production forecast. The OEB's mid-term review findings are set out in section 9 of this Decision.

While OEB staff and LPMA have proposed a higher production forecast for Pickering in the test period based on their analysis of historical and forecast Pickering production, the OEB approves OPG's proposal. The OEB accepts that the lower Pickering production forecast in the test period is largely related to the 7.5 TWh of production losses related to PEO,[10] and the planned 2021 vacuum building outage. The OEB notes that OPG's Pickering production forecast proposal is based on 5% FLR, which is challenging given the prior period FLR averaged 8.5%.[11]

The Pickering test period production forecast assumes that the PEO technical assessments will determine fitness for service beyond 2020, and that system planning and other regulatory considerations will be in place for operation in 2021. The OEB's findings on PEO are in section 5.7 of this Decision.

The OEB is not convinced that OAPPA's proposal, supported by LPMA, to replace Darlington PHT pump motors only during planned outages has fully considered all the risks. The consequences of pump motor failures are significant and result in an automatic reactor trip.[12] PHT pump motor failures resulted in production losses of 1 TWh in 2015 and 0.4 TWh in 2016.[13] The OEB approves OPG's proposal for Darlington production forecast and notes that the forecast is based on a 1% FLR for 2017 to 2019 versus 2.9% in the prior period. FLR will be higher as DRP progresses and refurbished units are returned to service beginning in 2020.

5.2 Nuclear Operations Capital and Rate Base

Background

The nuclear operations project portfolio includes OM&A projects and capital projects. The former are discussed in section 5.6 of this Decision. The historical and forecast nuclear operations capital expenditures, excluding DRP, are summarized in the following table:

[10] Reply Argument page 96.
[11] Exh E2-1-1 page 9.
[12] Reply Argument page 103.
[13] Tr Vol 13 pages 24-25.

Table 8: Nuclear Operations Capital Expenditures

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Capital Project Portfolio	157.0	135.3	145.9	191.0	269.8	292.5	322.0	253.0	238.0	248.0	259.0	180.0
Pickering 2/3 Isolation	5.9											
Darlington New Fuel										15.3		
Minor Fixed Assets	15.4	12.9	15.5	10.2	22.9	22.3	31.0	26.0	20.0	19.1	19.5	19.3
Total	178.3	148.2	161.4	201.2	292.7	314.8	353.0	279.0	258.0	282.4	278.5	199.3
Five Year Average		2011-2015 Average: $223.7 million						2017-2021 Average: $259.4 million				

Source: Exh D2-1-2 Table 2, EB-2013-0321 and EB-2016-0152

The increase in capital expenditures starting in 2014 is largely related to DRP projects that were reclassified to the nuclear operations portfolio as these projects were determined to support the daily operations of the entire station. In total, $329 million of DRP projects were reclassified. The portfolio budget is administered by the Asset Investment Steering Committee (AISC). OPG states that the AISC review and Business Case Summary approval processes enhance OPG's ability to complete projects within budget and on schedule.

The historical and forecast nuclear operations in-service additions are summarized in the following table:[14]

Table 9: Nuclear Operations In-service Additions

$million	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Forecast	191.5	175.5	187.6	180.7	158.3	141.7	497.0	389.0	315.2	239.3	300.4	215.6
Actual	249.0	103.2	131.9	212.6	148.6	204.1	292.0					
Variance	57.5	-72.3	-55.7	31.9	-9.7	62.4	-205.0					
Updated - J21.1							292.0	479.0	354.7	385.4	244.7	181.6
Five Year Average		2011-2015 Actual Average: $160.1 million						2017-2021 (Updated) Average: $329.1 million				

Source: Exh D2-1-3 Table 4, EB-2013-0321 and EB-2016-0152, Undertaking J21.1

The historical and proposed nuclear rate base are summarized in the following table. The proposed rate base has been revised by the second impact statement, Exh N2-1-1, which excluded the in-service amount related to the DRP Heavy Water Storage and Drum Handling Facility Project (D2O project). DRP in-service additions are discussed in section 5.3. Asset retirement costs are discussed in section 5.13:

[14] There are support services capital projects entering rate base as well. For the test period, these additions range from $5 million to $18 million per year. The in-service additions with respect to DRP are discussed in section 5.3.

Table 10: Nuclear Rate Base

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Net Plant (Excl DRP)	1,586.7	1,575.5	1,495.9	1,473.4	1,457.5	1,414.8	1,597.8	1,780.5	1,861.0	1,848.6	1,813.9	1,848.4
Net Plant (DRP)				60.2	121.2	192.6	419.1	611.9	601.5	586.7	4,699.1	5,154.5
Asset Retirement Cost	1,517.6	1,490.0	1,851.1	1,470.2	1,389.4	1,308.7	825.7	524.0	446.7	369.5	292.2	249.6
Total Nuclear Net Plant	3,104.3	3,065.5	3,347.0	3,003.8	2,968.1	2,916.1	2,842.6	2,916.4	2,909.2	2,804.8	6,805.2	7,252.5
Cash Working Capital	14.3	25.9	32.0	32.0	9.3	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Fuel Inventory	335.0	345.4	340.7	330.6	316.1	301.4	280.3	251.9	242.2	224.2	210.7	208.6
Materials and Supplies	441.8	421.9	413.3	413.5	420.8	426.7	438.7	448.7	444.5	436.3	427.0	415.0
Total Rate Base	3,895.4	3,858.7	4,133.0	3,779.9	3,714.3	3,655.2	3,572.6	3,628.0	3,606.9	3,476.3	7,453.9	7,887.1

Source: Exh B1-1-1 Table 2, Exh B3-1-1 Table 1 (EB-2013-0321 and EB-2016-0152), J21.1

Submissions of the Parties

Some intervenors questioned the pattern of nuclear operations capital spending and the proposed significant capital program in the test period. AMPCO observed that 2017-2021 capital expenditures are 20% higher than the period 2010-2015, and further observed that in-service additions as a percentage of capital expenditures was increasing. In reply, OPG provided reasons for the increasing capital expenditures, including the reclassification of DRP projects. The pattern of in-service additions as a percentage of capital expenditures is not smooth and reflects the multiple year duration of nuclear projects.

