CAPITAL BUDGET – REGULATED HYDROELECTRIC

1.0 PURPOSE AND OVERVIEW

This evidence provides an overview of the capital budget for OPG's regulated hydroelectric facilities for the historical years, bridge years, and the test period, as well as period-over-period explanations, and an overview of the hydroelectric project management processes.

2.0 CAPITAL EXPENDITURES SUMMARY

Capital expenditures for the regulated hydroelectric stations are dominated by the cost of the Niagara Tunnel project. The total estimated cost of this project is $985M, of which $517M is to be spent in 2008 and 2009. The project was approved by the Board of Directors on July 28, 2005, with an expected in-service date of 2010. In comparison, the balance of the regulated hydroelectric capital budget planned for 2008 and 2009 is $87M. The non-tunnel expenditures are primarily focused on the rehabilitation of generators G7, G9, G10 and G3 at the Sir Adam Beck I Generating Station, with planned in-service dates of 2008, 2009, 2010 and 2011 respectively. These four projects are estimated to cost a combined $127.7M, of which $63.3M is to be spent in 2008 and 2009. Estimates for G9, G10 and G3 are based on the estimates presented in the G7 business case approved by OPG's Board of Directors in August 2007.

The capital expenditures associated with these projects are consistent with OPG's mandate as set out in the Memorandum of Agreement with its shareholder, which provides as follows:

> "With respect to investment in new generation capacity, OPG's priority will be hydro-electric generation capacity. OPG will seek to expand, develop and/or improve its hydro-electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible"

Three other significant projects are the replacement of the heating, ventilation, and air conditioning system ("HVAC") at the R.H. Saunders Generating Station, the rehabilitation of the Sir Adam Beck I power canal, and grouting of the Sir Adam Beck Pump Generating

Station dyke foundation. The R.H. Saunders HVAC project, estimated at $11.5M, is expected to come into service at the end of March 2008. The rehabilitation of the Sir Adam Beck I power canal project is currently estimated at $51M and is expected to come into service at the end of 2011. Expenditures on the power canal project involve the inspection and repairs to the canal walls and civil structures. The canal walls below the waterline cannot be accessed while the canal is in operation. Repairs will be made where required to areas of the canal, and debris that is constricting flow will be removed. Costs are expected to be limited to about $500k for investigation and pre-engineering work during the test period. Finally, detailed inspections and testing of the Pump Generating Station dyke will commence during the test period in advance of the major grouting project in 2010. The total cost of the grouting project is $20M, of which $1M is to be spent during the test period.

Capital projects are listed in Ex. D1-T1-S2. These capital projects are required to sustain the availability and reliability of hydroelectric generation due to aging generators, associated mechanical and electrical equipment, and associated civil structures.

3.0 PERIOD-OVER-PERIOD EXPLANATIONS

2009 Plan versus 2008 Plan

Capital expenditures associated with the regulated hydroelectric facilities are expected to increase from $208.8M in 2008 to $395.6M in 2009, mostly due to incremental work associated with the Niagara Tunnel project. The lining of the tunnel with concrete is planned to be underway and will run concurrently with the excavation by the TBM. In addition, there will be work at the tunnel intake and outlet structures. In 2009, work will also be continuing on the rehabilitation of Generator G9 at Sir Adam Beck I, while the rehabilitation of Generator G10 and G3 will begin at Sir Adam Beck I.

2008 Plan versus 2007 Actual

Capital expenditures associated with the regulated hydroelectric facilities are expected to increase to $208.8M in 2008 from the $84.3M actual expenditure in 2007 due to the planned increase in the rate of excavation by the TBM (Niagara Tunnel project), the continuing work

on the frequency conversion of Generator G7 at Sir Adam Beck I, and the beginning of rehabilitation work for Generator G9 at Sir Adam Beck I. Some of the increase is offset by the reduction in capital requirements for the HVAC replacement project at R.H. Saunders as the project reaches completion in the first quarter of 2008.

2007 Actual versus 2007 Budget

The 2007 actual capital expenditure was $84.3M versus the 2007 budget of $229.4M.

As previously discussed, the Niagara Tunnel project was $144.6M under budget in 2007 due to slower than expected progress. Considerable uncertainty remains with respect to the schedule until the tunnel boring machine advances sufficiently beyond the St. David's Gorge (at approximately the 2.3 kilometre mark), and establishes consistent tunnelling performance. The contract structure places the onus on the contractor to mitigate schedule delays, and includes liquidated damages provisions for failure to meet the contractual in-service date. Based on the information provided by the contractor, the in-service date of the tunnel will be delayed from the original project completion schedule of June 2010. To mitigate the impact of the potential schedule delay, the contractor is investigating alternatives, including the realignment of the tunnel. The estimated in-service date will be dependent on the alternative selected by the contractor to mitigate the schedule delay. There is a potential that the schedule delay could significantly impact the project cost. The project cost estimate of $985 million will be reviewed in conjunction with the changes to the project completion schedule.

Capital spending at Niagara was $0.2M below plan resulting from the deferral or cancellation of a number of smaller projects, offset by the advancement of spending of approximately $0.9M on the G7 rehabilitation project.

R.H. Saunders Generating Station capital spending in 2007 was approximately $0.2M under plan ($10.53M versus $10.76M). The majority of the variance is attributed to:

- The HVAC replacement project spending was $1.1M below plan primarily as a result of very little discovery work requiring less of the contingency funds, and the late delivery of the heat exchangers which pushed some of the expenditures into 2008.

- The Domestic Water System replacement project was reclassified to capital from OM&A after the final assessment concluded that it was more cost effective to replace the system than to upgrade or refurbish it. This resulted in $0.7M of unplanned capital spending in 2007.

2007 Actual versus 2006 Actual

Regulated hydroelectric capital expenditures decreased to $84.3M in 2007 from $179.7M in 2006.

The main reason for the lower expenditures in 2007 is delays in the Niagara Tunnel project as a result of slower than planned progress of the tunnel boring machine (TBM) through the fractured rock formation along the tunnel. The fractured rock has required the installation of horizontal supports so the TBM can advance. To the end of 2007, the tunnel boring machine advanced 1.609 kilometers compared to a plan of 2.29 kilometers. OPG pays the contractor based on progress of the machine. As well, most of the cost for the TBM was incurred in 2006.

Some of the decrease in capital associated with slower TBM progress, was offset by the start of work on the frequency conversion of Sir Adam Beck I Generator G7, and the HVAC replacement at R.H. Saunders.

2006 Actual versus 2006 Budget

The 2006 actual capital expenditure was $179.7M versus a 2006 budget of $203.8M.

Capital spending on the Niagara Tunnel project was $25M lower than plan in 2006 due to the contactor's slower than planned progress by the tunnel boring machine, lower interest costs, and unspent contingency. The tunnel boring machine progress was slower than planned due to start-up technical problems, including groundwater inflow and faster than expected wear of the cutterheads. The contractor had to develop and implement a plan to address these

issues. The original plan for 2006 was for the tunnel boring machine to complete over 1 km of excavation, but the actual excavation distance was 0.2 km.

Capital spending for the Niagara Plant Group in 2006 was $7.3M, or $1.1M under a budget of $8.4M. The lower costs are attributed to lower than expected final closeout costs for the Sir Adam Beck II rehabilitation project. Based on the experience gained from the first units completed on the project, the manufacturer's original recommendations for follow-up work were modified resulting in significant cost savings.

Capital spending at R.H. Saunders Generating Station in 2006 was $3.1M which was $1.9M higher than planned. This difference was due to the need for two unplanned projects and higher costs of an already planned project, as follows:

- $0.7M to install a new fence for the purposes of public safety. The canal between the dam and the guardhouse was already fenced. However, security reports indicated that there was public trespass on the section of the canal just downstream of the guardhouse near a public bike path. A new fence was installed to reduce the risk to public safety.
- $0.6M for new sectional service gates to dewater units. The sectional service gates were an existing project which was delayed from a previous year due to technical and supplier issues.
- The remaining $0.6M was the result of higher than anticipated costs to complete the Iroquois Control Dam crane rehabilitation project. The increase in this project was due to an increased scope and higher than expected contractor bids.

<u>2006 Actual versus 2005 Actual</u>

The 2006 actual capital expenditure was $179.7M versus the 2005 actual expenditure of $84.6M.

