K20.2

EB-2016-0152

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), as amended;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. (OPG) under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving payment amounts for its prescribed generating facilities between 2017 and 2021.

Compendium Materials Panel 5B (Finance, DVA, Nuclear Liabilities, Cost of Capital, Corporate Groups)

ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS

("OAPPA")

April 2017

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Consultant to OAPPA

AMENDED AND RESTATED BRUCE POWER REFURBISHMENT IMPLEMENTATION AGREEMENT

Between

BRUCE POWER L.P.

- and -

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

DATED as of the 3rd day of December, 2015

"**EOD Date**" has the meaning ascribed to it in Section 11.2(a)(iii)(A).

"**EOD Date + 6**" has the meaning ascribed to it in Section 11.2(a)(iii)(B)(1).

"**EOD Date + 12**" has the meaning ascribed to it in Section 11.2(a)(iii)(B)(2).

"**EOD Month**" has the meaning ascribed to it in Section 11.2(a)(iii)(A).

"**EPSCA**" means the Electrical Power Systems Construction Association or its successors, which successors may include such association as it may be reconstituted by its members or replaced by another Person party to a labour agreement with certain trade unions or councils of trade unions governing construction tradework performed at electrical power generation facilities, including the Facility.

"**ETA**" means Part IX of the *Excise Tax Act* (Canada).

"**Event of Default**" means a Counterparty Event of Default or a Generator Event of Default, as the case may be.

"**Excluded Business**" means: (i) the business and undertakings of the Generator related to the marketing and trading functions of the Generator in respect of retail and wholesale Electricity supply or conservation, and retail and wholesale demand response, including any Financial Contracts, Physical Delivery Contracts, transmission rights agreements, or load-related Ancillary Service agreements entered into in connection with any of the foregoing to which the Generator is a party or an arranger, broker or aggregator, and any other trading or hedging activities related to the foregoing, but excluding any Financial Contracts or Physical Delivery Contracts in respect of Bruce Energy that the Generator enters into in accordance with the provisions of Section 1.10(b); (ii) the intangible property, inventory, activities, undertakings, revenues and goodwill related to the production or sale of By-products; and (iii) the business and undertakings of the Generator related to all other activities undertaken by the Generator that are not directly or indirectly related to the Facility or the site on which the Facility is located; and in the case of (i) and (iii) above, includes the assets, property, personnel, inventory, revenue and goodwill related thereto.

"**Expected Annual Operating Costs**" has the meaning ascribed to it in Exhibit 4.3.

"**Expected Planning Period per MWh Operating Costs**" has the meaning ascribed to it in Exhibit 4.3.

"**Expected End-of-Life Date**" means, in respect of a Unit, the approximate date on which such Unit is predicted by the Generator to start to be Effectively Decommissioned, which as at the date hereof is as follows:

Units 1 and 2:	December 31, 2043
Unit 3:	December 31, 2061
Unit 4:	December 31, 2062
Unit 5:	December 31, 2062
Unit 6:	December 31, 2058

Units 7 and 8: December 31, 2063

"**Facility**" means the Bruce nuclear power generation facilities leased and operated by the Generator and located near Tiverton, Ontario which comprises Bruce A, Bruce B and the Common Facilities.

"**Facility-Specific Common Assets**" means the facilities, assets, systems and equipment common to either the Bruce A Units or the Bruce B Units, as the case may be, including unit zero, fuel route and the control systems.

"**Fifth Unit**" means the fifth Unit to be Refurbished, which as at the date hereof is expected to be Unit 7.

"**Final Completion**" means final completion of a Refurbished Unit, being the earlier of: (i) the date that is 24 months after the Commercial Operation Date of such Refurbished Unit; and (ii) after the Commercial Operation Date, the date of completion of all punch list items in respect of Refurbishment of such Refurbished Unit.

"**Financial Contracts**" has the meaning ascribed to it in Section 2.15(b).

"**Financial Model**" means the Original Financial Model as the same may change from time to time in response to a Financial Model Adjustment or in accordance with the provisions of Exhibit 1.1(c).

"**Financial Model Adjustment**" means any adjustment from time to time to the then current Financial Model resulting from an Adjustment Event to reflect the impact of such Adjustment Event.

"**FIPPA**" means the *Freedom of Information and Protection of Privacy Act* (Ontario).

"**First ARR Date**" has the meaning ascribed to it in Exhibit 4.6.

