EB-2016-0152

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act*, *1998* for an Order or Orders determining payment amounts for the output of certain generation facilities.

CROSS-EXAMINATION COMPENDIUM OF THE SCHOOL ENERGY COALITION (Panel 1B)

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Corporate 2016 Balanced Scorecard

Corporate 2016 Balanced Scorecard - Proposed Metrics (Revised Feb 17, 2016)				
Weight	**Key Performance Indicators**	**Threshold**	**Business Plan**	**Stretch Target**
10%	**Safety, Environment, Reliability and Code of Conduct -** Deliver front-line/core services			
10%	**AIR:** All Injury rate	0.50	0.38	0.31
10%	• Safety focus areas: ○ Improvement in the area of Work Protection performance with emphasis on reducing human errors ○ Continued Focus on Situational Awareness and Routine Tasks. ○ Fostering a stronger employee health culture with a focus on enhanced support and mental health training. • No significant events that impact OPG's reputation	As determined by CEO		
50%	**Financial & Operating Performance –** Deliver customer value, Reduce costs & improve OPG financial health			
20%	EBT, excl. nuclear waste management segment ($M)	510	710	910
15%	Operating OM&A Expenses – Total OPG ($M)	2,625	2,500	2,375
15%	Production – Total OPG adjusted for SBG (TWh)	79.8	82.1	84.5
40%	**Long Term Energy Plan and Capital Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services			
10%	Refurbishment Project Cost – 2016 Actual Expenditures ($M) as a percentage of approved 2016 budget	100%	97.5%	95%
10%	Darlington Refurbishment Execution Schedule for Unit 2 - Defueling – Number of channels defueled on December 31, 2016	212	254	311
10%	Refurbishment Campus Plan - 3rd Emergency Power Generator engine set and Containment Filtered Venting System both in-service and D2O Heavy Water Storage Facility Ready to Receive Unit 2 PHT Water.	31-Dec	30-Nov	02-Nov
5%	Peter Sutherland Sr. Generating Station - Powerhouse Phase 1 Concrete Complete	26-Nov-16	26-Sep-16	15-Aug-16
5%	Refurbishment of PGS Reservoir - Completion of liner installation	15-Jan-17	15-Nov-16	30-Sep-16
100%				
These measures form the basis on which our overall Corporate performance will be assessed, but the scores against these measures and overall Corporate Score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.				

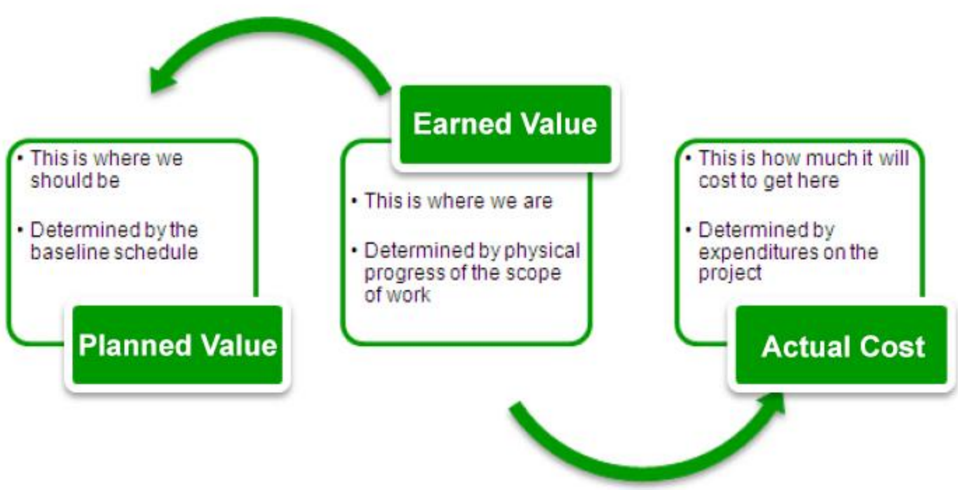
6.0 COST PERFORMANCE MONITORING

The Earned Value Management methodology is used by OPG as the primary architecture for DRP cost management and monitoring. Earned Value Management ("EVM") is a standard project management technique for quantifying and measuring project progress and performance. It not only compares actual costs against budgets, but also allows for continuous analysis of progress achieved against plan throughout the project timeline and across individual tasks forming part of a work component. In other words, the project "earns" progress as work steps are completed, thus allowing management to implement strategies should the project track "off-plan".

In order to conduct EVM analysis, three components are needed: (1) the Planned Value to be earned, (2) the Earned Value (physical progress percent complete against budgeted value), and (3) Actual Cost (from finance/accounting or contractor invoices and accruals). The Earned Value Process is illustrated in Figure 1 and further described below:

Figure 1

Earned Value Process Summary Diagram



Cost performance is measured using standard industry metrics at the program, project, and functional levels. The means by which these standard earned value metrics are calculated, and the significance of the resulting values, is demonstrated through the following scenario. In the scenario, assume that there are four valves that were to have been installed by the current date and that each has a budget or planned value of $1,000, for a total budget of $4,000. As of the current date, only three of the valves have been installed and the total amount spent has been $2,500. The cost of installing the fourth valve, based on experience installing the first three, is forecast to be $800. The standard earned value metrics would be as follows:

- *Schedule Performance Index ("SPI")* is a measure of progress achieved compared to planned progress (SPI = Earned Value / Planned Value). An SPI of 1.0 indicates that the project has completed all planned work. A value of less than 1.0 indicates that all work that was supposed to have been completed has not been completed. A value of greater than 1.0 indicates that work planned for the future has been advanced. Using the above scenario, the SPI would be $3,000/$4,000 or 0.75, which indicates that the project is behind schedule.
- *Cost Performance Index ("CPI")* is a measure of the value of work completed compared to actual cost incurred (CPI = Earned Value / Actual Cost). If the work was completed or 'earned' at the same cost as planned, the CPI would be 1.0. If the cost of the work was higher than planned, CPI will be less than 1.0 and if the work has been completed for less than the planned cost the CPI will be greater than 1.0. Using the above scenario, the CPI would be $3,000/$2,500 or 1.2, which indicates that the project is being executed more economically than had been planned.
- *Cost Variance* is the difference between the budgeted value of work performed and the actual cost of that work (Cost Variance = Earned Value - Actual Cost). For example, the Cost Variance is $3,000 - $2,500, or a favourable variance of +$500.
- *Schedule Variance* is the difference between the budgeted value of work planned and the actual cost of work performed (Schedule Variance = Planned Value – Earned Value). For example, the Schedule Variance is $4,000 - $3,000, or an unfavourable -$1,000.

Schedule Performance Index, CPI and variance metrics are all past-performance oriented. For the DRP, OPG also uses forecasts at the Program and project levels against approved life cycle estimates in order to proactively assess future success and take early corrective action where required. A key metric used for this purpose is *Forecast or Estimate at Completion*, which is determined by adding the Actual Cost and the Estimate to Complete (Estimate at Completion = Actual Cost + Estimate to Complete). For the example, the Estimate at Completion would be $2,500 + $800 based on the forecast provided, for a total of $3,300. Note that the forecast can be determined through a variety of methods, including simply by using the original planned value, or actual unit cost to determine the forecast. The *Variance at Completion* is equal to the Budget at Completion less the Estimate at Completion, which in the example is calculated as $4,000 - $3,300, or $700.

7.0 REPORTING

An integral part of successful project management is reliable and accurate performance information. Reporting provides this performance information through the collection, collation and presentation of data and information. The key objectives of reporting are to:

- ensure information is being communicated to the right stakeholders such that the appropriate decisions can be made, actions taken, or awareness generated;
- communicate the status of the program including any trends, variance from plan, and how the potential variance is being addressed or corrected; and
- ensure information is reliable, accurate and transparent.

OPG plans to issue annual status reports to the public for the duration of the Program through its website. This reporting will include a range of measures, including construction completion, cost performance, schedule performance and safety performance. Chart 1 illustrates the measures that will be provided in the public domain for the duration of the DRP.

Chart 1

AMPCO Interrogatory #30

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: D2-2-1 Page 3, Chart 1 & D2-2-8 Page 7, Chart 3

Preamble: OPG provides a cost breakdown of the total Darlington Refurbishment Program (DRP) Release Quality Estimate (RQE) showing the Program components.

a) Please confirm that the RQE provides the baseline cost estimate for each major program component that OPG will compare all future costs to until 2026.

b) Please add a column to Chart 1 to reflect the component costs approved by OPG's Board of Directors in November 2013.

c) Based on OPG's review of other nuclear refurbishment projects and other megaprojects please compare OPG's Contingency of 16.4% of the RQE (excluding interest & escalation) to the Contingency % of these other projects.

d) Based on OPG's review of other nuclear refurbishment projects megaprojects, please compare OPG's Functional Costs of 21.3% of the RQE (excluding interest & escalation) to the % of Functional Costs of these other projects.

e) Please provide the original and current (revised) Safety Improvement Opportunities and Facilities & Infrastructure Projects budgets and show the % of costs for each that have been reclassified to date.

Response

a) OPG will compare future costs to the baseline established by the RQE on a total program basis. As indicated at Ex. D2-2-8 p. 8, while actual costs may ultimately be different than forecast for individual major program components, OPG's success on refurbishing and returning Unit 2 to service and the Program as a whole, should be measured at the total envelope level.

b) In November 2013, OPG's Board of Directors did not approve any costs equivalent to the costs shown in Ex. D2-2-1 p. 3. The Board of Directors' approval was limited to a release of $680M to continue the Definition Phase of the Darlington Refurbishment Program (DRP) and complete planned 2014 deliverables. The life cycle estimate prepared in

November 2013 in support of the release was a preliminary estimate and is not directly comparable to the RQE, as the scope of work was yet to be finalized. However, an approximation of the comparison is identified below:

Chart 1

	Ex. D-2-2-1 p.3 Chart 1		**Nov. 2013 Total Cost Est (Release 4C)**		
Program Component	**RQE Total Cost ($2015B)(1)**	**RQE Total Cost (%)**	**Total Cost Estimate Converted to 2015$(1)**	**Total Cost (%)**	**Total Cost Estimate (2013$)(2)**
Major Work Bundles	5.54	43	4.35	38	4.18
Safety Improvement Opportunities	0.20	2	0.11	1	0.11
Facilities & Infrastructure Projects	0.64	5	0.57	5	0.55
OPG Functional Support	2.23	17	2.16	19	2.08
Early Release Funds	0.11	1	0.12	1	0.12
Contingency	1.71	13	2.16	19	2.08
Interest & Escalation($B) (3)	2.37	19	1.97	17	2.20
Total Cost Estimate ($B) (3)	**12.8**	**100**	**11.32**	100	**11.32**

(1) All numbers are in 2015$ except for Interest and Escalation and the Total Cost Estimate
(2) All numbers are in 2013$ except for Interest and Escalation and the Total Cost Estimate
(3) Interest and Escalation and the Total Cost Estimate are in nominal dollars, i.e. a sum of the dollars of the year in which they are expended

c) OPG does not have enough detailed information on the costs estimates developed for such projects and the percentage of contingency in those estimates to do the comparison requested.

d) Please see Ex. L 4.3-1 Staff-45, part c).

e) The requested information for Facilities & Infrastructure Projects is shown in the following chart:

Chart 2

Project Title	Total Project Cost (M$)		% of costs Reclassified
	Original Full Release	EB-2016-0152	
Darlington OSB Refurbishment	53.0	62.7	100
DN Auxiliary Heating System	99.5	99.5	100
D2O Storage Facility	110.0	381.1	0
Water & Sewer Project	40.6	57.7	0
Darlington Energy Complex	105.4	105.4	0
R&FR Island Support Annex	40.7	40.7	0
Refurbishment Project Office	99.9	99.9	0
Electrical Power Distribution System	16.9	20.8	0
GM Office Facility	9.3	9.3	0
Vehicle Screening Facility	3.0	6.6	0

The requested information for the Safety Improvement Opportunities (SIO) projects is shown in the following chart. No SIO projects have been reclassified.

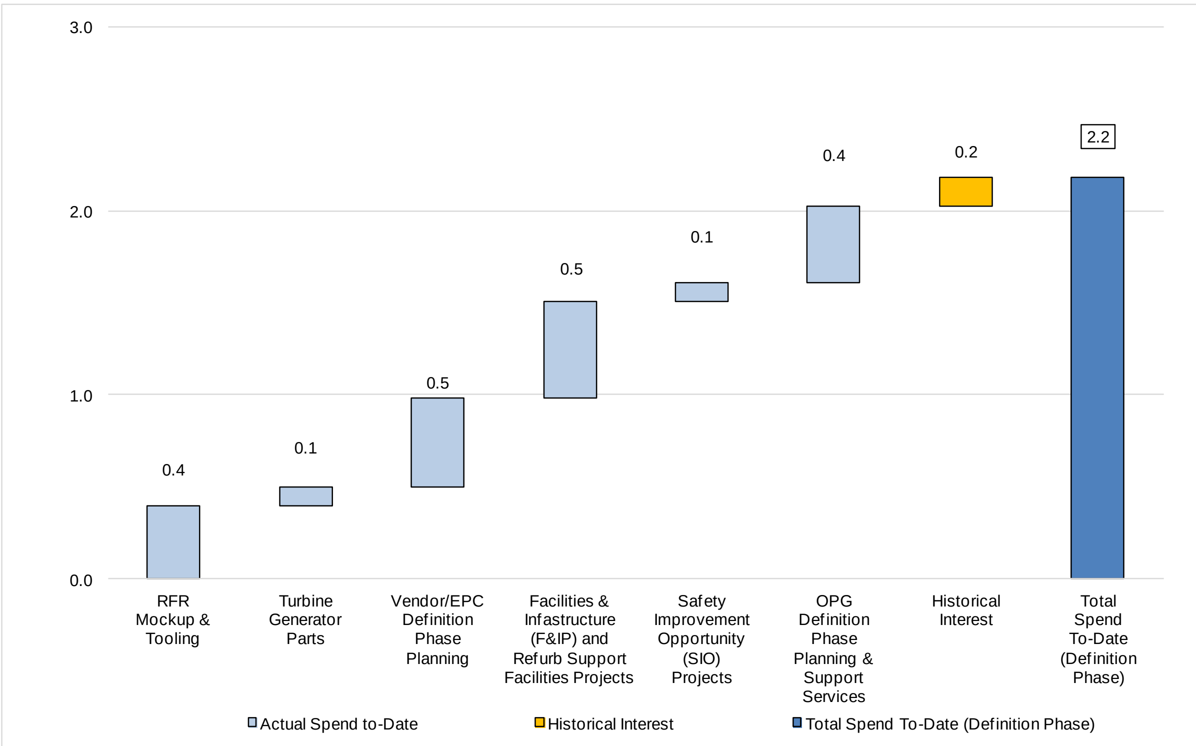
Chart 3

Project Title	Total Project Cost (M$)		% of costs Reclassified
	Original Release	EB-2016-0152	
Third Emergency Power Generator	88.2	120.4	0
Containment Filtered Venting System	80.6	80.3	0
Powerhouse Steam Venting System	5.6	5.6	0
Shield Tank Overpressure Protection	13.5	13.5	0
Emergency Service Water Buried Services	7.9	14.6	0

Note: The original release amounts for the SIO projects are based on the first approved Gate Progression Form or Change Control Form for Execution Phase.

Figure 1

Summary of Life to Date Definition Phase Spending to December 31, 2015 (B$)



The primary outputs of the Definition Phase was: (i) complete planning, including scoping, engineering, cost estimating, and scheduling, (ii) complete pre-requisite activities to enable the refurbishment including facilities, tooling, and a full scale reactor mock-up, and (iii) to obtain approval from OPG's Board of Directors as well as from the Province of the four-unit cost and schedule budget, or RQE, for the DRP. Obtaining RQE signified that detailed planning was complete and set in place a Program level scope, cost and schedule baseline for the four-unit DRP. In addition, RQE approval established the basis for release of Execution Phase funding for the Unit 2 refurbishment. OPG successfully met the following key Definition Phase milestones in order to obtain RQE approval:

- *Scope Definition*: Developed a detailed definition of scope, including clarification of what work is required to be done during the refurbishment outage versus the work occurring outside the refurbishment outage, and established the regulatory scope

Board Staff Interrogatory #54

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exh D2-2-4, Figure 1

The above reference shows the total definition phase expenditures to be $2.2B.

a) Please provide a variance of the actual amount of $2.2B to the budgeted amount for the definition phase.

b) Please provide the amount of the $2.2B that is attributable to Unit 2 versus supporting the entire four unit DRP.

c) Please provide details, i.e. projects and amounts, of the $2.2B that has been put in-service to the end of 2015.

Response

a) The $2.2B actual amount for the Definition Phase represents a variance of $0.3B below the budgeted amount of $2.548B, as shown in Ex. D2-2-8, Attachment 1, p. 5.

b) All of the Definition Phase costs to be placed into service with Unit 2 (i.e. $2.2.B) relate to preparation and planning work which was required to allow OPG to be ready to refurbish Unit 2. Figure 1 of Ex. D2-2-4 shows that the $2.2B Definition Phase expenditures were spent on the following:
   - RFR Mock-up and Tooling
   - Turbine Generator Parts
   - Vendor/EPC Definition Phase Planning
   - Facilities & Infrastructure (F&IP) and Refurbishment Support Facilities Projects
   - Safety Improvement Opportunities (SIO) Projects
   - OPG Definition Phase Planning and Support Services
   - Interest

   Approximately $1B, the largest portion of the $2.2B, is associated with the Early In-service Projects, F&IP, and SIO. The Early In-service Projects are assets arising from work performed for the unit refurbishments that will be placed in service and included in rate base before the refurbishment of the first unit because they provide immediate benefit to the station ahead of the Unit 2 return to service. As committed within the Environmental Assessment and Integrated Implementation Plan, the SIO are to be placed into service upon completion and are useful to OPG's current and future nuclear operations independent of whether the DRP is completed. The F&IP are pre-requisites for unit refurbishments and will be placed in service and included in rate base when they are used and useful to OPG. As discussed in Ex. D2-2-10, p. 7 and Ex. L-4.3-1 Staff-44, the F&IP are expected to be useful to OPG's current and future nuclear operations independent of whether the DRP is completed.

The planning costs for all subsequent units will be lower than that of Unit 2. Much of the planning for those units will be a replication of the work done for Unit 2. For example: (i) detailed design engineering packages will only need to be replicated with unit specific information for Units 3, 4, and 1; (ii) the database infrastructure which has been implemented to facilitate project controls will already be in place for subsequent units; and, (iii) the contracting strategy has been developed and contracts are in place for all four units.

c) $0.3B of $2.2B has been put in-service to the end of 2015. The details are provided in the following table.

Project	**LTD 2015 In-service Amounts**
Heavy Water Facility	$14.6M
Water & Sewer	$43.7M
Darlington Energy Complex	$82.5M
Retube Feeder Replacement Island Support Annex	$1.7M
Refurbishment Project Office	$94.3M
Electrical Power Distribution System	$18.1M
Vehicle Screening Facility	$4.1M
Third Emergency Power Generator	$9.7M
Powerhouse Steam Venting System Improvements	$5.2M
Emergency Service Water Buried Services	$13.3M
IFB Heat Exchanger Plate Replacement	$6.2M
Other Station Modifications	$1.2M
Total[1]	**$294.8M**

[1] Consistent with Ex. B3-3-1 Table 1 line 16 column (e)

AMPCO Interrogatory #69

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exhibit D2-2-7 Page 4

Preamble: The evidence indicates a comprehensive risk register including AACE estimate classifications for each project and detailed schedule logic was used to develop the contingency estimate.

a) Please provide the comprehensive risk register.

b) Please provide OPG's Risk Management Plan.

c) Please provide the top 10 contributors to cost risk.

d) Please provide the top 10 contributors to OPG-accountable delay risk.

e) Please provide the top 10 contributors to Contractor-accountable delay risk.

Response

a) Please see L-4.3-15 SEC-26, part f.

b) Please see L-4.3-1 Staff-48, Attachment 24.

c) The top ten contributors to cost risks are shown in the following chart:

Chart 1 – Top Ten Contributors to Cost Risk

Item	Risk Description	Risk Owner
1	Contingent scope due to unexpected Turbine Generator equipment conditions (could not inspect)	Turbine Generator Project
2	Vendor Performance issues resulting in increased costs	Project Execution (Program)
3	Insufficient Materials budget for emergent broke-fix maintenance during Shutdown, Layup and Run-up.	Project Execution (Program)
4	Concealed Conditions encountered during Execution	Retube and Feeder Replacement Project
5	Vendor Default results in need to secure New Vendor to execute refurbishment work	Project Execution (Program)
6	The Cyclic Maintenance budget may not have enough funds to cover Shutdown Maintenance Backlog	Project Execution (Program)
7	F&IP and SIO Projects exceed forecasted life cycle costs	Project Execution (Program)
8	Heavy Water Facility costs exceeds current estimate to complete	Project Execution (Program)
9	Discovery work scope caused by inspections with impact on long lead items or major repairs	Turbine Generator Project
10	Impact of Foreign Exchange on project costs	Project Execution (Program)

d) OPG as the project manager is accountable to manage all risks associated with the Darlington Refurbishment Program ("DRP"). The top twenty risks impacting schedule as generated by the contingency analysis are listed below in order from most impactful to the least. The current owners of these risks on behalf of OPG are listed in the following chart:

Chart 2 – Top Twenty Risks Impacting Schedule

Item	Risk Description	Risk Owner
1	Risk of increased scope for fuel defect management	OPG
2	End Fitting Waste Processing - First of a kind risks	OPG
3	Interference with RFR activities due to unexpected OPG RFR related activities	Joint Venture
4	Ineffective Practices in Maintaining the Tools	OPG
5	Improper brushing and excessive as found deposits (CTSB)	Joint Venture
6	Failure to eliminate current constraints on vault loading	OPG
7	Removal of shielding and bulkheads prior to staircase install	Joint Venture
8	Interference with RFR activities due to unexpected OPG Plant Operations activities (for in Vault Activities)	Joint Venture
9	All physical Interferences in Unit not identified	OPG
10	Excusable Delays	OPG
11	Rebar being hit causing additional PMOD or Safety Analysis	OPG
12	Interference with RFR activities due to unexpected OPG Plant Operations activities (for flask transfer activities)	Joint Venture
13	Ozone excursion into the vault	Joint Venture
14	APT breakdown -Bulkhead Install	Joint Venture
15	Safety events caused by OPG or other contractors (occurrences <3 days)	Joint Venture
16	Lack of Power for tools and supporting equipment (i.e. lighting, munters)	Joint Venture
17	Unexpected Vault Equipment Airlock Malfunction	Joint Venture
18	CTI falls out of tubesheet into lattice tube	Joint Venture
19	Loss of highly radioactive debris/particles - EF Removal	Joint Venture
20	Insufficient Qualified Radiation Protection Coordinators (BTU) to support Execution	OPG

e) Please refer to the response to part d).

AMPCO Interrogatory #87

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: D2-2-8 Attachment 2 Page 29

Preamble: Modus/Burns McDonnell states "The DR Team nonetheless has high confidence in the extent of the estimates it has prepared for RQE and are all-inclusive of what could reasonably be identified for staffing at this time. We believe that there is some risk that OPG will not meet its proposed plan in this area as the job functions and specific roles within the functional groups are not as defined as they could be. Additionally, the pace of the proposed ramp-up of the DR Team's staff over the next several months is very aggressive and will be very difficult to meet. In order to meet the plan, the DR Team would have to increase from 770 to just over 900 (17%) staff in less than 3 months. Moreover, the DR Team's projections for 2016 show a planned functional expenditure of $120M, excluding Operations & Maintenance and Engineering, which would equate to nearly 70% of the cost of these functions for the last 5+ years. The DR Team has been chronically under-spent during the Definition Phase, and missing these major ramp-up dates will further impact the accuracy of the team's staffing forecasts and potentially the status of preparatory work for breaker open.

a) How has OPG addressed the above concerns expressed by Modus/Burns McDonnell?

b) Please explain whether OPG was able to meet this plan staffing target or if OPG has put in place another viable option/plan.

c) Does OPG have experience in meeting staff increases of this magnitude in a short timeframe? Please explain and provide details.

d) Please provide details of the proposed ramp-up and the make-up of the staff compliment.

e) Please explain why OPG has been chronically under-spent during the Definition Phase, and missing major ramp-up dates?

f) Please discuss the current impact on the accuracy of the team's staffing forecasts and potentially the status of preparatory work for breaker open.

g) Are all of the functional roles and responsibilities/accountabilities been assigned for this work? If not, why not?

h) How are these functional roles being integrated with other major work bundle contractors?

