OPG 2014/2015 Payment Amounts Application

EB-2013-0321

AMPCO Compendium

Panel 4 Nuclear

Nuclear Business Planning
OM&A
Benchmarking
Nuclear Projects

June 19, 2014

to final approval by the IESO, which can deny this approval at any time up to the start of the outage.

For the test period, there is a single unit planned outage at Darlington in both 2014 and 2015. In addition, there is a VBO in which all 4 units will be shut down A station-wide 4 unit station VBO is required by the regulator every 12 years and a Station Containment Outage ("SCO") every 6 years. A SCO also requires that all 4 units be shut down, but for a shorter duration. A Darlington VBO was last conducted in 2009. The next planned VBO that was scheduled for 2021 has been moved forward to 2015, eliminating the need for a scheduled SCO in 2015 and a VBO in 2021. OPG is seeking regulatory approval to eliminate the need for SCO's going forward. This will shift these 4 unit station outages from a 6 year cycle to a 12 year cycle. This change will result in savings in the number of outage days in 2021 and beyond and will also reduce the complexity and resource demands during the Darlington Refurbishment Project.

The six Pickering units are on a two year planned outage cycle and therefore Pickering will be subject to 3 planned outages in both 2014 and 2015. In addition there is one mid cycle planned outage in 2014.

The outage durations include a station level allowance for uncertainty related to potential discovery work and a nuclear fleet level allowance under the control of the Chief Nuclear Officer to address risks to the completion of the outage on schedule, risks that could emerge from fleet aging issues, or the complexity in fleet level activities (e.g., availability of Inspection Maintenance Service resources to service multiple outages).

3. 1.2 <u>Forced Loss Rate (FLR)</u>

Variances to planned generation result from forced production losses (i.e., unplanned outages and derates). OPG projects FLR targets that reflect the risk of forced production losses at Darlington and Pickering. The FLR targets are based on the plants' historical performance, any known improvements or plant material condition issues, and initiatives to improve equipment reliability.

Board Staff Interrogatory #081

Ref: Exh F2-4-1, F2-4-2, N1-1-1 (page 15)

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

The application notes actual and forecast outage OM&A costs over the period 2010 - 2015 primarily reflect items including preparatory work in 2013 and 2014 for the 2015 Darlington Vacuum Building Outage ("VBO") followed by the four unit VBO outage in 2015. OPG also notes outage OM&A expenditures are forecast to increase by $68.0M in 2015 from 2014 plan levels, "primarily" due to the execution of the VBO at Darlington. In addition, outage OM&A expenditures in 2013 were forecast to increase $96.7M from the 2012 actuals and the main driver of that increase was the impact of Darlington's 3-year outage cycle which also included preparatory work for the 2015 Darlington VBO. The subsequent OPG Impact Statement stated that 39 additional planned outage days would be required for VBO Outage.

a) Please identify the costs associated with the VBO execution in 2015 and the amounts in 2013 and 2014 related to the VBO preparatory work.
b) Please identify the actual 2013 costs incurred for preparatory work for the 2015 VBO.
c) Please also identify the actual costs associated with the most recently completed VBO for both Pickering and Darlington broken down based on VBO preparatory work and VBO execution.

Response

a) In the 2013 - 2015 Business Plan, the costs associated with the VBO execution in 2015 is $74.3M. The VBO preparatory work is $3.5M in 2013 and $11.1M in 2014.

   In the 2014 - 2016 Business Plan, the VBO execution is $84.2M and the VBO preparatory work in 2014 is $11.8M. The primary drivers for the increase in the 2014 - 2016 plan is the additional funding for the Pressure Relief Valve replacement and Emergency Service Water piping replacement. (

b) The 2013 actual costs incurred for preparatory work for the 2015 VBO was $0.5M. The 2013 actual VBO costs were lower than plan due to the need to focus on higher priority work activities during Darlington's two planned outages and forced outages which delayed outage planning work for the VBO. The 2013 planned work will be completed in 2014.

c) The most recently completed VBO at Pickering was in 2010. The cost of preparatory work for the 2010 VBO was $6.5M and the execution cost was $30.1M.