The Niagara Tunnel project spending in 2006 was $103.1M more than 2005 ($169.3M versus $66.2M) because the project started in the third quarter of 2005 and ramped up during 2006. As well, the extra cash flow in 2006 was due to the following additional items (as compared to 2005) which were either completed or initiated in 2006:

- Most of the work associated with the tunnel boring machine fabrication and assembly occurred in 2006 with fabrication being completed in August 2006.
- The tunnel boring machine commenced excavation of the tunnel in September 2006 and continued into 2007.
- Work at the intake area (approach wall, accelerating wall and cofferdam) commenced in April 2006, with the accelerating wall being completed in 2006 and work on the approach wall and cofferdam continuing into 2007.
- Decommissioning of Ontario Power Generating Station and Toronto Power Generating Station commenced in 2006, with the decommissioning of Ontario Power Generating Station being completed and the Toronto Power Generating Station work, including the removal of all equipment, progressing on schedule.

Capital spending within the Niagara Plant Group was $7.3M in 2006 versus $16.6M in 2005. The reduction in capital was due to the completion of the majority of the Sir Adam Beck II rehabilitation project in 2005.

Capital spending at R.H. Saunders Generating Station was $3.1M in 2006 versus $1.8M in 2005 due to higher than planned spending in 2006 as described below, and the deferral of planned work associated with the HVAC project, as described in the previous section.

2005 Actual versus 2005 Budget

The 2005 actual capital expenditure was $84.6M versus the 2005 budget of $87.8M. The components of the variance are discussed below.

With respect to the Niagara Tunnel project, activities included: project design, tunnel boring machine fabrication, site clearing, and the start of the excavation at the outlet area. The Niagara Tunnel project costs were $3M under the 2005 budget amount of $69.2M. The variance was due to delays in awarding some contracts and lower interest and insurance premium costs.

The Niagara Plant Group's capital spending in 2005 was $0.5M over plan. The capital variance was mainly due to the reclassification of the DeCew Falls II Generating Station headgate project from OM&A to capital. OPG had originally planned to refurbish the headgate system, but further investigation revealed that a complete replacement was required. The decision to replace the headgate changed the classification of this project from an OM&A project to a $1.4M capital project. The additional capital requirement was partially offset by the deferral of the Sir Adam Beck I turbine modelling project ($300k), the controls upgrade project ($200k) at the Sir Adam Beck Pump Generating Station, and reduced work requirements on the replacement of fire protection systems at both DeCew Falls I and II ($300k). It was found that these projects could be deferred at an acceptable risk to the stations or the related Sir Adam Beck I turbine upgrade projects.

R.H. Saunders Generating Station capital spending in 2005 was $700k under plan ($1.8M versus a plan of $2.5M). The reduced spending was due to a deferral of the start of the HVAC replacement project until 2007. The original plan was to do the work in consecutive years with three distinct work packages in the spring and/or fall when the HVAC system could be removed from service. However, to improve efficiency and minimize employee disruption, the project is proceeding as one continuous work package without interruption. The project is expected to be completed in March 2008.

4.0 PROJECT MANAGEMENT – OVERVIEW

The stages of a hydroelectric project are:

- Identification phase
- Initiation phase
- Definition phase
- Execution phase
- Final closing phase

Each step in the project life cycle may require a significant amount of time and resources (as in the case of a major rehabilitation or new station construction), or represent steps that are

passed through relatively quickly in the case of the replacement of a minor plant component due to breakdown.

Between each phase, a distinct “decision gate” is reached, where a decision is taken on whether to allow the project to proceed to the next step, revert back to a previous step, or cease the project entirely.

In general, problems or opportunities are identified by plant group staff as part of: annual engineering reviews, periodic plant condition assessments, or ongoing maintenance activities (e.g., recurring equipment failures, technological obsolescence, or health and safety or environmental issues). If the identified problem or opportunity is likely to lead to a project, then the project is proposed as part of the business plan with a budgetary estimate and planned duration.

If, through the business planning process, the funding is approved for the identified project, the project enters the initiation phase. During this phase a project charter is normally created. The charter sets out the project objectives, defines the responsibilities of the project team, identifies stakeholders, and specifies the initial project scope and schedule. Project charters are normally prepared by a plant group’s Asset Management Department.

Where a definition phase is deemed necessary, the Asset Manager is accountable for carrying out the definition work according to the approved scope, cost, and schedule. This activity may be supported by the Project Manager. Where the definition work required is significant, the authorization to proceed is obtained through the approval of a developmental business case summary. Definition work consists mostly of investigations required to determine project scope, verify site conditions, perform preliminary engineering, and produce a release quality estimate and a detailed schedule.

Once the project has been evaluated and a decision has been made to seek approval for the execution phase of the project, a business case summary must be prepared. Business case summary preparation and approval is normally coordinated by the Asset Management

Department. Projects are reviewed and approved in accordance with OPG's organizational authority register, which sets out the approval authority for different levels of OPG management. For example, projects with an approved budget up to a total cost of $4M can be approved by the Plant Group Manager. Projects above $4M are reviewed and approved at higher levels in the organization. In addition as outlined in the OPG organizational authority register, a financial review is undertaken on all projects locally by the site controller and, depending on the project's total cost, again at a higher level in the Finance organization.

The plant group Project Management Department carries out the execution phase of a project. Activities associated with the execution phase typically include:

- Managing the people and resources required to complete the project deliverables.
- Managing the scope, quality, cost, and schedule.
- Managing project risks, health and safety, quality, and environmental requirements.
- Monitoring progress and forecasting time, effort, and cost to complete.
- Analyzing variances from the plan and re-planning the project as required.
- Managing project changes.
- Identifying and recording lessons learned as they occur.
- Commissioning, startup, and performance testing (in coordination with operations and maintenance staff).

Ongoing oversight is also performed by the Asset Management and Finance Departments through monthly cost review meetings.

For capital projects only, when equipment is placed into service, key accounting information is provided so the asset can be properly recorded on the OPG balance sheet.

On completion of the execution phase, a project closure report describing the final project costs is prepared within six months of the project's in-service date. In addition, if required a post-implementation review is prepared for the project. Post implementation reviews are required for all OM&A or capital projects over $200k in value. The purpose of the post-implementation review is to confirm whether the benefits and/or business objectives stated in

the business case summary have been achieved, and to communicate any lessons learned back to management to aid in future decisions. The post-implementation review will normally be completed within one year of the in-service date or as specified in the business case summary.

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D1
Tab 1
Schedule 1
Table 1

Table 1

Capital Expenditures Summary - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Niagara Plant Group**	16.6	7.3	9.9	33.6	42.2
2	**Niagara Tunnel Project**	66.2	169.3	63.9	170.6	346.8
3	**Saunders GS**	1.8	3.1	10.5	4.6	6.6
4	**Total**	84.6	179.7	84.3	208.8	395.6

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D1
Tab 1
Schedule 1
Table 2

Table 2
Comparison of Capital Expenditures - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Niagara Plant Group**	16.1	0.5	16.6	(9.3)	7.3	(1.1)	8.4	2.6	9.9
2	**Niagara Tunnel Project**	69.2	(3.0)	66.2	103.1	169.3	(24.9)	194.2	(105.4)	63.9
3	**Saunders GS**	2.5	(0.7)	1.8	1.4	3.1	1.9	1.2	7.4	10.5
4	**Total**	87.8	(3.3)	84.6	95.2	179.7	(24.1)	203.8	(95.4)	84.3

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
5	**Niagara Plant Group**	10.1	(0.2)	9.9	23.7	33.6	8.6	42.2
6	**Niagara Tunnel Project**	208.5	(144.6)	63.9	106.7	170.6	176.2	346.8
7	**Saunders GS**	10.8	(0.2)	10.5	(5.9)	4.6	2.0	6.6
8	**Total**	229.4	(145.1)	84.3	124.5	208.8	186.8	395.6

CAPITAL EXPENDITURES – REGULATED HYDROELECTRIC

1.0 PURPOSE AND OVERVIEW

The purpose of this evidence is to provide a project listing and business case summaries for capital expenditures for the regulated hydroelectric facilities during the test period.

2.0 CAPITAL PROJECTS LISTING

OPG has used a tiered structure for reporting on all capital projects which have budgeted expenditures during the 2008 and 2009 test period.

This tiered approach provides a comprehensive picture of OPG's capital project expenditures for regulated hydroelectric facilities. It also recognizes that different levels of information are appropriate for projects of different sizes, based on the large volume of projects undertaken within OPG.

The projects in each tier are shown in the attached tables, with supporting project documentation as required.