Response

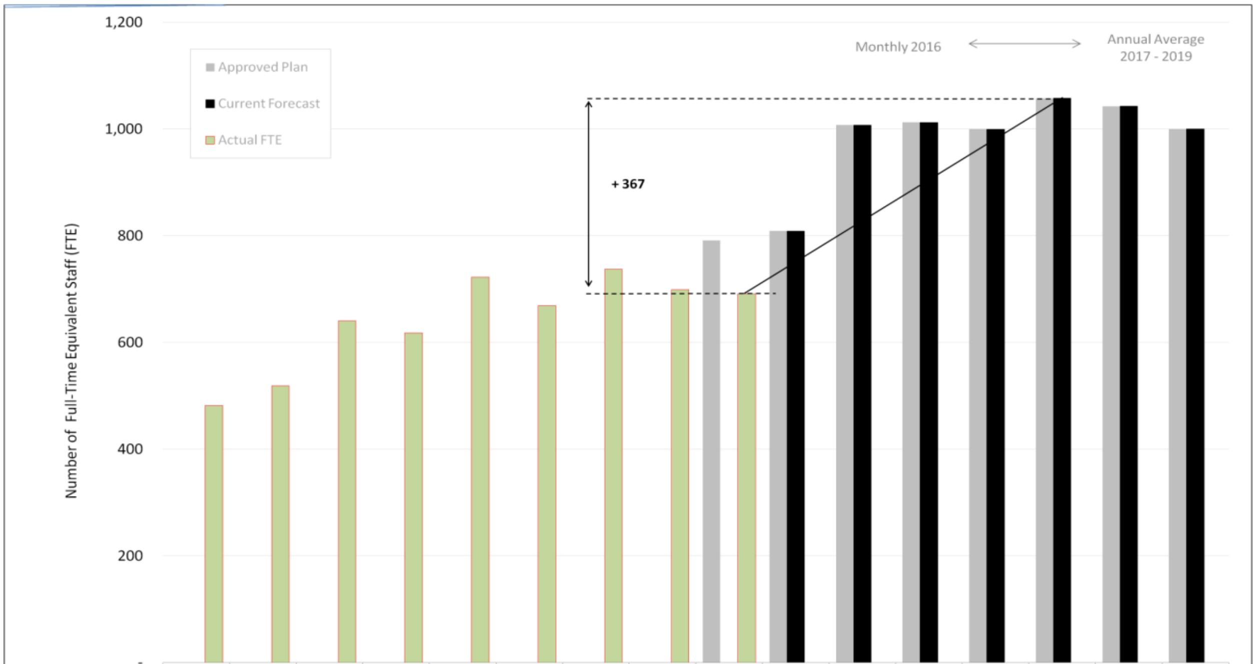
a) The project has a centralized Resource Management Team looking after all resource planning initiatives for the project, including advancing hiring and working with the recruitment organization to resource staff as efficiently as possible. In addition, OPG's recruitment organization has made several process improvements with regards to hiring, all aimed at helping the project to resource qualified candidates as quickly as possible.

b) The project continues to staff positions in a number of ways to ensure work is completed. This includes the use of augmented staff, utilization of Owner Support Services and managed task contracts, as well as movement of staff from other parts of OPG as needed and where work is emergent.

c) OPG has not had to staff to the levels required for the Darlington Refurbishment Program (DRP) in some time. Given the complexity of the DRP and the large numbers of staff required, OPG has recognized this and put in place process improvements and a dedicated team to advance all hiring.

d) The following chart (Figure 1) shows the current OPG resource demand (as of August month end, 2016) and the expected ramp-up over the next four months. The chart includes all resources working on and funded by the DRP including those that are provided by the station and or other business units, such as Corporate Finance or Supply Chain. A hiring campaign, as noted in part a), is underway to ensure that the resources are available when needed and to eliminate any resource shortfalls. Ramp-up of staff is underway via the use of station staff including Fuel Handling and Operations staff, and Radiation Protection staff that will transfer over to Refurbishment as required. In addition, hiring is underway for the Project Office, Construction, Engineering, and Project Planning & Controls and in the Project Management job categories.

Figure 1 - DRP Staff Demand Curve and Ramp-up (as at end of August 2016)



	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2017 Avg/mos	2018 Avg/mos	2019 Avg/mos
Approved Plan									791	809	1,007	1,012	999	1,058	1,042	1,000
Current Forecast										809	1,007	1,012	999	1,058	1,042	1,000
Actual FTE	482	519	641	618	722	669	737	699	691	-	-	-	-	-	-	-

e) Through the Definition Phase, OPG was unable to staff up to its planned levels and as a result had to rely on other service providers to meet the work demands, as noted in part b). In recognition of this, as noted in part a), OPG took actions to establish a recruitment program and put in place a centralized Resource Management Team to help the organization meet its staffing needs.

f) The new Resource Management Team is now accountable for 1) assessing the total staff demand, and 2) forecasting the timing of resource on boarding. This will continue to be monitored throughout the project and through monthly reporting. This shortfall in resources has put challenges on the organization; however, through the use of augment staff, contracted services, and other OPG staff, all of the deliverables to ensure readiness to commence Unit 2 refurbishment were met.

g) Yes, all functional roles and responsibilities for the project have been assigned. Functional Management Plans provide details about the work being performed.

h) All functional roles and the support provided to the major work bundles are detailed in the respective Functional Management Plan.

AMPCO Interrogatory #70

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exhibit D2-2-7 Page 5-6

Preamble: OPG indicates that its Monte Carlo simulation provides decision makers with a range of possible outcomes and the probabilities that those outcomes will occur to certain confidence levels.

a) Please provide the confidence levels tested and the contingency amounts at these confidence levels.

b) Were P10, P50 and P70 confidence levels tested? If not, please provide the total cost of the four units and the average cost per unit at low confidence (10%), medium confidence (50%), medium high confidence (70%) and high confidence (90%).

Response

a) The Monte Carlo Simulation generated a cumulative distribution from P0 to P99.9. Select high probability risks were added to contingency during final reviews by Management. Please refer to Ex. L-04.3-15 SEC-027 for calculated contingency amounts in 5% increments ranging from 70% to 95% and also the contingency amount at 99%.

b) Please refer to the chart below. Contingency amounts are in $2015 and exclude interest and escalation. Total costs for the Darlington Refurbishment Program include interest and escalation. Simplifying assumptions were made in order to generate the total DRP costs.

Chart 1

Reference Confidence Level (%)	Total DRP Contingency Estimate At Reference Confidence Level (2015$B)	Total Project Cost (1) $B
P10	1.2	12.1
P50	1.4	12.4
P70	1.5	12.6

Witness Panel: Darlington Refurbishment Program

SEC Interrogatory #27

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
[D2/2/7]

What would the required contingency be for a cost confidence level of 70%, 75%, 80%, 85%, 90%, 95% and 99%.

Response

The following chart outlines the required contingency at the specified confidence levels. All amounts are in $2015 and exclude interest and escalation.

Chart 1

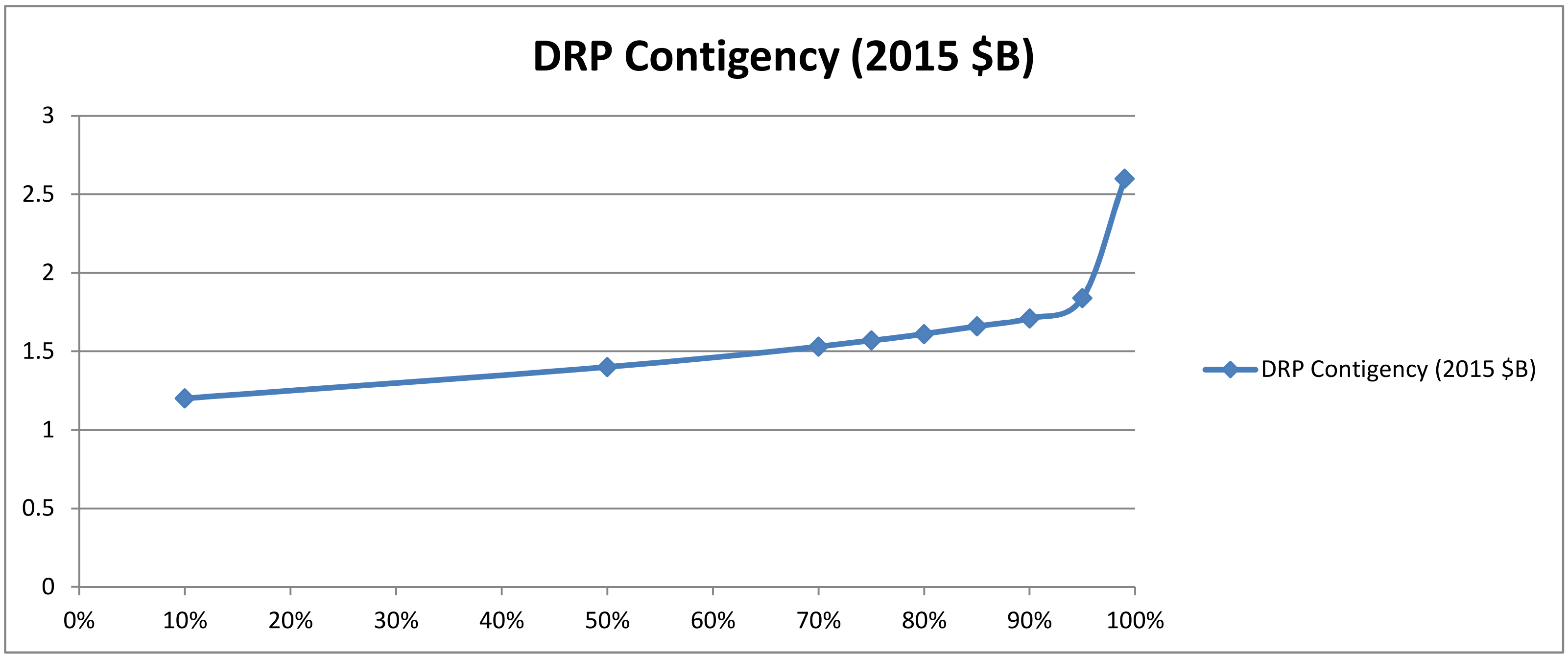
Reference Confidence Level	4-Unit Program Contingency Estimate (2015$B)
70%	1.53
75%	1.57
80%	1.61
85%	1.66
90%	1.71
95%	1.84
99%	2.60

P90	1.7	12.8

(1) A factor has been applied to approximate the impact of reduced escalation and interest resulting from reduced contingency expenditures

DRP Contigency	
Confidence Level	**DRP Contigency (2015 $B)**
10%	1.2
50%	1.4
70%	1.53
75%	1.57
80%	1.61
85%	1.66
90%	1.71
95%	1.84
99%	2.6

Source: L-4.3-2 AMPCO-70; L-4.3-15 SEC-27



The determination of the size of the contingency fund must take into the account the estimate accuracy and project phase.

Cost growth areas typically covered by estimating uncertainty contingency are more general than those covered by discrete risks, and include items such as:

- Minor errors in omissions in the estimating process (e.g. precise quantity is only known during execution)
- Variability of productivity (e.g. estimating based on execution in the summer, but actually executed in the winter)
- Variability in wages (e.g. labour agreements expiring during execution)
- Variability in prices (e.g. material prices assumed)

Effort must be made to ensure the factors covered by cost estimating uncertainty are not duplicated in the project risk register. Using three point estimates, the impact of the cost estimate uncertainty can be modelled in a Monte Carlo simulation to estimate the amount of contingency required to address these events.

Estimate uncertainty does not capture variability in scope.

5.1.3 Risk Tolerance and Confidence Levels

Risk tolerance is the degree, amount, or volume of risk that an organization is willing to accept. Nuclear Projects risk tolerance is informed by a number of contributors including the experience and instinct of the project management team, past performance of similar projects, and stochastic methods.

In stochastic risk analysis, it is often expressed in a percentage value called a confidence level. For example, a P50 value on a Monte Carlo contingency estimate means that a project manager can be 50% confident that the contingency allocated is sufficient to address the risks and uncertainties defined for the project.

In managing a portfolio or program of projects, the concept of confidence levels can be useful in managing contingency funds. For example, for a given project's contingency analysis, the following structure could be employed to support the approval authority of contingency funding. This is for illustrative purposes and may be applied differently for different funding streams and risk tolerances within the Nuclear Projects organization.

Contingency $ at Confidence Level	Up to P50 (Current Phase Risks and Uncertainties)	Up to P50 (Future Phase Risks and Uncertainties)	P50 → P70 (All Risks and Uncertainties)	P70 → P90 (All Risks and Uncertainties)
Treatment Upon Project Approval to Proceed	Released to Project	Allocated to Project but not Released	Allocated to Project but not Released to	Allocated to Management Reserves

		to Project	Project	
Authorization for Release to Project	N/A	VP Nuclear Projects	VP Nuclear Projects	SVP Nuclear Projects

Table 1: Example of how contingency developed for a specific project feeds into portfolio or program management

5.1.4 Probabilistic Analysis of Uncertainties

Monte Carlo simulation is a form of probabilistic analysis. It is a method to predict the impact of defined risks and uncertainties using project simulations. Gathering the three point estimates required for the Monte Carlo method can be quick and simple or rigorous, and should be commensurate to the overall magnitude or cost of the project. For example, small projects can use the projects manager's judgment for inputs but large projects should be done with rigor and inputs from knowledgeable personnel. Poor quality inputs to the Monte Carlo (including choosing a misrepresentative probability distribution, or omissions of key risks) will produce misleading results – "garbage in, garbage out".

The PMO risk department will perform the Monte Carlo analysis for risk and uncertainty inputs defined by the project manager. All contingency requests in support of funding approval packages are required to have a supporting Monte Carlo analysis, unless an exception is approved by the Director of the executing Nuclear Projects organization.

The general steps to executing the Monte Carlo contingency analysis are as follows. The PMO risk department can help provide direction and guidance to project teams where required:

(a) Confirm the basis of analysis. The project scope, schedule, and estimate should be well defined/finalized with minimal anticipated changes.

(b) Conduct risk screening to determine which risks are warranted to have contingency allocated against them. Not all risks are suitable for contingency allocation. Appendix E Table 2 provides a guideline on how risk screening should be conducted.

(c) Gather inputs for probabilistic analysis. This involves obtaining three point estimates (Most Likely, Optimistic, and Pessimistic) for residual risk impacts, cost uncertainty, and the logic tied critical path schedule activities.

(d) Run Monte Carlo simulations using software and analyze the results. Results will be presented as S-Curves or in other tabular forms/reports generated from the Monte Carlo tool.

(e) Determine the size of contingency required for the determined level of confidence.

(f) Reassess the inputs if required based on the outcome of the analysis and iterate steps (a) through (e).

3.2.3 Management Reserve

Management Reserve is the contingent funds for *unknown unknowns, or* unplanned changes to project scope and cost, such as natural disasters or prolonged labour strikes. It is an amount for discretionary management purposes outside the defined scope of the project.

3.3 Risk Tolerance and Confidence Levels

Risk tolerance is the level of uncertainty that an organization is willing to accept. It is often expressed in a percentage value called a confidence level. (E.g. a P50 value on a contingency estimate means a project manager is 50% confident that the contingency allocated is sufficient to address the risks in the project). Confidence levels are also useful in managing a program of different projects. For example, a project can be assigned a P50 level of contingency, and the difference between P70 and P50 can be kept at the program level as added assurance in case the project manager runs out of contingency funds.

3.4 Guidelines to Contingent Fund Development

Contingency fund determination should be conducted before each request for contingency funding, including gate submission and during the release planning process.

3.5 Project Contingency Constituents

The Project Manager, with support from Planning and Control (P&C) Leads matrixed to them, is responsible for determining the amount of Project Contingency required. Project contingency is made up of the following constituents:

(1) Cost uncertainty of the project work scope (identified by project bundle and by gate)

(2) Discrete risks (identified by project bundle and by gate) in the project risk register

The amount of contingency required for each constituent should be determined with inputs from knowledgeable personnel.

3.6 Program Contingency Constituents

The Risk section, P&C is responsible for determining the amount of Program Contingency required. Program contingency is made up of the following constituents:

(1) Cost uncertainty of the functional work scope (identified by release and function)

October 1, 2015

Darlington Refurbishment Program: Execution Phase Readiness and Business Case Summary

REASON FOR REPORT

The purpose of this report is to provide the following:

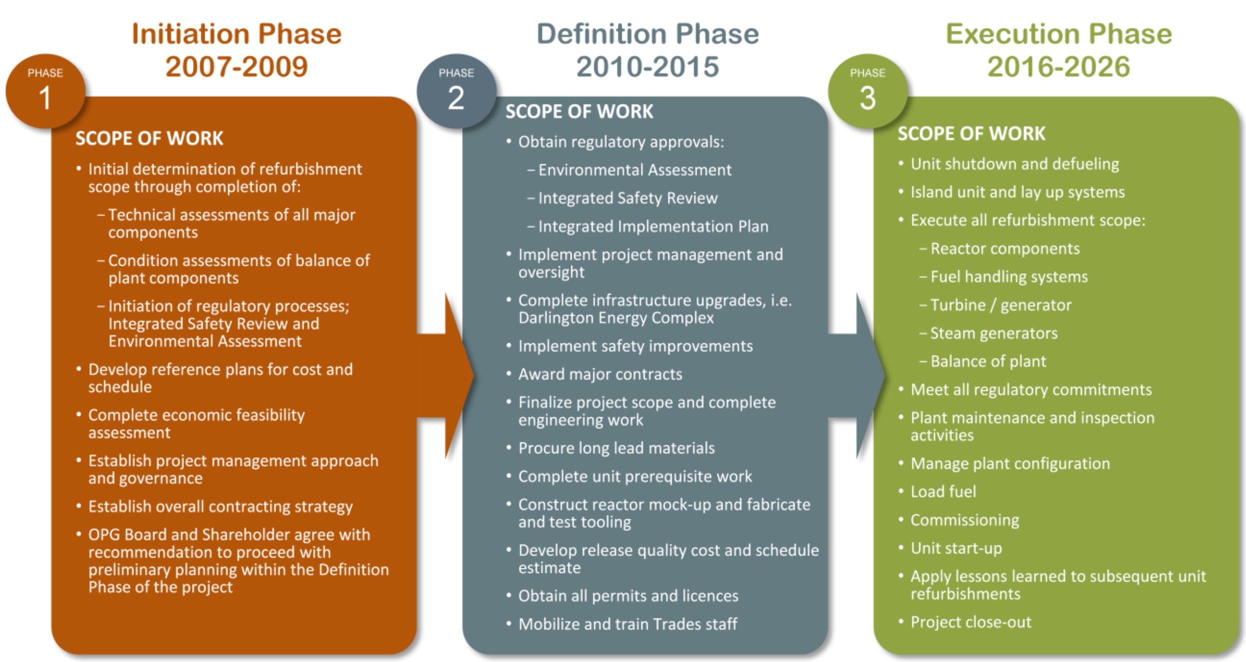
- An update on the status of the Darlington Refurbishment Program ("DRP") Definition Phase activities,
- An overview of the cost and schedule estimate for the execution phase to be presented in November with a recommendation on final contingencies and management reserve, and
- A summary of the business case including key OPG benefits and the expected energy cost from the refurbished Darlington station.

HIGHLIGHTS

Definition Phase Update

In 2009, the DRP identified three phases of project development as shown in Figure 1. The Initiation Phase, completed in 2009, concluded with the approval of a "Feasibility Business Case" allowing Management to proceed to the Definition Phase. In the past five years, the DRP has completed its planning deliverables including completion of the Canadian Nuclear Safety Commission's (CNSC) regulatory requirements related to the refurbishment and life extension of a nuclear plant, as identified in regulatory document RD-360. Management is now ready to proceed to the Execution Phase and have developed the overall 4-unit scope, cost, and schedule estimate including preparation of an execution phase business case, as outlined in this document.

Figure 1: Darlington Refurbishment Phases of Project Development



Execution Phase Cost Estimate

OPG is nearing completion of the development of its Execution Phase cost estimate. Estimates have been received from all vendors and have been integrated into the overall cost estimate and a detailed risk register has been developed. A preliminary cost and schedule contingency analysis has also been performed; however, further reviews are underway and the estimate will be finalized by October 15th in advance of the November Board meeting. Management believes that the base project estimate and contingency amounts provided within this document are bounding and that any further refinement will reduce the overall project estimate, before Management Reserve is applied.

Figure 3 provides a summary of the cost build-up for the Execution Phase of the project. Of the $12.8 Billion estimate, $2.3 Billion has been spent in the Definition Phase and the Execution Phase estimate is $10.5 Billion. In addition to external vendor bundle costs to execute the major scopes of work, the project is carrying costs for vendor oversight, operations and maintenance and general project support. The project estimate also includes an estimate for CNSC fees and insurance.

OPG is responsible for providing the insurance coverage under an Owner Controlled Insurance Program, where the project owner places the construction insurance program rather than the contractor. This allows OPG to leverage the insurers on the corporate program for optimal terms and conditions. The Insurance estimate includes Course of Construction-Property, Wrap-Up Liability, Marine Cargo and Advance Loss of Profit, Nuclear Energy Physical Damage-Property, and Delayed Start-up insurance.

Figure 3: Execution Phase Cost Estimate Build-up

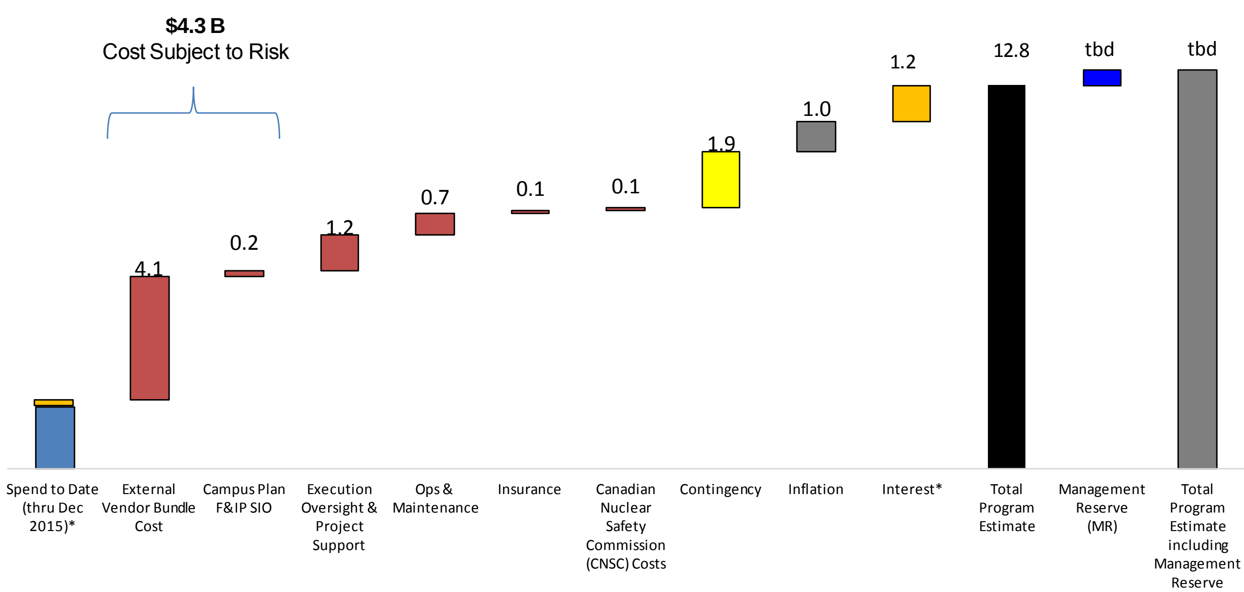


Figure 4 provides a breakout of external vendor bundle costs for EPC activities including those incurred in the Definition Phase and those to be incurred in the Execution Phase.

AMPCO Interrogatory #103

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: D2-2-11, Attachment 3, Page 27
Ref: D2-2-7, Page 6

Preamble: OPG and its experts claim that OPG's DRP project planning process is world class. In describing world-class project planning, Dr. Galloway describes "Management Reserve" as, "Unlike contingency, which covers identified, but not yet realized risks, management reserves are intended to address unforeseeable emergencies that cannot be effectively managed using contingency as they are such [sic] magnitude and rarity that they go beyond project-specific risks." OPG further states, "For a project of the size and duration of the DRP, there are a number of low probability high consequence events that could impact the Program and that are outside of the contingency determined for the Program." By its definition, Management Reserve covers items outside the scope of this hearing; however, it is within the scope of this hearing to determine if OPG has implemented its planning strategy appropriately, and to determine the magnitude of potential risks to the DRP. Therefore, given that OPG states that these risks exist, and given that world-class project planning includes Management Reserve, please:

a) Confirm that Management Reserve has not been included in the DRP estimates. If it has, please explain where and what risks it covers.

b) Confirm that OPG has calculated a Management Reserve estimate.

c) Report the magnitude of the Management Reserve calculated and list the risks it is intended to address.

d) If OPG has not prepared a Management Reserve estimate, explain why it has not in the context of its claims to have followed world-class procedures in project planning.

Response

a) Management reserve is not within the $12.8B estimate.

b) c) and d):

OPG considered management reserve during its project planning. During RQE planning, OPG performed a number of scenario analyses to determine potential impacts of a number of low probability high consequence events that could impact the project and that are outside of the contingency determined for the project, recognizing that these risks are outside of the control of the project to manage or influence. It is difficult to assess the impact of such events, however, OPG's assessment concluded that these low probability events, if they did occur, may result in a project cost impact of up to $800M. This was presented as information to the Board of Directors to consider as part of the decision to approve the RQE. The decision was to not include an explicit amount for Management Reserve within the approved budget. As noted in section 4.1 of Ex. D2-2-7, p. 6, should any of these risks occur, and should they result in the projected DRP cost to exceed $12.8B, Management would evaluate the cost and schedule consequences and provide a recommendation to the Board of Directors for approval on the appropriate response.

