 2015 Actual, 2016 Budget from Ex. G2-2-1 Table 7, line 37.
8. 2013 to 2015 Actual, 2016 Budget from Ex. G2-2-1 Table 7, line 45.

Table 7
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2013, 2014, 2015 and 2016

Line No.	Particulars	Note	2013 Actual[1]	2014 Actual	2015 Actual	2016 Budget
			(a)	(b)	(c)	
	Determination of Taxable Income					
1	**Earnings (Loss) Before Tax**	2	3.3	135.6	229.7	(92.7)
	Additions for Tax Purposes - Temporary Differences:					
2	**Base Rent Accrual**		42.3	44.3	46.3	63.8
3	**Depreciation**		104.5	104.0	102.9	100.9
4	**Accretion**		369.0	386.7	404.7	511.0
5	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		56.8	62.7	65.1	67.6
6	**Receipts from Nuclear Segregated Funds**		30.4	34.0	34.6	52.4
7	**Change in Fair Value of Bruce Derivative**		32.8	(44.7)	(224.9)	0.0
8	**Other**		2.5	4.9	2.8	7.7
9	**Total Additions - Temporary Differences**		638.4	592.0	431.5	803.4
	Deductions for Tax Purposes - Permanent Differences:					
10	**Deferred Rent Revenue**		14.2	14.2	14.2	14.2
	Deductions for Tax Purposes - Temporary Differences:					
11	**CCA**		5.7	5.3	5.3	5.8
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		91.3	100.1	88.4	162.6
13	**Contributions to Nuclear Segregated Funds**		85.9	(31.3)	(29.4)	(26.9)
14	**Earnings (Losses) on Nuclear Segregated Funds**		337.1	411.8	338.6	379.8
15	**Supplemental Rent Payment Reduction**		78.7	0.0	76.7	0.0
16	**Total Deductions - Temporary Differences**		598.6	485.9	479.6	521.3
17	**Taxable Income/(Loss) Before Loss Carry-Over**		29.1	227.5	167.3	175.2
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		(29.1)	(2.3)	0.0	0.0
19	**Taxable Income After Loss Carry-Over**		0.0	225.3	167.3	175.2
	Determination of Total Current Income Taxes					
20	**Taxable Income After Loss Carry-Over** (line 19)		0.0	225.3	167.3	175.2
21	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
22	**Income Taxes - Current**		0.0	56.3	41.8	43.8
	Determination of Total Deferred Income Taxes					
23	**Total Net Temporary Differences (line 9 - line 16)**		39.8	106.1	(48.2)	282.1
24	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%
25	**Deferred Income Taxes**	3	(10.0)	(26.5)	12.0	(70.5)
26	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)		(29.1)	(2.3)	0.0	0.0
27	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%
28	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		7.3	0.6	0.0	0.0
29	**Deferred Income Taxes - Total** (line 25 + line 28)		(2.7)	(26.0)	12.0	(70.5)
	Determination of Derivative and Non-Derivative Portions of Total Current Income Taxes					
30	**Taxable Income Before Loss Carry-Over - Impact of Derivative** (from line 15)		(78.7)	0.0	(76.7)	0.0
31	**Tax Loss Carry-Over From Prior Years - Impact of Derivative**	4	(29.1)	(2.3)	0.0	0.0
32	**Taxable Income After Tax Loss Carry-Over From Prior Years - Impact of Derivative** (line 30 + line 31)		(107.7)	(2.3)	(76.7)	0.0
33	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
34	**Income Taxes - Current - Derivative Portion**		(26.9)	(0.6)	(19.2)	0.0
35	**Income Taxes - Current - Non-Derivative Portion** (line 22 - line 34)		26.9	56.9	61.0	43.8
	Determination of Derivative and Non-Derivative Portions of Total Deferred Income Taxes					
36	**Net Temporary Differences - Impact of Derivative** (line 7 - line 15)		(45.8)	(44.7)	(301.6)	0.0
37	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%
38	**Deferred Income Taxes - Derivative Portion**		11.5	11.2	75.4	0.0
39	**Tax Loss Carry-Over - Impact of Derivative** (line 31)		(29.1)	(2.3)	0.0	0.0
40	**Income Tax Rate**		25.00%	25.00%	25.00%	25.00%
41	**Deferred Income Taxes - Tax Loss Carry-Over - Derivative Portion**		7.3	0.6	0.0	0.0
42	**Deferred Income Taxes - Total - Derivative Portion** (line 38 + line 41)		18.7	11.7	75.4	0.0
43	**Deferred Income Taxes - Total - Non-Derivative Portion** (line 29 - line 41)		(21.4)	(37.7)	(63.4)	(70.5)
	Income Tax Rate - Current					
44	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
45	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%
46	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Deferred					
47	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
48	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%
49	**Total Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%

Notes:

1 2013 Actual from EB-2013-0321 Ex. L-1.0-1 Staff-002, Att. 1, Table 38.