OEB staff and several intervenors submitted that the test period in-service additions should be adjusted to reflect the actual 2016 capital additions and historical overstatement of in-service additions, which totaled $(190.9) million in the period 2010 to 2016. OEB staff submitted that the in-service amounts should be reduced by $27.3 million in each year of the test period. OPG argued that the submissions of most of the parties ignored the $70.3 million of 2016 in-service capital that was placed into service in early 2017. Considering the combined effect of in-service additions and depreciation, OPG argued that updating for 2016 actuals and using its updated forecast of 2017-2021 in-service additions[15] results in a $60 million increase in revenue requirement because the project mix includes more Pickering projects which have higher depreciation rates. In OPG's view, the parties' argument regarding the historical overstatement hinges on the large 2016 variance (i.e. a single data point).

The Projects and Modifications (P&M) organization is responsible for nuclear operations capital projects. The effectiveness of P&M was reviewed in interrogatories, cross-examination and submissions. SEC analyzed nuclear capital projects that have gone into service between 2014 and 2016 and argued that the projects are 11.7% above the cost set out in the first execution business case, and that for projects larger than $20

[15] Undertaking J21.1.

million, the variance is 41.8%. Analysis of actual completion vs. scheduled completion for projects larger than $5 million, indicated average delays of 17 months.

OEB staff and several intervenors submitted that P&M performance has been weak and that this performance has been documented in reports prepared by Burns and McDonnell and Modus Strategic Solutions (Modus) for the Nuclear Oversight Committee of OPG's Board of Directors. Several parties referred to the 2nd Quarter 2014 Report wherein Modus cited P&M management failure for campus plan projects (projects related to DRP that also support ongoing operation of Darlington). The 2nd Quarter 2014 Report noted that P&M management failures were most evident with respect to the D2O Project[16] and the Auxiliary Heating System (AHS) project. AMPCO argued that OPG should undertake an audit of its P&M project controls in time for the mid-term review and provide a status report at that time.

The parties submitted that there should be rate base disallowances based on poorly developed estimates, flawed contractor selection and weak day to day risk management. The parties proposed reductions to in-service amounts ranging from $14.4 million to $53.1 million for the AHS project and reductions ranging from $7 million to $14.9 million for the Operations Support Building project. OPG argued that its application should stand, noting that increases are related to flawed initial estimates and that the final costs are the true costs of these projects.

Findings

Capital and Rate Base

This application is a five-year Custom IR. Accordingly, the opening rate base for 2017 should be based on the best information available. Undertaking J14.1 confirms that the 2016 nuclear operations in-service additions were significantly lower, i.e. $205 million lower, than planned. Undertaking J14.1 also notes that $70.3 million of the nuclear operations in-service additions originally planned for 2016 had been placed in-service by the first quarter of 2017. OPG has provided a revision to in-service amounts and rate base in Undertaking J21.1. That revision reflects the update for actual 2016 in-service amounts and changes in timing of in-service amounts in the test period underpinned by the 2017-2019 Business Plan. Some of the intervenors have submitted that the 2016 in-service additions should be revised, but that the test period in-service additions should

[16] In Exh N2-1-1 filed on February 22, 2017, OPG updated its application to remove the in-service amounts related to the D2O project due to project uncertainty. The revenue requirement impact will be recorded in the Capacity Refurbishment Variance Account once the project is in service.

remain as originally filed. The OEB finds that the Undertaking J21.1 forecast represents the appropriate starting point for the OEB's consideration. The forecast is updated to reflect OPG's best available information for the entire period from 2016 to 2021. The proposal of the intervenors to update only 2016 would not account for the cascading effects of additions in the test period. The OEB's finding on this matter applies to nuclear operations capital and support services capital.

The scope of capital expenditure on nuclear operations has expanded to include reclassified projects from DRP, replacement of obsolete equipment and additional Canadian Nuclear Safety Commission regulatory requirements, for example, related to Fukushima. As shown in Table 8, capital expenditures have increased in the bridge and test period. SEC submitted that the planned level of nuclear operations capital spending is much higher than historical levels. However OPG argued that the average 2017-2021 capital expenditures ($259.4 million) are in line with the historical period average 2013-2015 capital expenditures ($269.6 million).[17] The OEB observes, however, that a review of a five-year historical period average from 2011-2015 ($223.7 million) supports the SEC submission.