Please refer to section 4.1 of Ex. D2-2-7, p. 6, for examples of risks considered.

AMPCO Interrogatory #72

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exhibit D2-2-7 Page 7 Chart 1

a) Please explain how OPG determined the contingency $ split between Project Contingency and Program Contingency.

b) Please explain how Program contingency amounts were determined for each project in Chart 1.

c) Please explain why Program contingencies are greater than Project contingencies for the following projects: RFR, Fuel Handling and Defueling and Project Execution and Operations and Maintenance.

d) For each of the projects in Chart 1 please provide the allocation between the three key contributors to contingency (cost estimating uncertainty, schedule estimating uncertainty and discrete risks) for both Project contingency and Program contingency.

e) Have other nuclear refurbishment projects reviewed by OPG included an unallocated program contingency amount under Program contingency? If yes, please provide project details and compare to OPG's proposal.

f) Please provide the total contingency amount held by the contractors, i.e. total amounts included in contracts, that are in addition to the $1.7 billion help by OPG.

Response

a) Project contingency was derived from project specific discrete risks and estimating uncertainties. Program contingency was derived from program risks, the critical path schedule analysis, and functional support organization estimating uncertainties. Please see section 4 of Ex. D2-2-7 for more information.

b) Exhibit D2-2-7, p. 7, Chart 1, shows that the majority of the program contingency amounts are allocated to the Retube and Feeder Replacement (RFR), Defueling/Fuel Handling Project, and Project Execution and Operations and Maintenance, which forms a substantial portion of the overall critical path for the refurbishment. The program contingency figures shown represent the portion of program schedule contingency attributable to RFR and Defueling/Fuel Handling activities. The remainder of the schedule contingency was allocated to the Project Execution and Operations and Maintenance organization as they are accountable for integration and execution of activities on the critical path including reactor start-up after refurbishment of the unit.

c) As schedule contingency is held at the program level, the projects on the critical path will carry a higher share of the schedule contingency and thus, a higher program contingency.

d) Please refer to the chart below:

Chart 1

	Project Contingency			Program Contingency		
	% Cost Un-certainty	% Discrete Risks	% Schedule Un-certainty	% Cost Un-certainty	% Discrete Risks	% Schedule Un-certainty
RFR	18	82	0	0	31	69
Turbine Generator	14	86	0	0	80	20
Steam Generators	24	76	0	N/A		
Fuel Handling/ Defueling	17	83	0	0	6	94
Balance of Plant	30	70	0	N/A		
F&IP and SIO	0	100	0	0	100	0
Project Execution and Operations and Maintenance	100	0	0	0	80	20
Unallocated Program Contingency (1)	N/A			0	48	52

(1) Refers to contingency that is not directly allocable to specific projects, and is held at the program level only.

e) OPG cannot answer this question as it does not have access to that level of detail in the cost estimates reviewed for other refurbishment projects.

f) For target price contracts (RFR Engineering, Procurement and Construction Contract (EPC) and the Turbine Generator EPC), the contingency embedded within their Execution Phase Target Cost is $371M and $28.4M, respectively.

The value of the fixed price contracts, namely Steam Generators EPC and the Turbine Generator Engineering Support and Equipment Supply Contract, were negotiated to be inclusive of contractor contingency. The magnitude of such contingency is not disclosed to OPG.

Additional oversight for the RQE development process has been provided by BMcD/Modus. The RQE oversight provided by BMcD/Modus has been carried out as part of its broader role in providing DRP oversight. In particular, BMcD/Modus assessed the process used for developing RQE, with a particular focus on the development of detailed cost estimates that are of sufficient quality and basis in order to establish a four-unit, program level control budget for DRP. In addition to considering OPG's processes relative to its governance and industry guidance, particularly from AACE, BMcD/Modus considered whether the RQE process was sufficiently thorough and robust, whether contingency was developed in a manner consistent with industry practices and whether RQE was appropriately documented to permit vetting by senior management. A copy of the resulting BMcD/Modus report is provided in Attachment 2.

Based on its three years of DRP oversight, including one year with a particular focus on RQE, BMcD/Modus found that the processes used to develop RQE and the critical path schedule that forms the basis for RQE meets or exceeds industry thresholds. It found the RQE to be based on well-defined scope and detailed engineering, which was sufficiently mature to allow the intended classification based on AACE guidelines. The RQE was also found to be based on a level of detail in line with that seen for other projects of a similar nature, which will support a robust project controls regime to track progress. However, they also identified some risks associated with certain components of the RQE that, if not corrected before the Unit 2 full execution release in Q3 2016, could impact the Unit 2 estimate. OPG has therefore put a process in place to address the recommendations from BMcD/Modus and is tracking all actions to completion within this timeframe.

3.0 DRP COST BREAKDOWN

Chart 3 below provides a detailed cost breakdown of the RQE components.

Chart 3

DRP RQE Breakdown (M$)

#	Bundle / Category	RQE Total Cost	%
1	Retube & Feeder Replacement	3,598	28

#	Bundle / Category	RQE Total Cost	%
2	Turbine Generators	657	5
3	Balance of Plant	967	8
4	Fuel Handling/Defueling	198	2
5	Steam Generators	123	1
6	Subtotal Major Work Bundles	5,543	43
7	Facility and Infrastructure Projects	640	5
8	Safety Improvement Opportunities	205	2
9	Subtotal F&IP/ SIO	845	7
10	Project Execution	322	3
11	Contract Management	52	0
12	Engineering	283	2
13	Managed Systems Oversight	41	0
14	Planning & Controls	136	1
15	Nuclear Safety	83	1
16	Program Fees & Other Support	341	3
17	Supply Chain	86	1
18	Work Control	80	1
19	Operations & Maintenance	805	6
20	Early Release 3[1]	102	1
21	Early Release 4[1]	7	0
22	Subtotal OPG Functions	2,336	18
23	Contingency	1,706	13
24	Subtotal Before Interest & Escalation	10,429	81
25	Interest[2]	1,473	12
26	Escalation[3]	898	7
27	Subtotal Interest & Escalation	2,371	19
28	Total High Confidence Estimate	12,800	100

[1] Early Releases 3 and 4 are costs that were incurred during the preliminary planning phase of the Definition Phase before the DRP organization was in place. As a result, they cannot be attributed to the work bundles or functions. These costs are primarily related to EA, ISR and early planning work.

[2] Interest is applied monthly to cumulative capital expenditures in the previous months at a rate of 5 per cent until 2021, consistent with OPG's business planning assumptions and 6% thereafter.

[3] Escalation is set at 2 per cent on a per annum basis.

AMPCO Interrogatory #44

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: D2-2-3 Attachment 1 Page 2

Preamble: The Summary of EPC Contract for RFR with SNC/Aecon JV states that the contractor and OPG developed an execution phase plan that included a cost estimate, schedules and a risk register for the execution phase. The evidence states "The cost and schedule estimates developed by the contractor were subject to a P50 analysis and the P50 analysis was the basis for establishing the target cost and target schedule under the agreement".

a) Please provide the risk register.

b) Please explain why a P50 analysis was selected.

c) Were higher confidence levels tested? If yes, please provide the results. If not, why not?

d) Please explain how the contractor's fixed fee was calculated based on the target cost.

Response

a) Please see Ex. D2-2-3 Attachment 6, the Retube and Feeder Replacement (RFR) contract; the risk register used for the purposes of developing the execution phase plan is Exhibit 3.5(g) to the contract.

b) P50 means that, all other things being equal, there is an equal probability of the final result being better than or worse than the calculated outcome. It would not be appropriate, when negotiating a contract, for either party to aim for higher than P50, as that would imply that one party was attempting to achieve greater certainty at the expense of the other party taking on more risks. P50 is also a standard analysis based on AACE International Recommended Practice No. 18R-97. A P50 analysis was established by OPG prior to the RFP process and agreed to by the contractor during the RFR negotiations.

c) Yes, higher confidence levels were tested, particularly for schedule confidence. The results, as expected, were that the target price would have increased, as higher confidence would have required the contractor to take accountability for a greater number of risks, some of which they were not in the best position to manage. Please see Attachment 1, Darlington RFR Class II Estimate Monte Carlo Model Report, for more information.

d) Please see Attachment 1, Appendix I.

RQE Contingency Development

N. Ryan Smith, Manager
Risk Management, Nuclear Refurbishment
June 24, 2015

BEHAVIOURS

- Integrate & Collaborate
- Think Top & Bottom Line
- Simplify It
- Say It. Do It
- Tell It As It Is

▪ SAFETY ▪ INTEGRITY ▪ EXCELLENCE ▪ PEOPLE & CITIZENSHIP ▪

PEOPLE POWERING THE FUTURE OPG NUCLEAR

ONTARIO POWER GENERATION

Confidence Levels and Authority for Use



	Up to P50	ΔP50→P70	ΔP70→P90
Cost Estimate Uncertainty (Project)	Project Contingency	Program Contingency	Management reserve
Cost Estimate Uncertainty (Functions)	Program Contingency	Program Contingency	Management Reserve
Schedule Estimate Uncertainty (Program Only)	Management reserve	Management Reserve	Management Reserve
Discrete Risks (Project)	Project Contingency	Program Contingency	Management Reserve
Discrete Risks (Program/Functions)	Program Contingency	Program Contingency	Management Reserve

Authority Levels: All contingency shall be accessed via the change control process. Project Contingency shall be authorized for use by the Project Directors. Program Contingency shall be authorized for use at the VP Level. Management Reserve shall be authorized for use by the SVP. No delegates shall have authorization rights.

SEC Interrogatory #26

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

[D2/2/7] With respect to the DRP contingency amount:

a. [p.2; D2/2/8, Attach 2, p.33] Please confirm the modelling expert referenced was from the Palisade Corporation.

b. [D2/2/8, Attach 2, p.33] Please provide a copy of the report provided by Palisade Corporation.

c. [D2/2/8, Attach 2, p.33] Please explain which recommendations of Palisade Corporation were not implemented.

d. Please provide the results of the Monte Carlo simulation, including any reports, opinions and analyses that were created for OPG, or by OPG, regarding the results of the simulation.

e. Please explain how the individual risks were costed for the purpose of the Monte Carlo simulation.

f. [p.4] Please provide a copy of both, the current DRP risk register and the register used at the time of the Monte Carlo simulation.

g. [p.4] Please highlight the difference between the current DRP risk register differs from the register used at the time of the Monte Carlo simulation.

h. [Attach 1, p.5] Please provide further details of the "Risk Management and Oversight Tool" ("RMO"); specifically, please explain what the tool is and how it will be used through the DRP process.

i. [Attach 1] Who are the authors of the KPMG Report? Please provide a copy of their CVs.

Response

a. OPG confirms that the modeling expert, Gustavo Vinueza, is from Palisade Corporation.

b. A copy of the report produced by Palisade Corporation (Palisade) is provided as Attachment 1. The final version of the report contained redactions as shown.

c. Four out of 37 recommendations from the Palisade report were not implemented:

   i. Addition of uncertainty to yearly breakdown
   ii. Addition of uncertainty to yearly assignments
   iii. Addition of a “Dashboard” view to display the results of the model outputs from the various model sheets.
   iv. Addition of a “Risk Map” view to demonstrate the highest impact risks in a summary view.

   These recommendations were not pursued because they were minor improvements related to annual flows of the contingency estimates or because they related to alternative views of the outputs from the model. These improvements would have had no impact on the contingency estimates. Palisade concurred that the implementation of these recommendations would make no material difference to the modeled contingency estimates.

d. The results of the Monte Carlo simulation for cost uncertainty (including discrete risks and cost impacts of schedule uncertainty) and for schedule uncertainty are provided in Attachment 2. Please note that the total presented in Attachment 2 of $1.460B does not include project contingency for the Facilities and Infrastructure Projects and Safety Improvement Opportunities ($44M) and unallocated program contingency ($202M). The total of these amounts is $0.246B, thereby yielding the total contingency amount of $1.706B ($1.460B +$0.246B). Please refer to Ex. L-4.3-2 AMPCO-073 for a discussion of unallocated program contingency.

e. Please refer to Ex. L-4.3-1 Staff 48, Attachment 24, for a full description of the risk management process for the Darlington Refurbishment Program (DRP). In summary, optimistic, most likely, and pessimistic estimates of the impacts of cost and schedule risks are developed by the Project Manager. The uncertainty ranges and impacts are subsequently reviewed by an experienced panel and risks checked for duplication among projects and with program risks. In the event that there was no detailed basis or operating experience available to assess the cost impact of a risk, or other constraints would not allow a detailed basis to be developed, the estimates were based on Project Manager judgment and experience and the ranges for optimistic, most likely, and pessimistic were adjusted as appropriate based on challenges and feedback. These ranges and impacts formed the initial inputs to the contingency model. Subsequently, further challenge meeting were held with DRP Management to assess the reasonableness of the costs attributed to each risk.

f. The risk register at the time of the Monte Carlo simulation for the Release Quality Estimate (RQE) and the current risk register are provided in Attachments 3 and 4 (Attachments 3 and 4 are confidential), respectively. Please note that not all of the risks in the risk register required contingency amounts to be assigned (e.g. some mitigation actions were expected to retire the risk).

g. Given the large number of risks in the risk registers, OPG is unable to provide a detailed comparison of the risk register at RQE compared to the current risk register. The risk registers for each project bundle and the program have been adjusted as the Definition Phase ended and the Execution Phase began. During the project, new risks will emerge and risks that were expected to occur may or may not occur. This process will continue throughout the DRP as new risks emerge and other risks are retired or realized.

h. The Risk Management and Oversight (RMO) tool is an application which refurbishment staff use to perform risk management activities for the projects. It is the central risk registry for the project, and facilitates risk management through outputs such as risk reports, mitigating action assignments, action tracking, and reporting.

i. The authors of the KPMG Report “Independent Review Services for the Darlington Refurbishment Project – Risk Management” are listed on page 9 of the report filed as Ex. D2-2-7, Attachment 1. Please refer to L-4.3-15 SEC-033 for the authors’ CVs.

ONTARIO POWER GENERATION

Risks and Mitigating Actions

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
Project: Balance of Plant -																	
12389	Financial risk to all projects due to 4D Challenge	This risk is opened to document the variance between the amount of reduction we are able to disposition and the total 4D cost reduction challenge.Realisation to this risk could result in increases to cost compared to 4D.	4	Active	Scott GUTHRIE	Ralph LAURICH	04-Jun-15	Monitor	15-Oct-15	4	3	1	12	4	3	1	12
			There are no Not Started, In Progress Actions associated with the risk.														
13261	PHT & Aux - R003 on 84.0 elevation may contain many hotspots	The risk is that the room where the D2O collection tank and vent condenser heat exchagers (2-33810-HX1/2) currently contains a hot spot and may contain many more after the PHT drain. The Heat exchangers are located in Room-003 on the 84.0 elevation, at one of the lowest elevations of the station. During refurbishment, the removal of the D2O in the PHT Auxiliary system will be completed via a gravity drain, causing many particulates and radioactive particles to be drained to the lower elevations of the plant.	1	Active	Scott GUTHRIE	Katie STEWART	04-Jun-15	Monitor	30-Jul-17	4	2	3	12	4	2	3	12
			There are no Not Started, In Progress Actions associated with the risk.														
13653	Vendor Material Tracking/Timely Delivery for Execution	There is a requirement that Vendors demonstrate how they are proactively managing material procurement/delivery to meet project cost/schedule milestones with the appropriate level of quality & value for money. Effective engagement by BoP vendors to utilize the OPG Material Tracking system is required to establish baseline data and status on-going afterwards.	3	Active	Scott GUTHRIE	Katie STEWART	10-Aug-15	Mitigate	10-Dec-15	4	3	3	12	3	3	3	9
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5406	In Progress	BoP NPC Material Tracking	Ensure all ScopeID 7012 materials are input and all data verified in the Material tracking system. Critical that the vendor demonstrates data that shows RFQs have been issued/purchasing times validated so IPG timelines can be reviewed with Station personnel.	Scott GUTHRIE	Katie STEWART	14-Aug-15	July 13/15 Update: All material data to be input into Material Tracking File (MTF) for Scope ID 7012 by Aug 13/15 - project Engineer to validate data is in the tool and confirm what Z299.2/3 materials are at risk for T-8 per MA-22. Aug 12/15 Update: [redacted] Contingency planning for Q1 2016 field work commenced, EOC review underway.							
13654	ES MSA Vendor Capability/Experience	[redacted]	3	Active	Scott GUTHRIE	Scott GUTHRIE	13-Jul-15	Mitigate	06-Apr-16	4	3	3	12	3	2	3	9
			There are no Not Started, In Progress Actions associated with the risk.														
12365	Risk to SDC modification Detail Design	BecauseProcurement & Construction (PC) vendor for SDC modification project is not yet identifiedand engaged, there is a risk of not having the detail design completed as committed. This translates in not having the PO for pump-motor set (Long Lead Material) issuedin a specific timeframe, and subsequently the pump-motor information (flow diagrams, drawings, etc) will notbe provided to Engineering vendor as per current engineering schedule.		Active	Scott GUTHRIE	Katie STEWART	04-Jun-15	Mitigate	15-Feb-15	5	2	1	10	2	2	1	4
			There are no Not Started, In Progress Actions associated with the risk.														
13263	PHT & Aux - PHT Pumps Will Require Repairs	During DNRU2 a single PHT Pump (2-33120-P3) will be inspected to determine the condition of the pump and if any contingency repairs are required. The risk is that the 2-33120-P3 is in poor condition and will require full repairs. This will lead to inspections of 2-33120-P1/P2/P4 and potential additional repairs. This would also impact the scope for the remaining refurbishment unit outages.	1	Active	Scott GUTHRIE	Katie STEWART	04-Jun-15	Monitor	30-Jul-17	2	4	5	10	2	4	5	10
			There are no Not Started, In Progress Actions associated with the risk.														
12318	Stopple Plug Cost Increase due to Extended Services	If the sub-vendor Supplied equipment (TDW) is required for the entire 60 day LPSW outage, this will result in increased costs.The current assumption / plan is to use this for only small portion of the LPSW window (less than 7 days).	3	Active	Scott GUTHRIE	Jessica PERRYMAN	13-Jul-15	Mitigate	27-Feb-15	3	1	3	9	2	1	2	4
			There are no Not Started, In Progress Actions associated with the risk.														
13295	Risk of Fire Protection Emergent Repair Scope	DSRs IP1220-14, IP1300-1, and IP1220-3 are DSRs to perform assessments. Should deficiencies be found during these inspections/assesssments, there is a generic contingency DSR for any work required in Engineering Scope. Currently, this DSR does not carry any funding to perform the work.	3	Active	Scott GUTHRIE	Craig VERWEY	13-Jul-15	Monitor	27-Jul-16	3	3	2	9	2	3	2	6
			There are no Not Started, In Progress Actions associated with the risk.														

40

Risks and Mitigating Actions

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
Project: Pre-requisite Projects - 73398																	
12334	16-31555 D2O Storage Project: Construction Delays Due to LLM Ordering Delays	There is a risk that long lead materials (LLM) will not be ordered in time to support the construction schedule. Delays in EPC Vendor PO issuance to material vendors have prevented ordering of nearly $21M in LLMs.	3	Active	Anthony COLELLA	Atul SAVALIYA	04-Aug-15	Mitigate	30-Jun-15	5	3	5	25	4	3	4	16
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			3034	In Progress	#12334: Long Lead Material Delivery Risk	Review RFP delivery dates (material suppliers) to identify which long lead materials (LLM) are at risk of arriving later than their required installation dates and assess the possibility of acquiring funding for expedition(I/P) This is being reviewed weekly with the contractors.	Michael TAGUIAM	Atul SAVALIYA	20-Dec-15								
12240	Containment Filtered Venting System: (CFVS) Filter Train LLM Delivery and schedule delays including final AFS	Potential project schedule extension due to further delay in Filter train delivery. projected delay in filter train delivery from June to October has been incorporated in the project schedule. Potential added delays: for first of a kind design, for fabrication difficulties, for shipping difficulties to USA facility, for second stage assembly at USA facility, for shipment difficulties to Oshawa port and installation deliveries from Oshawa to site. Impact potentially 3 added months (assuming one month for each stage) Delivery delays directly extend AFS date (currently April 22 2016 in schedule) Jan 25 update, with delivery schedule delayed to Dec 15 2015, risk is may miss use of Saint Lawrence which closes end of December with potential 3-4 month further delay on deliver- = 3-4 months delay of AFS and > $1M cost impact.	3	Active	Bill DEVLIN	Colin BARFOOT	14-Jul-15	Mitigate	01-Apr-16	4	2	5	20	3	2	4	12
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			3081	Not Started	CFVS - Filter Train LLM Delivery and schedule delays including final AFS	Mitigating actions: 1. Complete design and include filter installation and testing assessment in design. 2. initiate installation and testing planning as soon as design is complete.	Colin BARFOOT		01-Apr-16	Nov. 17 update: 1. Tie-in installation planning advanced to Jan. 8, 2015 2. Filter manufacturing is currently on schedule.							
12432	10-73370-PSVS- Tie-ins and commissioning may not complete in summer time for all units.	PSVS modification require a large number of terminationd in CDF and relay panels. Due to this, commissioning of all units may not be completed during the summer time when PSVS is in summer mode.	4	Active	Bill DEVLIN	Vijay PANDYA	15-Jul-15	Mitigate	30-Sep-15	4	1	5	20	2	1	3	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			3528	In Progress	10-73370-PSVS- Tie ins and commissioning may not complete in summer time for all units.	PSVS modification require large number of termination on CDF and relay panels. Due to this commissioning of all units may not be completed during summer time when PSVS is in summer mode.If this risk is realized then commissioning of the rest of the units may be extended in next summer. This may increase cost and schedule of the project.	Anthony COLELLA	Vijay PANDYA	31-Dec-15	This risk has been realized. The project schedule has been extended due to various reasons. Due date has been extended to 31 December, 2015							
12434	RFRISA - Electrical Supply to the Building	There is a risk that the RFRISA electrical feed will not be available in time for RFRISA AFS due to delays in boring under the fence & conduit/manhole installation that are required in order tie-in to SWGR 53 (outside the PA; applies to D2O Storage & RFRISA). This may result in delays to commissioning activities for the building, resulting in a subsequent cost and schedule impact.	4	Active	Bill DEVLIN	Courtney BRISEBOIS	16-Jul-15	Monitor	24-Jul-15	4	2	5	20	4	1	4	16
			There are no Not Started, In Progress Actions associated with the risk.														
12471	73365 CFVS Cold Weather Construction Risks	Current Schedule for CFVS has mutiple critical construction activities occuring during the cold windy winter months. Impacts of weather or high wind are schedule delays standby and overall project cost increases.	3	Active	Bill DEVLIN	Colin BARFOOT	14-Jul-15	Mitigate	29-Apr-16	4	2	5	20	2	1	4	8
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			3816	In Progress	73365 CFVS - Cold Weather Construction Risk	Due to cold weather there is a risk that lowtemperatures and high wind will cause delays to outdoor work and result in increased project costs. The following mitigating actions will be used: 1. expedite funding approval from gate 3D 2. support fastest lowest schedule risk excavation - straight cut 3. pre-order materials critical for buried piping to ensure excavation is backfilled ASAP. 4. coordinate with VBO to remove the VBO elevator and equiment as early as possible. 5. Extend work crews for critical path activities related to outdoor work 6. Work to expedite filter delivery	Anthony COLELLA		29-Apr-16								
13287	Aux Heating Steam - Vendor Cost to Complete Potential Under Estimate	The Vendors Cost To Complete (CTC) estimate provided on Feb 9, 2015 states that $18.1M is required. The Vendor stated the assumption in the CTC if the AFS date extends past August 15, 2015 extra funding would be required. Currently the AFS date has slipped to Oct 27, 2015 and the Project could be short in funding.	3	Active	Mike NAIRNE	Lori MIRSCH	05-Aug-15	Mitigate	20-May-15	4	5	4	20	3	4	3	12
			There are no Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risks and Mitigating Actions