2 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 11 and Total Costs Before Income Tax in Ex. G2-2-1 Table 5, Line 8 for each corresponding year.

3 Effective 2015, OPG adopted US GAAP changes that require entities to present deferred income taxes as long term. For consistency purposes, the deferred income taxes for 2013 and 2014 were presented on the same basis as 2015 and subsequent years.

4 As noted in EB-2013-0321, Ex. L-1.0-1 Staff-002, Table 38, Note 2 the full amount of brought forward Bruce tax losses would be utilized in 2012 in the absence of the income tax deductions for the supplemental rent payment reduction in 2012. As such, in the abscence of this deduction, no losses would be available for utilization against the non-derivative portion of the 2013 and 2014 taxable income.

Numbers may not add due to rounding.

Table 8
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2017, 2018, 2019, 2020, and 2021

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Taxable Income						
1	**Earnings (Loss) Before Tax**	1	(92.9)	(103.8)	(114.5)	(109.4)	(124.1)
	Additions for Tax Purposes - Temporary Differences:						
2	**Base Rent Accrual**		65.5	67.2	(9.1)	(9.1)	(9.1)
3	**Depreciation**		100.8	100.8	100.8	100.7	100.7
4	**Accretion**		531.4	552.4	573.9	595.6	617.8
5	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		73.5	73.5	77.3	84.6	68.3
6	**Receipts from Nuclear Segregated Funds**		66.1	51.7	74.5	59.4	72.8
7	**Other**		3.4	2.2	2.8	2.3	2.3
8	**Total Additions - Temporary Differences**		840.7	847.8	820.1	833.5	852.7
	Deductions for Tax Purposes - Permanent Differences:						
9	**Deferred Rent Revenue**		14.2	14.2	0.0	0.0	0.0
	Deductions for Tax Purposes - Temporary Differences:						
10	**CCA**		6.3	6.0	5.7	5.6	5.5
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		172.1	186.7	207.9	237.0	231.5
12	**Contributions to Nuclear Segregated Funds**		6.8	18.1	22.6	97.5	97.5
13	**Earnings (Losses) on Nuclear Segregated Funds**		395.7	413.7	432.8	454.8	479.8
14	**Total Deductions - Temporary Differences**		580.9	624.6	669.1	794.8	814.2
15	**Taxable Income/(Loss) Before Loss Carry-Over**		152.7	105.1	36.6	(70.8)	(85.7)
16	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		0.0	0.0	0.0	0.0	0.0
17	**Taxable Income After Loss Carry-Over**	2	152.7	105.1	36.6	(70.8)	(85.7)
	Determination of Current Income Taxes						
18	**Taxable Income After Loss Carry-Over**		152.7	105.1	36.6	(70.8)	(85.7)
19	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
20	**Income Taxes - Current**	2	38.2	26.3	9.1	(17.7)	(21.4)
	Determination of Deferred Income Taxes						
21	**Total Net Temporary Differences** (line 8 - line 14)		259.8	223.1	151.1	38.7	38.4
22	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%
23	**Deferred Income Taxes**	3	(65.0)	(55.8)	(37.8)	(9.7)	(9.6)
24	**Tax Loss / Tax Loss Carry-Over** (line 15 or line 16)		0.0	0.0	0.0	0.0	0.0
25	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
26	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		0.0	0.0	0.0	0.0	0.0
27	**Deferred Income Tax - Total** (line 23 + line 26)		(65.0)	(55.8)	(37.8)	(9.7)	(9.6)
	Income Tax Rate - Current						
28	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
29	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
30	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Deferred						
31	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
33	**Total Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%

Notes:

1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 11 and Total Costs Before Income Tax in Ex. G2-2-1, Table 5, Line 8 for each corresponding year.

2 The benefit of carrying back the 2020 and 2021 tax losses to 2017 and 2018, respectively, would reduce the current income tax expense reported for 2020 and 2021, respectively, in accordance with GAAP for non-regulated businesses. The forecast income tax expense for 2020 and 2021 is presented on this basis.

3 Effective 2015, OPG adopted US GAAP changes that require entities to present deferred income taxes as long term.