Based on the variance between 2010 to 2016 forecast and actual in-service additions, OEB staff submitted that in-service additions should be reduced by $27.3 million for each year of the test period (the total seven-year variance offset by the 2017 additions previously forecast for 2016). SEC submitted that a 12.5% reduction (the total seven-year variance as a percentage of the total additions) was appropriate. AMPCO argued that in-service additions should be reduced by 15% annually based on the in-service variance and AMPCO's review of variances for projects of different sizes and schedule delays. AMPCO suggested that a lumpy pattern of in-service capital additions and positive and negative variances would not be unexpected. The OEB concurs with OPG that the 2010-2016 seven-year variance of $(190.9) million is largely driven by the 2016 variance of $(205.0) million.

The forecast and actual in-service additions for 2016 are significantly higher than the period 2010 to 2015 and the forecast for the test period, both as filed and as revised, is higher than historical. The five-year 2010-2015 average actual in-service additions is $160.1 million while the five-year 2017-2021 average revised in-service additions is $329.1 million. OPG was not able to achieve the forecast 2016 nuclear operations in-service additions, and it is uncertain whether OPG will have the resources to execute a nuclear operations capital program with higher capital expenditures and a much higher level of in-service additions. The elevated capital expenditures and in-service additions

[17] Reply Argument page 33.

are concurrent with DRP which could further divert resources from the ambitious nuclear operations capital program, also contributing to delayed in-service additions.

The OEB finds that some reduction to the in-service capital additions is required. The OEB finds that the reductions proposed by SEC and AMPCO are too aggressive. Instead, the OEB finds that a 10% reduction each year (2017-2021) to the non-DRP nuclear operations and support services in-service capital additions is appropriate (using the updated forecast from Undertaking J21.1 as the starting point). The OEB notes that a similar reduction was ordered by the OEB in the last OEB decision on payment amounts with respect to OPG's hydroelectric in-service additions.[18]

The OEB's findings on nuclear Custom IR and productivity are in section 8.2. In accordance with those findings, the OEB orders OPG to apply a 0.6% stretch factor to the revenue requirement associated with the nuclear operations and support services in-service capital additions in each year from 2017 to 2021. The revenue requirement reductions related to the application of the stretch factor shall be applied in the typical manner whereby the reductions in each year persist going forward (during the entire 2017-2021 period). The OEB finds that the application of a stretch factor to the nuclear operations and support services in-service capital additions is appropriate. The OEB expects that OPG will achieve productivity improvements with respect to the delivery of its nuclear operations capital program during the 2017-2021 term and those productivity savings should be passed on to ratepayers.

Projects & Modifications Performance

The effectiveness of the P&M organization has been criticized by some intervenors. The evidence relied on by the intervenors included the 2nd Quarter 2014 Report to the Nuclear Oversight Committee of OPG's Board of Directors, prepared by Burns and McDonnell and Modus Strategic Solutions (Modus report), as well as OPG internal audit reports. SEC has completed an analysis of cost and schedule for historical projects and submitted that, "The Board can expect projects to continue to be over-budget and behind schedule. This means OPG will either overspend compared to its budget or, more likely, do fewer projects. Neither scenario is good for ratepayers."[19] OPG replied that the Operations Support Building project and the AHS project are the main contributors to the variances, and that OPG is close to budget otherwise. OPG stated that factors such as limited outage windows affect project scheduling.

[18] EB-2013-0321, Decision with Reasons, page 21.
[19] SEC Submission page 58.

AMPCO reviewed iterations of business case summaries and submitted that the number of superseding business cases indicated poor P&M performance. AMPCO also submitted that P&M has delayed implementing lessons learned and that project management practices such as the gated process were mentioned in the previous cost of service proceeding. Energy Probe questioned why it has taken OPG so long to overhaul its procedures for the P&M group. OPG maintains that it has been responsive to the Modus report and that subsequent reports have acknowledged OPG efforts to improve P&M.

As in all cases, it is the utility's responsibility to file an application that supports its proposals. It is not clear to the OEB that P&M project management processes and outcomes exhibit continuous improvement. There is a large volume of evidence – filed with the application, with interrogatory responses and in undertakings. There was extensive examination regarding estimates, classes of estimates, process controls, independent reviews and internal audits. OEB staff and the intervenors have argued that there are some P&M deficiencies. OPG argues that that the intervenors do not fully understand the reasons for schedule delays or the business case summary process,[20] and did not refer to the positive findings of internal OPG audit reports subsequent to the Modus report. The OEB finds that there is room for improvement in P&M performance and the findings on stretch factor implement this finding. The OEB also finds that disallowances related to two projects, the Operations Support Building (OSB) and the AHS, are appropriate, as discussed below.

AMPCO submitted that OPG should undertake an audit of its P&M project controls and file a status report at the mid-term review. OPG argued that this amounts to micromanaging. The OEB is not convinced that project controls are as robust as they could be. Robust project controls are a critical component of good planning and execution of capital projects that allow projects to be completed on time and on budget. Therefore, the OEB directs OPG to file an independent audit of its nuclear P&M organization including adherence to best practices, measures and reporting regarding cost and schedule performance, and implementation of lessons learned. The audit report will be filed with OPG's next cost-based application.

Auxiliary Heating System and Operations Support Building

OEB staff, AMPCO, CME, Energy Probe, LPMA, SEC and VECC have all proposed disallowances with respect to AHS and OSB rate base additions. These projects were classified as DRP projects in the previous EB-2013-0321 proceeding, but have since been reclassified. However, P&M managed the AHS and OSB projects when they were

[20] Reply Argument page 38.

considered DRP projects. The parties have suggested a range of disallowances referring to the range of estimates and forecasts filed in this proceeding[21] and the Modus report. The AHS project was specifically reviewed in the Modus report.