Based on the tiered reporting structure, the following information is provided for capital projects:

- For large projects (i.e., total costs greater than $10M and representing six projects), project summaries or business case summaries are provided.
- For mid-range projects (i.e., total costs of between $5M and $10M and representing two projects), short project descriptions are provided.
- For other projects (up to $5M), an aggregate of the total project costs is provided.

LIST OF ATTACHMENTS

Attachment A: Niagara Tunnel Project (EXEC0007) Business Case Summary

Attachment B: R.H. Saunders G.S. – Replace HVAC Project Summary (H-97-1864)

Attachment C: Sir Adam Beck I G.S. – Unit G9 Upgrade Project Summary (SAB10047)

Attachment D: Sir Adam Beck I G.S. – Unit G10 Upgrade Project Summary (SAB10050)

Attachment E: Sir Adam Beck I G.S. – Rehabilitate Canal Lining Project Summary (SAB10056)

Attachment F: Sir Adam Beck I G.S. – Unit G7 Generator Frequency Conversion from 25Hz to 60Hz (SAB10032) – Recommendation (Redacted)

Attachment G: Sir Adam Beck I G.S. – Unit G3 Upgrade Project Summary (SAB10064)

Attachment H: Sir Adam Beck Pump Generating Station – Dyke Foundation Grouting Project Summary (SABP0022)

ONTARIO POWER GENERATION

BUSINESS CASE SUMMARY

Niagara Tunnel Project (EXEC0007)
July 28, 2005 (Confidential)

FULL RELEASE FOR NIAGARA TUNNEL PROJECT (EXEC0007)

1. RECOMMENDATION:

Approve the release of $963 M for design and construction of the Niagara Tunnel Project (the "Project"), bringing the total Project cost estimate to $985 M, including $22.5 M previously approved. Based on the recommended design / build proposal, the new tunnel will be in-service by June 2010, will increase the diversion capacity of the Sir Adam Beck Niagara GS complex by 500 m^3/s and facilitate a 1.6 TWh increase in average annual energy output. The cost contingency and schedule contingency included ([redacted]) are each based on a confidence level of 90%. This Project compares favourably with other renewable electricity supply options and is aligned with directions provided to OPG by the Province. Project approval is contingent upon financing, satisfactory to OPG, being provided by the Province.

Total Investment Cost: $985 M (including $22.5 M previously approved)

Year	To 2004	2005	2006	2007	2008	2009	2010	Totals
Project Capital	4	69	194	215	228	209	66	985
2005 Business Plan	5	65	170	160	180	140	15	735
Variance	-1	4	24	55	48	69	51	250

Type of Investment: Strategic Projects (OAR - Section 1.3)

Release Type: Full

Funding: The Niagara Tunnel Project is in the approved Business Plan as presented above, contingent on financing being provided by the Province.

Investment Financial Measures: The increased energy output resulting from the Project will receive a regulated rate as part of OPG's regulated hydroelectric assets. An equivalent Power Purchase Agreement (PPA) Price estimated for the incremental energy output is 6.7 ¢/kWh (2011$) and compares favourably with the approximately 8.0 ¢/kWh (2011$) PPA rate offered under the recent RFP for renewable energy development. Other project financial metrics and sensitivities are presented in the Financial Analysis section of this BCS.

2. SIGNATURES

Submitted by:

Emad Elsayed — Aug 8/05
Emad Elsayed — Date
Vice President
Niagara Tunnel Project

Reviewed By:

Jim Burpee — Aug 8/05
Jim Burpee — Date
Senior VP
Energy Markets

Approved By:

Donn Hanbidge — Aug 9/05
Donn Hanbidge — Date
Chief Financial Officer (Acting)

Approved By:

Jim Hankinson — Date
President and CEO

3. BACKGROUND & ISSUES

Background

- The Sir Adam Beck (SAB) hydroelectric complex at Niagara consists of two generating stations (SAB1 and SAB2), and a pumping / generating station (SAB PGS). SAB1 and SAB2 have a total generating capacity of 1,960 MW. SAB PGS has a capacity of 174 MW and is generally utilized to pump / store water during off-peak periods for use during periods of peak electricity demand. The SAB complex currently produces average annual energy output of approximately 12 TWh.

- The Niagara Tunnel development is a unique, site-specific opportunity for OPG to produce additional, low-cost, renewable and environmentally sustainable energy for its customers, enhancing the existing Sir Adam Beck – Niagara hydroelectric facilities in the efficient use of Niagara River flow available to Canada for power generation with a resultant 14% increase in average annual energy output.

- The Canadian streamflow share of the Niagara River has been calculated as ranging from about 600 to 3000 m^3/s, averages about 2000 m^3/s and exceeds the capacity of the existing SAB diversion facilities (canal and two tunnels) about 65% of the time.

- Feasibility studies for expansion of Ontario Hydro's hydroelectric facilities at Niagara commenced in 1982. Definition phase engineering and environmental assessment work started in 1988 and was suspended in 1993. The Environmental Assessment (EA) was submitted in March 1991 and approval was obtained on October 14, 1998.

- The Environmental Assessment (EA) approval was for the Niagara River Hydroelectric Development consisting of two new tunnels, an underground powerhouse and transmission improvements in the Niagara Peninsula. The EA approval provided Ontario Hydro with the flexibility to undertake the development in phases. A plan to proceed with only one tunnel was initiated in 1998, and tenders were called for detailed design and construction, but work was suspended in 1999 due to uncertain market conditions and imminent corporate reorganization. Expenditures in 1998/99 totalled $2.5 M and are included in the estimated total project cost. Earlier definition phase expenditures of $57 M on the Niagara River Hydroelectric Development were written off by Ontario Hydro.

- In November 2002, the Province announced that it had directed OPG to proceed with a new water diversion tunnel at Niagara and subsequently indicated a strong desire to have the project completed in the shortest possible timeframe.

- The timing for completion of the new tunnel is also linked to the required rehabilitation of the 83-year old SAB1 canal, which delivers over one third of the water used at the SAB complex. The canal rehabilitation work is expected to start in 2011 and will require taking the canal out of service for approximately 8-12 months. Having the new tunnel in place will avoid an energy generation loss of 2.7 to 4.0 TWh caused by the canal outage (depending on available Niagara River flow and outage duration).

- On June 24, 2004, the OPG Board of Directors approved a preliminary release of $10 M to conduct a Request For Proposal process and to carry out such preconstruction activities as OPG deems necessary. Commitments for this work, to the end of June 2005, total $8.7 M.

- Provisions of an agreement between the Niagara Parks Commission (NPC) and OPG, dated February 18, 2005 (which agreement forms part of the larger Niagara Exchange transaction concerning the long term disposition of water rights on the Niagara River), committed OPG to undertake remedial work at the retired Ontario Power and Toronto Power generating stations as part of reversion of these stations to the NPC and secured the agreement of the NPC that until 2056 it would grant water rights to no party other than OPG. An associated [redacted] settlement with

Fortis Ontario, approved by the OPG Board on February 8, 2005, secured an irrevocable assignment of the water associated with Rankine GS. These costs are included in the release estimate for the Project.

- Under Ontario Regulation 53/05, effective April 1, 2005, the Project will become part of OPG's regulated hydroelectric assets and OPG will be given a fair opportunity to recover prudently incurred costs through the regulated rates.

- OPG has been in discussions with the Province regarding financing for the project. However, formal agreement including cabinet approval is still pending.

Project Execution Strategy

- A Design / Build contracting approach was selected for the Niagara Tunnel Project to minimize Project duration, to capture contractor experience and innovations, to appropriately allocate project risks and to provide as much price certainty as practical for design and construction of the Project.

- The Design / Build Contract transfers most tunnel design and construction risks to the contractor and includes bonuses for exceeding the Guaranteed Flow Amount[1] (tunnel flow capacity) and for early Substantial Completion[2] (In-Service Date), and liquidated damages for failure to achieve the Guaranteed Flow Amount and late Substantial Completion.

- The proposal process followed to determine the preferred Design / Build Contractor for this undertaking included:
  - prequalification following receipt of seven responses to an international invitation for expressions of interest
  - an invitation to four contractor consortia to submit proposals
  - submission of proposals by three contractor consortia
  - proposal evaluation and negotiation
  - contract award based on the best value considering evaluation criteria that included the design and construction approach, cost, risk profile, tunnel flow capacity, schedule, project team, health and safety management, environmental management and quality management.

Regulatory Approvals & Third Party Agreements

- Conditions of the EA Approval have been addressed to the extent possible without contractor input regarding means and methods to be employed during construction.