"**First Unit**" means the first Unit to be Refurbished, which as at the date hereof is expected to be Unit 6.

"**Fixed Asset Management Costs**" has the meaning ascribed to it in Exhibit 4.10.

"**Flexible Nuclear Generation**" means the component of the Facility that has flexibility for reductions due to the operation of condenser steam discharge valves, and that is made available, in accordance with Section 2.16, at the sole discretion of the Generator to manoeuvre without requiring a Unit to shut down under normal operations, while respecting safety, technical, equipment, environmental and regulatory restrictions.

"**Force Majeure**" has the meaning ascribed to it in Section 12.4.

"**Force Majeure – Eligible Asset Management Work**" means: (i) all Asset Management Work in respect of a Unit that occurs between the Refurbishment Outage Date and the Commercial Operation Date of such Unit; (ii) the specific components of Asset Management Work listed in Exhibit 12.4; and (iii) any work listed under the heading of Balance of Plant on Exhibit 2.1 and that is carried out on a Terminated Unit pursuant to a Unit Extension Plan.

Unit	Scheduled Refurbishment Outage Date	Planned Duration
First Unit	January 1, 2020	48 months (December 31, 2023)
Second Unit	January 1, 2023	42 months (June 30, 2026)
Third Unit	January 1, 2025	36 months (December 31, 2027)
Fourth Unit	July 1, 2026	36 months (June 30, 2029)
Fifth Unit	July 1, 2028	36 months (June 30, 2031)
Sixth Unit	July 1, 2030	36 months (June 30, 2033)

Each period set out in the column "**Planned Duration**" above is an estimate only by the Generator as at the date hereof of the Refurbishment Outage for such Unit.

2.3 Refurbishment Timing

Subject to the provisions of this Agreement, the Generator will commence the Refurbishment Work for each of Units 3 through 8 in accordance with the schedule for commencing the Refurbishment Outage set out in the second column of the table in Section 2.2, as it may be changed in accordance with the following:

(a) The Contract Price will not be adjusted (including for greater certainty due to changes in the timing of Refurbishment Outages and timing of Refurbishment Costs) as the result of:

(i) the Generator not being able to operate a Unit until its Scheduled Refurbishment Outage Date; or

(ii) additional Outages taken or expenditures made on a Unit for maintenance or capital expenditures required in order for such Unit to remain in operation until its Scheduled Refurbishment Outage Date except in respect of the movement of Asset Management Work in accordance with the provisions of Sections 2.11 and 4.10 and the provisions set forth in Exhibit 4.10.

(b) Prior to the Refurbishment Lock-In Date of a Unit, the Generator may, acting reasonably, on prior notice to the Counterparty move the Scheduled Refurbishment Outage Date of such Unit earlier without the Counterparty's approval, or later, pursuant to this Section 2.3(b), by up to an aggregate of three months without the Counterparty's approval. There will be no Contract Price Adjustment for such a change to a Scheduled Refurbishment Outage Date.

(c) Prior to the Refurbishment Lock-In Date of a Unit, the Generator may, by notice to the Counterparty, propose a delay of greater than three months to the Scheduled Refurbishment Outage Date of such Unit. Such notice will provide reasonable details of the proposed change and the reasons therefor. In addition, such proposal will specify the proposed new Scheduled Refurbishment Outage Date, reasonable details of all corresponding changes to the then current

Ontario

NEWS

Ministry of Energy

Ontario Commits to Future in Nuclear Energy

Agreement Secures Low-Cost, Clean Electricity Supply and Supports 23,000 Jobs Across Province

December 3, 2015 9:15 A.M.

Ontario has updated its contract with Bruce Power and will proceed with the refurbishment of six nuclear units at the Tiverton-based nuclear generation station.

Nuclear refurbishment will boost economic activity across Ontario, create jobs, ensure savings for ratepayers and secure a clean supply of reliable electricity. The Bruce Power refurbishment project will make up to 23,000 jobs possible and generate about $6.3 billion in annual economic benefits in communities throughout the province. Ontario is home to a globally recognized CANDU nuclear supply chain with more than 180 companies employing thousands of highly skilled workers.

The government was further able to optimize the nuclear refurbishment schedule in order to maximize the value of existing nuclear units. The revised timeline will mean construction commences in 2020, rather than the previously estimated start date of 2016.