OPG submitted that the majority of the variances relate to initial estimation concerns and scope additions, and that the OEB should accept the OPG proposal as filed. Had the work been properly estimated and the full scope of work been known initially, OPG submitted that the original cost would be close to the current cost.

The estimates and forecasts for the AHS are:

- EB-2013-0321 as filed – $36.3 million (last EB-2013-0321 update $75.3 million)
- First execution business case – $45.6 million
- Forecast/proposed final cost – $107.1 million ($98.7 million in-service amount)

Clearly the original forecast has grown substantially from what was filed in the EB-2013-0321 proceeding.

The OEB does not accept OPG's position. The current cost is not the same as the prudently incurred cost. It is not obvious whether the best alternative was selected or whether costs for the alternative selected were contained. The Modus report states that, "P&M gave only token consideration to determining which contractor had a better approach for executing the work. P&M chose the 'low bidder' even though the other contractor's qualifications and project approach were viewed more favorably."[22] CME submitted that the evidence demonstrates that OPG's management of the AHS fell short of what ratepayers should expect: "OPG's argument that ratepayers are receiving value for the scope of work which was ultimately involved in completing the AHS project fails to take into account the lost opportunity to pursue alternative and less costly options for achieving the same outcome."[23] In response to cross-examination by SEC, OPG agreed that poor baseline information can lead to cost increases and schedule delays.

The parties have proposed disallowances that range from 100% of the variance between the first execution business case and the proposed in-service addition to 50% of the variance. The OEB has considered the submissions of the parties as well as the

[21] JT2.16.
[22] Exh L-4.3-Staff-72 Attachment 4.
[23] CME Submission page 25.

Supplemental Report prepared by Modus.[24] That report comments on the D2O and AHS projects, and states that the causes of cost overruns “root from mistakes made by management.” The report also states that “many of the cost variances appear to be scope based, i.e. OPG is getting more value albeit for a higher cost.” On the basis of these two considerations, mismanagement and increased scope, the OEB disallows 50% of the variance between the first execution business case and the proposed in-service addition on a permanent basis. The OEB estimates the reduction resulting from its finding to equal about $27 million. However, in the draft payment order, OPG should provide the detailed calculation showing the OEB ordered reduction related to the AHS based on 50% of the variance between the in-service amount set out in the first execution business case and the current proposed in-service amount.

The OEB is prepared to accept that there may be some merit to OPG's argument that there was an increase in scope. However, the OEB is not prepared to accept that the entire increase in cost is due to an increase in scope. The evidence shows that there were other options available to OPG when selecting a contractor that may not have been adequately explored. In addition, the Modus report speaks to issues with management of the project. The OEB cannot determine on an exact basis how much of the increased cost is due to additional scope and how much is due to project management issues. Therefore the OEB has considered both factors and has determined it will allow 50% of the increased cost on account of increased scope and disallow 50% of the increased cost to account for poor management.

The estimates and forecasts for the OSB are:

- EB-2013-0321 as filed – $29.7 million (last EB-2013-0321 update $45.1 million)
- First execution business case – $47.8 million
- Forecast/proposed final cost – $62.7 million ($60.6 million in-service amount)

Clearly the original forecast has grown substantially from what was filed in the EB-2013-0321 proceeding.

The submissions of OEB staff and the intervenors on the OSB are similar to their submissions on the AHS. The OEB finds that final costs for a building refurbishment that are double those initially filed in EB-2013-0321 are not reasonable. A senior OPG executive made a notation that “This is poor performance” on the Project Over-Variance Approval form seeking an increase from $53 million to $62 million for the

[24] Undertaking J15.3 Attachment 1 page 3.

OSB.[25] The notation on the Variance Approval form does not speak to the entire increase in cost of the OSB, but it does indicate that there was a performance issue on this project as well. Because the OEB cannot determine the exact amount of increased cost due to performance issues, the OEB has exercised its judgment and disallows 50% of the variance between the first execution business case and the proposed in-service addition on a permanent basis. The OEB calculates the reduction resulting from its finding to equal about $6 million. However, in the draft payment order, OPG should provide a detailed calculation showing the OEB-ordered reduction related to the OSB based on 50% of the variance between the in-service amount set out in the first execution business case and the current proposed in-service amount.

The methodology proposed by OPG to calculate rate base is accepted. However, the OEB's findings with respect to nuclear operations capital will impact the rate base amount. The OEB's findings for establishing the nuclear operations and support services rate base and capital additions shall be implemented as follows. The starting point for the rate base amounts and in-service capital additions for the 2017-2021 period is the updated forecast provided by OPG in Undertaking J21.1. The permanent disallowances associated with the AHS and OSB should first be removed from the amounts set out in the updated forecast. The 10% reduction should then be applied to the in-service capital additions net of the permanent disallowances. Finally, the stretch factor should be applied to the revenue requirement associated with the reduced nuclear operations and support services in-service capital additions resulting from the OEB-ordered disallowances.

For future proceedings, the OEB directs OPG to file, at a minimum, the costs for each major capital project based on the first execution business case and the final proposed amount for which OPG is seeking approval. The information provided should be sufficiently detailed as to adequately highlight both the total cost and the related in-service amount.