- The Community Impact Agreement, signed with the host communities on December 23, 1993 addresses predicted impacts on tourism, roads, domestic water supply, and sewage treatment during construction of the Project and includes provisions for engagement of local contractors, suppliers and labour and for local road improvements.

- The Project incorporates work and associated costs required under terms of the agreement between the Niagara Parks Commission and OPG as described above.

Project Management

[1] Guaranteed Flow Amount means the tunnel flow capacity guaranteed by the contractor at the reference hydraulic head and the reference elevation of energy grade line defined in the Design / Build Agreement.

[2] Substantial Completion means work has progressed to the point where the tunnel facility is ready for use and is sufficiently complete to be used for it's intended purpose.

- A strong team has been assembled for management and execution of the Niagara Tunnel Project and includes:
  - The OPG Project Director empowered to ensure effective integration of internal and external resources and timely communications between the project team and other stakeholders
  - Other OPG personnel representing Niagara Plant Group, Water Resources, Law Division, Supply Chain, Corporate Finance, Real Estate, Health & Safety and Risk Management
  - Hatch Mott MacDonald (HMM), an Ontario-based consultant with considerable experience in tunnel design and construction, has been engaged as Owner's Representative and holds primary responsibility for project management, design review and construction oversight with Acres International providing assistance in the areas of geotechnical and hydraulic engineering and third party liaison
  - Torys has been engaged as external legal counsel and has been part of the core project team providing advice on contractual, procedural fairness, environmental, real estate and regulatory matters
  - Strabag AG (a large Austrian construction group, supported by ILF Beratende Ingenieure of Austria, Morrison Hershfield of Toronto, and Dufferin Construction of Oakville), the selected Design / Build Contractor, has extensive international experience in tunnelling and heavy civil underground works.
  - Expert consultants and contractors are engaged, as required, to provide support in areas such as project risk assessment, financial modeling, teambuilding, field investigations, surveying, etc.

- Decision authority for this Project remains with OPG and delegation will be in accordance with OPG's Organization Authority Register (OAR).

- A Project Execution Plan, currently focussed on pre-construction efforts, has been developed and issued to provide the framework for management of the Niagara Tunnel Project, and will be reviewed and revised as necessary during project execution.

- The favourable score of 115, achieved on the Construction Industry Institute's Project Definition Rating Index (PDRI) in April 2005, indicates a high likelihood that completed project planning will result in a successful project (less than 200 = within budget and schedule).

- OPG, with the assistance of URS (a specialist consultant), completed a comprehensive risk assessment (qualitative and quantitative) for design and construction of the Niagara Tunnel Project based on "The Joint Code of Practice for Risk Management of Tunnel Works in the UK", and the recommendations have been incorporated into the project including maintenance of the Risk Register by the Owner's Representative. The quantitative risk assessment provided the basis for establishing the required cost contingency and schedule contingency.

4. ALTERNATIVES AND ECONOMIC ANALYSIS

Investment Cost and Project Funding Assumptions:

- Key assumptions are documented in the Niagara Tunnel Project Model Support Documentation binder.
- The Project is estimated to cost $985 M, including the previously released funding.
- The Project will receive a 10-year "holiday" for Gross Revenue Charge (GRC) payments.
- The Project will be funded through financing arranged with the Province.

Base Case – Do Nothing (Not Recommended)

- The Do Nothing option would forego the opportunity for OPG to significantly increase average annual energy output from the Sir Adam Beck generating stations and underutilization of Niagara River water available to Canada for power generation would continue. In addition,

OPG commitments, under the Niagara Exchange Agreement, for remedial work at the retired Ontario Power and Toronto Power generating stations would continue to be required as part of the reversion of these stations to the Niagara Parks Commission. A write-off of about $37 M would be required to cover expenditures committed to date ($22.5 M) and remaining costs associated with the reversion of the Ontario Power and Toronto Power generating stations.

Alternative 1 – Design & Construct a Diversion Tunnel (Preferred Alternative)

- Design, construct and commission a new diversion tunnel to convey 500 m^3/s from the upper Niagara River to the Sir Adam Beck GS complex at Queenston using a design / build contracting approach developed to minimize the risk to OPG, optimize the additional diversion capacity, and achieve price and schedule certainty. The total cost for the Project is estimated at $985 M.

- **Appendix A** provides a more detailed breakdown of costs for the Project.

Financial Analysis

- While the Niagara Tunnel is expected to be part of OPG's regulated hydroelectric assets and receive a regulated rate reflecting cost recovery and a return on capital, it is appropriate to consider several financial metrics, as follows, to ensure that this is an economic investment relative to other generation options:

  - Levelized Unit Energy Cost (LUEC) represents the price required to cover all forecast costs, including a return on capital over the service life, escalates over time at the rate of inflation, and it permits a consistent cost comparison between generation options with different service lives and cost flow characteristics.
  - Equivalent Power Purchase Agreement (PPA) Price represents the price required if one were to bid the project into the renewable RFP. It is similar to LUEC except only 15% of the PPA escalates at the Consumer Price Index.
  - Revenue Requirement is a measure that represents the annual accounting cost of this project including an allowed return on capital employed. Revenue Requirement generally declines over time as the rate base is depreciated.
  - These metrics are equivalent in present value terms over the life of the asset and reflect full recovery of costs including a return on the investment.

Financial Analysis	Base Case	Alt.1
Initial or Remaining Costs (M$)	14	963
NPV (current year PV M$)	n/a	n/a
Impact on Economic Value (current year PV M$)		n/a
for Value Enhancing projects include:		
IRR (%)		n/a
Discounted Payback Period (years)		n/a
LUEC (¢/kWh in 2005$)		4.8
Equivalent PPA Price (¢/kWh in 2011$)		6.7
Revenue Requirement (¢/kWh in 2011$)		5.8
Revenue Requirement for OPG Baseload Hydroelectric (¢/kWh in 2011$) - Includes 10% Return on Equity	3.8	3.9

- The estimated equivalent PPA Price of 6.7 ¢/kWh (2011$) is approximately 84% of the estimated average PPA Price of 8.0 ¢/kWh (2011$) for the successful proponents in response to the Province's recent RFP for renewable electricity supply alternatives.

- Completion of the Project will result in a significant increase in average annual energy output from the Sir Adam Beck GS complex with only a marginal increase in the estimated regulated rate for OPG's hydroelectric assets.

- Key assumptions used in the financial analysis are listed in **Appendix B.**

Financial Sensitivity Analysis

- Financial sensitivity analysis of the Project is summarized below and indicates economic results that compare favourably with other future electrical energy supply options in Ontario, including recent submissions for renewable generation options.

Sensitivity Analysis [Jun-2010 In-Service Date]	Incremental Energy TWh	LUEC ¢/kWh in 2005$	Equivalent PPA Price ¢/kWh in 2011$	Revenue Requirement ¢/kWh in 2011$
Preferred Alternative	1.6	4.8	6.7	5.8
Water Availability				
Lower quartile for first 5 years of service	0.7[1]	5.4	8.1	n/a
Upper quartile for first 5 years of service	2.4[1]	4.2	5.5	n/a
Overall reduction of 5% in Niagara River Flow[2]	1.2	6.4	9.3	n/a
Higher Cost (+10%)	1.6	5.2	7.4	6.3
Shorter Service Life (30 year Life)	1.6	5.8	7.6	7.1
Elimination of 10 year Gross Revenue Charge Holiday	1.6	5.8	8.5	9.1
Other Renewable Supply			8.0	

(1) Calculated for the first 5 years of service only
(2) Annual flows assumed to be reduced by 5% each year, compared to historical flows for the life of the tunnel

- Overall, the project economics compare favourably against other renewable options. The sensitivity results indicate that the calculated equivalent PPA Price will continue to be competitive even under a range of pessimistic assumptions for water availability, project cost and service life.

5. THE PROPOSAL

- Enter into a fixed-price Design / Build Contract with Strabag AG to design, construct and commission a new diversion tunnel to convey approximately 500 m^3/s of water from the upper Niagara River to the Sir Adam Beck GS complex at Queenston. The concrete-lined tunnel will be approximately 10 km long and have an average internal diameter of 12.6 m. Flow will exceed the increased diversion capacity only about 15% of the time compared to the current 65%, and resultant incremental average annual energy output from the Sir Adam Beck generating stations is estimated at 1.6 TWh (14%). The project includes a new intake and associated modifications to the existing International Niagara Control Works, an outlet incorporating the emergency closure gate near the existing PGS reservoir, and removal of the PGS canal dewatering structure. The new tunnel will be in-service by June 2010 based on Project approval by the OPG Board in July 2005 and award of the Design / Build Contract by September 1, 2005.