Accordingly, the updated agreement has achieved $1.7 billion in savings for electricity customers when compared to the forecast in the 2013 Long-Term Energy Plan (2013 LTEP). This means a reduction in forecast household electricity bills by about $66 each year over the next decade. The contract also protects the interests of electricity consumers by ensuring Bruce Power assumes full risk for any potential cost overruns or delays.

Key aspects of the updated agreement include:

- Securing 6,300 MW of emissions-free, baseload generating capacity while deferring major project work to 2020, to maximize value of the units
- Bruce Power would invest approximately $13 billion of its own funds and agrees to take full risk of cost overruns on refurbishments of the six nuclear units

- Initial price for Bruce Power's generation set at $65.73/MWh starting January 1, 2016. The average price over the life of the contract is estimated to be $77/MWh, or 7.7 cents per kilowatt hour (kWh).
- Both prices are within the range assumed in the 2013 LTEP for refurbished nuclear energy and are lower than the average price of electricity generation in Ontario, which in 2015 was $83/MWh
- Definitive contract off-ramps that allow the government to assess Bruce Power's cost estimates for each reactor prior to its refurbishment and stop the refurbishment if the estimated cost exceeds a pre-defined amount

The province is achieving balance by contracting affordable, stable and reliable generation for residents and businesses while securing investments that will be a key source of local job creation and economic growth.

Securing clean, reliable baseload power for decades to come is part of the government's plan to build Ontario up. The four-part plan is includes investing in people's talents and skills, making the largest investment in public infrastructure in Ontario's history, creating a dynamic, innovative environment where business thrives and building a secure retirement savings plan.

QUOTES

" This agreement makes 23,000 jobs possible and supports an estimated $6.3 billion in annual, local economic development. Our updated agreement with Bruce Power secures 6,300 MW of emission-free, low-cost electricity supply. These actions will save the electricity system $1.7 billion and provide important relief for electricity consumers."
- Bob Chiarelli
Minister of Energy

" Today is a major milestone in the history of Bruce Power as we build on our existing agreement with the province and extensive experience to enter the next phase of our site development. This provides us the opportunity to secure our long-term role as a supplier of low-cost electricity by demonstrating we can successfully deliver this program incrementally."
- Duncan Hawthorne
President and CEO, Bruce Power

QUICK FACTS

- Following the release of the 2013 LTEP, the amended BPRIA was negotiated over two years by the Independent Electricity System Operator (IESO).

- The Bruce nuclear site is the world's largest operating nuclear facility. Since it was formed in 2001, Bruce Power and its industry partners have engineered and developed first-of-a-kind technologies that helped return four dormant nuclear units to service.
- Nuclear energy plays a fundamental role in Ontario's electricity system. It provides over half of Ontario's annual generation, meeting most of Ontario's baseload requirements.

LEARN MORE

- Learn about Bruce Power
- Read Affordable Power. Jobs & Growth. By the Numbers: Securing both affordable power
- Read Ontario's 2013 Long-Term Energy Plan
- Lean more about the amended BPRIA

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Disponible en Français

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)

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

[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. Low & Intermediate Level Waste Management Revenues: 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.

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

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

Numbers may not add due to rounding.

Table 4

Impact of Year End 2015 Adustment - Assignment of ARO Adjustment and Allocation of ARC to Nuclear Stations ($M)

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	OPG Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	December 31, 2015 Actual:								
1	Decommissioning Program	3.2	5.4	7.3	15.9	(42.9)	288.0	245.0	260.9
2	Low and Intermediate Level Waste Storage Program	(4.2)	(19.7)	168.4	144.5	(57.4)	109.4	52.0	196.5
3	Low and Intermediate Level Waste Disposal Program	(21.0)	(41.3)	149.2	86.9	(172.2)	157.6	(14.6)	72.3
4	Used Fuel Disposal Program	47.5	13.4	(668.7)	(607.8)	(258.5)	2,702.6	2,444.1	1,836.3
5	Used Fuel Storage Program	(28.7)	(37.0)	8.7	(57.1)	24.9	(4.0)	21.0	(36.1)
6	ARO Adjustment Assignment to Station Level	(3.1)	(79.2)	(335.2)	(417.5)	(506.2)	3,253.6	2,747.5	2,330.0
7	Asset Retirement Cost Adjustment	(3.1)	(79.2)	(335.2)	(417.5)	(506.2)	3,253.6	2,747.5	2,330.0

Numbers may not add due to rounding.