The most recently completed VBO at Darlington was in 2009. The cost of preparatory work for the 2009 VBO was $9.0M and the execution cost was $35.4M. The 2015 VBO costs are significantly higher than the 2009 VBO as the 2015 VBO includes additional scope to allow for the transition to a 12 year station outage frequency which will eliminate a full station outage during the refurbishment project.

AMPCO Interrogatory #030

Ref: Exhibit E2, Tab 1, Schedule 1 Page 3

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please provide the equivalent TWh for the following outages that OPG has accounted for in its test period production forecast:

- Darlington Vacuum Building Outage in 2015
- Pickering Unit #1 mid-cycle planned outage of 20 days
- Pickering's forecast Forced Loss rate of 7.8% in 2014 and 5.5% in 2015
- Darlington's Forced Loss Rate of 1.3% in 2014 and 1.0% in 2015

Response

- Darlington Vacuum Building Outage in 2015:
  The Darlington Unit 3 planned outage overlaps with the Darlington VBO. The impact of the VBO on the Unit 3 planned outage is 7.2 days

  Unit 1 – 47.5 days
  Unit 2 – 51.5 days
  Unit 3 – 7.2 days
  Unit 4 – 50.8 days
  Total = 157.0 days (3.31 TWh)

- Pickering Unit #1 mid-cycle planned outage of 20 days:
  0.25 TWh in 2014

- Pickering's forecast Forced Loss rate of 7.8% in 2014 and 5.5% in 2015:
  1.82 TWh in 2014
  1.29 TWh in 2015

- Darlington's Forced Loss Rate of 1.3% in 2014 and 1.0% in 2015:
  The 2014 forced loss rate is actually 1.25% (i.e., was rounded to 1.3%), which is 0.31 TWh. The comparable figure for 2015 is 0.27 TWh.

AMPCO Interrogatory #032

Ref: Exhibit N1, Tab 1, Schedule 1, Page 15

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Preamble: OPG indicates that the updated production forecast for Darlington for 2014 and 2015 in the 2014-2016 Business Plan shows a 1.6 TWh reduction in generation compared to the 2013-2015 Business Plan, due to an increase of 61.9 planned outage days over the two-year period:

Please provide the equivalent TWh for the following:

a) 39 additional planned outage days for VBO in 2015

Response

a) The 39.0 additional planned outage days is equivalent to 0.83 TWh.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2009 Plan versus 2008 Plan

The OPG nuclear fleet production forecast for 2009 of 49.9 TWh is 1.5 TWh less than the 2008 plan of 51.4 TWh.

The reduction in planned production in 2009 compared to 2008 is driven by a significant increase in the number of planned outage days at Darlington due to the station containment/vacuum building outage ("VBO"). This outage will take all four Darlington units off-line for approximately four weeks. The VBO is required to complete a thorough inspection/maintenance program of the station's containment system, one of its major safety systems. The inspection/maintenance activities are prescribed by the Canadian Nuclear Safety Commission and are required to maintain Darlington's operating licence (Canadian Nuclear Safety Commission licensing is further discussed at Ex. A1-T6-S1). Consequently, in 2009 Darlington will require 100.3 additional outage days versus the 2008 plan and produce 2.1 TWh less generation than the 2008 plan.

Other outage work activities planned for Darlington include replacement of feeders which cannot be completed in tandem with the VBO, but must be undertaken by way of a series of separate planned outages. The VBO makes the containment function unavailable, thereby restricting operations and maintenance on systems/equipment that require containment availability. There are also logistical and resource constraints that limit the outage work activities during the VBO.

While 2009 production for the combined nuclear fleet is forecast to be lower than in 2008 due to the VBO at Darlington, OPG is forecasting an 0.3 TWh generation increase at Pickering B due to a 14 day reduction in Pickering B's planned outage program. The reduction in planned outage days at Pickering B in 2009 compared to 2008 reflects completion of steam generator repairs and service water work in 2008. Pickering A's planned outage program for 2009 also contains 3 fewer Planned Outage days then the 2008 schedule.

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transformer, and three separate forced outages, totaling 74 days, due to problems with Unit 4's liquid zone control system. Pickering A's FLR benefited from a decision by the CNSC on November 16th, 2009 to remove the forced derate (3.0 per cent annually) at Pickering A.