- Extend the contract with Hatch Mott MacDonald, supported by Acres International, as Owner's Representative for project management, design review, geotechnical and hydraulic engineering, third party liaison and construction oversight.

- Execute remedial work required at the retired Ontario Power and Toronto Power generating stations related to the reversion of these stations to the Niagara Parks Commission (NPC) to secure agreement that the NPC will grant water rights to no party other than OPG.

- The estimated project cost of $985 M includes a negotiated firm price for the tunnel Design / Build Contract, agreed payments under the Community Impact Agreement, engineering estimates for Niagara Exchange Agreement costs, Owner's Representative costs, and OPG direct costs, and an overall contingency of approximately [redacted] to address project risks, including risks not transferred to the Design / Build Contractor.

- Provided that the Design / Build contract is awarded by September 1, 2005, the Substantial Completion (In-Service) Date guaranteed by the recommended Design / Build Contractor is October 2009, however a schedule contingency of approximately [redacted] is recommended to address potential schedule extension due to residual OPG risks primarily associated with differing subsurface conditions. This contingency brings the expected completion date to June 2010.

- The design / build contracting approach for a fixed-price proposal from qualified contractors will reduce the risk of construction cost and schedule over-runs, however, OPG has retained risks associated with differing subsurface conditions and included cost and schedule contingencies accordingly, as described above.

- The estimated project cost flow is as follows:

Project Cost Flow Estimate ($M) (Including Contingency)	To 2004	2005	2006	2007	2008	2009	2010	Totals
OPG Project Management	[redacted]							
Owner's Representative								
Other Consultants								
Environmental / Compensation								
Tunnel Contract								
Other Contracts / Costs								
Interest								
Total Project Capital	3.5	69.2	194.1	215.5	227.7	208.9	66.2	985.2
Costs Approved to Date	3.5	19.0						22.5

6. QUALITATIVE FACTORS

- Sustainable Energy Development
  - The new tunnel will enable increased generation at the Sir Adam Beck GS complex utilizing Niagara River flow available to Canada for power generation that exceeds the capability of the existing diversion system (canal and two tunnels), and reducing spill over Niagara Falls from approximately 65% to approximately 15% of the time.
  - Rehabilitation of Sir Adam Beck GS No.2, completed in April 2005, including overhaul or replacement of primary mechanical / electrical equipment, improving conversion efficiency, increasing discharge capacity by 11% and adding 194 MW (15%) of capacity increases the gap between the existing diversion capacity and generating station discharge capacity.
  - There is potential to upgrade units at Sir Adam Beck GS No.1 by 100 to 150 MW, including conversion of the 25 Hz units, and further optimize conversion efficiency of the additional water to be supplied by the Niagara Tunnel Project.
  - Completion of the Niagara Tunnel Project in advance of an 8 to 12 month outage required for rehabilitation of the Sir Adam Beck GS No.1 diversion canal will significantly reduce associated energy losses (2.7 to 4.0 TWh) and financial losses.

- Community, Government & Customer Relations
  - The Province, through the Ministry of Energy, has indicated a strong desire for the Niagara Tunnel Project to be completed in the shortest possible timeframe.
  - There is broad support for the project in the host communities.
  - There will be significant benefits to the local economy during the approximately 4-year construction period.

- Technical / Operational Considerations
  - The Niagara Tunnel design life is 90 years without the need for any planned maintenance.

- Health & Safety
  - Safety program / performance was a significant factor in contractor pre-qualification.
  - The Design / Build Contractor will be required to develop and implement comprehensive project site specific plans for construction safety and for public safety and security.

- Staff Relations
  - An agreement has been reached with The Society of Energy Professionals regarding "purchased services" required for the Niagara Tunnel Project.
  - Purchased Services Agreement discussions have been completed with the Power Workers Union.
  - In accordance with the Chestnut Park Accord Addendum, trades work has been assigned to the Building Trades Unions.
  - Electric Power Systems Construction Association (EPSCA) conditions apply to the performance of this work.

7. RISKS

- OPG, with the assistance of URS (a specialist consultant), conducted a comprehensive risk assessment (qualitative and quantitative) for design and construction of the Niagara Tunnel. Major project risks were identified through a series of workshops involving the project team and key stakeholders.
- A Risk Register and associated Risk Management Plan will be maintained throughout project execution to manage residual risks.
- Project risks, consequences, mitigation activities and residual risks are summarized in **Appendix C**.
- Based on risks identified and mitigation measures implemented, it has been determined that the contingency for OPG residual risks associated with the tunnel construction component of the Project, based on a 90% confidence level, is [redacted] and this provision has been included in the release estimate. The overall Project contingency included in the release estimate is [redacted]
- [redacted]
- The financial analysis completed for the recommended alternative is based on spending the entire cost and schedule contingency and is therefore considered to be conservative and robust.

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

Type of PIR	Target Project In Service Date	Target PIR Completion Date
Comprehensive	June 2010	December 2010

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Tunnel Capacity	500 m^3/s	500 m^3/s	Flow test using tracer transit time method.	Design / Build Contractor with oversight by an independent Chief of Test retained by OPG
In-Service Date	June 2010		Compared with contracted Substantial Completion Date and approved changes.	
Actual Cost	$985 M		Compared to the approved release.	

Responsibilities

- The OPG Project Director will be responsible for the execution of the Project, and will be responsible for the completion of the PIR.
- The PIR will be undertaken after Substantial Completion of the Project (within 3-6 months).

Project Execution Monitoring

- The OPG Project Director, with the assistance of the Owner's Representative, will monitor on an ongoing basis and summarize as part of the PIR:
  - Project costs to ensure there are no material variances,
  - Project schedule and Schedule Performance Index (SPI) to track progress and to ensure completion in accordance with the contract,
  - Compliance with legislation and project-specific permits and approvals including periodic audits and non-compliance reporting
  - Compliance with the Project Execution Plan including scope management, deliverables, program and resource management, execution, risk management and the handling of health and safety issues.

- Disruption to the local community is to be minimized and will be measured by the public reaction including the number of complaints received

- Oversight by the Major Projects Committee will include frequent updates and guidance provided to the project team at critical points of Project development.

Remedial Work at Ontario Power GS and Toronto Power GS

- Confirm the completion of remedial work required at the retired Ontario Power and Toronto Power generating stations and the subsequent reversion of these facilities to the Niagara Parks Commission.

Tunnel Flow Capacity Verification

- Verification will be completed using the tracer transit time method established by the International Electrotechnical Commission Publication 41 (IEC 41), with testing performed under the direction of a Chief of Test engaged by OPG, and witnessed by OPG and the contractor. This testing will be used to determine whether a bonus or liquidated damages apply relative to the contracted Guaranteed Flow Amount.

Project Financial Analysis

- Re-evaluate financial metrics and compare to Business Case Summary as applicable.

Lessons Learned

- Document over-all lessons learned for future improvement in other projects.
- Review effectiveness of the design and construction contract arrangements and how effectively they were implemented, including an assessment of any liquidated damages and bonuses paid.

ONTARIO POWER GENERATION

BUSINESS CASE SUMMARY

Niagara Tunnel Project (EXEC0007)
July 28, 2005 (Confidential)

ONTARIO POWER GENERATION	**PROJECT** **Summary of Estimate**	Date	14-Jul-2005
		Project #	**EXEC0007**

Facility Name:	
Project Title:	**Niagara Tunnel Project**

Estimated Cost in Million $

Year	2004	2005	2006	2007	2008	2009	2010	Totals	%
OPG Project Management	[redacted]								
Consultants									
Design & Construction									
Other Contracts / Costs									
Interest									
Contingency									
Totals	3.5	69.2	194.1	215.5	227.7	208.9	66.2	985.2	100.0

Notes:

1. Schedule — Start Date: June 2004; In-Service Date: June 2010
2. Interest and Escalation rates are based on current allocation rates provided by Corporate Finance
3. Includes Removal Costs of: **n/a**
4. Includes Definition Phase Costs of: **n/a**
5. Percentages above relate to the total cost.

Prepared by:	**Approved by:**
R.A. Everdell Project Support Manager	E.E. Elsayed Vice President – Niagara Tunnel Project

Appendix B:
Niagara Tunnel Financial Model – Assumptions

Following are the key assumptions used during the modeling of the Niagara Tunnel Project.