Operation of CRVA and Nuclear Operations Capital Projects

The Capacity Refurbishment Variance Account (CRVA) was established pursuant to section 6(2)4 of O. Reg. 53/05 to record the variance between certain actual capital and non-capital costs incurred and those costs underpinning payment amounts. The costs eligible for the CRVA are related to projects that increase the output of, refurbish or add operating capacity to a regulated generating facility.

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[25] Exh D2-1-3 Attachment 1 Tab 1.

OEB staff raised a double counting concern in its submission.[26] If OPG placed less nuclear operations capital in service than approved, and if OPG places more CRVA eligible capital in service than approved, OPG would notionally recover the revenue requirement twice. OEB staff proposed that any nuclear operations in-service addition "credits" offset any CRVA "debits". CCC explored this matter in cross-examination.[27] CCC compared OPG's hydroelectric proposal with respect to the operation of the CRVA with OPG's proposed status quo operation for the nuclear sub-account of the CRVA. While the nuclear revenue requirement is based on annual capital plans for five years instead of mechanistic updates, CCC submitted that the remedy proposed by OEB staff should be implemented.

OPG has proposed that the operation of the nuclear sub-account of the CRVA continue as it has operated since the account was established. OPG argued that OEB staff and CCC's comparisons are wrong as different regulatory frameworks have been applied for the hydroelectric and nuclear businesses.[28] The OEB does not agree with OEB staff's and CCC's proposal. The potential outcome of the proposal is that prudently incurred CRVA eligible costs will be disallowed for recovery. OPG is entitled to recover prudently incurred CRVA-eligible costs as per the regulation. The OEB finds that the operation of the nuclear sub-account of the CRVA will continue as proposed by OPG.

Nuclear Projects Subject to CRVA

Under issue 4.1, OPG requested that section 6(2)4 of O. Reg. 53/05, and the associated CRVA treatment, apply to: (a) the capital and non-capital costs of the DRP; (b) the capital and non-capital costs of the Darlington Spacer Retrieval Tooling project; (c) the non-capital costs for the PEO project (including the Fuel Channel Life Assurance project); (d) the non-capital Fuel Channel Life Extension project (including ongoing costs); and (e) the Fuel Channel Life Management project.[29]

OEB staff submitted that the DRP and the other nuclear projects discussed above, as set out at OPG's updated response to an OEB staff interrogatory, meet the requirements of section 6(2)4 of O. Reg. 53/05 and therefore CRVA treatment applies.

The OEB finds that the projects for which OPG requested section 6(2)4 of O. Reg. 53/05 apply are appropriate. The OEB notes that no parties disagreed with OPG's request.

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[26] OEB staff submission page 62.
[27] Tr Vol 20 page 82.
[28] Reply Argument page 207.
[29] Exh L-4.1-Staff-24 pages 1-2.

Capitalization of Darlington Unit 2 New Fuel

OPG proposes to capitalize half of the cost of new fuel for Darlington Unit 2 in 2019 when the fuel is loaded into the reactor, to be depreciated after the unit is in service over the life of the station. AMPCO submitted that it is not OPG's past practice to capitalize new fuel and that OPG's evidence to support the capitalization is weak. OPG replied that AMPCO mischaracterized the interrogatory response regarding new fuel.[30] There is no past OPG practice as Darlington Unit 2 is the first instance of a full new fuel load since OPG's inception. However, the practice is consistent with USGAAP and was applied by the former Ontario Hydro. The OEB accepts the new fuel capitalization proposal as it is consistent with accounting guidance and past practice.

Projects for Future Review

Undertaking J7.3 is an internal OPG audit, "Project Controls Audit – Project & Modifications Group," March 9, 2016. The report reviewed 13 projects and identified deficiencies related to cost and schedule baseline information. OEB staff observed that the Darlington Class II Uninterruptable Power Supply Replacement and the Fukushima Phase 1 Beyond Design Day Event Project are not near completion. OEB staff submitted that the in-service amounts may include costs that were imprudently incurred and that the OEB should identify these two projects as requiring further review at the cost rebasing when these projects are complete. OPG argued that this advance identification is unwarranted and unnecessary as the OEB has the ability to assess any cost variances at rebasing. The OEB finds that processes in place are sufficient and that advance identification is not necessary.

Draft Payment Amounts Order

The OEB requires OPG to incorporate the OEB's findings on nuclear operations and support services rate base and in-service additions in the determination of revenue requirement. The filing will be consistent with the LPMA submission with respect to the filing of fixed asset continuity schedules and changes in depreciation, to which OPG agreed. OPG shall file detailed fixed asset continuity schedules for each year that reflect the changes ordered by the OEB as well as the details of changes in the depreciation expense as part of the draft payment amounts order.

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[30] Exh L-6.3-Staff-111.