Pickering B's actual 2009 production was 1.0 TWh less than budget primarily as a result of a 27.7-day forced extension to the Unit 5 planed outage to address high pressure service water and shutdown cooling pump discovery work. Pickering B's actual FLR in 2009 was 5.8 per cent, an improvement over the forecast FLR of 6.2 per cent. A significant achievement at Pickering B during 2009 was the successful completion of the 70 day planned outage at Unit 6 ahead of schedule.

<u>2009 Actual versus 2008 Actual</u>

The nuclear production for 2009 of 46.8 TWh was 1.4 TWh lower than the 2008 actual nuclear production of 48.2 TWh. As shown in Ex. E2-T1-S2 Table 1b, Darlington and Pickering A production in 2009 is lower than in 2008, while Pickering B's production is greater.

The main reason that Darlington's production in 2009 was lower than 2008 is the increase in the number of planned outage days due to the 2009 VBO. This outage resulted in all four Darlington units being off-line for approximately four weeks. The VBO was required to complete a thorough inspection/maintenance program of the station's containment system, one of its major safety systems. The inspection/maintenance activities are prescribed by the CNSC and are required to maintain Darlington's operating licence (CNSC licensing is further discussed at Ex. A1-T6-S1). Consequently, in 2009, Darlington required 101.2 additional outage days as compared to 2008 resulting in a production decline of 2.9 TWh compared to 2008. Darlington's performance was also impacted by a total of 11.9 days of forced extension to the planned outages related to the VBO.

Darlington's 2009 FLR also increased from 2008. Darlington's FLR in 2008 was exceptionally good at 0.7 per cent. While Darlington's FLR in 2009 of 1.6 per cent exceeded Darlington's 2008 FLR, Darlington's 2009 FLR was still better than forecast.

Board Staff Interrogatory #67

Ref: Exh N1-1-1 pages 15-23

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Planned outage days for Darlington are increased by a total of 61.9 days, with 93% (57.6 days) of the outage occurring in 2015. 39 additional planned outage days are added because of an increase in the vacuum building outage ("VBO") scope.

a) What factors were involved in changing the planning for VBO outages from the 2013-2015 Business Plan to the current plan?
b) In Exh E2-1-1, page 6, OPG states that it is seeking regulatory approval (presumably from the CNSC) to eliminate the station containment outages going forward and that this strategy of moving forward the VBO to 2015 is part of that regulatory plan.
   i. How critical is CNSC approval to the outage plans?
   ii. When will OPG know if they are successful with this strategy?
   iii. If regulatory approval is not obtained, what is OPG's plan to accommodate this scenario?
c) On page 15, the evidence contains the following statement: "….the 2015 VBO eliminates the need for the 2021 VBO, reducing the complexity and resource demands during the Darlington Refurbishment Project." To support this statement, did OPG prepare any analysis of the cost and benefits of moving the VBO forward to 2015?

Response

a) Please see the response to Ex. 05.5-17 SEC-074.

b)
   i. CNSC approval is required to change the frequency of the SCO as the requirement for the SCO is documented in the Darlington License Condition Handbook/Darlington Power Operating License.

   ii. During the SCO that has been combined with the VBO, OPG will complete the required testing to demonstrate future SCO's are not required. It is anticipated that the results will support OPG's request to the CNSC to eliminate the need for any future SCO outages.

   iii. Darlington submitted a request to the CNSC for approval to eliminate the 2021 SCO. If regulatory approval is not obtained, OPG will perform additional inspections or analysis to confirm to the CNSC that future SCO's are not required.

c) A high level summary was prepared which established a positive payback to implementing a 12 year VBO/SCO cycle for the life of the plant compared to a 12 year VBO/6 year SCO cycle. Also, eliminating the VBO/SCO in 2021 will have a benefit when Darlington is scheduled to have two units in refurbishment by reducing complexity and resource demands.

SEC Interrogatory #077

Ref: N1-1-1/p15

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Please provide the basis for updating Lake Ontario water temperatures (.28 TWH reductions). Also provide OPG's budget forecasts for the last 5 years for lake temperature forecast and the actual average. Please describe the relationship between lake temperature and generation output (e.g. in terms of temperature vs. output).