Project Cost Assumptions:

1. Design/Build contract costs of [redacted] which include [redacted] for contingency and GFA (Guaranteed Flow Amount) bonus allowance
2. Other cost of [redacted] which include [redacted] for contingency
3. Interest during Construction (IDC) of [redacted]

Financial Assumptions:

1. Debt Rate of 6%
2. Return on Equity (ROE) of 10%
3. Debt Ratio of 55%

Project Life Assumptions:

1. Substantial Completion Date provided by the proposed Design/Build contractor of Oct, 2009. [redacted]
2. The tunnel life is 90 years

Energy Production Assumptions:

1. The tunnel will contribute an additional ~1.6 TWh/yr to the production at the SAB facilities
2. The tunnel will "re-capture" ~1.1 TWh during the SAB1 canal outage in 2011
3. Water transfers to NYPA, consistent with historical conditions, were incorporated into the calculation of the incremental energy output.

Operating Cost Assumptions:

1. When energy production begins OPG will realize a 10 year holiday on Gross Revenue Charge (GRC)
2. Annual OM&A costs of ~$.1M

Appendix C – Project Risk Profile

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigation Activity	Risk After Mitigation
Cost				
The contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Report (GBR)	Unexpected, adverse subsurface conditions could slow tunnel construction and require the contractor to undertake remedial / extra work resulting in legitimate claims for extra costs and / or schedule extension for differing subsurface conditions (DSC).	High	• The GBR is based on extensive field investigations carried out over a 10-year period and knowledge gained through construction of the existing SAB2 tunnels. • The 3-stage GBR process used facilitates contractor input and concurrence before construction begins. • [redacted]	Medium
Insurance coverage is inadequate or unavailable because underground construction has developed a reputation for cost over-runs and a negative perception from insurers.	Establishing an Owner Controlled Insurance Program (OCIP) to mitigate insurable risks for OPG, the Owner's Representative, the contractor and affected third parties.	Medium	• Engagement of key underwriters through project presentations. • Following, in principle, the UK Code of Practice for Risk Management of Tunnel Works. • A conservative estimate for insurance costs is included in the release estimate.	Low
The design / build contractor may not complete the tunnel due to non-performance or default.	OPG would need to engage another contractor to complete the tunnel construction.	Medium	• Requirements in the design / build contract for the contractor to provide bonds and / or letters of credit as security for non-performance or default. • Requirements in the design / build contract for the contractor to provide a parental guarantee.	Low

Appendix C – Project Risk Profile

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigation Activity	Risk After Mitigation
Scope				
OPG triggers variations in the scope of work.	Significant scope changes initiated by OPG could add significant cost and extend the project schedule.	Low	• Credible potential changes are limited because of the configuration of project and contracting approach. • The change control process is documented in the PEP and includes a Change Control Board comprised of OPG and Owner's Representative senior managers.	Low
Schedule				
Inability to meet environmental approval conditions in a timely manner.	Schedule delays could result from late submissions, unforeseen requirements or inability to satisfy stakeholder requirements.	Medium	• Proactive engagement of regulatory authorities • Use of a tracking system containing a comprehensive list of required permits and approvals. • Regular meetings with Ministry of Environment staff to review status and address outstanding issues. • The release estimate includes provisions to address outstanding issues (Welland River).	Low
Delay in manufacturing and / or delivery of the tunnel boring machine (TBM).	Potential delays in TBM manufacturing, delivery or assembly will be on the critical path for this project and will affect the overall project schedule.	Medium	• Schedule set by the Design / Build Contractor. • Contract provisions including liquidated damages for project delays and performance bond for default. • OPG / Owner's Representative will monitor progress at the TBM manufacturer's facilities.	Low
Inadequacy of the TBM and support systems to achieve required excavation and lining productivity.	Poor performance of the TBM, including frequent breakdown, could delay the completion date, increase the project cost.	Medium	• Design / Build Contract includes liquidated damages for late Substantial Completion valued to include incremental OPG costs and lost energy production for a period of about 16 to 18 months.	Low

Appendix C – Project Risk Profile

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigation Activity	Risk After Mitigation
Resources				
OPG resources with knowledge and experience required for design and construction of a major tunnel are severely limited.	OPG resource limitations could have significant impacts on project quality, cost and schedule.	High	• OPG has engaged Hatch Mott MacDonald, an Ontario based consultant with considerable tunnel design and construction management experience, as Owner's Representative for this project. • The design/ build contracting approach, engaging internationally-experienced tunnelling experts, will provide the necessary engineering and construction expertise.	Low
There is potential for a shortage of skilled construction labour resources qualified for performance of major tunnel construction by TBM.	A shortage of required construction labour resources, primarily operating engineers and labourers, could result in higher costs for imported labour or schedule extension.	Low	• The workforce required is relatively small and the contractor is expected to fill key positions with experienced, regular staff, reducing the likelihood that construction labour resources will limit tunnel construction progress.	Low
Technical				
Queenston shale, the host rock formation for the majority of the tunnel, has swelling properties when exposed to fresh water.	Swelling of the Queenston shale surrounding the tunnel could over-stress the tunnel lining and cause damage that would interrupt flow through the tunnel and require expensive remedial work.	High	Because this kind of damage could take decades to develop, penalties, warranties or holdbacks are impractical. Instead this risk is being mitigated through conservative, mandatory engineering specifications for aspects of the tunnel design related to rock swelling.	Low

Appendix C – Project Risk Profile

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigation Activity	Risk After Mitigation
Design / Performance Criteria Not Met	The constructed tunnel may not meet design / performance criteria such as the guaranteed water flow capacity, accommodation of swelling of the host bedrock, particularly Queenston shale, or design for a 90-year service life.	High	• Mandatory design requirements established by OPG / Hatch Mott MacDonald. • Design Review by an experienced Technical Review Committee. • Design / Build Contract includes liquidated damages for failure to achieve the agreed diversion capacity (Guaranteed Flow Amount) valued to compensate OPG for the reduced energy production throughout the 90-year service life. • Performance / warranty bonds and / or letters of credit provided by the Design / Build Contractor.	Low
Environmental / Regulatory				
Delay in obtaining Regulatory Approvals and Permits	Delay in obtaining required permits, failure to identify required permits or legislative changes requiring new or revised permits have the potential to extend the project schedule.	Medium	• Regulatory risks are relatively low because Environmental Assessment approval was obtained in 1998 and it is expected that outstanding conditions of the approval will be resolved before tunnel construction commences.	Low
Inability of OPG to fully recover the project costs through the Regulated Rate	Adverse financial impact on OPG	Low	• Demonstrate prudence in managing project cost through a comprehensive cost control process • Project costs include a contingency allowance which corresponds to a 90% confidence level that the project will be completed within the estimated costs.	Low

Appendix C – Project Risk Profile

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigation Activity	Risk After Mitigation
Health & Safety				
Serious Construction Accident	There are many safety hazards associated with tunnel construction that need to be identified and appropriately managed (steep grades, slips and falls, falling objects, water hazards, confined space, truck traffic, operating machinery, noise, dust, etc)	High	• Safety program / performance was a significant factor in contractor pre-qualification • Contractor required to develop and submit an acceptable comprehensive site specific safety plan prior to start of construction activities • Safety accountabilities clearly identified • Site safety monitoring by the Owner's Representative.	Low
Public Safety and Security	Risk of incidents, accidents and potentially fatalities to unauthorized persons entering the construction site and gaining access to areas and activities having High MRPH hazards.	High	• Contractor to implement an approved site-specific Security, Public Safety & Emergency Response Plan that is consistent with the Niagara Plant Group's managed system. • Site safety monitoring by the Owner's Representative.	Low
Fire in the tunnel during construction	Health & Safety of construction personnel (and visitors) could be endangered and there could be significant schedule and cost impacts depending on the extent of damage.	Medium	• Contractor to implement an Emergency Response Plan and provide adequate ventilation. • Contractor to provide back-up power supply, a dedicated water supply, and trained personnel to facilitate fire fighting in the tunnel during construction. • Project insurance will cover repair of damages.	Low