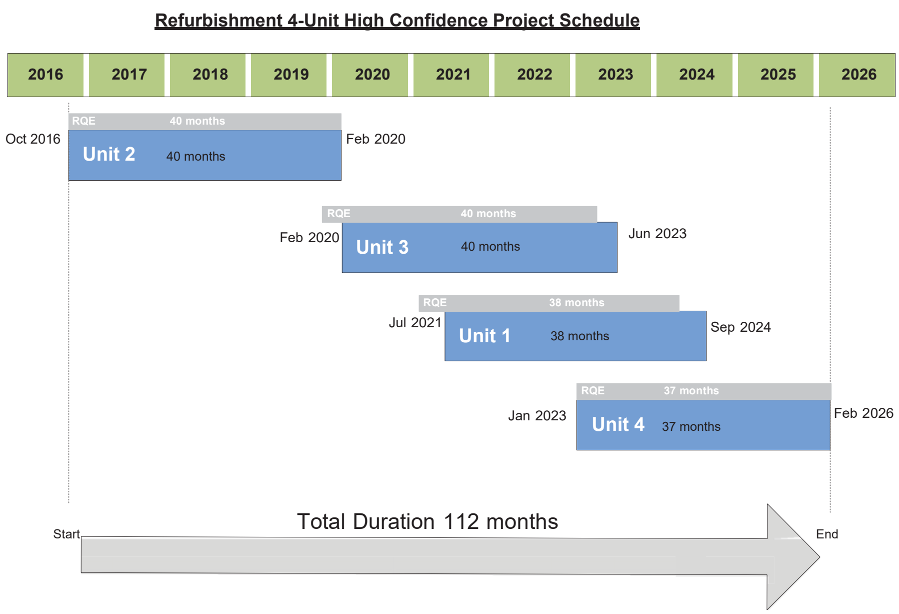
5.3 Darlington Refurbishment Program

5.3.1 DRP Planning and Costs

Background

The Darlington Refurbishment Program (DRP) is a $12.8 billion “megaprogram” to refurbish all four units at the Darlington nuclear station with a view to extending the life of the station until approximately 2055. OPG calls it a “destiny project” on which the company’s future, and indeed the future of the Canadian nuclear industry, depend.

The first unit to be refurbished, Unit 2, was disconnected from the power grid (breaker open) in October 2016, and is forecast to come back online in February 2020. As the schedule below shows, the last of the units is expected to be completed in 2026.[31]



After ten years of planning, OPG’s board of directors approved a Release Quality Estimate (RQE), setting out the detailed budget and schedule for the entire four-unit program, in November 2015. The RQE breaks down the $12.8 billion total cost as follows:

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[31] Exh L-4.3-Staff-55 Attachment 1.

Table 11: Release Quality Estimate

Program Component	RQE Total Cost (Billion $)	RQE Total Cost (%)
Major Work Bundles	5.54	43
Safety Improvement Opportunities	0.20	2
Facilities & Infrastructure Projects	0.64	5
OPG Functional Support	2.23	17
Early Release Funds	0.11	1
Contingency	1.71	13
Interest & Escalation	2.37	19
Total Cost Estimate	**12.8**	**100**

The RQE is said to represent a "P90" confidence level. As OPG explains in its Argument in Chief, "A P90 estimate means there is a 90% chance that the actual project cost will not exceed the estimated amount." This confidence level was determined through statistical modeling of risks identified by OPG.

By the time of the hearing, about $2.9 billion of the $12.8 billion had already been spent.

In this application, OPG is seeking approval for rate base additions of $4.8 billion of in-service amounts associated with the Unit 2 refurbishment (including contingency, interest and escalation), along with $377 million in in-service amounts for other DRP-related facilities that will enter into service during the test period. No costs for the refurbishment of the other three units are requested in this proceeding, as they will not complete their refurbishments during the test period.

For the reasons that follow, the OEB approves the additions to rate base as proposed by OPG.

Regulatory Framework

The OEB's jurisdiction in respect of the DRP is limited by O. Reg. 53/05. The regulation states in paragraph 6(2)12 that "the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment." The question of whether the DRP makes economic sense or is otherwise justified as a matter of electricity system planning was therefore out of scope in this proceeding.

The 2013 Long-Term Energy Plan, to which the regulation refers, states that "The government is committed to nuclear power," and that "Refurbished nuclear is the most cost-effective generation available to Ontario for meeting base load requirements." The Government of Ontario reiterated its support for the DRP in January 2016, after the RQE was finalized.

The regulation also stipulates in paragraph 6(2)4 that the OEB must allow OPG to recover DRP-related costs so long as they are prudent: "The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project … including, but not limited to, assessment costs and pre-engineering costs and commitments… if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made."

This requirement is reflected in OPG's Capacity Refurbishment Variance Account (CRVA), which the OEB has approved in every payments amount case since it was given jurisdiction over payment amounts.[32] Under the CRVA, if OPG were to go over budget on the DRP, a balance would build up in the CRVA, and the OEB would review the prudence of the overruns before approving the disposition of the balance. The CRVA is symmetrical: if the program went under budget, the excess amounts collected through payment amounts would be returned to ratepayers in a future proceeding.

Matters related to the safety, security and environmental impacts of the Darlington station and the DRP are regulated by the Canadian Nuclear Safety Commission (CNSC). The CNSC reviewed OPG's environmental assessment of the DRP and determined in March 2013 that the program would not result in significant adverse environmental effects given the proposed mitigation measures. In December 2015, the CNSC renewed the operating licence for Darlington until November 30, 2025 and found that OPG is qualified to undertake the DRP.

Planning, Contracting and Oversight

Much of the evidence in this proceeding related to the extensive planning efforts that OPG has undertaken to prepare for the execution of the DRP. OPG explained that there are three phases to the DRP: Initiation, Definition and Execution. The exploratory Initiation Phase began in 2007 and was completed at the end of 2009 when OPG's board of directors agreed to proceed with the DRP. The Definition Phase culminated in the RQE, which was approved by the board of directors in November 2015, and endorsed by the Minister of Energy shortly thereafter. OPG explained that the Definition Phase included an extensive effort to define the scope of the program. The RQE incorporates a high-confidence (P90) budget and schedule.[33]

[32] In the first payment amounts decision, EB-2007-0905 (November 3, 2008), the OEB wrote: "In light of the obligation imposed on the Board by Section 6(2)4, the Board accepts that a variance account is required for the period beginning April 1, 2008 and authorizes OPG to establish the capacity refurbishment variance account."
[33] Tr Vol 1 page 32.