Response

The basis for the forecast losses due to high lake water temperature was the trend in actual production losses from 2009 to 2012. The actual production losses due to high lake water temperature ("HLWT") for the period 2009 - 2013 are shown in the table below:

Actual HLWT Production Losses (TWh)					
Station	2009	2010	2011	2012	2013
DN	0.23	0.22	0.23	0.27	0.19
PN	0.08	0.07	0.08	0.13	0.07
Total	**0.30**	**0.28**	**0.32**	**0.40**	**0.26**

OPG's forecast for production losses due to high lake water temperature for the last 5 business plans are summarized in the following charts. Darlington accounted for HLWT as a contributor to FLR in the 2010 - 2014 Business Plan and not as a separate component. However, following a review of past production losses in 2011, OPG determined that it had overstated the production forecast due, in part, to the impact of HLWT and began to separately account for HLWT in the production forecast.

Forecast HLWT Production Losses (TWh) - 2014-2016 BP			
Station/Year	2014	2015	2016
DN	0.34	0.34	0.34
PN	0.06	0.06	0.06
Total	**0.40**	**0.40**	**0.40**

Forecast HLWT Production Losses (TWh) - 2013-2015 BP			
Station/Year	2013	2014	2015
DN	0.20	0.20	0.20
PN	0.06	0.06	0.06
Total	**0.26**	**0.26**	**0.26**

Forecast HLWT Production Losses (TWh) - 2012-2014 BP			
Station/Year	2012	2013	2014
DN	0.20	0.20	0.20
PN	0.06	0.06	0.06
Total	**0.26**	**0.26**	**0.26**

Forecast HLWT Production Losses (TWh) - 2011-2015 BP					
Station/Year	2011	2012	2013	2014	2015
DN	0.15	0.15	0.15	0.15	0.15
PN	0	0	0	0	0
Total	**0.15**	**0.15**	**0.15**	**0.15**	**0.15**

Forecast HLWT Production Losses (TWh) - 2010-2014 BP					
Station/Year	2010	2011	2012	2013	2014
DN	0	0	0	0	0
PN	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**

As lake water temperature rises, so does the condenser temperature and pressure increase which leads to a decrease in generator output. The decrease in generator output is a result in a reduction of thermodynamic efficiency as a result of an increase in condenser pressure. The relationship is shown in the attached graph is similar to what would be seen in any thermal unit (be it nuclear or a conventional unit).

The relationship is shown in the attached graph to final approval by the IESO, which can deny this approval at any time up to the start of the outage.

For the test period, there is a single unit planned outage at Darlington in both 2014 and 2015. In addition, there is a VBO in which all 4 units will be shut down A station-wide 4 unit station VBO is required by the regulator every 12 years and a Station Containment Outage ("SCO") every 6 years. A SCO also requires that all 4 units be shut down, but for a shorter duration. A Darlington VBO was last conducted in 2009. The next planned VBO that was scheduled for 2021 has been moved forward to 2015, eliminating the need for a scheduled SCO in 2015 and a VBO in 2021. OPG is seeking regulatory approval to eliminate the need for SCO's going forward. This will shift these 4 unit station outages from a 6 year cycle to a 12 year cycle. This change will result in savings in the number of outage days in 2021 and beyond and will also reduce the complexity and resource demands during the Darlington Refurbishment Project.

The six Pickering units are on a two year planned outage cycle and therefore Pickering will be subject to 3 planned outages in both 2014 and 2015. In addition there is one mid cycle planned outage in 2014.

The outage durations include a station level allowance for uncertainty related to potential discovery work and a nuclear fleet level allowance under the control of the Chief Nuclear Officer to address risks to the completion of the outage on schedule, risks that could emerge from fleet aging issues, or the complexity in fleet level activities (e.g., availability of Inspection Maintenance Service resources to service multiple outages).

3. 1.2 <u>Forced Loss Rate (FLR)</u>

Variances to planned generation result from forced production losses (i.e., unplanned outages and derates). OPG projects FLR targets that reflect the risk of forced production losses at Darlington and Pickering. The FLR targets are based on the plants' historical performance, any known improvements or plant material condition issues, and initiatives to improve equipment reliability.

AMPCO Interrogatory #033

Ref: Exhibit N1, Tab 1, Schedule 1, Page 16

Issue Number: 5.5
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

a) Please confirm the total allowances in the production forecast for 2014 and 2015 separately for Darlington and Pickering.