Appendix C – Project Risk Profile

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigation Activity	Risk After Mitigation
Investment				
OPG has retained the hydrologic risk (uncertainty regarding Niagara River flow).	Incremental average annual energy output from the SAB complex could be less than 1.6 TWh resulting in a need to increase base load hydroelectric energy rates to recover project costs.	Medium	• Financial sensitivity analyses demonstrate that the Niagara Tunnel Project remains competitive with future renewable electricity supply options if less water is available throughout the expected service life. • Being part of OPG's regulated hydroelectric assets, the hydrologic risk is expected to be borne by electricity customers through the water variance account.	Low
A successful claim by others in Canada or the United States to use Niagara River water available for power generation that exceeds OPG's capacity.	OPG could lose rights to use some of the Niagara River water available for power generation.	Medium	• Under the terms of the Niagara Exchange Agreement, the Niagara Parks Commission provided covenants securing the assurance of NPC that it would grant water rights to no party other than OPG through 2056. • Complete the new tunnel so OPG has adequate facilities to utilize Canada's entitlement to water available for power generation to reduce the risk of a claim by others to unused water.	Low
The 1950 Niagara Diversion Treaty is now subject to renegotiation following a 1-year notice period.	The government in either Canada or the United States could pursue renegotiation of the 1950 Treaty to address issues raised by other stakeholders that could result in a reduction of flow available to OPG for power generation at the SAB complex.	Low	• No mitigation possible.	Low

Appendix C – Project Risk Profile				
Description of Risk	**Description of Consequence**	**Risk Before Mitigation**	**Mitigation Activity**	**Risk After Mitigation**
Other				
Failure to adequately address public / community issues concerning the Project.	OPG's reputation could be damaged by negative public reaction to the Project.	Medium	• Implementation of the Community Impact Agreement (tourism, traffic, noise & dust, etc). • Regular public communications. • A Project website maintained with current information. • A Project hotline to receive public concerns / feedback, including timely response.	Low

Ontario Power Generation – Project Summary

Project Name:
R.H. Saunders Generating Station – Replace Heating, Ventilating, and Air Conditioning ("HVAC") System

Project Number:	Project Category:	Project Type:
H-97-1864	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☒ Capital ☐ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
May 2007	May 2008

Project Description:

This project includes the replacement of the HVAC system in the administration building, and the removal of asbestos insulation on the associated piping and air handler units.

Project Need (i.e., justification for the project):

The primary objectives/drivers of this project are to:

- Eliminate the increasing cost of repairs. The HVAC system is original to the station and is experiencing an increasing rate of component failure and piping leaks.
- Replace two HVAC chillers and refrigerant to comply with tabled Ministry of Environment legislation.
- Eliminate the health risk of staff exposure to designated substances (asbestos and red lead) in the existing HVAC system.
- Eliminate the risk of possible production losses due to potential HVAC system leaks in the administration building generator control and supervisory areas.
- Achieve the energy efficiency associated with a new HVAC system.

Project Costs:

	LTD Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total
Capital	$ 0.3 M	$ 0.2 M	$ 8.0 M	$ 3.0 M			$ 11.5 M
OM&A							

Initial Release Amount:	Current Release Amount:	Variance (Current Release – Initial Release):
$ 7.6 M	$ 11.7 M	$ 4.1 M

Variance Explanation (required if current release - initial release >10 percent of initial release):

In 2004, a consultant was retained to provide the HVAC system design, specifications, project schedule, project estimate, and bid package for tendering. Based on the consultant's estimate the project was approved for the initial release amount of $7.6M. In October 2006, contractor bids were received, which were considerably higher than the cost assumed in the project release estimate. The variance of $4.1M is mostly due to these external contractor costs. A number of factors have been identified as causes of the cost increase:

- Additions to the work scope during the tendering period that were not part of the original estimate.
- There was a one year gap between the completion of the project estimate by the consultant and the receipt of project bids. Economic factors in effect during that period led to a rapid rise in material and labour costs.
- The original project cost was underestimated.

Ontario Power Generation – Project Summary

Project Name:
Sir Adam Beck I Generating Station – Unit G9 Upgrade

Project Number:	Project Category:	Project Type:
SAB10047	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☒ Capital ☐ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
January 2008	December 2009

Project Description:

This project includes: a new generator (with related excitation and governor equipment), a new transformer, new breakers, and new efficient turbine runner. This project will be coordinated and approved with an overhaul of the remaining turbine components (SAB10048), at a cost of $0.8M (not reflected in the costs below). The design and work scope is expected to be similar to the frequency conversion of Unit G7, planned for 2008.

The project is expected to return Unit G9 to its full operating capacity (it is currently de-rated by 30 percent or 10 MW), and provide a further 4.5 MW increase due to the more efficient turbine runner.

Project Need (i.e., justification for the project):

Unit G9 is in poor condition and can no longer be counted on to provide reliable long-term operation; there are substantial issues with major components of both the generator and the turbine. Although frequent maintenance and continual attention have enabled continued operation, the equipment issues are substantial enough that they should be resolved through unit rehabilitation.

Unit G9 has not had a major rehabilitation since 1974 and is substantially degraded. Very high vibration levels and unit balance issues have resulted in restricting the generator to 70 percent output. Further deterioration and eventual failure is expected. Allowing Unit G9 to fail from service does not permit maximum utilization of Niagara River flows when additional water will become available to the Sir Adam Beck generating stations through the new Niagara Tunnel.

Project Costs:

	LTD Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total
Capital				$6.0 M	$ 23.0 M	$ 1.0 M	$ 30.0 M
OM&A							

Initial Release Amount:	Current Release Amount:	Variance (Current Release – Initial Release):

Variance Explanation (required if Current Release - Initial Release >10% of Initial Release):

Ontario Power Generation – Project Summary

Project Name:
Sir Adam Beck I Generating Station – Unit G10 Upgrade

Project Number:	Project Category:	Project Type:
SAB10050	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☒ Capital ☐ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
August 2009	December 2010

Project Description:

This project includes: a new generator (with related excitation and governor equipment), a new transformer, new breakers, and new efficient turbine runner. This project will be coordinated and approved with an overhaul of the remaining turbine components (SAB10051), at a cost of $0.8M (not reflected in the costs below). The design and work scope is expected to be similar to the frequency conversion of Unit G7, planned for 2008. The installation of a new more efficient turbine runner is expected to increase the capacity of the unit by up to 10 MW.

Project Need (i.e., justification for the project):

Unit G10 is near the end of its useful life. It was converted to 60 Hz and underwent a major mechanical overhaul in 1956. The turbine runner was replaced in 1986. However, recent inspections have revealed significant cavitation damage in the turbine. The generator is also in a deteriorated state, and the existing electrical equipment (e.g., breakers, transformer) currently do not have the capability to accommodate the anticipated increase in turbine capacity.

Further deterioration and eventual failure is expected. Allowing Unit G10 to fail from service does not permit maximum utilization of Niagara River flows when additional water will become available to the Sir Adam Beck generating stations through the new Niagara Tunnel.

Project Costs:

	LTD Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total
Capital				$ 0.5 M	$ 6.0 M	$24.5 M	$ 31.0 M
OM&A							

Initial Release Amount:	Current Release Amount:	Variance (Current Release – Initial Release):

Variance Explanation (required if Current Release - Initial Release >10% of Initial Release):

Ontario Power Generation – Project Summary

Project Name:
Sir Adam Beck I Generating Station – Rehabilitate Canal Lining

Project Number:	Project Category:	Project Type:
SAB10056	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☒ Capital ☐ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
June 2009	December 2011

Project Description:

The canal rehabilitation work consists of the following:

- Repair the eroded uppermost portion of the concrete liner near the water level to prevent further erosion and to ensure a smooth flow of water.
- Repair the deteriorated 1920's concrete walls above the water to restore integrity and prevent failure of overlying walls and soil slopes.
- Apply a concrete liner on the rock walls above the existing concrete liner/walls to prevent further weathering and rock falls, and to maintain the stability of walls and slopes above.

The condition of the concrete walls and floor below the water are unknown at this time and will be investigated in a definition phase study prior to the release of this project.

The timing of this project has been coordinated with the completion of the Niagara Tunnel project in order to minimize the production losses associated with removing the canal from service.

Project Need (i.e., justification for the project):

The open cut canal is one of three major water paths to the Sir Adam Beck generating stations delivering approximately 600 cubic metres per second. It has a total length of 20.75 km, with an average water depth of 9 to 11.5 metres. It was built prior to 1920 in order to supply water to the Sir Adam Beck I Generating Station. The canal last underwent a major rehabilitation in 1964.

In general, the canal liner is in poor condition. A collapse of any portion of the canal liner wall could result in significant production losses and negatively impact to the City of Niagara Falls' water supply.