During the Definition Phase, OPG also sought to identify and incorporate "lessons learned" from other nuclear projects and other megaprojects. This included a thorough review of why prior refurbishments of CANDU nuclear power plants have experienced challenges, namely the refurbishments at Bruce Power, Point Lepreau (New Brunswick) and Wolsong (South Korea). OPG also built a full-scale reactor mock-up in order to test tools and train staff – something that had not been done for the earlier CANDU refurbishments. OPG awarded the major DRP contracts, and worked with the contractors to complete the detailed engineering for the program. In total, OPG spent $2.2 billion during the Definition Phase.

OPG is using a "multi-prime contractor model" where there is more than one prime contractor and OPG has a separate contract with each of them. As the owner and integrator between contractors, OPG has overall project management responsibility and design authority, with the assistance of external technical and project management experts. The benefits of this model are said to be that OPG retains control over the project, including deliverables, costs and schedules. OPG's functional support costs for DRP are forecast to be $2.2 billion.

OPG explained that it used different contracting strategies for each of the five major work bundles (retube and feeder replacement [RFR], turbine generator, steam generator, defueling and fuel handling, and balance of plant), which it says balanced the need and ability of OPG to transfer risk to its contractors against the benefit of achieving a lower price. By far the largest contract by value is the $3.4 billion contract for the RFR. The RFR contract is based on the Engineering, Procurement and Construction model and combines fixed pricing for known or highly definable tasks with target pricing for work that is less definable. If the actual cost of the work ends up being more or less than the estimate, the difference (outside a neutral band) would be shared by OPG and the contractor, through a system of incentives and penalties. The major DRP contracts were filed with OPG's application (with some redactions approved by the OEB for the versions placed on the public record).

OPG provided an assessment of its contracting strategies prepared by Concentric Energy Advisors (which was initially filed in the EB-2013-0321 case). Concentric concluded that the commercial strategies employed by OPG were appropriate and met the regulatory standard of prudence. In July 2016 Concentric provided an update report on the RFR contract and stated that the terms of the finalized contract, including the target price and the allocation of risk, are prudent.

OPG also filed an expert report by Dr. Patricia Galloway of Pegasus Global Holdings Inc., an expert in megaprojects, on the degree to which OPG's plan and approach to the execution of the DRP was consistent with the way other projects of comparable size and complexity have been carried out. Dr. Galloway states in her report that, "Based on the review of OPG's governance, policies and procedures, and project controls developed and in use for the Program, and interviews conducted with OPG personnel, I found that OPG has reasonably and prudently prepared for its execution of the DRP."[34] Other key findings by Dr. Galloway include:

- "OPG sought to find the most qualified individuals in the industry to manage the Program and the individuals that were assigned to manage the Program are qualified and competent"[35]
- "OPG's oversight process is thorough, complete and consistent with what I would expect from a reasonable and prudent utility company embarking on this type of megaprogram"[36]
- "In reviewing OPG's policies and procedures, both from an organizational and program-specific standpoint, I found they are exemplary in their thoroughness and alignment with other individual policies and procedures providing OPG with a comprehensive tool from which it can properly execute the Program"[37]
- "I found the methodologies employed by OPG to develop the RQE estimate to be *world-class*"[38]

OEB staff also engaged an independent expert in megaproject planning and risk management: Kenneth M. Roberts, the chair of the construction law group at the US law firm, Schiff Hardin, LLP. Mr. Roberts agreed with Dr. Galloway that OPG's planning was thorough and in accordance with industry standards. Asked to summarize his conclusions at the oral hearing, Mr. Roberts answered:

> Specifically, my opinions included the following: That the DRP risk and OPG risk assessment are in fact consistent with industry standard practices used by utilities and large capital construction projects of similar size and complexity; that OPG's planned project control system for the DRP to manage costs and schedule are consistent with industry standard practices used by utilities in large capital construction projects of similar size and complexity; that OPG's program and project management staffing plans and the written management policies and procedures for the DRP are consistent with industry standards used by utilities in large capital projects; that OPG's contracting strategy, contract terms, and contractual risk allocation between OPG and the contractors for the DRP are consistent with industry standards for [risk] shifting on projects of this size and complexity.[39]

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[34] Exh D2-2-11 Attachment 2, page 8.
[35] Exh D2-2-11 Attachment 2, page 40.
[36] Exh D2-2-11 Attachment 2, page 40.
[37] Exh D2-2-11 Attachment 2, page 43.
[38] Exh D2-2-11 Attachment 2, page 51 [emphasis in original].
[39] Tr Vol 7 pages 13-14. The transcript erroneously refers to "rate shifting" in the last sentence.

He cautioned, however, that no amount of planning can ensure the smooth execution of a megaproject: “All megaprojects experience some form of cost and/or schedule issues, which may include but [are] not limited to commercial challenges, changes, unexpected and high-impact events and/or delays. It's not a question of whether these types of events will occur. It’s a matter of how OPG handles and responds to these issues when they arise.”[40]

The DRP is now in the third and final phase: the Execution Phase. There are multiple layers of oversight, including but not limited to: a special DRP committee of the board of directors, which has engaged its own external expert; OPG’s internal audit group; and the Refurbishment Construction Review Board, which is made up of external individuals with expertise in megaprojects and nuclear power and which reports to OPG’s CEO and the Chief Nuclear Officer. OPG’s shareholder, the Province of Ontario, also has an oversight role, through the Ministry of Energy, which has retained outside experts through Infrastructure Ontario to provide oversight and report back on findings.