Response

a) The 2014 - 2016 Business Plan has a nuclear fleet level allowance for Pickering planned outages in 2014 and 2015 of 102.8 days. The equivalent TWh is 1.27 TWh.

The 2014 - 2016 Business Plan has a nuclear fleet level allowance for Darlington planned outages in 2014 and 2015 of 23.7 days. The equivalent TWh is 0.50 TWh.

This is due to an increase of 86.6 planned outage days over the two-year period, as follows:

- An additional 23 day mid-cycle Unit 5 outage in 2014. In the 2013 Unit 5 outage, unexpected reductions in pressure tube to calandria tube gaps were noted. The 2014 mid-cycle planned outage is therefore required to measure the gap and to perform maintenance as required. Monitoring and maintaining the gap between calandria and pressure tubes is critical since there is the potential for blistering if the pressure tube and calandria tube touch which can result in failure of the pressure tube.
- The 2013 Unit 4 outage was deferred to January 2014. This resulted in the timing of all future Unit 1 and 4 planned outages being similarly deferred (e.g., the 2014 Unit 1 outage is deferred to 2015; and, the 2015 Unit 4 outage is deferred until 2016). The deferral of the 2013 Unit 4 fall outage into 2014 results in an additional seven planned outage days over the test period due to additional scope.
- An additional 28 day 2015 mid-cycle outage has been added to the 2014 - 2016 Business Plan in support of OPG's 2016 targeted reduction in FLR to 5.0 per cent. Pickering has a two year planned outage cycle (i.e., each Pickering unit is subject to a planned outage once every two years). However, starting in 2012, OPG began implementing short duration, mid-cycle planned outages (i.e., an additional planned outage within the two year cycle) for Pickering Units 1 and 4 to focus on preventative maintenance and to lessen the risk of future forced outages thereby improving reliability and reducing the FLR.
- OPG's generation plan includes allowances (Ex. E2-1-1, p. 6) to account for risks that can result in an extension of an outage. The reassessment increased the allowance for Pickering planned outages by a total of 28.6 outage days (0.30 TWh) over the two-year test period. This increase is based on an assessment of historical performance which showed that over the period 2005 to 2013, the average annual forced extension to planned outages at Pickering was 82.5 days (0.87 TWh per year).

2.3.1.2 <u>Darlington</u>

The Darlington production forecast for 2014 and 2015 in the 2014 - 2016 Business Plan has a 1.6 TWh reduction in generation compared to the 2013 - 2015 Business Plan.

be the last 4-unit station outage for 12 years including the term of the entire refurbishment project.

The reassessment also increased the allowances for Darlington planned outages by a total of 22.0 outage days (0.49 TWh) over the two-year test period. This increase is based on historical performance over the period 2005 - 2013. During this period the average forced extension to planned outages at Darlington was 0.24 TWH per year.

Nuclear fuel bundle costs have decreased by $19.3M over the test period (Table 4), primarily as a result of the lower forecast production.

Chart 8

Fuel Bundle Costs: Plan over Plan Changes

OPG Nuclear		**2014 ($M)**	**2015 ($M)**	**Total Variance ($M)**
Total Fuel Bundle Cost	2014-2016 Nuclear Business Plan	208.4	199.6	
	2013-2015 Nuclear Business Plan	220.3	207.0	
	Variance (BP2014-16 vs 2013-2015)	-11.9	-7.4	-19.3

2.3.2 <u>Previously Regulated Hydroelectric</u>

The updated previously regulated hydroelectric production forecast for 2014, included in the 2014 - 2016 Business Plan, is 20.1 TWh, or 1.0 TWh more than the forecast included in the 2013 - 2015 Business Plan. Increased production is forecast as a result of higher flows forecast for the Niagara and St. Lawrence Rivers.

Along with the higher production, the GRC costs for 2014 in the 2014 - 2016 Business Plan are $14.0M more than the original forecast. GRC costs for Niagara and Saunders increased as a result of higher forecast production.