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13290	73365 CFVS SChedule Delay for stack installation due to delay in VBO elevator removal	CFVS design utilizes embedded parts in vacuum building on one side that are also used by VBO elevator. new attachment points for the VBO elevator are designed into CFVS stack structural steel. Vacuum Building Outage (VBO) elevator was installed in fall 2014 using the current CFVS construction site when no CFVS work was ongoing, to support planned VBO execution in Spring 2015, with this schedule the VBO elevator would have been removed months before the major civil works and CFVS stack piping installation start and would have had a minimal delay on the scheduled excavation scope. The CFVS excavation has started at end of April 2015 and will prevent the smaller crane from removing the elevator from the CFVS excavation site. During the VBO the IMS trailers are using the only other area available to allow a smaller crane to be used to remove the VBO elevator. Coordination between Project Outage and IMS to suuport early IMS trailer removal - tentatively approved. Regardless of where the elevator is removed from there will be a minimum 10 day push to the CFVS project critical path. As construction work must stop during craning overhead. This delay is incorporated in the CFVS schedule. As identified by maintenance contracts, after the VBO the probability is that the temperature will be too low for the radiation monitoring equipment to work to allow for the VBO crane removal from the IMS trailer location. VBO Elevator removal after Feb 1 2016 will add day for day to the CFVS critical path, for an up to 3 month schedule extension for end of April 2016 VBO elevator removal.	3	Active	Bill DEVLIN	Colin BARFOOT	14-Jul-15	Avoid	02-Jun-16	4	2	5	20	1	2	4	4
			There are no Not Started, In Progress Actions associated with the risk.														
13449	16-31555 D2O Storage Project: Delay In Completing Seismic Foundation	There is a risk that we will not turnover the D2O footprint to the new EPC Contractor by Nov 30th, 2015 as commited; thereby resulting to additional cost and schedule impact due to recent delays (weather, water ingress issues)		Active	Anthony COLELLA	Anthony COLELLA	04-Aug-15	Mitigate	30-Oct-15	5	1	4	20	3	1	4	12
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5212	In Progress	#13449: Delay In Completing Seismic Foundation Construction	OPG Project to continue to work with civil and small M&E contractor to look for additional opportunities for schedule improvements and progress work. Vendors to provide schedule recovery plans as applicable.	Anthony COLELLA	Anthony COLELLA	30-Oct-15								
12132	RFRISA - commissioning activities coincident with VBO may create conflicting resource priorities	The risk is that the DNGS SCO/VBO (which is scheduled for September 2015) coincides with the commissioning period for the RFRISA facility leading to conflicting resource priorities (Ops & Mtce & Craft Labour) resulting in a delay to the RFRISA schedule.	3	Active	Bill DEVLIN	Courtney BRISEBOIS	16-Jul-15	Mitigate	15-Jul-15	4	1	4	16	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			3095	In Progress	RFRISA - Commissioning Coincident with VBO	1) ES FOX to present commissioning plan to OPG (TCD 1-May-15) - Complete 2) OPG to review NIMS and work to schedule tasks requiring CM support prior to the VBO. (Complete - Fire Detection Tie-In advanced to WW35); workplan with NR CM. - Complete 3) OPG to monitor field work; ensure vendor ready to execute according to schedule. (on-going). 4) OPG to ensure remaining activites requiring station support (ie: rad monitor testing) are scheduled appropriately. List provided to D. Sommervile. C. Brisebois to follow up TCD 13-May-15. 5) ES FOX to scope inject work for rad monitoring calibration activities. Action: V. Solanki TCD 10-Jul-15.	Courtney BRISEBOIS		15-Jul-15								
12189	EPG3 - Long Lead Material Vendors Ability to Meet Schedule	The risk is that Long Lead Material Vendors will not be able to meet the Project's compressed schedule (Design input documents or physical delivery of materials). Delayed delivery of design input documents or equipment will affect cost and schedule. Sufficient qualified vendors may not be available for critical equipment.	3	Active	John IERACI	Mark CIANA	19-Aug-15	Monitor	17-Sep-15	4	2	4	16	4	1	3	12
			There are no Not Started, In Progress Actions associated with the risk.														
12289	EPG3 - Commissioning Level of Effort	This is a first time evolution for these modifications and there is limited commissioning experience with this type of equipment. The risk is that the commissioning of this new system may take longer and be more challenging than anticipated/estimated resulting in numerous work interruptions/clarifications and extension to the schedule or missing AFS (OPEX from Pickering Temporary Emergency Power System). NOTE: EPG3 is an expedited SIO (schedule advanced 1 year), any extension to commissioning activities will delay in-service date.	1	Active	John IERACI	Mark CIANA	19-Aug-15	Mitigate	30-Nov-15	4	1	4	16	4	1	4	16
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

Appendix C: Risk Assessment Criteria/Scale

C.1.0 PROGRAM AND FUNCTIONAL RISK ASSESSMENT CRITERIA/SCALE

Risk Attribute	Definition	1 (Minimal)	2 (Minor)	3 (Notable)	4 (Substantial)	5 (Major)
Probability	The probability that a risk will occur	Improbable (<20%)	Unlikely (20%-40%)	Possible (40%-60%)	Likely (60%-80%)	Probable (>80%)
Financial Impact	The financial consequences of a risk should it occur	Minimal (<$50M)	Minor ($50M-$100M)	Notable ($100M - $200M)	Substantial ($200M - $400M)	Major (>$400M)
Schedule Impact	The impact that a risk would have on the overall program schedule should it occur	Minimal (No impact to critical path)	Minor (<2 weeks delay to critical path)	Notable (2 weeks – 2 months delay to critical path)	Substantial (2-6 months delay to critical path)	Major (>6 months to critical path)

C.2.0 PROJECT EXECUTION RISK ASSESSMENT CRITERIA/SCALE

Risk Attribute	Definition	1 (Minimal)	2 (Minor)	3 (Notable)	4 (Substantial)	5 (Major)
Probability	The probability that a risk will occur	Improbable (<20%)	Unlikely (20%-40%)	Possible (40%-60%)	Likely (60%-80%)	Probable (>80%)
Financial Impact	The financial consequences of a risk should it occur	Minimal (<$1M)	Minor ($1M-$10M)	Notable ($10M - $50M)	Substantial ($50M - $200M)	Major (>$200M)
Schedule Impact	The impact that a risk would have on the project bundle schedule should it occur	Minimal (No impact to critical path)	Minor (<1 weeks delay to critical path)	Notable (1 weeks – 2 weeks delay to critical path)	Substantial (2-6 weeks delay to critical path)	Major (>6 weeks to critical path)

C.3.0 URGENCY ASSESSMENT CRITERIA/SCALE

Urgency Score	NR Timeline for risk response	Urgency Assessment Criteria
1	>1yr	Risk treatment activities complete or risk not required to be addressed for the foreseeable future
2	6 months – 1 yr	Risk may still be addressed in the long term and risk treatment will still be effective
3	1-6 months	Risk should be addressed in the medium-term for risk treatment to be effective
4	Within 1 month	Risk must be addressed immediately for the risk treatment to be effective

Appendix D: AACE Estimate Class and Expected Accuracy Ranges

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Table 1 - AACE Estimate Class and Expected Accuracy Ranges

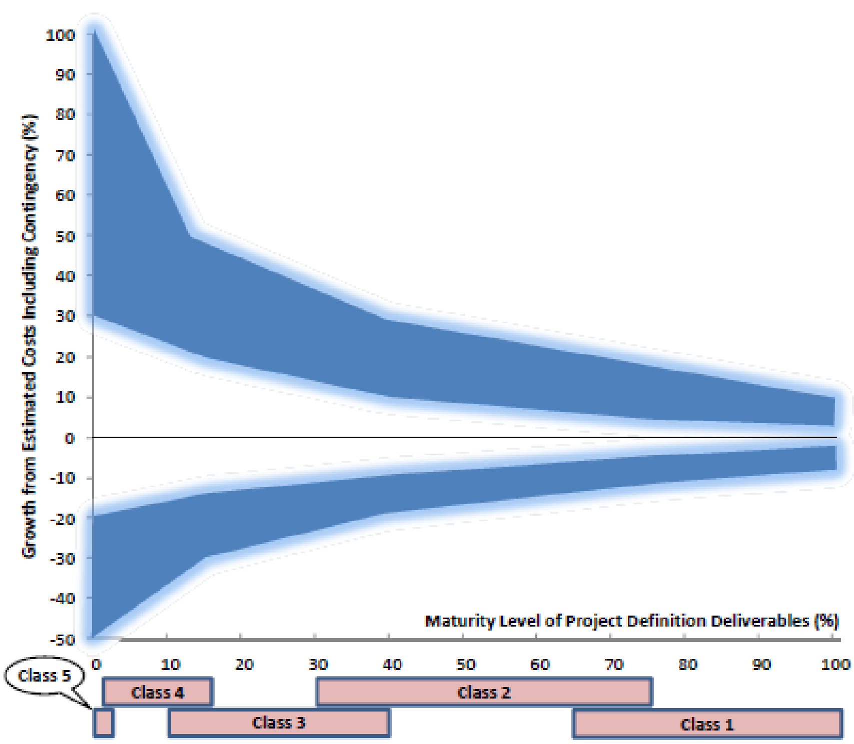


Figure 5-1 AACE Estimate Class and Expected Accuracy Ranges

Appendix E: Guidelines to Risk Screening

Following the identification of risks that can potentially affect the project, it is important to differentiate those risks that are minor and thus should not require significant further attention from those that require follow-up, analysis, active mitigation and management. Similarly, not all risks are warranted for contingency allocation. One commonly used risk tool is shown in figure 5-2 .It allows assigning a risk to one of four quadrants based on a qualitative assessment of its relative impact and the probability of its occurrence. Table 3 summarizes the optimal risk response dependent on the qualitative assessment.

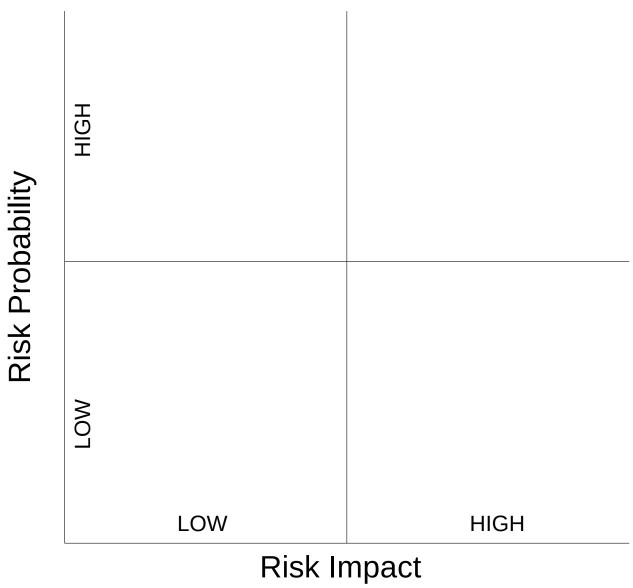


Figure 5-2 Risk Probability and Impact Matrix

Quadrant	Description	Optimal Response	Contingent Funds Assignment?
Low Impact, Low Probability	• Essentially negligible • In the unlikely condition that it does arise it should be possible to deal with it simply and with minimal impact	• Monitored to determine that the impact or likelihood does not increase	No
High Impact, High Probability	• Management should determine if project should proceed or if the benefits of taking the risks is justified	• Budget for mitigating actions in the project scope to lower the probability and impact of the risk	Yes – for the residual risk post-mitigation

Quadrant	Description	Optimal Response	Contingent Funds Assignment?
Low Impact, High Probability	• Uncertainties from common sources in a project (e.g. cost of labour, materials, actual duration of activities, productivity, etc.) • Each of these uncertainties alone would have little impact, but the cumulative effects may have impact	• Reduce uncertainties in estimates by obtaining additional information or improving work processes • Budget for mitigating actions in the project scope to lower the probability and impact of the risk, if reasonable to do so	Yes – for the residual risk post-mitigation
High Impact, Low Probability	• Rare occurrences • Difficult to assign probabilities based on past events • Cannot be effectively funded by contingency, especially if maximum impact is realized	• Budget for mitigating actions in the project scope to lower the probability and impact of the risk, if reasonable to do so	Case-by-case basis. If yes, should be covered by Management Reserve

Table 2 Optimal Response based on Risk Probability and Impact

4.1.2.2 Risk Titles

Risk titles describe the event and the context of the event.

"*There is a risk of insufficient welders available** <event> **to support Execution** <context>"***

4.1.2.3 Risk Descriptions

Risk descriptions should be comprised of the risk ***event***, the ***cause*** of the event, and the ***impact*** of the event on project objectives. The absence of any one of these critical items would preclude the item from being added to the risk register due to the inability to define a proper risk treatment.

"There is a risk of insufficient welders available <event> **to support Execution due to competition with other large industrial projects in the province** <cause>**, resulting in a delay that will impact the critical path by 30 days** <impact>**".**

4.1.2.4 Opportunities

An opportunity is an event that, if it is implemented or occurs, increases the likelihood of achieving project objectives. An opportunity must demonstrate a clear benefit to achieving a project objective *in sufficient magnitude to offset the risk presented by changing course*. Opportunities identified in the SharePoint log "Opportunities Inbox" will be reviewed periodically by the PMO risk department and reported in the Risk Oversight Committee meetings for further consideration. In all instances where opportunities are identified as valid, they are to be pursued with focus (i.e. exploited to the extent possible).

4.1.3 Risk Assessment

4.1.3.1 Risk Register

A project risk register is a living repository of risks and is the project manager's tool for identifying, assessing, monitoring, and updating project and program risks. The RMO tool contains the risk registers for all nuclear Projects – it is the working tool and also provides storage and backup of all risks and the associated logs. Risks included in the risk register should include ***all project life cycle risks*** that can be properly defined, without speculation, bias, or other such features identified in section 4.2.1.

4.1.3.2 Qualitative Scoring of Risks

Qualitative risk scores assist those inside and outside project team in quickly determining the biggest risks to the project. A "heat map" scoring approach is taken based on the probability of occurrence, schedule impact and financial impact of a risk (refer to Figure 2). After the probability, financial impact and schedule impact scores are determined the risk score is calculated by multiplying the probability score with the financial or schedule score, whichever is highest. The heat map scoring is standard for probability and schedule impact, but scaled to four categories for cost assessment criteria based on magnitude of the project and financial impact of the risk. This scaled approach allows all project managers to qualitatively assess and prioritize risks to their project, with the understanding that a high risk to a $500K project is not as impactful as high risk to a $100M refurbishment project that has the same score.

Impact Score						
	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5
RED = Major Risks YELLOW=Significant Risks GREEN = Minor Risks		**1**	**2**	**3**	**4**	**5**
		Probability Score				

Figure 2: Generic Heat Map identifying the potential qualitative risk scores for Nuclear Projects

Refer to Appendix D for the risk assessment criteria/scale and guidelines for how to use the heat map.

4.1.3.3 Urgency

Urgency is another qualitative risk measure that assists project managers in prioritization. In the RMO, an urgency score shall be applied for each risk. The measure of urgency for risks in Nuclear Projects is as defined below:

Urgency Score	Approximate Timeline for risk response	Urgency Assessment Criteria
1	> 1yr	Risk treatment activities complete or risk not required to be addressed for the foreseeable future
2	6 months – 1 yr	Risk can be addressed in the long term and risk treatment will still be effective
3	1-6 months	Risk should be addressed in the midterm for risk treatment to be effective
4	Within 1 month	Risk must be addressed immediately for the risk treatment to be effective

4.1.3.4 Quantitative Risk Analysis

Quantitative risk analysis is the process of assigning a dollar value to the effect of identified risks on overall project objectives. Quantitative risk analysis is performed on risks that have a significant qualitative residual risk score and require contingency funding. Not all risks qualitatively scored and managed per this process will require contingency (refer to Section 5.1 for guidelines). Wherever possible, the estimating group should be engaged in supporting the determination of the cost impact of a risk to the project plan. If the quantification of risk exceeds the cost benefit argument for the project, the viability of the project should be revalidated.

4.1.4 Risk Treatment

Risk treatment requires effort to develop a plan to minimize the risk and implement response actions where appropriate. All risks in the risk register should have one of the following risk responses:

- **Avoid –** Obtain information to better define the risk source, eliminating the risk entirely. In this case the residual risk score should be reduced compared to the current risk score to reflect the level of confidence in the ability to avoid this risk.
- **Transfer** – Shifting some or all negative impacts of a threat to a third party (e.g. to a contractor via contract terms and conditions). If this response is chosen, the risk owner is still accountable to manage this risk on an ongoing basis. In this case the residual risk score should be less than the current risk score due to the consequence of the risk being transferred to a third party.
- **Mitigate –** Take actions to reduce the probability and/or impact of an adverse risk event to be within acceptable limits. In this case the residual risk score should be less than the current risk score due to mitigation actions being taken.
- **Accept –** Take no action and accept the possibility that the risk could occur. In this case the residual risk should reflect the current risk score, because nothing is being done to reduce the risk. Accepting risk may result in significant cost impacts, as such the risk owner is required to gain the endorsement of the responsible project director prior to selecting this response.
- **Monitor –** Periodically assess the risk through the normal course of project execution until, a) clear mitigating actions are identified, or b) a more appropriate risk response is identified. In this case the residual risk should reflect the current risk score, because nothing is actively being done to reduce the risk.

An informal cost-benefit analysis may be performed to evaluate the appropriate of the risk response. For example, if the cost to mitigate the risk is greater than accepting the probability and the impact of the risk “as-is”, then the risk response should be “Accept” and not “Mitigate”.

4.1.4.1 Evaluating the Effectiveness of Risk Responses

All risks in the risk register should have three risk scores:

(a) **Pre-Response Risk Score –** the score assuming that the risk will be accepted. This is a one-time assessment at the ‘’point of discovery” of the risk.

(b) **Post-Response Risk Score –** the score of the residual risk assuming the risk response is completed successfully. This score is subjective and based on the confidence level of the risk owner in the effectiveness of their risk response. This post response score is a gauge of how manageable the risk owner believes the risk is.

(c) **Current Risk Score –** the score reflecting the current status of the risk. This is the primary measure of risk exposure for the purpose of planning and risk metrics/response analysis.

4.2 Risk Monitoring and Control

4.2.1 Risk Reviews

The risk owner identified in the RMO tool has complete accountability for the content of their risks in the tool and for the implementation regular reviews of these risks. This is true even if they have delegated their authority to update or manage the risk to others. Each risk owner shall perform, at minimum, monthly risk reviews to:

- Ensure risk responses are optimal based on the latest information;
- Ensure mitigation actions are on track and status the actions in the actions log in the RMO tool and initiate new actions were warranted;
- Determine if the assumptions related to the risks are still valid and update in the Assumptions log in the RMO tool, if applicable;
- Determine if the risk characteristics have changed;
- Determine if new risks should be identified;
- Determine if risk has been realized or has expired and can be closed in the RMO Tool (with justification).
- Assess, modify and validate the risk score and any other applicable fields (such as owner, comments, etc.) in the risk register as required.

4.2.2 Risk Reporting

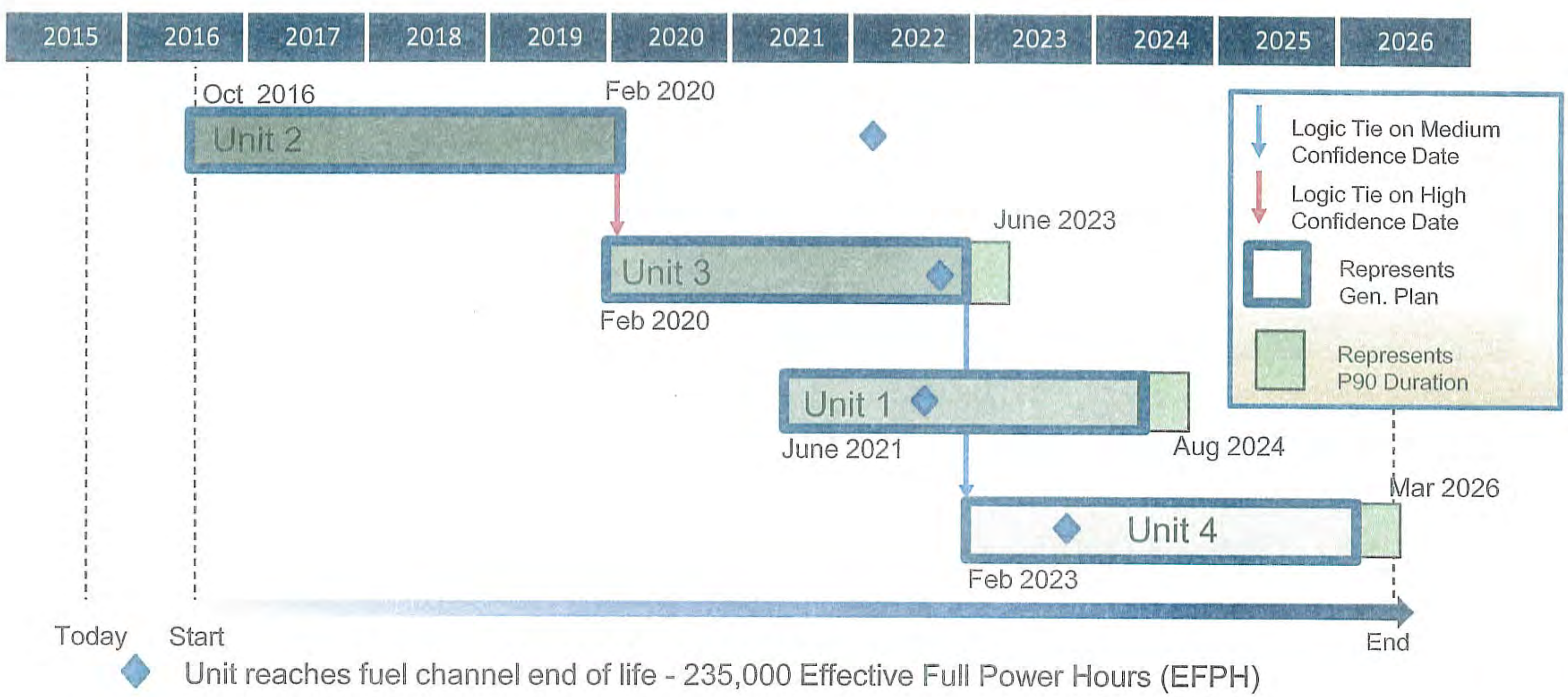
Risk reporting is performed in line with monthly or quarterly reporting cycles. The content of risk reports can be taken directly from the RMO Tool using the Business Intelligence (BI) report engine. For senior management and external stakeholder reporting, the PMO risk department may make the the risk wording in the RMO tool more concise to align with the level of detail required in the specific reporting vehicle.

Examples of reporting vehicles for risk include:

- Risk Dashboard
- Key Risk Area Summary Report
- Program Reports
- Quad Charts
- NOC (Nuclear Oversight Committee) Reports
- Quarterly ERM (Enterprise Risk Management) Reports
- User Reports (“boxed” reports) from BI

Schedule: Business/Generation Plan View

- The **APPROVED** high confidence schedule, which <u>includes</u> contingency, assumes the first unit outage will commence in Oct. 2016 with each unit lasting 37 to 40 months.
  - For Generation planning, OPG assumed the high confidence 40 month schedule for the first unit and the medium confidence schedule for the subsequent units.
- The LTEP and the Shareholder require us to incorporate off-ramps, thus, it is imperative that we succeed on each unit in order to get the approval to proceed to the next unit.



CCC Interrogatory #18

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Reference: Ex. D2/T2/S11 Attachment 3 p. 8
This testimony from Dr. Patricia D. Galloway asserts at several places that OPG used a "p90" confidence level when setting the contingency amount for the DRP of $1.7B.

a) What is the level of contingency that would result from utilizing a p50 confidence level?

b) Please provide a table that illustrates, for the test period, both the "as filed" in service additions for the DRP and the reduced in service additions for the DRP during the test period based on the lower contingency amount that results from using a p50 confidence level. Please estimate the reduced revenue requirement for each of the test years in relation to the p50 scenario.

c) Please list and describe all of the risks that OPG considered may contribute to increased costs for the DRP where the nature of the risk is such that if manifested the added cost would not be appropriately recovered from either OPG's contractors or from OPG's ratepayers, but rather absorbed by OPG directly.

Response

a) The level of contingency that would result from using a P50 confidence level is $1.4B (2015$) excluding interest and escalation. Please see L-4.3-2 AMPCO-70.

b) The total contingency for Unit 2 is $694.1M (Ex. D2-2-7, p. 7) which includes interest and escalation. This amount is included in the in-service amount of $4.8B for Unit 2 in 2020. As noted in part a), the amount of contingency for the four unit refurbishment at the P50 confidence level is $1.4B (2015$). The contingency amount for Unit 2 at the P50 confidence level is estimated by prorating the P50 and the P90 contingency estimates in the RQE and is therefore estimated to be $578M ($694.1M X ($1.4B/$1.7B)), including interest and escalation. Thus, the estimated revised in-service amount for Unit 2 in 2020 would be reduced by $116M ($694M-$578M) to $4,693M.

Please refer to the chart below for the revised in-service amounts:

Chart 1

	2017 ($M)	2018 ($M)	2019 ($M)	2020 ($M)	2021 ($M)
Filed Evidence – In-Service Additions (1)	374.4	8.9	0.0	4,809.2	0.4
Estimated In-Service Additions with Unit 2 P50 Contingency	374.4	8.9	0.0	4,693	0.4

Note (1) – Please see Ex. D2-2-10, Table 5.

OPG estimates that in-service additions of $4,693M in 2020 and associated reductions in capital expenditures leading up to that point would reduce the 2017-2021 revenue requirement by approximately $18M, as follows: $2M increase in 2019, $9M decrease in 2020 and $11M decrease in 2021. These estimated amounts were derived in the manner shown in L-04.3-2 AMPCO-77.

c) There are no risks that OPG considered at the program or project level that would not appropriately be recoverable through the CRVA.