The President and CEO of OPG, Jeff Lyash, appeared before the OEB twice in this proceeding – first at the presentation day on September 1, 2016 and then on the first two days of the oral hearing on February 27 and 28, 2017 – to speak to the importance of the DRP to the company and the company’s efforts to ensure it is executed successfully. He explained:

> What incentive does OPG have to come in under budget? I think there is a layered set of incentives that we have, beginning with the fact that we're an Ontario business corporation, so, as part of that, we have an obligation, a fiduciary obligation, to run the company in a certain manner, and as part of that, our long-term objective is to satisfy our customers so that we're rewarded with net income and return on equity. Successfully completing this project on or under budget, on or under schedule, we believe substantially increases the company's potential to be successful in the long run.
>
> The second incentive I point out to you is that, in regard to Darlington, we’re a regulated generating company, and part of the compact for being a regulated generating company is to deliver value to the customer. And that’s at the heart of the value proposition for a regulated utility. It is for OPG. And so delivering projects ahead of schedule and under budget in a way that lowers the customer's price is part of our core objectives.
>
> The third element, I think, that provides us an incentive is that our shareholder in this case, unlike most other companies, are the citizens of Ontario. And so they, through the provincial government, own the company. And so, in defining what shareholder value we're delivering, ahead of schedule, under budget, and lowest customer price is what our

[40] Tr Vol 7 page 15.

> shareholder demands, and they exercise that through the Minister of Energy, and he has made that very clear.
>
> Another significant element here is that this is a destiny project for the company, and it is, frankly, a destiny project for the nuclear industry, and we're all very clear that meeting or exceeding expectations has tremendous value for the company and the industry in the long-term. This is also tied directly to management compensation, delivering not only the project but reliable and cost-effective operation of the units post-refurbishment.
>
> And then lastly – and I would ask Mr. Reiner to comment on this – we have built incentives down through the project management team and the contracts that we've structured.[41]

At the time the oral hearing began, at the end of February 2017, OPG advised that it was "tracking slightly under budget at this point in time, as of end of January, about $59 million".[42]

OEB staff submitted that OPG has planned effectively and that an appropriate framework has been implemented for DRP, but concurred with Mr. Roberts about execution phase risk. SEC's submission is similar:

> OPG appears to have tried their best to put in place project controls, a risk management framework, and a schedule that will ensure completion on time and on budget.
> All of this is a very positive sign. But it is only that. In no way does good planning guarantee successful execution.[43]

Proposed Additions to Rate Base

In this application, OPG asks the OEB to approve in-service additions to rate base for Unit 2 (the only unit planned to be completed in the test period) of $4,800.2 million in 2020 and 2021. In addition, OPG seeks approval for in-service additions of $377.2 million for other DRP-related projects, known as "campus plan projects", comprising the "early in-service projects", the facilities and infrastructure (F&I) projects, and the safety improvement opportunities (SIO) projects.[44]

[41] Tr Vol 1 pages 37-38. March 2017 status reports were filed with Undertaking JT2.10
[42] Tr Vol 1page 16.
[43] SEC Submission page 42
[44] The early in-service projects are projects that will be placed in service before the refurbishment of Unit 2 is completed because they provide immediate benefit to the Darlington station even before Unit 2 is returned to service. The F&I projects are certain projects that OPG says are necessary to enable execution of the DRP, but which would be useful to the station even if the DRP were not completed. The SIO projects are initiatives that OPG committed to completed in the environmental assessment for the DRP that was approved by the CNSC, and would be useful to the station even if the DRP were not completed.

OPG is seeking approval of in-service additions to rate base associated with the DRP as set out in the following table:

Table 12
Bridge Year and Test Period In-Service Amounts ($ million)

	2016	2017	2018	2019	2020	2021	Total	Ex Campus Plan	Campus Plan
1 Original	350.4	374.4	8.9	0	4,809.2	0.4	5,543.3	4,800.2	743.1
2 Update		(365.9)		0			(365.9)		(365.9)
3 Net	350.4	8.5	8.9	0	4,809.2	0.4	5,177.4	4,800.2	377.2

Sources:

1. Original Request: Exh D2-2-1 page 6.
2. Update for removal of the Heavy Water Facility project (D2O project): Exh D2-2-10 Table 2 and Exh N2-1-1.
3. Net: Confirmed Tr Vol 1 pages 23 and 24 and Exh N2-1-1.

In an update to its original application,[45] OPG removed the Heavy Water Facility project (the D2O project), which will store large volumes of heavy water, but which has experienced delays and cost overruns. OPG testified that, despite these difficulties, the completion of the D2O project did not threaten the overall Unit 2 schedule and budget. Although some other DRP-related projects, including the Third Emergency Power Generator project, have also encountered delays or overruns, OPG did not seek to update the associated in-service amounts (and the timing of those amounts) as originally filed.

The Unit 2 in-service amounts are broken down as follows:[46]

[45] Exh N2-1-1.
[46] Exh D2-2-1 Figure 1.