Table 3
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2013 to 2021

Line No.	Description	Note	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)
	ASSET RETIREMENT OBLIGATION										
1	Opening Balance	2	7,125.5	7,461.2	7,814.5	10,946.0	11,362.0	11,794.8	12,234.0	12,677.3	13,120.4
2	Used Fuel Storage and Disposal Variable Expenses		54.0	58.9	61.0	65.1	71.4	70.8	74.9	81.7	64.2
3	Low & Intermediate Level Waste Management Variable Expenses		2.8	1.5	1.5	2.5	2.1	2.6	2.4	2.9	4.1
4	Accretion Expense		369.0	386.7	404.7	511.0	531.4	552.4	573.9	595.6	617.8
5	Expenditures for Used Fuel, Waste Management & Decommissioning		(90.0)	(94.6)	(85.3)	(162.6)	(172.1)	(186.7)	(207.9)	(237.0)	(231.5)
6	Consolidation and Other Adjustments		(0.1)	0.8	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0
7	Closing Balance Before Year-End Adjustments (lines 1 through 6)		7,461.2	7,814.5	8,195.9	11,362.0	11,794.8	12,234.0	12,677.3	13,120.4	13,575.0
8	Year-End 2015 Adjustment Reflecting Nuclear Station End of Life Changes	3	0.0	0.0	2,747.5	0.0	0.0	0.0	0.0	0.0	0.0
9	2012 CNSC Requirements Adjustment	4	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0
10	Closing Balance (line 7 through 9)		7,461.2	7,814.5	10,946.0	11,362.0	11,794.8	12,234.0	12,677.3	13,120.4	13,575.0
11	Average Asset Retirement Obligation ((line 1 + line 7)/2)		7,293.3	7,637.8	8,005.2	11,154.0	11,578.4	12,014.4	12,455.6	12,898.8	13,347.7
	NUCLEAR SEGREGATED FUNDS BALANCE										
12	Opening Balance	2	6,400.1	6,792.7	7,139.1	7,413.8	7,714.3	8,050.7	8,430.9	8,812.0	9,304.7
13	Earnings (Losses)		337.1	411.8	338.6	379.8	395.7	413.7	432.8	454.8	479.8
14	Contributions		85.9	(31.3)	(29.4)	(26.9)	6.8	18.1	22.6	97.5	97.5
15	Disbursements		(30.4)	(34.0)	(34.6)	(52.4)	(66.1)	(51.7)	(74.5)	(59.4)	(72.8)
16	Closing Balance (line 12 through 15)		6,792.7	7,139.1	7,413.8	7,714.3	8,050.7	8,430.9	8,812.0	9,304.7	9,809.2
17	Average Nuclear Segregated Funds Balance ((line 12 + line 16)/2)		6,596.4	6,965.9	7,276.5	7,564.0	7,882.5	8,240.8	8,621.4	9,058.3	9,557.0
	ASSET RETIREMENT COSTS (ARC)										
18	Opening Balance	2	1,944.8	1,843.6	1,743.8	4,390.9	4,290.7	4,190.5	4,090.3	3,990.1	3,889.9
19	Reconciliation Adjustment		0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Depreciation Expense		(101.2)	(100.4)	(100.4)	(100.2)	(100.2)	(100.2)	(100.2)	(100.2)	(100.2)
21	Closing Balance Before Year-End Adjustments (line 18 + line 19 + line 20)		1,843.6	1,743.8	1,643.5	4,290.7	4,190.5	4,090.3	3,990.1	3,889.9	3,789.7
22	Year-End 2015 Adjustment Reflecting Nuclear Station End of Life Changes	3	0.0	0.0	2,747.5	0.0	0.0	0.0	0.0	0.0	0.0
23	Closing Balance (line 21 + line 22)		1,843.6	1,743.8	4,390.9	4,290.7	4,190.5	4,090.3	3,990.1	3,889.9	3,789.7
24	Average Asset Retirement Costs ((line 18 + line 21)/2))		1,894.2	1,793.7	1,693.6	4,340.8	4,240.6	4,140.4	4,040.2	3,940.0	3,839.8

Notes:

1 As shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Table 7, col. (b)

2 Opening balances in col. (a) from EB-2013-0321, Ex. C2-1-1 Table 3, col. (c).

3 Adjustment recorded on December 31, 2015 reflecting the changes to station end-of-life date assumptions underlying the ARO calculation, see Ex. C2-1-1 Table 4.

4 See Ex. C2-1-1 Table 2, Note 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).