Figure 2: Linkages to OPG and DR Program Objectives

OPG's Business Objectives	DR Program Objectives		Commercial Guiding Principles
Generating electricity safely, reliably and efficiently today, and being an enabler for adequate supply of clean energy in the future.	**Meet Regulatory Requirements** Meet all required standards for safety, environmental compliance, and the CNSC/other applicable quality standards.	DR Program Commercial Strategy	**Accountability** Accountability can be ensured through In-depth planning and preparedness; which is achieved through early communication with OPG stakeholders, compliance with applicable provincial and regulatory directives, high quality vendor teams, and the implementation of effective contracting strategies and contracts by OPG Teams.
	Maintain OPG Control OPG has the ultimate accountability for delivering the DR Program and hence must retain the overall responsibility for the DR Program as the Program Manager.		**Value For Money** Value for money is accomplished through due diligence on current marketplace conditions and projects, early communications with vendors, competition, market acceptance of contracting strategy, ongoing communications with pre-qualified vendors, scope definition and work packaging, cost effectiveness, planning for change, using OPG's knowledgebase, and utilizing linkages to other DR projects.
	Minimize Impact on Existing Units Minimize disruption to operating units where safety of the units is involved and where production is potentially disrupted.		**Fairness & Transparency** OPG will operate openly, transparently and in the public interest by establishing strong working relationships with vendors. This is accomplished by clearly defining roles and responsibilities, collaborating on cost and schedule, exchanging information, implementing incentives, balancing resources, leveraging vendor capabilities, and effectively working as a team.
	Achievable Schedule and Budget Schedule and budget are to be realistic and achievable. Cost recovery and financing methods must be in place.		**Risk Transfer/Sharing** Allocation of risk to the appropriate party will minimize the difficulties associated with managing that risk. Contractual attempts to fully shift accountability to the vendors may not always be achievable or may command too high a risk premium. Incentive mechanisms and effective oversight will be used to mitigate any risks for when OPG is partially accountable, and appropriate risk mitigation or management techniques will be used for risks retained by OPG.
	Demonstrate Success Demonstrate to the public and shareholder that the Program is a success.		

6.0 OVERALL COMMERCIAL STRATEGY

OPG has determined that it will fulfill the role of a GC as it is essential for OPG to maintain control and effective management of the overall DR Program and its

Chart 2 - Overview of Major Work Bundle Contracts for DRP Four Unit Refurbishment

Work Bundle (Contractor)	Description	Contract Model	Pricing Model	Value of Contract
RFR • SNC/ Aecon	• Definition Phase Work o Retube Waste Processing Building design and construction • Execution Phase Work (Refurbishment of units 2, 1, 3 & 4): o Removal/replacement of 480 pressure and calandria tubes o Replacement of 960 feeder pipes o Support Services & Equipment	EPC	Target Price	$3.4B See section 3.2 for detailed breakdown
	• Construction of the mock-up facility • Design and production of tooling	EPC	Fixed Price	
	• Owner Specified Materials (OSM) and Goods • Commissioning	EPC	Cost + Markup	
Turbine Generators • Alstom	• Engineering Support and Equipment Supply Agreement	ESESA	Fixed/Firm Price + Limited Target Price	$333M
Turbine Generators • SNC/Aecon	• Fieldwork required for inspections, repairs and retrofits of hardware and hydraulics on the turbine generators • Control system upgrades from analog to digital system	EPC	Target Price	$284M
Defueling - defuel hardware, software and services • GE-Hitachi	• Design, supply and technical support for OPG work for defueling of all four reactors	ESESA	Fixed/Firm Price + Limited Reimbursable Costs	$23M
Fuel Handling – powertrack refurbishment • ES Fox	• Supply and install replacements for the main components of the fueling machine power track system	ESMSA – Procure / Construct	Target Price	$126M
Steam Generators • BWXT + Candu Energy	• Inspections and maintenance work	EPC	Fixed/Firm Price + Limited Target Price	$110M
Balance of Plant • Many	• Various smaller equipment repair and replacement projects and system upgrades • Includes; Balance of Plant, Unit Islanding, Refurbishment Support Facilities, Shutdown Layup and Services, and Specialized Projects	ESMSA, EPC	Target Price	$783M

3.1.1 <u>Pricing</u>

In determining the appropriate pricing model for each work bundle, the need and ability for OPG to transfer risk to its contractors was balanced against the benefit of achieving a lower contract price or target cost. High levels of complexity and uncertainty in certain work packages (e.g., RFR) made the transfer of significant pricing risk to the contractor less commercially feasible.

OPG's major contracts include the following pricing models:

- *Target Price* – Under target pricing, the contractor is paid its actual (allowed) costs (other than overhead costs) incurred in performing the work and is entitled to a fixed fee as compensation for all of its overhead costs, profit and risk. Parties share savings below targets and overruns above targets. The target price incentive and disincentive mechanism, which includes a neutral band, is structured to achieve alignment of contractor interest and limit cost increases and schedule delays.

- *Fixed Price/Firm Price* – Contractors complete their work within a set budget and time period. Price only varies in specified circumstances or where OPG changes scope. The price of fixed price contracts is a defined value whereas firm price contracts allow escalation for inflation.
- *Reimbursable Costs or Cost Plus Mark-up* – Contractors are paid actual labour and materials with mark-ups for overhead and profit (as a percentage of costs).

Figure 1 below illustrates the pricing models for the major contracts and the risk transfer associated with the pricing model.

Figure 1 - Pricing Models and Associated Risk Transfer

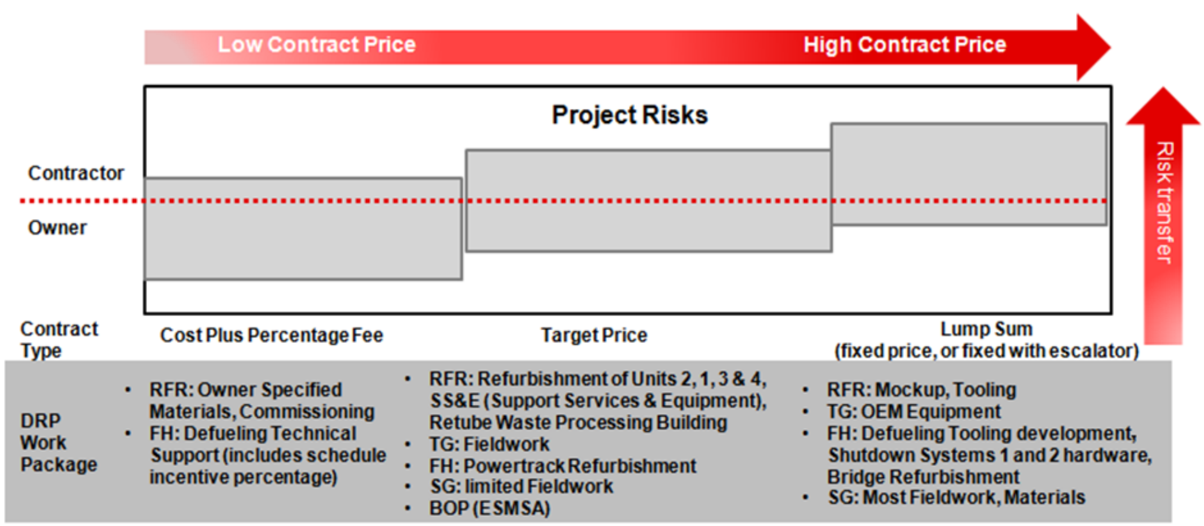
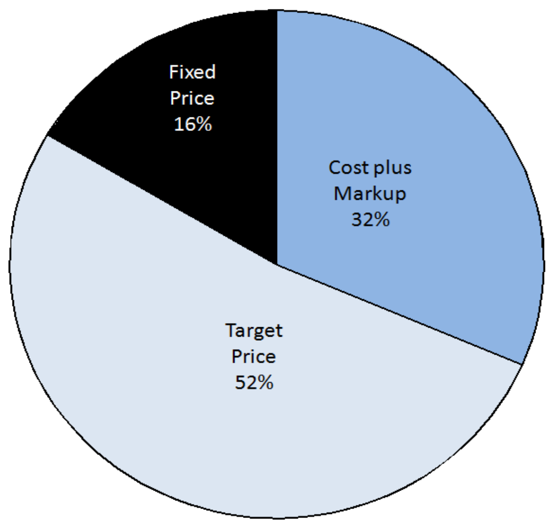


Figure 2 provides a breakdown of the contract costs across the three pricing models.

Figure 2 - Breakdown of contract costs across the pricing models



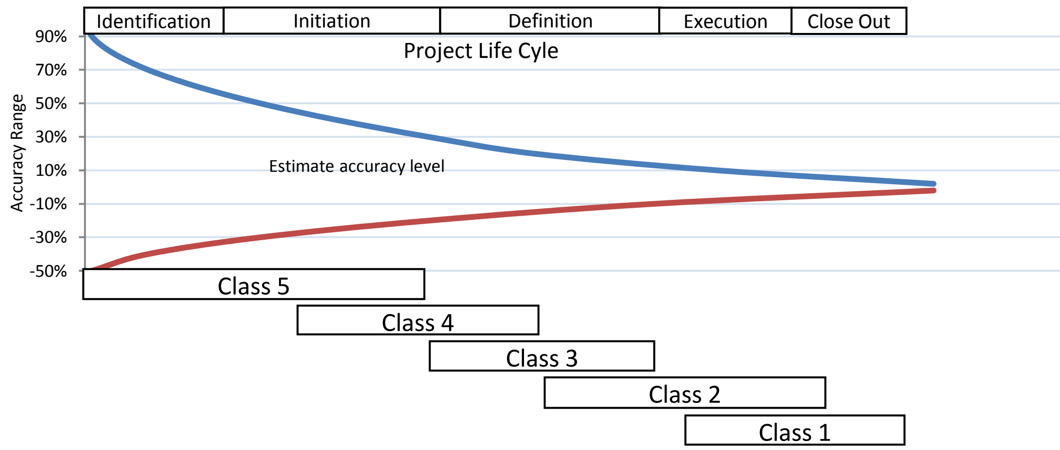
3.1.2 Contract Terms and Conditions

A number of terms and conditions are consistent across the contracts. These are described below and not repeated in the detailed discussion of each major work bundle:

- *Project Change Directives* – The major work bundle contracts limit the ability for the contractors to initiate project change directives, except in limited circumstances (e.g., force majeure)[2]. The limitation on contractor initiated project change directives reduces OPG's risk exposure to changes in target costs, target schedules or fixed fees.
- *Excusable Delays and Force Majeure* – For a specific set of circumstances beyond its control, the contractor could receive schedule or cost relief.
- *Warranty Provisions* – The warranty periods are sufficiently long for OPG to identify any potential defects with work performed by the contractors or owner-specified materials supplied by the contractors.
- *"Open Book" Approach and OPG Audit Rights* – OPG may review, audit and dispute invoiced costs.
- *Termination for Convenience* – OPG may terminate the contracts for convenience at any time, providing an important off-ramp to OPG.

[2] The ESMSA does not include this limitation on project change directives.

Figure 1, Total Project Estimate Accuracy During Typical Project Lifecycle



Estimate accuracy is classified per the Association for the Advancement of Cost Engineering International (AACEi) standards Class 1 through 5. Class 1 is the most accurate.

Table 1 - AACEi Estimating Classification

Estimate Class	*Primary Characteristic*	*Secondary Characteristic*		
	Maturity Level of Project Definition Deliverables Expressed as % of complete definition	**End Usage** Typical purpose of estimate	**EXPECTED ACCURACY** Typical variation in low and high ranges [a]	**Methodology** Typical estimating method
Class 5	0% to 2%	Concept screening	L: -20% to -50% H: +30% to +100%	Ratio from existing units, sales estimates, or published costs. Factored estimate based on appropriate equipment sizes, general features and dimensions Examples Methods Capacity Factored Parametric or Analogous Estimating Method Expert Judgment Analogy
Class 4	1% to 15%	Study or feasibility	L: -15% to -30% H: +20% to +50%	Factored estimate based on equipment sizes, soil and site data, site work, buildings, structures, piping, mechanical and electrical information. Allowances where required for non-quantifiable requirements. Example Methods Equipment Factored Parametric Estimating Method
Class 3	10% to 40%	Budget authorization or control	L: -10% to -20% H: +10% to +30%	Some factoring, some quantity takeoff from preliminary equipment arrangements and architectural drawings and information. Vendor quotes for major equipment. Other owner's costs included. Allowances where required. Example Methods Semi-Detailed Unit costs with Assembly level line items
Class 2	30% to 70%	Control or bid/tender	L: -5% to -15% H: +5% to +20%	Detailed activity-based unit-cost with forced detailed takeoff. Example Methods More definitive, various including, expert opinion, learning curve.
Class 1	50% to 100%	Check estimate or bid / tender	L: -3% to -10% H: +3% to +15%	Detailed activity-based unit-cost with detailed takeoff Example Methods Deterministic, most definitive, including expert opinion; learning curve

Note [a]:The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Table 1 - AACEi Estimating Classification, lists the AACEi classes of estimates, their intended purpose, the level of definition and the methodology used to prepare them. Refer to Appendix A for further information regarding estimating methods.

Estimate Class requirements for each phase/Gate per manual N-MAN-00120-10001-GRP, Nuclear Projects Gated Process, are listed in Table 2. The estimate for the work pertaining to the next immediate phase is required to be of higher accuracy than the balance of the project as the scope for the next immediate phase should be well defined and planned.

Table 2, Typical Project Phase / Gate Estimate Requirements

Project Phase	**Business Proposal**	**Identification Phase**	**Initiation Phase**	**Definition Phase**	**Execution Phase**
Gate	**G0**	**G1**	**G2**	**G3**	**G4**
Gate Purpose	Initial evaluation - Feasibility of proposed projects; Identification Phase Funding Concurred	Identify Gap & Screen Business Need; Initiation Phase Funding Concurred	Evaluate & Develop Alternatives, Select Preferred Alternative; Definition Phase Funding Concurred	Develop & Define Preferred Alternative and Execution Phase Plans; Execution Phase Funding Concurred	Implement (Install) & Deliver Preferred Alternative; Close-out Phase Funding Concurred .
Estimate Class for Next Phase(s)	**Class 3**	**Class 3**	**Class 3**	**Class 3** (w/o Detailed Design Complete) **Class 2** (w/ Detailed Design Complete)	**Class 2**
Estimate Class for Total Project	**Class 5**	**Class 5**	**Class 4**	**Class 3**	**Class 2**
Level of Project Definition	Between 0 to 1% of total engineering	Between 1 to 2% of total engineering	Between 1 to 15% of total engineering	Varies from 10% to 100% of total engineering	Project definition 100% done; plus possible Engineering Field Change

1.2.1 Projects should scope and estimate projects against the Work Breakdown Structure (WBS) and/or Code of Accounts in order to allow:

- Monitoring of variance between actual costs and budget (estimate)
- Consistent format for cost reporting across projects.
- Comparison of project performance across a portfolio or program.
- To consolidate cost data for future projects.

2.0 BASIS OF ESTIMATE (BOE)

The BOE documents the parameters and scope used in support of developing the estimate and also includes the completed estimate details and breakdown. The BOE is generally started prior to developing the estimate and finalized once the estimate is complete. A Scope of Work (SOW) document may be used to initiate an estimate however a BOE is still required.

Note: The BOE may be incorporated as part of the PMP.

			% Contractor Cost Savings = 1%				
#	**Category ($ Million)**	**Contract Costs (from table 3)**	**Contractor Cost**	**Cost Variance**	**Impact to Contractor**	**Impact to OPG**	**OPG Payment to Contractor**
1	Definition Phase Target Cost (Incl RWPB)	185	183	(2)	0	(2)	183
2	Definition Phase Fixed Fee	74	73	(1)	(1)	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				0	0	0
4	Execution Phase Target Cost	1,667	1,650	(17)	0	(17)	1,650
5	Execution Phase Fixed Fee	492	487	(5)	(5)	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				0	0	0
7	Mock-up Fixed Price	38	38	(0)	(0)	0	38
8	Non-target Reimbursable Costs	6	6	(0)	0	(0)	6
9	Tooling Fixed Price	375	371	(4)	(4)	0	375
10	OSM	579	573	(6)	0	(6)	573
11	Goods	48	48	(0)	0	(0)	48
12	Total	3,464	3,429	(35)	(10)	(25)	3,439

In the second scenario set out below in Chart 5, the contractor achieves a 10 per cent cost savings. For the fixed price portions of work, there continues to be no impact to OPG (Chart 5, lines 2, 5, 7 and 9). For the target cost portions of work, OPG shares in the contractor's cost savings as the contractor is reimbursed for only its actual costs (Chart 5, lines 1 and 4). At 10 per cent cost savings, the savings for the Definition Phase Target Cost are $19M and fall outside the $2.5M neutral band for Definition Phase. As a result, an incentive payment of $3M applies. For the Execution Phase Target Cost, the savings are $167M and also falls outside the $75M Execution Phase neutral band. OPG pays the contractor a cost incentive for coming in below the target (Chart 5, lines 3 and 6). As the total demonstrates (Chart 5, line 12), the contractor is incented to come in below target cost in order to take advantage of the cost incentive payments, and OPG benefits from significant cost savings even after payment of the cost incentive. OSM and Goods are paid at actual costs and OPG retains those savings.

Chart 5 - Illustrative Scenarios of RFR Target Pricing (Contractor 10% Cost Savings)

			% Contractor Cost Savings = 10%				
#	**Category ($ Million)**	**Contract Costs (from table 3)**	**Contractor Cost**	**Cost Variance**	**Impact to Contractor**	**Impact to OPG**	**OPG Payment to Contractor**
1	Definition Phase Target Cost (Incl RWPB)	185	167	(19)	0	(19)	167
2	Definition Phase Fixed Fee	74	66	(7)	(7)	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				(3)	3	3
4	Execution Phase Target Cost	1,667	1,500	(167)	0	(167)	1,500
5	Execution Phase Fixed Fee	492	443	(49)	(49)	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				(18)	18	18
7	Mock-up Fixed Price	38	34	(4)	(4)	0	38
8	Non-target Reimbursable Costs	6	5	(1)	0	(1)	5
9	Tooling Fixed Price	375	338	(38)	(38)	0	375
10	OSM	579	521	(58)	0	(58)	521
11	Goods	48	43	(5)	0	(5)	43
12	Total	3,464	3,117	(346)	(119)	(227)	3,237

In the third scenario, the contractor incurs a 1 per cent cost overrun. For the fixed price portions of work, there is no negative cost impact to OPG (Chart 6, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 6, lines 1 and 4). As the 1 per cent cost overrun falls inside both the Definition Phase and Execution Phase neutral bands ($2.5M and $75M respectively), there is no cost disincentive payment from the contractor for coming in above the target (Chart 6, lines 3 and 6). OSM is at actual cost and OPG pays the 1 per cent cost overrun.

Chart 6 - Illustrative Scenarios of RFR Target Pricing (Contractor 1% Cost Overrun)

			% Contractor Cost Overrun = 1%					
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	187	2	0	2	187
2	Definition Phase Fixed Fee	74	74	1	1	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				0	0	0
4	Execution Phase Target Cost	1,667	1,684	17	0	17	1,684
5	Execution Phase Fixed Fee	492	497	5	5	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				0	0	0
7	Mock-up Fixed Price	38	38	0	0	0	38
8	Non-target Reimbursable Costs	6	6	0	0	0	6
9	Tooling Fixed Price	375	379	4	4	0	375
10	OSM with Fee(estimate)	579	585	6	0	6	585
11	Goods with Fee(estimate)	48	48	0	0	0	48
12	Total	3,464	3,498	35	10	25	3,488

In the fourth scenario, the contractor incurs a 10 per cent cost overrun. For the fixed price portions of work, there continues to be no negative cost impact to OPG (Chart 7, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 7, lines 1 and 4). For the Definition Phase Target Cost, the cost variance is $19M (Chart 7, line 1), which is outside the $2.5M Definition Phase neutral band. As a result, the contractor must pay a disincentive payment of $3M to OPG. The 10 per cent cost overrun for the Execution Phase Target Cost is $167M (Chart 7, line 4) and also falls outside the $75M Execution Phase neutral band. As a result, the contractor must additionally pay OPG a disincentive payment of $18M for coming in above the target (Chart 7, lines 3 and 6). OSM and Goods are paid at actual costs and the cost overrun is paid by OPG.

As the total line demonstrates (Chart 7, line 12), the pricing mechanisms and disincentives discourage the contractor from incurring cost overruns as it will not be paid for any cost overrun on fixed price portions of work, and it will also have to pay OPG cost disincentive payments (a specified percentage of its Fixed Fee portions of work, as described above) for overruns it incurs on target price portions of work that fall outside of the neutral band. Cost overruns outside of the neutral band therefore reduce the contractor's expected profits. Since the contractor's Fixed Fee was established as a percentage of the Execution Phase Target Cost, and contractor overheads increase in a cost overrun scenario, the contractor's lost profit includes both the disincentive payments and the loss associated with the requirement to pay incremental overheads not covered in the fixed fee.

Chart 7 - Illustrative Scenarios of RFR Target Pricing (Contractor 10% Cost Overrun)

			% Contractor Cost Overrun = 10%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	204	19	0	19	204
2	Definition Phase Fixed Fee	74	81	7	7	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				3	(3)	(3)
4	Execution Phase Target Cost	1,667	1,834	167	0	167	1,834
5	Execution Phase Fixed Fee	492	541	49	49	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				18	(18)	(18)
7	Mock-up Fixed Price	38	42	4	4	0	38
8	Non-target Reimbursable Costs	6	7	1	0	1	7
9	Tooling Fixed Price	375	413	38	38	0	375
10	OSM with Fee(estimate)	579	637	58	0	58	637
11	Goods with Fee(estimate)	48	53	5	0	5	53
12	Total	3,464	3,810	346	119	227	3,690

OPG also conducted a rigorous vetting process to establish the Execution Phase Class 2 estimate for the RFR. The process included detailed review of the elements of the estimate by the project management team and a strategy to validate elements of the estimate and assess the gaps OPG identified in the original estimate submission. Further information on the vetting process is provided in Ex. D2-2-8.

Also discussed in Ex. D2-2-8, Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company ("BMcD/Modus") were engaged by OPG to assess the process undertaken by OPG in developing the RQE. A copy of the BMcD/Modus report is provided in Ex. D2-2-8 Attachment 2. In their assessment, BMcD/Modus addresses the costs of the RFR contract and concludes that the results are appropriate:

Chart 4 - Illustrative Scenarios of RFR Target Pricing (Contractor 10% Cost Overrun)

			% Contractor Cost Overrun = 10%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	204	19	0	19	204
2	Definition Phase Fixed Fee	74	81	7	7	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive	0			0	0	0
4	Execution Phase Target Cost	1,667	1,834	167	0	167	1,834
5	Execution Phase Fixed Fee	492	541	49	49	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive	0	0	0	18	(18)	(18)
7	Mock-up Fixed Price	38	42	4	4	0	38
8	Non-target Reimbursable Costs	6	7	1	0	1	7
9	Tooling Fixed Price	375	413	38	38	0	375
10	OSM with Fee(estimate)	579	637	58	0	58	637
11	Goods with Fee(estimate)	48	53	5	0	5	53
12	Total	3,464	3,810	346	116	230	3,694

OPG also conducted a rigorous vetting process to establish the Execution Phase Class 2 estimate for the RFR. The process included detailed review of the elements of the estimate by the project management team and a strategy to validate elements of the estimate and assess the gaps OPG identified in the original estimate submission. Further information on the vetting process is provided in Ex. D2-2-8.

Also discussed in Ex. D2-2-8, Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company ("BMcD/Modus") were engaged by OPG to assess the process undertaken by OPG in developing the RQE. A copy of the BMcD/Modus report is provided in Ex. D2-2-8 Attachment 2. In their assessment, BMcD/Modus addresses the costs of the RFR contract and concludes that the results are appropriate:

> BMcD/Modus closely monitored the development of SNC/Aecon's cost estimate and OPG's vetting of same, and believes the process the parties used to develop the cost estimate was reasonably robust, producing an estimate with significant detail. Moreover, we have witnessed the relationship between the parties substantially improve at every level, which will be important as issues arise. Based on the initial commercial goals the parties set forth, the contract and the resultant cost and schedule estimating process appears to have thus far driven appropriate behaviours and a beneficial result.

Further contractual safeguards, including limitations on contractor-initiated change directives, will reduce OPG's exposure to increases in RFR target cost, target schedule and the fixed fee. In addition, provisions allowing for OPG to terminate for convenience and to take ownership of critical tooling provide OPG with the flexibility to adapt the RFR contracting strategy if required.

SEC Interrogatory #15

Issue Number: 4.3

Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

[D2/2/3, p.11-14]

Please provide a similar chart showing the following scenarios for the RFR Target Pricing:

a) Contractor cost overrun of 25%

b) Contractor cost overrun of 50%

c) Contractor cost overrun of 75%

d) Contractor cost overrun of 100%

Response

OPG provides the requested scenarios below as illustrative examples to demonstrate how the Retube and Feeder Replacement (RFR) contract mechanisms work. OPG notes, however, that at cost overruns such as those contemplated by the requested scenarios, OPG would have taken a number of actions before these levels were reached. OPG also carries contingency for certain events. Furthermore, these examples do not consider schedule impacts, which would likely drive different outcomes at the overrun thresholds contemplated in the requested scenarios. Also, OPG notes that as the mock-up is complete, the inclusion of the mock-up overruns in the examples is for illustration only and to reflect the original example in the evidence at Ex. D2-2-3. Finally, although OPG's contract with the SNC/AECON Joint Venture utilizes cost-plus mark-up pricing for the owner specified materials (OSM), a large portion of the SNC/AECON Joint Venture's contracts with its subcontractors for this work is on a fixed/firm price model, and therefore the cost overruns depicted below are unlikely.