Appendix A: Summary of Key Technical, Regulatory, Reputation and Economic Risks Associated with Continued Operations

Risk Description	Consequence	Mitigation Strategy	Impact on Continued Operations	Prob. of Success (Very High, High, Medium, Low, Very Low Unknown	Industry issue or unique to Pickering 5-8?
Technical Risks – Pressure Tubes					
Pressure tube to calandria tube contact	Potential for defect formation	**Technical:** SLAR all channels to 247k EFPH. SLAR revisits to address potential for post-SLAR spacer movement. Currently, the risk is being managed by probabilistic assessments and targeted revisits.	Additional planned outage days in Generation Plan to execute SLARs and SLAR "re-visits" to assure contact-free operation to 247,000 EFPH.	2yrs - High 5 yrs – Med-High	Unique to Pick 5-8 and some other Candu units.
Pressure tubes - hydrogen ingress to body of tube and rolled joint	Embrittlement of pressure tubes	**Technical:** Sampling of P/Ts (Scrape) to trend ingress rates. Laboratory testing to demonstrate P/T integrity at higher hydrogen concentrations **Regulatory:** Provide evidence to regulator to obtain increased limits	Potential additional time in outages to conduct sampling activities. If limits cannot be changed, potential to exceed limits near end of Continued Operations period	2yrs - High 5 yrs – Med-High	Industry
Pressure tube defects	Defect growth	**Technical:** Monitor in-service defects every outage; manage heat up/cool down cycles **Regulatory:** Gain acceptance of new assessment methodologies	Potential need to extend forced outages to inspect and disposition defects.	2yrs – Very High 5 yrs – Very High	Industry, but problem more acute for Pickering 5-8 due to higher flaw population
Technical Risks –Reactor Components					
Calandria tube defects	Leaking calandria tubes – unit shutdown	**Technical:** Tooling, procedures and capability are in place in the event of future failures.	Judged to be low probability based on P7A13 root cause assessment.	2 yrs – Very High 5 yrs - High	Industry
Liquid Injection Shutdown System Nozzle / Calandria tube contact	Leaking calandria tubes – unit shutdown	**Technical:** Follow-up inspections in upcoming outages and replacements of fuel channels if required. Tooling, procedures and capability are in place.	Could lead to a small number of pressure tube and calandria tube replacements.	2yrs – High 5yrs - High	Industry

Nuclear Business Plan Risks (Continued)

Risk Description	Risk Treatment	Residual Risk
Pickering Fuel Handling Failures Impact Station Operations		
Fuel Handling systems are at the end of 30 year design life, and reliability is poor.	Component obsolescence and end of life challenges will be addressed through component replacements. AP-913 will be implemented to identify issues and develop project scope. Fuel Handling FLR will be monitored through the Plant Health process.	Not all Single Point Vulnerable components will be replaced.
Vendor Quality Issues Impacting Equipment Reliability		
Nuclear generation lost due to vendor quality issues amounted to $74.5 million in 2010 (or 1.4 TWh) and $5.2 million in 2011 (or 0.1 TWh). As of July 2012, nuclear generation lost, due to vendor quality issues, was $20 million (or 0.3 TWh).	In 2011, OPG implemented a new management system for managing and monitoring supplier's quality performance including a process on tracking, controlling and dispositioning counterfeit, fraudulent, and/or sub-standard items (CFSI). In 2012, continued to refine the management system implemented in 2011. Supplier performance monitored using KPIs and metrics for generation loss, threats, and rework. Completed a self assessment on 'near miss' or lower tier quality incidents that could have negatively impacted on generation. Corrective action plan is in progress.	Target is 0.3 TWh by 2015. Continued vendor quality/CFSI issues causing lost generation.
Loss of Atomic Energy of Canada Limited (AECL) Capability and Knowledge		
Nuclear relies on AECL to support many maintenance and project activities. Due to the Government of Canada's annouced restructuring of AECL, there continues to be substantial uncertainty around the future capabilities of AECL.	OPG reviewed its AECL contracts and is negotiating with AECL for a long term service agreement for intellectual property (IP) owned by AECL. OPG is also negotiating with AECL for a separate IP agreement which clarifies OPG's rights to use the IP where past contracts were silent or unclear. Where OPG has clear IP rights, OPG is exploring Engineering, Procurement, Construct contracts with other vendors.	Residual risk relates to those specialized services and tooling which AECL has uncontested, or potentially contested, IP rights and/or existing capabilities such that an option of selecting an alternative vendor is not possible for OPG now, nor would OPG be able to quickly contract with an alternative vendor following demise of AECL. A subcomponent of residual risk is that some IP rights reside within AECL repository, so that future access could also be restricted.
Darlington Emergency Power Generator Failures (EPG) Impacting Station Operations		
EPG2 high bearing vibrations and nozzle cracks reduce service life and carry risk of failure.	Project will optimize strategy for installation of 3rd EPG and refurbishment of EPG2. Minimize thermo shock during testing and monitoring.	Failure of EPG2 followed by functional failure of EPG1 results in station outage and high cost to repair EPG2.
Surplus Nuclear Inventory Value Exceeds Provision at Pickering End of Life		
The value of surplus nuclear inventory on hand at the time Pickering reaches end of life (EOL) exceeds the set aside provision. An inadequate inventory obsolescence provision may eventually result in extraordinary charges to OPG's reported income.	A cross functional team with Supply Chain, Nuclear Operations and Finance staff has been developing a Project Charter and detailed action plans, including a third party wall to wall physical count in 2013, of Nuclear inventory, to validate the accuracy of inventory.	There may be surplus inventory on hand at the time of Pickering's end of life that exceeds the end of life provision. The financial impact could be between $50 and S100 million. This residual risk is to be re-assessed after risk treatment actions are completed.