For all of the scenarios below, all the same features and assumptions for Charts 4-7 in Ex. D2-2-3 apply:

- Scenarios are based on approved scope at the time of the Release Quality Estimate.
- The contractor Fixed Fee was negotiated as a percentage of target cost. Once established, the Fixed Fee paid by OPG does not change as actual costs change, and is subject to the incentive/disincentive mechanism. In the examples, the "contractor cost" for the Fixed Fee varies with the scenarios to represent changes in contractor overheads and profits based on changes in actual costs.

- For simplicity, an incentive or disincentive adjustment of 20% is used for target cost savings or overruns outside of the neutral band. The actual percentage is calculated using a graded approach.
- Also for simplicity, the cost categories of OSM, Reimbursable Costs and Goods assume the increased costs all include any contractor markups, and any cost savings or overruns are excluded from the Fixed Fee incentives/disincentives.
- No schedule disincentives are applied.
- The numbers may not add due to rounding.

a) In the first scenario set out in Chart 1 below, the contractor incurs a 25% cost overrun. For the fixed fee or price portions of work, there is no negative cost impact to OPG (Chart 1, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 1, lines 1 and 4). For the Definition Phase Target Cost, the cost variance is $46M (Chart 1, line 1), which is outside of the $2.5M Definition Phase neutral band. The contractor must pay OPG a Definition Phase disincentive payment of $9M (Chart 1, line 3). Additionally, for the Execution Phase Target Cost, the cost variance is $417M (Chart 1, line 4), which is also outside of the Execution Phase neutral band of $75M. The contractor must pay OPG a disincentive of $68M (Chart 1, line 6). OSM and Goods are paid at actual costs and the cost overrun is paid by OPG.

Chart 1 – Contractor Cost Overrun of 25%

			% Contractor Cost Overrun = 25%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	231	46	0	46	231
2	Definition Phase Fixed Fee	74	92	18	18	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				9	(9)	(9)
4	Execution Phase Target Cost	1,667	2,084	417	0	417	2,084
5	Execution Phase Fixed Fee	492	615	123	123	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				68	(68)	(68)
7	Mock-up Fixed Price	38	48	10	10	0	38
8	Non-target Reimbursable Costs	6	8	2	0	2	8
9	Tooling Fixed Price	375	469	94	94	0	375
10	OSM with Fee(estimate)	579	724	145	0	145	724
11	Goods with Fee(estimate)	48	60	12	0	12	60
12	Total	3,464	4,329	866	322	544	4,008

b) In the second scenario set out in Chart 2 below, the contractor incurs a 50% cost overrun. For the fixed fee or price portions of work, there is no negative cost impact to OPG (Chart 2, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 2, lines 1 and 4). For the Definition Phase Target Cost, the cost variance is $93M (Chart 2, line 1), which is outside of the $2.5M Definition Phase neutral band. The contractor must pay OPG a Definition Phase disincentive payment of $18M (Chart 2, line 3). Additionally, for the Execution Phase Target Cost, the cost variance is $834M (Chart 2, line 4), which is also outside of the Execution Phase neutral band of $75M. The contractor must pay OPG an Execution Phase disincentive payment of $152M (Chart 2, line 6). OSM and Goods are paid at actual costs and the cost overrun is paid by OPG.

Chart 2 – Contractor Cost Overrun of 50%

			% Contractor Cost Overrun = 50%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	278	93	0	93	278
2	Definition Phase Fixed Fee	74	110	37	37	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				18	(18)	(18)
4	Execution Phase Target Cost	1,667	2,501	834	0	834	2,501
5	Execution Phase Fixed Fee	492	738	246	246	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				152	(152)	(152)
7	Mock-up Fixed Price	38	57	19	19	0	38
8	Non-target Reimbursable Costs	6	9	3	0	3	9
9	Tooling Fixed Price	375	563	188	188	0	375
10	OSM with Fee(estimate)	579	869	290	0	290	869
11	Goods with Fee(estimate)	48	72	24	0	24	72
12	Total	3,464	5,195	1,732	659	1,073	4,536

c) In the third scenario set out in Chart 3 below, the contractor incurs a 75% cost overrun. For the fixed fee or price portions of work, there is no negative cost impact to OPG (Chart 3, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 3, lines 1 and 4). For the Definition Phase Target Cost, the cost variance is $139M (Chart 3, line 1), which is outside of the $2.5M Definition Phase neutral band. The contractor must pay OPG a Definition Phase disincentive payment of $27M (Chart 3, line 3). Additionally, for the Execution Phase Target Cost, the cost variance is $1,250M (Chart 3, line 4), which is also outside of the Execution Phase neutral band of $75M. The contractor must pay OPG an Execution Phase disincentive payment of $235M (Chart 3, line 6). OSM and Goods are paid at actual costs and the cost overrun is paid by OPG.

Chart 3 – Contractor Cost Overrun of 75%

			% Contractor Cost Overrun = 75%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	324	139	0	139	324
2	Definition Phase Fixed Fee	74	129	55	55	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				27	(27)	(27)
4	Execution Phase Target Cost	1,667	2,917	1,250	0	1,250	2,917
5	Execution Phase Fixed Fee	492	861	369	369	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				235	(235)	(235)
7	Mock-up Fixed Price	38	67	29	29	0	38
8	Non-target Reimbursable Costs	6	11	5	0	5	11
9	Tooling Fixed Price	375	656	281	281	0	375
10	OSM with Fee(estimate)	579	1,013	434	0	434	1,013
11	Goods with Fee(estimate)	48	84	36	0	36	84
12	Total	3,464	6,061	2,598	996	1,601	5,065

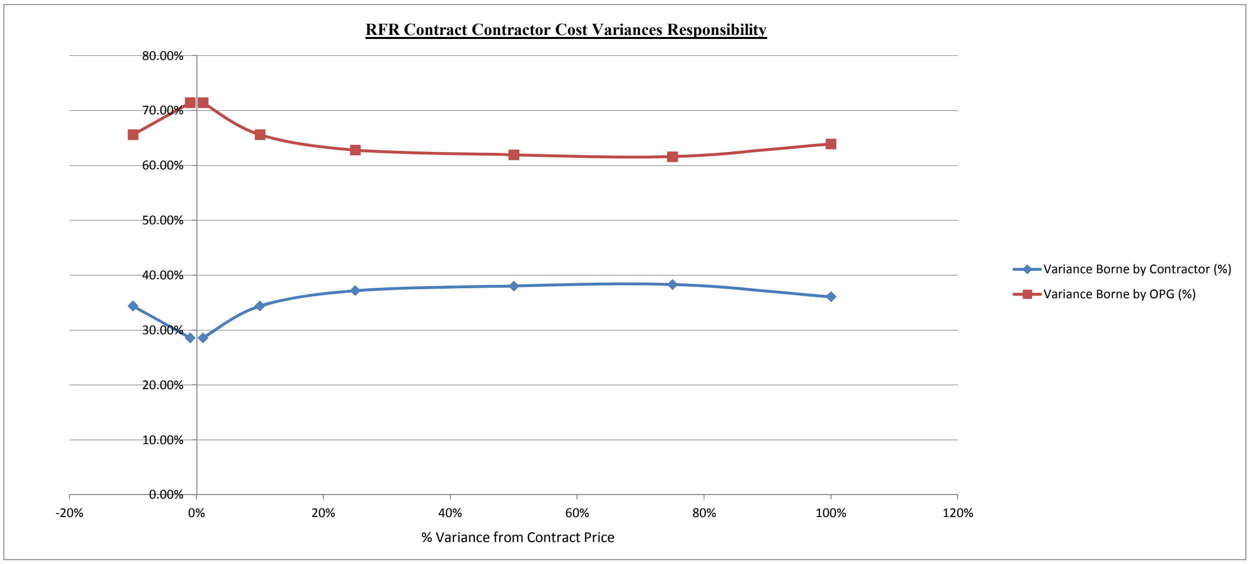
d) In the fourth scenario set out in Chart 4 below, the contractor incurs a 100% cost overrun. For the fixed fee or price portions of work, there is no negative cost impact to OPG (Chart 4, lines 2, 5, 7 and 9). For the target cost portions of work, OPG reimburses the actual (allowed) costs of the contractor and pays the cost variance to the contractor (Chart 4, lines 1 and 4). For the Definition Phase Target Cost, the cost variance is $185M (Chart 4, line 1), which is outside of the $2.5M Definition Phase neutral band. Because the Definition Phase Cost Disincentive is capped at 48% of the Definition Phase Fixed Fee, the contractor must pay OPG a Definition Phase disincentive payment of $35M (as opposed to $36M) (Chart 4, line 3). Additionally, for the Execution Phase Target Cost, the cost variance is $1,667M (Chart 4, line 4), which is also outside of the Execution Phase neutral band of $75M. Similarly, because the Execution Phase Cost Disincentive is capped at 48% of the Execution Phase Fixed Fee, the contractor must pay OPG an Execution Phase disincentive payment of $236M (as opposed to $318M) (Chart 4, line 6). OSM and Goods are paid at actual costs and the cost overrun is paid by OPG.

Chart 4 – Contractor Cost Overrun of 100%

			% Contractor Cost Overrun = 100%				
#	Category ($ Million)	Contract Costs (from table 3)	Contractor Cost	Cost Variance	Impact to Contractor	Impact to OPG	OPG Payment to Contractor
1	Definition Phase Target Cost (Incl RWPB)	185	370	185	0	185	370
2	Definition Phase Fixed Fee	74	147	74	74	0	74
3	Definition Phase Fixed Fee Incentive/ Disincentive				35	(35)	(35)
4	Execution Phase Target Cost	1,667	3,334	1,667	0	1,667	3,334
5	Execution Phase Fixed Fee	492	984	492	492	0	492
6	Execution Phase Fixed Fee Incentive/ Disincentive				236	(236)	(236)
7	Mock-up Fixed Price	38	76	38	38	0	38
8	Non-target Reimbursable Costs	6	12	6	0	6	12
9	Tooling Fixed Price	375	750	375	375	0	375
10	OSM with Fee(estimate)	579	1,158	579	0	579	1,158
11	Goods with Fee(estimate)	48	96	48	0	48	96
12	Total	3,464	6,927	3,464	1,250	2,214	5,677

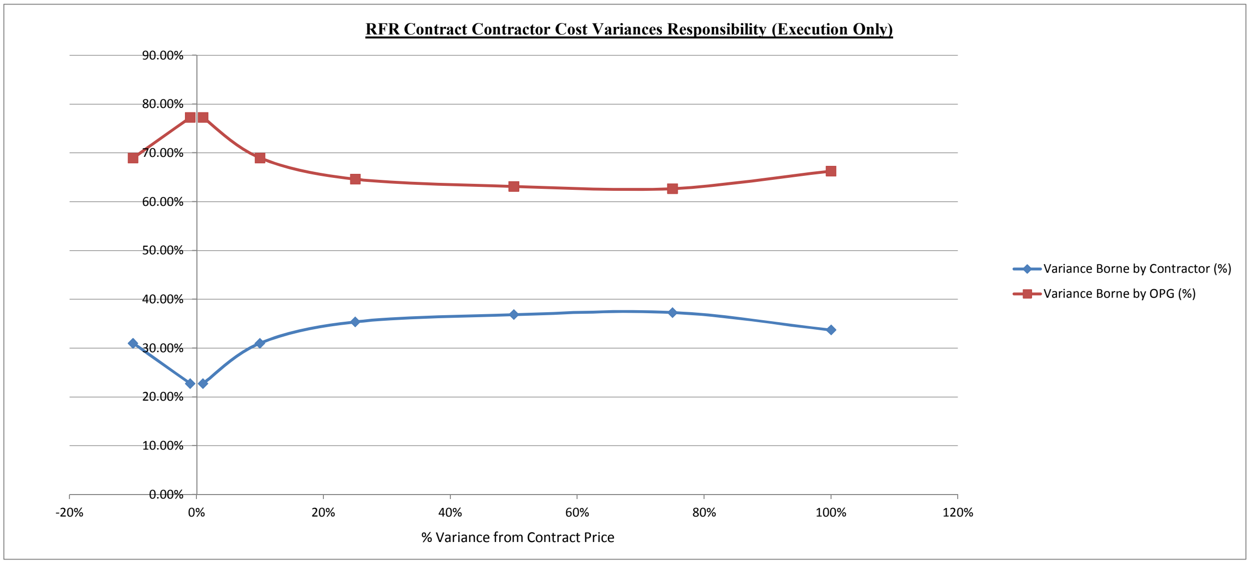
RFR Contract Contractor Cost Variances Responsibility										
	Cost Variance	Original Contract Cost ($M)	Contractor Cost ($M)	Cost Variance ($M)	Impact to Contractor ($M)	Impact to OPG ($M)	OPG Costs ($M)	Variance Borne by Contractor (%)	Variance Borne by OPG (%)
10% Savings	-10%	3464	3117	-346	-119	-227	3237	34.39%	65.61%
1% Savings	-1%	3464	3429	-35	-10	-25	3439	28.57%	71.43%
On Budget	0%	3464	3464				3464		
1% Cost Overrun	1%	3464	3498	35	10	25	3489	28.57%	71.43%
10% Cost Overrun	10%	3464	3810	346	119	227	3691	34.39%	65.61%
25% Cost Overrun	25%	3464	4329	866	322	544	4008	37.18%	62.82%
50% Cost Overrun	50%	3464	5195	1732	659	1073	4537	38.05%	61.95%
75% Cost Overrun	75%	3464	6061	2598	996	1601	5065	38.34%	61.62%
100% Cost Overun	100%	3464	6927	3464	1250	2214	5678	36.09%	63.91%

Source: D2-2-3, p.12-14; L-4.3-6 SEC 16



RFR Contract Contractor Cost Variances Responsibility (Execution Only)									
	Cost Variance	Execution Phase Contract Cost ($M)	Contractor Cost ($M)	Cost Variance ($M)	Impact to Contractor ($M)	Impact to OPG ($M)	OPG Costs ($M)	Variance Borne by Contractor (%)	Variance Borne by OPG (%)
10% Savings	-10%	2159	1943	-216	-67	-149	2010	31.02%	68.98%
1% Savings	-1%	2159	2137	-22	-5	-17	2142	22.73%	77.27%
On Budget	0%	2159	2159				2159		
1% Cost Overrun	1%	2159	2181	22	5	17	2176	22.73%	77.27%
10% Cost Overrun	10%	2159	2375	216	67	149	2308	31.02%	68.98%
25% Cost Overrun	25%	2159	2699	540	191	349	2508	35.37%	64.63%
50% Cost Overrun	50%	2159	3239	1080	398	682	2841	36.85%	63.15%
75% Cost Overrun	75%	2159	3778	1619	604	1015	3174	37.31%	62.69%
100% Cost Overun	100%	2159	4318	2159	728	1431	3590	33.72%	66.28%

Source: D2-2-3, p.12-14; L-4.3-6 SEC 16



Board Staff Interrogatory #50

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Reference:
Ref: Exh D2-2-3, Chart 1

Interrogatory

a) Describe all "off ramps" for each major work bundle. What is the governing process for OPG to determine whether to exercise the off-ramps? How will this decision be communicated to all interested parties? What are the cost categories that will be payable to the contractors upon execution of each of the off-ramps?

b) Describe what information OPG will gather, who will receive the information, when the information will be provided, and how the decision will be made whether to the exercise the off-ramp during or after the completion of Unit 2. Provide the same information for all of the other units and the process OPG will use to assess whether to exercise the off-ramps throughout the project.

c) Describe the governing process regarding the off-ramp for when a prime contractor is substantially below expectation. What does "substantially below expectation" mean? What information will this determination be based on? Who will have access to that information, when will it be provided, and who will make that decision?

d) What actions must the contractors take to recover in the event of a project schedule delay for which the contractor is responsible?

Response

a) OPG has incorporated both a termination for convenience and a termination for default clause in each of its major work bundle contracts. This allows OPG to take an "off ramp" at any time and terminate its contracts:

Termination for Default: If the contractor defaults, OPG will be entitled to terminate the agreement and exercise a number of self-help remedies. Termination for default would permit OPG to make a claim against the contractor for full contractual damages (subject to a percentage cap formula that is linked to the total contract price and certain other amounts).

Termination for Convenience: The agreement permits OPG to terminate the agreement for convenience at any time. Certain types of direct damages (but not full contractual damages) will be payable by OPG to the contractor in such circumstances. Examples of direct damages under the contracts (with some variation between the contracts) are:

- work that has been performed to the date of the termination and for which OPG has not yet made payment;
- an equitable portion of any fees which would have otherwise been payable on the next milestone date;
- any contractor costs incurred in providing any work in progress; and
- reasonable extra direct damages suffered by the contractor arising from the termination (such as out of pocket costs for demobilization).

Each circumstance will be dealt with as appropriate based on the facts. There is no special governance process required other than compliance with the contractual terms. Formal communications will be made in accordance with the contract terms; additional communications will be made as appropriate. Prior to terminating any contract, the OPG Project Manager will request a review by OPG's Senior Management team, which includes Finance, Law and Supply Chain.

Upon decision to terminate for convenience, OPG is to provide written notice to the contractor, as set out in the contracts.

b) As discussed in L-4.3-1 Staff-44, beyond being guided by the 2013 LTEP principles for nuclear refurbishment, OPG has no insights into what factors the Government of Ontario would consider in making a decision to direct OPG to take an off-ramp.

Internally, if Unit 2, or any other Unit, was forecasting to be over budget beyond a certain threshold, OPG would be required to issue a superseding business case summary. The superseding business case summary would include information such as updated cost estimates, LUEC, and alternative proposals. The option to take an off-ramp may be one of many considered alternatives. Approval of any superseding business case summary would be sought from OPG's Board of Directors.

c) If a contractor is performing "substantially below expectation", OPG likely would terminate the agreement for default as opposed to termination for convenience.

Performance that is "substantially below expectation" will be determined on a case-by-case basis, but will include evaluation of the contractor's performance on safety, quality, schedule and cost aspects of the work being undertaken as well as their actions, or lack of action, taken to recover the performance gap.

d) OPG expects contractors to be on plan for their work. Recovery plans are required if a contractor deviates from plan and a milestone is at risk of being missed. Steering Committees consisting of senior management from both OPG and the contractor provide oversight on all aspects of contractor performance. OPG expects all defective parts of the project to be corrected at the contractor's cost. In some contracts, a schedule incentive/disincentive regime is in place to encourage the contractors to be on or ahead of schedule.

AMPCO Interrogatory #53

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: D2-2-4 Page 4 Chart 1

a) Please complete the following Table to compare the nuclear stations reviewed by OPG to DRP.

Nuclear Station	**Total # Units**	**# of Units Refurb**	**# Full Time Staff**	**Annual MW**	**Start Date**	**Planned/Actual Duration**	**Planned/Actual Costs**	**Planned/Actual LUEC cents/kWh**
DRP								

Response

OPG has completed Chart 1 below with the requested information where it is available. OPG does not have information on Full Time Staff, Planned/ Actual LUEC and Annual MWh. Please see Ex. L-4.3-1 Staff-52 for a summary of similarities and differences between the DRP and the CANDU plants which have undergone refurbishment.

While OPG has provided planned and actual costs for some refurbishments, the costs for the projects are not directly comparable. The details of what is included in the other utilities' costs are not available to OPG. While the core scope for the projects in Chart 1 included replacement of the fuel channels and all or most of the feeder pipes, the remainder of the scope is not comparable across projects. Even with the core scope, the different reactor designs result in a significant difference in the number of fuel channel replacements at Pt. Lepreau and Wolsong. A further limitation when comparing different projects is the differing operating constraints of the execution of refurbishment work.

Some of the known differences between the DRP and the Bruce 1 and 2 units are:

- Bruce Units 1 and 2 were "cold and defueled" at the start of refurbishment. In addition, the two units under refurbishment were adjacent units which simplifies defueling and islanding.

- Costs are not directly comparable because of the timing of expenditures.
- It is unclear whether interest costs are included in the Bruce Units 1 and 2 final cost of $4.8B for 2 units.

Station	Total # Units	# of Units Refurb	Start Date(1)	Planned/ Actual Duration (per unit) (months) (2)	Planned/ Actual Costs
Darlington	4	4	2016	39 per unit/not available	$12.8B/ not available
Bruce A(3)	4	2	2005	25/84 for 2 units in parallel	$2.75B / $4.8B
Pt. Lepreau	1	1	2008	18/55	$1.0B/$1.4B(4)
Wolsong	8	1	2009	22/28	not available
Gentilly	1	1	N/A	35/not available(5)	$1.9B/not available(5)

Notes:

(1) Timing of Darlington, Pt. Lepreau and Bruce Units 1 and 2 refurbishments are different, therefore costs cannot be directly compared (different year's dollars)

(2) Pt. Lepreau and Wolsong are for CANDU 6 designs with 380 calandria/pressure tubes and a dedicated fuelling machine versus the Darlington and Bruce designs of 480 pressure tubes and a shared fuel handling system.

(3) Refurbishment of Bruce Units 1 and 2 commenced in October 2005 with Unit 1 complete in September 2012 and Unit 2 in October 2012, for a total of 7 years (84 months). The cost estimate publicly quoted is from November 2010; it is uncertain whether this cost estimate included capitalized interest costs.

(4) An additional $1B in replacement energy costs, operations and maintenance costs, and incremental financing for non-project related costs was incurred by NB Power.

(5) Refurbishment of Gentilly 2 did not proceed after a cost re-assessment concluded in 2012 that the cost would be $4.3B.

Board Staff Interrogatory #52

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exh D2-2-4, page 3

The above reference indicates that OPG reviewed past CANDU and other nuclear refurbishments such as Point Lepreau refurbishment, OPG's Pickering 'A' return to service and safe storage projects, Bruce Power's Unit 1 and 2 refurbishments, and Korea Hydro & Nuclear Power's Wolsong-1 refurbishment.

Please describe, in general terms, the similarities and differences between the DRP and these other refurbishment projects.

Response

In. Ex. D2-2-4, p. 3, OPG indicates that, other than nuclear refurbishments, OPG's planning efforts included operational experience from OPG's nuclear and hydroelectric projects. OPG's Pickering A Return-to-Service and Pickering Safe Store were not refurbishment projects and are, therefore, quite different from the other projects cited.

The primary similarity between the Pt. Lepreau, Bruce Power Units 1 and 2, Korean Hydro and Nuclear Power's (KHNP's) Wolsong 1 refurbishment and the Darlington Refurbishment Program (DRP) is that the core scope included replacement of the fuel channels and all or most of the feeder pipes.

Bruce Units 1 and 2 are the most similar to DRP in that they are part of a multi-unit station. However, these units had been cold and defueled for several years prior to commencement of refurbishment in 2005. These two units, which form a Unit Pair, were effectively refurbished in parallel. The number of fuel channels is the same as at Darlington (480 fuel channels per reactor). Other similar scope included refurbishment of the turbine-generator sets and significant balance of plant work. Steam generators were replaced a Bruce Units 1 and 2, which is a significant difference from DRP. Islanding challenges were not as significant as at DRP because at DRP a unit under refurbishment will be immediately adjacent to an operating unit in that unit pair (see Ex. L4.3-1 Staff-59).

Pt. Lepreau is a single unit station (known as the CANDU 6 design) with a smaller reactor core (380 fuel channels) than the Darlington and Bruce units. Islanding of the unit was not required. OPG's understanding is that there was minimal balance of plant scope carried out at Pt. Lepreau.

Wolsong Unit 1 is a CANDU 6 design with the same number of fuel channels as Pt. Lepreau. Although it is part of a multi-unit station, the CANDU 6 design has its own dedicated fuelling machines, therefore the islanding challenges (discussed in Ex. L-4.3-1 Staff-59) were not as significant as at DRP.

The timing of the refurbishment of the units is also a difference. Bruce Units 1 and 2 were completed over the period of 2005 to 2012. The Pt. Lepreau refurbishment was completed over 2008 to 2012 and the Wolsong refurbishment was completed over the period of 2009 to 2011.

To OPG's knowledge, the Bruce Units 1 and 2 and Pt. Lepreau projects employed a general contractor to co-ordinate all sub-contractors. OPG's multi-prime contracting model for the DRP, where the owner retains control and is the general contractor, is a further difference compared to these two projects.

Board Staff Interrogatory #53

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exh D2-2-4, page 3

a) Please provide information the OPG team reviewed during the Planning Phase regarding the following projects: Point Lepreau Nuclear Generating Station, Bruce Nuclear Generating Station, Pickering Nuclear Generating Station, Wolsong Generating Station, Vogtle Electric Generating Plant, Watts Bar Nuclear Generating Station, London Olympics, and Heathrow International Airport.

Response

a) The attached table provides details on information the OPG Team reviewed regarding the Point Lepreau Nuclear Generating Station, Bruce Nuclear Generating Station, Pickering Nuclear Generating Station, Wolsong Generating Station, Vogtle Electric Generating Plant, Watts Bar Nuclear Generating Station, London Olympics, and Heathrow International Airport during the Planning phase of the Darlington Refurbishment project.

Attachment to L-4.1-1 Staff 53

Facility	Information Reviewed
Pickering Nuclear Generation Station	• Work management • Organizational design considerations • Transition and turnover plans • Commissioning and return to service • Radiation protection
Point LePreau Generating station	• Work management, organizational design considerations, transition and turnover plans, commissioning and return to service, and radiation protection • Plant status control during restart activities post refurbishment stage • Preparation and readiness of Operations and Maintenance • Effective communication with and oversight of contractor staff with respect to chemistry requirements and a managed system for control of chemical products brought on site • Various aspects of Turbine Generator refurbishment project including contract management and oversight, engineering process and vendor quality assurance programs • Radiation protection, As Low As Reasonably Allowable (ALARA), Constructability, Operability, Maintainability, and Safety (COMS), Tooling • Refurbishment of Steam Generators • System-heat conditioning for post-refurbishment restart of reactors • Project management, corrective action program • Interface with the regulator, quality management and project oversight, record management, relationship with contractors and post-refurbishment experience

Facility	Information Reviewed
Bruce 1 & 2	• Fuel Handling (FH) Refurbishment (FH scope defined for life extension, execution strategy and schedules, contract strategies vs. Original Equipment Manufacturer (OEM), challenges/lessons learned) • De-fueling (de-fuel method, options considered, decision criteria, contingencies, challenges/lessons learned) • Training • Work management, organizational design considerations, transition and turnover plans, commissioning and return to service, and radiation protection. • Effective communication with and oversight of contractor staff with respect to chemistry requirements and a managed system for control of chemical products brought on site • Refurbishment of Steam Generators • Various aspects of their approach to heavy water management • Licensing process • Radiation protection, As Low As Reasonably Allowable (ALARA), Constructability, Operability, Maintainability, and Safety (COMS), tooling • System-heat conditioning for post-refurbishment restart of reactors • Refurbishment project, with focus on design engineering, system engineering, nuclear safety, and quality engineering • Corrective action plan for construction activities at conference • Review of benchmarking of refurbishment Engineering Change Control (ECC) process with “Bruce Power's Engineering Change Control Management • Engineering strategies and processes between the Darlington Refurbishment Program and Bruce Power with a focus on large projects. Capitalize on opportunities to share best practices and realize returns for both companies by improving efficiencies
Wolsong Generating Station	• Effective communication with and oversight of contractor staff with respect to chemistry requirements and a managed system for control of chemical products brought on site • System-heat conditioning for post-refurbishment restart of reactors

Facility	Information Reviewed
Vogtle Electric Generating Plant	• Oversight, interaction with Operating Plant • Project Controls and reporting • Corrective action program, procurement, strengths, document management • Transition from Readiness for Service to placing systems in service, and use of digital equipment
Watts Bar Generating Plant	• Schedule integration and processes to improve refurbishment work control • Refurbishment Construction Organization structure
London Olympics	• Program structure, including use of a Delivery Partner with experience in large-scale construction projects • Effectiveness of health and safety communication
Heathrow International Airport	• British Airport Authority contractor model • Transparency on costs • Cultural commitment to focus on partnering, trust and co-operation

Appendix 1: Darlington Refurbishment Pre-Requisite Projects Key Lessons Learned Summary

During the Definition Phase of the Darlington Refurbishment Program (DRP), OPG will have constructed approximately $1 Billion of Facilities and Infrastructure and Safety Improvement Opportunity projects. These projects, which were performed in an expedited manner during the Definition Phase, provided a number of key lessons that have been applied to the DRP.

Key Lessons	Refurbishment Application of Lesson
Collaborative Planning	Collaborative front end planning was put in place to complete engineering, procurement, and detailed work planning to ensure effective integration with the site. Detailed design is complete for Unit 2, over 12 months in advance of the first unit.
Scope Clarity and Control	Processes are being enhanced to align stakeholders on scope, early in the process. Controls are put in place for effective management of scope changes.
Estimating	The DRP has centralized its estimating effort. OPG has completed detailed cost estimates for all scopes of work; over 90% of the Refurbishment scope is at Class 3 or better.
Scheduling	A detailed integrated schedule will be issued prior to the start of the first unit outage. Scheduling standards including work breakdown structure and earned value methods are in place and all vendors are preparing schedules in accordance with those standards. The Project Controls team validates that the schedule meets the required quality prior to acceptance. Work Management integrates the schedule to confirm that the work is doable within the timeframes provided.
Material Tracking	A material tracking database is now in place. Each Project Manager is developing a 'Playbook' that will outline the preparation milestones for Unit 2 Refurbishment. The Playbook dates will align with the Contract Milestones and will ensure the Unit 2 Outage Director that work will be ready to execute for Unit 2, including identification of all materials.
Contractor/Construction Oversight	The amount of field oversight of contractor work was underestimated. Resources to perform construction oversight, clear barriers for contractors, and performance measurement and progress, are included in the refurbishment plan. The existing Contractor Management Office is being enhanced.
Field Engineers	Engineering to support construction activities in the field is built into refurbishment plans.
Sub-surface Risks	An underestimation of sub-surface issues due to incomplete drawings, buried construction debris, groundwater ingress and dewatering, and soil contamination. Additional ground surveys are planned and additional allowances to deal with the unknown sub-surface conditions have been built into project plans. For the Re-tube Waste Processing Building, additional geo-technical surveys as well as allowances to deal with these risks are incorporated into the plan.
Contract and Claims Management	The effort, capability, and timeliness required to monitor and control contract issues and related claims is being enhanced and integrated with project controls systems.

Project Reports

1. Bruce Power A

Background

- The Bruce nuclear facility, located on the eastern shore of Lake Huron, was constructed in stages between 1970 and 1987 by what was then Ontario Hydro, a provincial Crown corporation. The facility consists of two power plants (A and B) and is one of the largest nuclear generating facilities in North America. Each plant hosts four CANDU reactor units, with a maximum capacity permitted by their licenses of over 6,200 megawatts (MW) of electrical power (a net capacity of 769 MW/unit for A and 785 MW/unit for B). In the summer of 2004, Bruce Power approached the province of Ontario with a financial proposition to refurbish and restart Units 1 & 2 of Bruce A, which once refurbished and operational, would be able to meet 7% of Ontario's energy needs

- Bruce Nuclear Generating Station on Lake Huron in Ontario is the largest operating nuclear plant in the world by output. According to the 2012 Annual Report, "Bruce Power invested more than $7 billion in its Bruce A and B facilities to restart and optimize the performance of its nuclear fleet over the last decade and has successfully carried out massive refurbishment and plant life extension projects on all of its operational units." During its peak, the Bruce A Restart project was named the largest infrastructure project in Canada, and it was widely considered as one of the most complex engineering challenges Ontario has ever seen.

Overview:

- Bruce A – Units 1 and 2. After cost and schedule overruns, Bruce Power completed the Units 1 and 2 Restart Project in 2012, originally estimated to take 5 years and cost C$2.75 billion. According to the company, there were numerous first-of-a-kind programs in safely and successfully returning the two reactors to service for the first time since 1995 (Unit 2) and 1997 (Unit 1).

- Bruce A – Units 3 and 4. (2012):
  Unit 3, which was returned to service in 2004 after a long term shutdown, underwent a six-month 'West Shift' outage. The $300 million investment in the unit allowed crews to adjust fuel channels after they were lengthened by years of high temperatures, radiation and pressure. The program extended the life of Unit 3 through the end of the decade.
  Unit 4, returned to service in 2003, was taken offline mid-year for a lengthy maintenance outage that would also extend its life through the end of the decade.

- Bruce B.
  A multi-billion dollar refurbishment strategy for Units 5-8 (as well as for Bruce A Units 3 and 4) is planned to take place over a 20-year period if Bruce Power can secure a contract with the province and funding from its owners in 2015.

Project Scope – Bruce A Units 1 – 4

- In 2004, the "Bruce A Refurbishment for Life Extension and Continued Operations Project" comprised several activities including:
  - Required maintenance of Units 1&2 during lay-up
  - Fuel Channel Replacement in Units 1-4
  - Nuclear Systems Upgrade in Units 1-4 (including steam generators)
  - Balance of Plant Upgrade in Units 1-4 (conventional systems)
  - Refueling Units 1&2 with initial load of fuel

- Restarting Units 1&2 and operating through their extended lives including maintenance
- Potentially loading Low Void Reactivity Fuel and subsequently operating at an uprated maximum reactor power (Units 1-4)

- These project activities require amendments to the license by the CNSC, including an Environmental Assessment under the Canadian Environmental Assessment Act (CEAA).

- The Bruce A Units 1 and 2 restart project included required maintenance, refurbishment, upgrade, and enhancement of existing nuclear generating units to enable up to 30 additional years of life. Specifically, upgrades included:
  - Pressure tube and calandria tube replacement
  - Steam generator replacement
  - Electrical systems upgrades
  - Main condenser refurbishment
  - Feed water heater refurbishment
  - Shutdown System 2 (SDS2) enhancement, and
  - Significant other maintenance on nuclear and balance of plant equipment

Major Stakeholders

- In 2001, OPG (Ontario Power Generation) entered into a long-term lease agreement (18 years) with Bruce Power, a private sector partnership made up of British Energy PLC (79.8%); the Cameco Corporation (15%); and the facility's two primary unions (5.2%) to take over operation of the Bruce facility.

- Financial concerns involving its operations outside of Canada led British Energy PLC to withdraw from Bruce Power in 2003. Bruce A LP's owners are TransCanada Pipe-Lines (47.4%), OMERS (47.4%), and the facility's two primary unions (5.2%).

Funding Sources and Budgetary Approval Issues

- After extensive negotiations, the Minister of Energy announced on October 17, 2005, that the government and Bruce Power had reached an agreement for the refurbishment of Bruce A Units 1, 2 and 3. On August 29, 2007, the Ontario Power Authority confirmed the expansion of the agreement to include the full refurbishment of Unit 4 (with the Independent Electricity System Operator - IESO).

- Under the Refurbishment Agreement, Bruce Power expected to invest $4.25 billion to cover the capital costs of refurbishing the Bruce A facility (Ontario Auditor General, 2007):
  - $2.75 billion to refurbish Units 1 & 2
  - $1.15 billion to refurbish Unit 3 when it reached the end of its operational life in
  - 2009; and
  - $350 million to replace Unit 4's steam generators

- The government's original 2005 contract with Bruce Power stipulated that all cost overruns would be equally shared for the first C$300 million. Beyond that, the province would be required to pay only a quarter of the added cost. That contract was amended in July so that the province wouldn't have to cover any costs beyond C$3.4 billion.

Other Issues

Political

- Bruce Power made great effort to maintain positive relationships with the Aboriginal population in the area.

Regulatory
- Bruce Power applied for a license at the Canadian Nuclear Safety Commission (CNSC) to ship 16 radioactive steam generators through the Great Lakes and St. Lawrence Seaway to Sweden. City mayors, US Senators, environmental groups, First Nations communities and other civil society groups have raised many important concerns about this shipment. Bruce Power has applied for a special license because they are unable to meet the packaging requirements set out in the CNSC's Packaging and Transport of Nuclear Substances Regulations. The total radioactive level also exceeds the legal limits set out in International Atomic Energy Agency's Regulations for the Safe Transport of Radioactive Material by 6 times.
- Required federal, municipal, and provincial authorizations are discussed in the Project Description.

Major Risk Faced by Developers
- Disposal of toxic and hazardous waste materials
- Aquatic and terrestrial biology of the Lake Huron area
- Numerous potential environmental issues
- Potential for accidental radioactive release to the workplace and the environment

Actions Taken to Mitigate Risk
- A detailed assessment of the risks identified (mentioned above) are outlined although a risk mitigation plan is not specifically laid out.

Other Information
- Safety was a key component of the Restart initiative for both Bruce Power and its contractors. The project marked an astounding 24 million hours worked without a single acute lost-time injury. For a project this significant, this was a remarkable landmark for the entire industry.

Project Cost and Schedule Performance

- November 2009: Units 1 and 2 at the Bruce A plant have been undergoing a major refurbishment which is over budget by almost $1 billion Canadian dollars, with work more than 12 months behind schedule. Bruce Power originally hoped the two reactors would be back in service in late 2009 or early 2010. But one of the project's key investors, TransCanada Corp., disclosed on November 4, that the first of the two reactors now won't be online until mid-2011, with the second reactor following about four months later.
    - The original cost of the project was C$2.75 billion, but an independent review revealed in April 2008 that costs had climbed at least C$350 million and the overrun could reach C$650 million.
    - TransCanada then confirmed in July (2009) that the project would cost at least C$3.4 billion, adding it "may exceed that amount by approximately 10 percent" – or another C$340 million. This would bring the total overrun to nearly C$1 billion, or 36 percent above the original cost estimate.
- Originally, the unit first scheduled to synchronize to Ontario’s grid was Unit 2, but an issue with a generator on the non-nuclear side of the plant delayed its return by five months. This allowed Unit 1 to be the first to provide electricity to Ontarians. The generator had been replaced as part of the refurbishment project by Siemens Canada.

The whole project was expected to cost C$5.25 billion, with C$2.75 billion for Units 1 and 2, C$1.15 billion for Unit 3 and $1.35 billion for Unit 4. Early in 2008, with C$2 billion spent, it was announced that the cost of Unit 1 & 2 refurbishment would be about C$3 billion, which late in 2010 was increased to C$4.8 billion.

Cost and Schedule Overview

1995-1998	2003-2004	2005	2011	2012
• October 1995: Unit 2 is taken out of service long term due to steam generator corrosion • 1997: Unit 1 is taken out of service long term in October to concentrate resources on other reactors in the fleet • 1998: Units 3 and 4 begin long term shutdown	• Bruce Power invests $720 million in restarting Units 3 and 4	• Multi-billion dollar agreement reached with Ontario Power Authority to restart Units 1 and 2	• Units 1 and 2 made CANDU history by successfully completing the refueling process	• Units 1 and 2 returned to service in October adding an additional 1,500 MWe to Ontario's electrical grid • Unit 3 restarted after a six-month 'West Shift' outage • Unit 4 was back after being taken offline mid-year for a lengthy maintenance outage

Projected Costs	Projected Timing	Actual Costs	
$4.25 Billion (Canadian)	**5** Years	**~$7.00** Billion (Canadian)	**7** Years

President and CEO of Bruce Power, Duncan Hawthorne, said Bruce learned valuable lessons from its work, and noted that the two units had been idled for 17 years, making the job far more complicated than the planned work on currently operating units. He said the work schedule was far too ambitious in the earlier refurbishment.

Lessons Learned

Underestimating the technical challenges associated with nuclear refurbishment projects is the most commonly attributed reason for cost and schedule overruns.

- Bruce A – Duncan Hawthorne, President and CEO of Bruce Power, stated that Bruce A Units 1 and 2 having been idled for 17 years made the job "far more complicated" and that the work schedule was "far too ambitious." Hawthorne also stated that the innovative programs of Bruce A "will be held up as a shining example for all CANDU operators facing refurbishment challenges in the future."

Early engagement of stakeholders has helped other refurbishment projects establish and maintain public support.

- Bruce Power – As of 2013, community support for Bruce Power remained high in spite of significant cost and schedule overruns. According to polls, 90% of respondents agreed that Bruce Power is involved with the community in a positive way. Additionally, 82% said they supported the refurbishment of units 1 and 2. The main reasons for supporting the refurbishment project were job creation (16%), good source of power (10%), already here (9%), and overall good for the economy (8%).

2. Gentilly-2

Background

- Gentilly-2 nuclear generating station was commissioned in October 1983. It was designed to have a useful life of 30 years, given the inevitable aging of several major components. A reliable, non-intermittent source of power located close to major load centers, this facility played a valuable role in ensuring the stability and reliability of the Hydro-Québec transmission system.
- The most important aspect of the Gentilly-2 refurbishment is the replacement of several components in the plant's reactor. The work will also involve upgrading the turbine-generator unit and auxiliary systems, which will increase installed capacity to 700 MW.

Project Scope

- The facility's current operating license required that the facility be shut down at the end of 2012 and prohibited any extension of operations beyond that time without major refurbishment. In the mid-2000s, Hydro Quebec commissioned exploratory research into the costs of refurbishing the Gentilly-2 plant to allow it to operate until 2040.
- These draft-design studies took nearly 8 years and cost approximately $160 million.
- In August 2008, upon completion of these studies, Hydro-Québec announced its decision to proceed with the refurbishment. The cost of refurbishment was estimated at $1.9 billion
- However, work was halted in 2011 and a cost reassessment was conducted for refurbishment. Concluded the 2012, the new analysis put the cost of refurbishment at $4.3 billion, with refurbishment beginning in January 2014 and the plant becoming operational in September 2016.

Major Stakeholders

- Hydro-Québec Équipement, was the prime contractor for the company's major hydropower and transmission projects, was to have been in charge of the project overall. This division was to contribute its expertise in procurement planning and work scheduling, workforce management, the jobsite health and safety program, and contract management.
- GE Energy was to have been responsible for refurbishing the turbine-generator unit—in particular, replacing the two low-pressure rotors in the turbine and the rotor windings in the 675-MW generator, the most powerful in the Hydro-Québec fleet. GE Energy was the original manufacturer of the generating unit and has been involved in its maintenance since it first went into operation.

Funding Sources and Budgetary Approval Issues

Details not available

Other Issues

Political Issues:

- The former Liberal provincial government decided in 2008 to rebuild Gentilly-2 at a projected cost of about $2 billion, but stopped work after the Fukushima disaster in Japan in 2011. The decision to shut down the reactor drew swift criticism from the union representing the more than 700 employees at the facility, as well as Liberals, now Quebec's Official Opposition. The group claims the Gentilly-2 power plant constitutes a key element in the province's energy safety. It also said it was surprised by Hydro-Québec's recommendations to shut down the nuclear plant.

Regulatory Challenges

- Hydro-Québec faced significant regulatory uncertainty regarding the extension of the Gentilly-2 operating license. Hydro-Québec would have been obliged to make substantial expenditures on safety studies that could reveal needs for costly modifications of the plant. Hydro-Québec had already stated that the economic case for refurbishment and life extension of Gentilly-2 was weak. Accounting for regulatory uncertainty could further weaken that case. Additional weakening could come from consideration of the risk of onsite economic impacts from fuel-damage events.

Major Risk Faced by Developers

- Plants of the CANDU-6 design pose additional risks that arise from basic features of the design, especially the use of natural uranium as fuel and heavy water as moderator. Those features create additional risks in two respects. First, a CANDU-6 reactor could experience a violent power excursion, potentially leading to containment failure and a release of radioactive material to the environment. Second, spent fuel discharged from a CANDU-6 plant could be diverted and used to produce plutonium for nuclear weapons.

Project Cost and Schedule Performance

Cost and Schedule Overview

1982	2008	2011	2012	2012
Commercial operation at Gentilly-2 is started in December	Hydro-Québec announced plans to move ahead with the refurbishment in order to extend its useful life to 2040	Refurbishment project is postponed due to major problems with other AECL refurbishment projects	Quebec government announced the company would not proceed with refurbishment	December 28th Gentilly-2 reactor is shut down permanently

Projected Costs	Projected Timing	Actual Costs	
$1.9 Billion (Canadian)	2 Years	NA	NA

Hydro-Québec initially announced the planned refurbishment would come at a total cost of $1.9 billion in order to extend its useful life for another 30 years. After postponements and reevaluations, Hydro-Québec decided it would cost less ($1.8 billion) to shut down Gentilly-2 permanently than to refurbish (new estimated costs were $4.3 billion).

Lesson Learned

Reasons for Postponement and Eventual Cancellation of Refurbishment Plans

- Several factors led to the postponement of the refurbishment project. Major problems were encountered by Atomic Energy of Canada Limited (AECL) in the refurbishment of similar nuclear plants in New Brunswick and South Korea, and the federal government's decision to sell AECL, announced in 2009, caused further uncertainties. Then came the nuclear incidents in Fukushima, Japan, in 2011. In light of these events, Hydro-Québec decided to slow down preparations for the refurbishment of Gentilly-2.

- Feedback obtained from the projects in South Korea and New Brunswick enabled a better assessment of the full refurbishment cycle of a nuclear facility such as Gentilly-2. Based on the new data, the cost of a second life cycle would amount to $6.3 billion, plus operating expenses. The refurbishment of Gentilly-2 would cost $4.3 billion and extend from January 2014 to September 2016.
- The refurbishment project would require a financial commitment of nearly $3.4 billion over and above the $965 million invested to date. This translates into a unit cost of 10.8¢/kWh, or 8.3¢/kWh on an incremental basis compared to the cost of a 2012 closure.
- Market conditions have also changed since 2008. Potential export revenue from the sale of energy produced at Gentilly-2 would be on the order of 4¢/kWh in 2017, given the spectacular drop in natural gas and electricity prices stemming mainly from the development of the US shale gas industry.
- The increase in project costs, combined with the decrease in accessible market revenue, led Hydro-Québec to conclude that the project was no longer justified from a financial standpoint.

3. Point Lepreau

Background

- Point Lepreau has one 660 megawatt nuclear reactor, a CANDU-6. It was the first CANDU-6 to be licensed and began commercial operation in 1983.
- The unit supplies about 30% of the energy consumed in the province and is the only nuclear generating facility located in Atlantic Canada.
- Economic end of life was determined to be 2010 (limited by fuel channels and feeders).
- After completing the first refurbishment of a CANDU-6 reactor in the world, the life of the station has been extended for an additional 25 to 30 years.
- The Point Lepreau Generating Station was declared commercially operational in November 2012 after undergoing a major overhaul.

Project Scope

A study on the long-term economic life of Pt. Lepreau GS was conducted in 1997 and 1998. The study concluded that refurbishment may be economically desirable. It addressed the capital investment required to replace the reactor fuel channel assemblies and to refurbish other equipment. Also, it recommended that NB Power conduct a more detailed technical and financial assessment prior to committing such investment. In February 2000, the necessary funds were committed to conduct the assessment to refurbish the Point Lepreau GS with a target date for refurbishment in 2006. The project had three phases:

Project Definition Phase 1

- The Definition Phase evaluated the risks associated with proceeding with a major refurbishment of PLGS, including regulatory, financial, performance and schedule, and market risks. The product of the Definition Phase was a business case establishing the economic viability of the project and a Project Execution Plan (PEP) that defined scope, cost, and schedule, along with a plan for execution and an objective analysis of the risks involved.
- A comprehensive Condition Assessment process of the station's structures, systems and components was conducted to determine the other issues that would have to be addressed to extend the life of station. An Integrated Safety Review (addressed the safety factors covered in a Periodic Safety Review) was done based on IAEA NS-R-1, IAEA NS-G-2.10 and CNSC RD-360 (draft) to determine gaps with international Safety Goals, modern codes and standards and regulatory requirements. The outputs from these analyses determined the scope of a Refurbishment Outage.

Project Execution Phase 2: Pre-Outage

- The Project Execution Phase commenced on approval of the NB Power Board of Directors and other authorities in 2005. Activities in this phase were detailed design, preparation of work packages and completion of the deterministic and probabilistic safety analyses.

Project Execution Phase 3: Refurbishment Outage

- At the end of March 2008, PLGS was shut down to commence the Refurbishment Outage. The Refurbishment Outage had three phases:
  - Station shutdown, defueling and dewatering
  - Execute the modifications, replacements and repairs
  - Commission and return to service

- Scope:
  - Approximately 230 design changes were implemented and more than 9000 maintenance orders will be performed. The work can be roughly categorized as:
  - Improve safety (regulatory commitments and improvements in severe core damage frequency and large release frequency)
  - Improve reliability (address ageing issues and fix deficiencies)
  - Increase output

Major Stakeholders

- New Brunswick Power Nuclear Corporation is a subsidiary of New Brunswick Power Corporation, the largest electric utility in Atlantic Canada.
- Atomic Energy of Canada Limited is the lead contractor on 2008-2012 refurbishment work
- Siemens AG manufactured parts.

Funding Sources and Budgetary Approval Issues

- New Brunswick's Premier Bernard Lord announced that the province would fund the project, which he said represented "the lowest-price option of all the options on the table".

Other Issues

Political Issues

- Environmentalists strongly disagreed that nuclear power is safe and environmentally friendly. They said it's like owning the most expensive car in the world – every time something goes wrong, it costs a small fortune to fix it. David Coon of the New Brunswick Conservation Council says there's no justification for nuclear power. "The conservation council's position is that making electricity from splitting the atom is inherently risky and it produces lethal radioactive waste that we don't know how to dispose of or neutralize to make them safe, so we can't be convinced that there's any basis for refurbishing it."
- Premier Lord had asked Prime Minister Paul Martin to provide central government funds for the refurbishment but had been turned down. Martin said that such a deal would create a bad precedent because other provinces with units in need of refurbishment might then seek government funds. But Lord said: "We were very disappointed by the decision to say no to New Brunswick. I'm also surprised that they would support the nuclear industry in foreign countries, such as China, but not support the industry here at home."

Regulatory Challenges

- In March 2013, the Energy and Utilities Board approved Point Lepreau's 27-year operational plan, but notified the utility it would review that approval if the reactor strayed too far from its short term performance targets.

Major Risk Faced by Developers

- In November 2013, water laced with low levels of the toxic chemical hydrazine spilled from New Brunswick's Point Lepreau nuclear power plant into the Bay of Fundy. According to NB Power, water leaked from a valve on the non-nuclear side of the Point Lepreau Generating Station. Samples taken along the shoreline of the Bay of Fundy contained 0.009 parts per million of hydrazine.