2.4 Nuclear Production Forecast

The updated nuclear production forecast for 2014 is 0.5 TWh lower than in the 2014-2016 Business Plan due to lower forecast production for Pickering in 2014. There is no change to the Darlington forecast for 2014 and no change to the 2015 production forecast for both Pickering and Darlington. The changes in 2014 are summarized in Chart 4.

Chart 4

Updated Nuclear Production Forecast[1]

OPG Nuclear		2014	2015	Total Variance
Generation - TWH	Updated Forecast	48.5	46.1	
	2014-2016 Nuclear Business Plan	49.0	46.1	
	Variance (Updated Forecast vs. BP 2014-16)	-0.5	0.0	**-0.5**
FLR %	Updated Forecast	4.6	3.1	
	2014-2016 Nuclear Business Plan	4.1	3.1	
	Variance (Updated Forecast vs. BP 2014-16)	0.5	0.0	**0.5**
Planned Outage Days	Updated Forecast	430.3	585.1	
	2014-2016 Nuclear Business Plan	409.3	585.1	
	Variance (Updated Forecast vs. BP 2014-16)	21	0	**21**

1 Numbers may not add due to rounding

The Pickering production forecast for 2014 shows a 0.5 TWh reduction compared to the 2014-2016 Business Plan due to the following:

- The projected number of Pickering outage days has increased by a net 21 days (0.26 TWh) from 327.9 days to 348.9 days. This is due to a combination of an increase in forced extension to planned outages for Pickering Units 4 and 8 in spring 2014, and the cancellation of the 23 day mid-cycle Unit 5 outage, which was identified in the first Impact Statement filed in December as being required to address the gap between calandria tubes and pressure tubes (see Ex. N1-1-1, page 14, lines 2-7). The Pickering Unit 4 and Unit 8 outages were extended primarily due to increased discovery work and parts quality issues. The mid-cycle outage has been cancelled following CNSC acceptance of the fuel channel component disposition, which eliminated the requirement for pressure tube inspections for Unit 5 in 2014.
- The FLR projection for Pickering in 2014 has increased from 7.8% to 8.9% (0.24 TWh).

SCO/VBO Business As Usual Vs. OPG Proposed

Cost

Business As Usual	2009	2015	2021	2027
SCO (6 Yr Cycle)			x	x
(L-6.3-081) VBO (12 Yr Cycle)	$ 44.4		x	
Subtotal				
OPG Proposal	**2009**	**2015**	**2021**	**2027**
eSCO/VBO (12 Yr Cycle)		$ 96		x

(L-6.3-081)

TWh

Business As Usual	2009	2015	2021	2027
SCO (6 Yr Cycle)			x	x
VBO (12 Yr Cycle)			x	
Subtotal	2.1 TWh			(EB-2007-0905 E2-1-2-3
OPG Proposal	**2009**	**2015**	**2021**	**2027**
eSCO/VBO (12 Yr Cycle)		4.14 TWh		x

(L-5.5-081/032)

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