Other Information

- Point Lepreau has been shut down multiple times following its return to commercial service:
  - o Various problems with boiler water chemistry, refueling procedures and steam lines drove production levels down significantly during its first 12 months back from the maintenance outage.
  - o In April 2013, the plant went offline for a few days due to a problem with one of the turbine system pumps on the non-nuclear side.
  - o The Point Lepreau Nuclear Generating Station was experiencing new operational problems and shut down for two weeks in late 2013 for repairs, documents filed with the Energy and Utilities Board revealed. According to the filings, Point Lepreau has developed a vibration in a non-nuclear pipe that transports steam, likely to the plant's turbines, and has been unable to achieve full power because of the problem.
  - o The facility was taken offline March 19, 2015 due to problems with a fuelling machine and heat transport system. The shutdown was expected to last two weeks, but the deadline was pushed back on April 9 and again on April 13. The latest maintenance outage has been extended for at least another week. NB Power says more repairs are required to the station's heat transport system.

Project Cost and Schedule Performance

Cost and Schedule Overview

1983	2005	2008	2010	2012
In February, the world's first CANDU-6 is supplying energy to the New Brunswick power grid	Decision is made to refurbish Point Lepreau by the government	Point Lepreau is shut down in March to commence the refurbishment	AECL recommends additional work and a revised project schedule is created	Station is returned to commercial service at the end of November

Projected Costs	Projected Timing	Actual Costs	
$1.4 Billion Canadian ($1.15 Billion US)	**~1.5** years (18 months)	**$2.4** Billion Canadian	**4.5** Years (54 months)

It cost an approximate **$1 million dollars a day for replacement power** for every day the refurbishment was delayed.

- A memo prepared for the Prime Minister's Office in December 2012 says AECL's total costs were $1.17 billion, more than double the $540 million it initially budgeted for the refurbishment when it won the bid in 2005. It says most of that was driven by labor costs.

Lessons Learned

- One of the biggest lessons to be learned was how to properly replace the plant's 380 calandria tubes, which house fuel channels and uranium fuel bundles that power the reactor. The first effort by Atomic

Energy of Canada Ltd. to install the tubes failed when tiny scratches caused by wire brushes raised concerns that joints might not be reliable for 25 years. Dozens of calandria tubes failed air tightness tests after being fused with special inserts designed to hold them in place. The calandria tubes were the first major pieces of equipment to be installed in the reactor as part of Point Lepreau's much delayed refurbishment. The tubes had to be taken out and then reinstalled.

- AECL benefited from that lesson when they began a similar refurbishment of the Wolsong-1 reactor in South Korea, NB Power says. The refurbishment of the CANDU-6 at Wolsong began in April 2009 — a year after the start of the Lepreau project — and ended in July 2011.
  - "The lessons that they've learned from our jobs were applied at Wolsong," Gaetan Thomas, President and CEO of NB Power, said. "That is why we believe they have a responsibility for some of these delays." The New Brunswick government have tried in vain to convince Ottawa to shoulder the extra costs of the Point Lepreau refurbishment, arguing the province should not be on the hook for AECL's delays climbing the learning curve of fixing a CANDU-6 reactor. But the federal government has not budged, saying only that his government will abide by the terms of the contract, which have not been made public.
  - The cost overruns have stoked fears that customers in the province could face steep rate hikes in the future.
- According to the auditor general, NB Power did not adequately address the financial risks posed by the refurbishment of Point Lepreau even though it had a rigourous oversight process in place.

4. Wolsong-1

Background

- The Wolsong 1 nuclear power plant first came on line in 1983. Owned and operated by Korea Hydro and Nuclear Power (KHNP), the reactor achieved a lifetime capacity factor of 86.2%, making it one of the top- performing reactors in Korea. Wolsong 1 is the first of a four-unit CANDU plant, the largest CANDU facility outside of Canada. In June 2006, KHNP signed a contract with Atomic Energy of Canada Ltd. (AECL) to initiate a re-tube project for the Wolsong 1 reactor.

Project Scope

- A major refurbishment of Wolsong-1 (a CANDU-6 PHWR) was undertaken from April 2009 to July 2011 (839 days) including replacement of all 380 calandria tubes to enable a further 25 years operational life.
- Other plant refurbishment activities included DCC (plant control computer) replacement, probabilistic safety review follow-up actions, safety system upgrades, and aging component replacement.
- It had been operating at slightly derated capacity (~622 MWe gross) since 2004, but Wolsong-1's refurbishment resulted in a power uprate from 622 megawatts to 657 MW.
- In 2011, Unit 1 at Wolsong was restarted, marking the first time that a Candu-6 reactor was successfully dismantled, retubed, and restarted.

Major Stakeholders

- Korea Hydro and Nuclear Power Company (KHNP)
- Candu Energy Inc. (formerly AECL) retained the vast majority of key staff involved in the Wolsong life extension project
- ATS Automation Tooling Systems Inc.; contracted in the first stage of Wolsong refurbishment to provide a volume reduction system

Funding Sources and Budgetary Approval Issues

Information not available

Other Issues

Political Issues

- Heightened public opposition following the Fukishima meltdown.
- In February 2015 as the Nuclear Safety and Security Commission (NSSC) gave approval for the Wolsong-1 Nuclear Power Plant at Gyeongju to continue operating, local opposition and civic groups strongly protested the decision.

Regulatory Issues

- Wolsong-1's operating license expired 2012 November at the end of the unit's original 30 year design life so it had to be taken offline for its second Periodic Safety Review (PSR) and, in this case, to meet additional requirements for operation beyond design life. These additional requirements had to be met in order to obtain approval from the nuclear regulator for continued operation.

- In February 2015, South Korea's nuclear safety regulator approved a seven-year license extension for the refurbished and uprated Wolsong-1 reactor. The unit had been offline for two years while discussions continued on renewing its license.

Major Risk Faced by Developers

- Project management up front was key considering: the project was more than 10,000 km away from critical support at the designers' home office; the need to move, house and support more than 200 people and their families; the 5,500 items in the Wolsong-1 retube toolset; and 1,500 crates of permanent plant components.

Actions Taken to Mitigate Risk

- Remotely-controlled tools and massive, highly-shielded machines were required to conduct the work safely inside the reactor due to the highly radioactive environment.
- The optional SALTO review was in addition to the latest Intensive PSR for Wolsong-1. A SALTO follow-up was scheduled to happen 18 to 24 months after initial SALTO which occurred April 2014.

Other Information

- Wolsong-1 had experienced several incidents in which the reactor leaked heavy water. In 1984, 23 tons of heavy water leaked, and in 1988 a pinhole puncture in a monitoring line forced the reactor to be shut down for three days. Additionally, 20 liters of cooling water leaked in May 2000, exposing several technicians to radiation.
- Nuclear power is a primary energy source for the country. It provides 27 percent of the country's power generation. The Wolsong-1 reactor had the capacity of generating 5 billion kilowatt-hours a year as of 2008 and is capable of providing 80 percent of the power to homes in Daegu and North Gyeongsang Province.

Project Cost and Schedule Performance

Cost and Schedule Overview

2009	2011	2012	2014	2015
Wolsong-1 is shutdown and refurbishment begins	Unit 1 is restarted following the completion of the refurbishment of the PHWR	In November, Wolsong-1 is shut down again when the 30-year license expires	In October, the Korean Institute of Nuclear Safety (KINS) approves Unit 1 to operate to 2022	In February, NSSC renews license to 2022 Commercial operation is expected by summer

Projected Costs	Projected Timing	Actual Costs	
NA	NA	₩560 Billion KRW ($520 million)	~2.5 Years (839 days)

AECL also worked on a similar refurbishment project at Canada's Point Lepreau which ran well over budget and behind schedule. Lessons learned from Point Lepreau were said to be invaluable for the refurbishment of Wolsong-1.

Lessons Learned/Best Practices

AECL has stated that they benefited from that lessons learned, particularly in regards to the technical challenges, in the refurbishment of the Wolsong-1 reactor.

5. Watts Bar-2

Background

- The Watts Bar Nuclear Plant is the Tennessee Valley Authority's third nuclear power plant. Construction began on Watts Bar Units 1 and 2 in 1972, Watts Bar Unit 1 came into operation in 1996, Watts Bar Unit 2 has been undergoing refurbishment since 2007 and Unit 2 would be the first nuclear reactor to achieve commercial operations in the United States in the 21st century.
- Construction began on Watts Bar Units 1 and 2 in 1972, however production was halted in 1985 due to safety concerns regarding other TVA units. Construction resumed on Watts Bar Unit 1 in 1990, leading to its completion in 1996. However, TVA decided to defer construction on Watts Bar Unit 2 "for the benefit of its customers in the future". Market conditions were central to this decision: the economic recession lowered electricity demand and construction was halted on most newly planned reactors.
- Refurbishment on Watts Bar Unit 2 began in 2007 following a study of costs which projected refurbishment to cost $1.7 billion with the plant becoming operational in 2012. However, the project ran over budget and behind schedule. In 2012, the TVA released their new Estimate to Complete which projected the cost to be $4.2 billion completed in December 2015

Project Scope

- TVA's Integrated Resource Plan (IRP) identified the project as an essential new source of safe, clean, reliable and economical baseload generation. Unit 2 will help meet growing demand for electricity in the Tennessee Valley and replace capacity lost to retiring older, more expensive coal plants in the face of increasingly expensive regulatory requirements. Watts Bar Unit 2's new generation will come without adding to TVA's overall carbon emissions. The unit is expected to generate about 1,150 megawatts (summer net capability), which would equal several coal units and could supply enough power for about 650,000 Tennessee Valley homes.
- The purpose of the refurbishment program is to ensure that Watts Bar Unit 2 plant equipment meets its original licensing, design and equipment vendor specifications by performing inspections/evaluations, refurbishment/replacement and system testing.

Major Stakeholders

- Siemens Power Generation received a $170 million order from Tennessee Valley Authority to refurbish and upgrade the turbine island.
- Day & Zimmermann will provide managed task, maintenance, modification and refurbishment services including the replacement, refurbishment, modification and installation of major plant components in the plant's turbine building.
- Bechtel has the lead role in completing the engineering design, procuring equipment and materials and finishing the physical construction of Watts Bar 2 with oversight from TVA.
- Westinghouse received a $200 million deal for equipment upgrades and support services. The company will upgrade and replace most instrumentation and control systems and supply new reactor coolant pumps and cranes. It will service steam generators and conduct probabilistic risk assessments, licensing services and safety analyses.

Funding Sources and Budgetary Approval Issues

Information not available

Other Issues

Political Issues

- Five anti-nuclear groups served notice they will ask federal regulators not to license another reactor at Watts Bar. The groups filed a petition to intervene against TVA's license request before the U.S. Nuclear Regulatory Commission (NRC). The groups contend another reactor could unduly heat up the Tennessee River and poise an undue risk to the public.

Regulatory Challenges

- As of October 2014, the reactor was nearing completion and open vessel testing has begun as well as testing on plant systems. Initial fuel load could come as early as spring 2015. The plant could come online as early as December 2015 or early 2016. This could be affected by delays in issuance of the unit's operating license from the NRC. Because Watts Bar Unit 2 was constructed under the NRC's original licensing regime, its current license applies only for construction. The operating license is issued after construction.
- Watts Bar Unit 1 received a full power operating license in early 1996, and is presently the last power reactor to be licensed in the U.S. In 2007, TVA informed NRC of its plan to resume construction of Watts Bar Unit 2. The NRC staff is working towards supporting an operating license decision in 2015.
- The NRC's Near-Term Task Force on the Fukushima Daiichi March 2011 accident included requests for assessment of flood risk at U.S. nuclear power plants. In February 2013, the NRC censured TVA that they had been using outdated and inaccurate calculations in estimating the maximum potential flood threat should upriver dams be breached, the end result of which could be loss of cooling function and reactor meltdown.

Major Risk Faced by Developers

- Some challenges are arising, these include: completing complex work and required documentation, performing testing on shared Unit 1 and Unit 2 systems without impacting the safe and reliable operation of Unit 1, addressing regulatory and licensing issues, and successfully transitioning the site to dual-unit operations.
- In addition to future energy demand uncertainties and large cost overrun of Watts Bar 2, safety issues remain unresolved both for the existing Watts Bar 1 reactor and the yet to open Unit 2. Not least both reactors are ice condenser design which makes them vulnerable to hydrogen build up and containment failure.

Actions Taken to Mitigate Risk

- The Unit 2 organization is adjusting as necessary to facilitate the resolution of challenges and risks. The organization is also aligning itself to support the continued reliable operation of Unit 1 while delivering the safe and high quality completion of Unit 2 within budget and on time — and to transition Watts Bar successfully to dual-unit operations.
- As a result of the events at the Fukushima Daiichi Nuclear Plant in Japan in March 2011, the NRC now requires U.S. nuclear plants to upgrade their facilities to provide diverse and portable means of supplying cooling water and AC power during an extended period of loss of offsite power and loss of normal access to the ultimate heat sink. The modifications project at Watts Bar, which has been designated as a pilot for the industry, has established a path forward that meets the NRC

requirements to date, resulting in a lower risk. As a result, Unit 2 will be much more resilient to a broader range of unexpected environmental events.

Project Cost and Schedule Performance

Cost and Schedule Overview

1985	1999	2007	2011	2012	2015
Construction stops on both Watts Bar units Unit 2 is eventually placed in deferred construction status in 1990	Extension of construction permit is requested for Unit 2; permit is extended to December 2010	TVA Board authorizes completion of Unit 2 in a projected 5-year project; engineering work begins in October	TVA performed a root cause analysis of the issues responsible for the schedule and budget problems	TVA Board approves revised estimate and schedule	Commercial operation is slated for December

Projected Costs	Projected Timing	Actual Costs	
$2.5 Billion	**5** Years	TBD	TBD

The TVA Board of Directors approved continuing the construction of Watts Bar Unit 2 with a revised estimate for completion at **$4 billion to $4.5 billion**. Estimates have it that the unit will be completed between September 2015 and June 2016, resulting in an 8-9 year total timeline.

Lessons Learned/Best Practices

- A Detailed Scoping, Estimating and Planning (DSEP) study in 2007 found Watts Bar Unit 2 to be effectively 60 percent complete and estimated that Unit 2 could be finished in about 60 months at a cost of about $2.5 billion. Based on this analysis, the TVA board of directors approved the Unit 2 completion on Aug. 1, 2007.
- In 2007, and based upon its projected increased energy demand, the TVA board approved a 5-year plan to complete Watts Bar 2. The TVA Board of Directors approved the restart of construction for completion of WBN2 in August 2007. During the ensuing four years of project duration, WBN2 did not meet performance expectations for schedule or budget. By 2012 TVA admitted that "the project had not been successful in meeting its construction schedule... and that previous efforts at project recovery were not successful." The completion cost also escalated from $2.5 billion in 2007 to between $4-$4.5 billion.
- TVA began a root cause analysis of Watts Bar Unit 2's schedule and costs when it became clear in 2011 that fuel load could not be accomplished before September 2012. TVA reported in its third-quarter financial filing to the Securities and Exchange Commission on Aug. 11, 2011, that "current and past estimates of the construction project cost and schedule for Watts Bar Nuclear Plant Unit 2 are currently being reviewed by TVA. The project's schedule has experienced some delays as a result of lower than expected construction productivity, and the construction of Watts Bar Unit 2 will take longer than originally planned."

- The TVA analysis, independently verified by an outside firm, cited four major factors that led to an extended schedule and higher costs to complete Watts Bar Unit 2: project leadership, original estimate, project execution and project oversight.
  - Leadership: The capabilities of management and the project organization were not adequately matched with the unique characteristics of the Watts Bar Unit 2 project, resulting in an improper understanding and evaluation of the complexity of the project.
  - The Watts Bar Unit 2 project plan relied on lessons learned from the restart of Browns Ferry Unit 1 in 2007 rather than the completion of Watts Bar Unit 1 a decade earlier. Although the five-year, $1.8 billion Browns Ferry Unit 1 project came in on time and just slightly over budget, the experience didn't translate entirely to Watts Bar Unit 2 (different reactors, maintenance vs. construction project, different work environment).
  - Estimate: An inadequate understanding of the work required on Watts Bar Unit 2 led to a significant underestimate of the project scope and complexity in terms of planning, contingencies and risks. Walk-downs to confirm plant condition, construction quantities and work to be performed were not fully completed.
  - Cost estimates did not account for declines in productivity (recognized in the industry) and the challenges of working in cramped places in Watts Bar Unit 2. The 2007 Detailed Scoping Estimating and Planning (DSEP) study was, in certain cases, an order-of-magnitude estimate rather than an estimate based on specific details. It presented a target cost and schedule rather than a range of potential outcomes, leading to overly optimistic projections of cost and schedule.
  - Execution: The DSEP was an example of inadequate, front-end project planning and incomplete definition of the scope of work. Construction was allowed to begin in some cases before engineering was complete. The ability to effectively forecast progress or plan the work was limited because the project was managed primarily through financial metrics rather than through commodity or system completion indicators that track actual engineering and field progress.
  - Oversight: Early warning signs of project problems were not recognized and corrective actions were not properly identified due to a lack of sufficient oversight. Project teams did not effectively use established processes that could have addressed project deficiencies and helped make sure project goals were achieved. Project reports were unreliable and provided inconsistent information on the status of the project.

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ONTARIO POWER GENERATION

FOR INFORMATION to the Darlington Refurbishment Committee

March 3, 2016

DARLINGTON REFURBISHMENT PROGRAM – APPLICATION OF LESSONS LEARNED FROM VOGTLE NUCLEAR GENERATING STATION

REASON FOR REPORT

This report provides feedback on the recent article published in the Nuclear Intelligence Weekly regarding the progress of the new build at Vogtle Nuclear Generating Station**.**

HIGHLIGHTS

Recently, an article in Nuclear Intelligence Weekly detailed the continuing new build efforts at Vogtle NGS in Waynesboro, Georgia. The theme of the story was to highlight the ongoing delays of the project, and the continued lack of public confidence in the forecasted completion dates. According to the article, the project is now forecasting a 39 month delay compared to the original project completion date.

Specifically referenced as causes of the delay are:
1) Overall lack of schedule adherence;
2) Late designs and design changes;
3) Complex and congested rebar installations; and
4) A high rework rate.

The article also identified as impediments to progress:
1) Low confidence in the contractors' competency to complete the job; and
2) Insinuation of contractual and commercial friction between the owner and contractors that has only just been resolved.

The observations in the article reflect the major issues of a megaproject engaged in an ongoing execution phase, which the Darlington Refurbishment Program (DRP) is just entering into. The DRP is, however, well positioned to avoid these types of events based on detailed planning and the incorporation of lessons learned during the execution of the Facilities and Infrastructure (F&IP) and Safety Improvement Opportunities (SIO) projects. The Unit 2 definition phase work is complete and the facilities and infrastructure projects are now substantially progressed and approaching completion. The leadership team has already integrated the major learning's from this phase into refurbishment outage planning and have exhibited an ability to work collaboratively with the vendor partners to meet project milestones despite challenges in both design and execution.

The refurbishment outage scope underwent an extensive five year planning phase, specifically learning from other comparable projects that experienced similar issues as Vogtle due to inadequate planning. This sets the DRP up for successful execution during the refurbishment outages. It also gives confidence that major issues experienced on the Vogtle project can be avoided entirely or predicted early and managed in the event they begin to emerge.

The table below compares the Vogtle project issues, similar F&IP and SIO challenges faced and U2 Execution strategies to avoid them during the in-plant work.

Vogtle Project Issues	Past Experience and Darlington Unit 2 Execution Strategy
Lack of Schedule Adherence	During the F&IP projects, many of the schedules, such as the Heavy Water Storage Project, were not of sufficient quality and detail to effectively manage the project and understand progress. Changes to schedule and forecasts resulting from realized risks were not updated quickly and effectively, exacerbating these challenges. The refurbishment outage work will be run with a fully integrated schedule,

Vogtle Project Issues	Past Experience and Darlington Unit 2 Execution Strategy
	closely managed on a daily basis by the project team. A detailed review and validation of the schedule with all vendors will take place in a set of three day offsite meetings in February and March, 2016. During execution, daily schedule reviews and progress meetings will be held to ensure the project is progressing as planned, and to implement recovery plans when necessary. These meetings will be regularly attended by executive leadership to ensure accountability and emphasize the importance of maintaining the schedule. A schedule centric focus, combined with effective forecasting and change control processes will ensure that the schedule is always up-to-date, useful, and viewed as the fundamental tool to manage project execution.
Late Designs and Design Changes	The designs for the F&IP and SIO projects were not 100% complete prior to starting field work in most cases. Changing seismic requirements (Heavy Water Storage Project) and the discovery of field conditions such as soil contamination and abandoned buried services required design revisions and impacted schedule significantly. A major focus of the DRP planning and definition phase was to ensure the completion of detailed designs well in advance of starting execution work. This milestone was achieved in late Q3 2015, such that assessing work and comprehensive work packages could be completed to support the finalization of the integrated schedule for Unit 2 execution. In addition, a rigorous condition assessment, inspection program, and integration in normal station outages provides confidence that the scope identified is stable and there is low risk that new design packages will be required. As is the case in any project of this magnitude, a certain amount of design change, field implemented changes (FICs) are anticipated and the execution organization is resourced to efficiently support this requirement. As the refurbishment outage work will take place inside the station, which is a very well controlled and documented environment, unanticipated or unknown conditions are bounded and contingencies are in place for items such as discovery work.
Complex and Congested Rebar Installations	During the installation of Emergency Power Generator 3, the project experienced exactly this type of issue that has resulted in schedule delays. The in-plant DRP work does not have the complex rebar installations that would be required to construct a new power plant, however there are a number of very complex projects requiring very careful planning and execution in order to ensure quality and schedule adherence. One example of such work is defueling the reactor at the outset of each refurbishment outage. This work, as with all DRP work, is being challenged rigorously in the schedule development process in a series of horizontal and vertical schedule reviews involving inputs from experienced trades and construction resources, operations resources, safety resources and a panel of others to ensure there is no element overlooked in the planning of the work. Further, risks associated with the work have been considered in the planning of the execution windows, and reasonable durations, simulated in a test environment where possible, were used as the basis for planned durations represented in the schedule.
High Rework Rate	A recent quality issues report conducted for Emergency Power Generator 3 indicated there were areas for improvement related to records management, quality, and technical rigour. This specific project has implemented corrective actions but in a broader application DRP has identified key focus areas for Unit 2 to minimize rework. This includes the implementation of processes and critical check points to ensure parts have pedigree, engineering records are in place with verification that proper steps were followed, and inspection and test plans are witnessed and signed off. To assist in ensuring effectiveness, the DRP has dedicated construction oversight resources to augment the vendor partners own oversight and quality programs to ensure the work being performed in the DRP is done properly, the first time. Industry expertise has been retained (Kiewit) and is overseeing construction activities, alongside OPG's and the vendors' own construction management organizations. Quality of installation and minimization of rework is a key

Vogtle Project Issues	Past Experience and Darlington Unit 2 Execution Strategy
	focus area of the organization during Unit 2 execution.
Low Confidence in Contractors	The F&IP and SIO projects have experienced challenges and the project has had to remove vendors who have not performed to expectations. This surfaced an issue of bench strength amongst the vendors with master services agreements (MSA) and DRP has taken action to onboard a new MSA vendor and is in the process of reviewing more potential service providers. For the Unit 2 work, a rigorous pre-qualification process was undertaken to select contractors that have a demonstrated ability to execute the scope of work for Refurbishment. With all contracts awarded early on in the planning phase, and the required detailed schedules and plans (such as procurement plans) in place and established, DRP is now working through the training and qualification programs to onboard the large number of contractor staff. Corrective actions are being taken early when required and the collaborative model of execution (a major lesson learned from the definition phase projects, where contractor performance issues resulted in major schedule delays) is being exploited to foster a team environment and emphasize the shared responsibility for project success.
Contractual or Commercial Conflicts	F&IP and SIO projects were performed under existing master services contract that were not specifically tailored to the type of work being undertaken. Some of these projects are large and complex. As such, some of the detailed planning work that typically results from project-specific contract discussions did not occur, including issues such as ensuring the contractor fully understands the scope, the allocation of responsibilities and risk, etc. The executed contracts for the bulk of the refurbishment work (such as Retube and Feeder Replacement and Turbine/Generator) were built from the ground up and were specifically tailored to the work being performed. They include well defined criteria outlining accountabilities and thresholds for key potential project issues such as rework and discovery work. The pricing mechanisms were designed to be appropriate for the various scopes of work, using a range of pricing models including fixed price, target price and cost plus a mark up. The intent is that risk should be borne by the party who has the best ability to mitigate the risk. Where items are not clearly defined and occur, conflict resolution mechanisms are in place to ensure field work progresses and the schedule is maintained while the issue at hand is dealt with. OPG recognizes that the volume of commercial discussions will likely increase as we move into the Execution Phase of the project. OPG is therefore conducting an RFP to retain a third party expert to assist OPG in resolving commercial issues before they become formal disputes.

CONCLUSIONS

Some refurbishment F&IP/SIO projects were carried out with an expedited execution strategy and experienced issues similar to the project cost and schedule drivers identified in the NIW article on Vogtle. The rigorous 5 year planning and development process and the in-plant nature of the work for Unit 2 combined with the focus placed on integrating lessons learned from the F&IP/SIO projects provides confidence that the DRP is well positioned to minimize the issues endured at Vogtle.

Submitted by:

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APPENDICES

None