Project Costs:

	LTD Actual	2006 Actual	2007 Budget	2008 Plan	2009 Plan	Future Plan	Total
Capital					$ 0.5 M	$ 50.5 M	$ 51.0 M
OM&A							

Initial Release Amount:	Current Release Amount:	Variance (Current Release – Initial Release):

Variance Explanation (required if Current Release - Initial Release >10% of Initial Release):

SIR ADAM BECK 1 GS UNIT 7

G7 GENERATOR FREQUENCY CONVERSION FROM 25HZ TO 60HZ

Project Number: SAB10032

Niagara Plant Group

SIR ADAM BECK 1 GS UNIT 7

G7 GENERATOR FREQUENCY CONVERSION FROM 25HZ TO 60HZ

SAB10032

RECOMMENDATION

Approve the release of $ 33.4 M for the conversion of the 25 Hz G7 unit to a new 60 Hz unit. This will return G7 to service and increase the installed capacity of Sir Adam Beck 1 GS (SAB 1) by 68.5 MVA. (61.5 MW). G7 will optimize energy production by efficiently utilizing the water available to the Sir Adam Beck Complex, including water availability from the Niagara Tunnel. This generation will be incremental to the 1.6 TWh of generation identified in the Niagara Tunnel Project Business Case in July 2005.

The energy generation from G7 will be possible by increased use of the Pump Generating Station (PGS) to shift energy from off-peak to on-peak, increasing capacity output of the SAB facility.

This project is consistent with OPG's objective of continuing to optimize production from its existing hydroelectric generating assets. The unit is expected to produce an incremental 99 GWh annually.

With equipment upgrades, it is expected that current technology and materials can provide improvements in efficiency. Competitive bids have been obtained for the installation of a new 68.5 MVA, 60 Hz generator. The upgraded G7 is scheduled to be commissioned and placed into service by March 2009.

This project is identified in the current approved business plan with cash flows in 2007 and 2008. A developmental release of $1.8M has been approved. The total project cost will be $35.2M.

$000s	2007	2008	2009	Total
Currently Released	1,800			1,800
Requested Now (Full Release)	6,100	23,364	3,946	33,410
Total Project Costs	7,900	23,364	3,946	35,210
Investment Type	**Class**	**NPV**	**IRR**	**Discounted Payback**
Value Enhancing	17	7,091 (using SEVs)	11.9% (using SEVs)	21 years (Using SEVs)

Investment Financial Measure: The increased energy output resulting from the Project will receive a regulated rate as part of OPG's regulated hydroelectric assets. This project will be included as part of the OPG rate submission to the Ontario Energy board.

2. SIGNATURES

Submitted by:

29 May 2007

John Murphy
Executive Vice President - Hydro
Date

Recommended by:

Aug 15/07

Pierre Charlebois
Senior Vice President and
Chief Operating Officer
Date

Finance approval:

Aug 17/07

Donn Hanbidge
Senior Vice President and
Chief Financial Officer
Date

Line Approval:

Jim Hankinson
President and CEO
Date

3. BACKGROUND AND ISSUES

Sir Adam Beck 1 GS (SAB 1) is a ten unit station located on the Niagara River. It was placed in service in 1922 and has seven 60 Hz generating units and three 25 Hz generating units. The station currently has a total capacity of 447 MW, an annual energy production of approximately 1,670 GWh and 2005 production revenue of $55.1 million (at $33/MWh).

SAB 1 G7 is a 25 Hz unit. In 2005 the Johnson valve that controls the water flow to the G7 turbine failed, and because OPG's obligation to the 25 Hz market could be met by the SAB 1 GS 25 Hz units G1 and G2, G7 was decommissioned. G7 was subsequently deregistered with the IESO.

As of April 2009, the IESO will end the 25 Hz energy market and 25 Hz power will have no market value. There is no future benefit to having G7 available to generate 25 Hz power.

Beginning in 2009, additional water will be supplied to the SAB complex by the new Niagara Tunnel. A new 60 Hz generating unit will make use of this additional water. Deferring this project will mean OPG will not make full use of the water diversion available.

Similar work involving the replacement of a 25 Hz generator with a new 60 Hz generator and associated components was carried out on SAB 1 G6 in 1994/95. Lessons learned and experiences acquired during that project have been incorporated into this project.

A life cycle plan for SAB1 is currently being prepared which will include the conversion of this unit, the plans for the other 9 units and the impact on the transmission system.

4. ALTERNATIVES & ECONOMIC ANALYSIS

Base Case (Status Quo): Leave SAB1 G7 Out of Service

This alternative does not make use of the water available for generation and does not maximize the generation of hydroelectric energy.

- **This alternative is not recommended.**

Alternative 1:

Install a new 68.5 MVA (61.5 MW capacity) 60 Hz Generator, Transformer, Headgates, Runner, and Upgrade the Turbine

This alternative brings to service a 61.5 MW capacity hydroelectric generating unit that optimizes the use of the water available. It includes a new generator with new protections and controls, a new exciter and digital governor head, new switchgear, new headgates, a new transformer and removal of the failed internal components of the Johnson valve. It also includes a new efficient runner and a turbine upgrade.

- **This is the recommended alternative**

Alternative 2:

Install a 56.7 MVA (51 MW Capacity) 60 Hz Generator, Transformer, Headgates, Upgrade the Turbine and Re-use the Existing 70-year-old Runner

This alternative is rejected because it does not optimize the use of the water available. Re-using the existing runner, which has an output of approximately 51 MW, limits the size of the new generator to 51 MW, well below the optimal size.

- **This alternative is not recommended.**

Financial Analysis:

$ Million's	Base Case	Alt 1 (recommended)	Alt 2
Project Cost	0	35.2	34.0
NPV (after tax)	0	7.1	2.5
Impact on Economic Value	0	7.1	2.5
IRR %	0	11.9	10.7
Discounted Payback (Yrs)	n/a	21	31

The NPV calculations are conservative as they exclude some potential benefits.

Additional generation available at the Beck Complex is considered to have a capacity benefit, as it would likely displace other more expensive generation at peak times. However, due to the variety of operational parameters and water constraints during peak months of the Beck Complex, it is very difficult to quantify the capacity benefit with a high degree of precision. They have therefore been excluded to be conservative. To put this into context, a conservative estimate of 5 MW would increase the NVP to $8.8M, and a capacity benefit of 20 MW would increase the NPV to $14.0M.

The Beck Complex is often operated for operating reserve and paid through an operating reserve revenue stream. The NPV calculations do not include that benefit as this value is determined at the time of operation depending on system requirements, and how the units are required to operate.

In a rate regulated environment, OPG will receive market prices for any generation exceeding 1,900 MW from the regulated hydroelectric fleet. The addition of G7 will allow generation above 1,900 MW on a more frequent basis. Because this level of generation can not be assured, a conservative approach has been taken and the quantitative benefit has not been included.

The breakeven levelized Unit Energy Cost (LUEC) for this project over a 50 year period is $43.32/MWh. This is lower than the recent OPA contracts that are > $70/MWh.

The Sir Adam Beck facilities are part of OPG's regulated hydroelectric fleet. A Power Purchase Agreement cannot be obtained for this generation. This project will be included in the OPG rate regulation submission. The impact on regulated rates required to recover the costs of this project is expected to be approximately 0.07%

5. THE PROPOSAL

Results to be delivered:

Construct a new SAB1 G7 generator to supply 60 Hz power to the Hydro One connection point. The generator is scheduled to be commissioned by the end of March 2009. The resulting generation capacity will provide an average of 99GWh annually and increase the Beck Complex's ability to provide operating reserve as well as provide assistance with EBG on the system.

This project includes the removal of the existing 54 MVA, 25 Hz, G7 generator and the supply and installation of a new generator, a new transformer, new headgates and a new runner and the upgrade of the turbine and the remaining associated unit components.

Runner

The existing runner dates from 1936. It was last inspected in 2001 and reported to be in good condition but with some cavitation and pinholes in the stainless steel overlay.

Preliminary engineering analysis indicates that power available through the G7 water conveying structures is in excess of 58 MW. The existing runner is rated to produce only approximately 51 MW of power. The existing runner is, therefore, unable to fully utilize the available water.

A contract has been awarded for runner design, runner model development and model testing for new runners for SAB 1 GS. Preliminary engineering indicates that a new runner with an efficiency of approximately [redacted]% and a corresponding output of 58 MW, at efficiency, can be supplied by the runner manufacturer as part of the purchase option OPG has retained.

Generator:

A new 68.5 MVA (61.5 MW capacity), 60 Hz generator can be installed to match the maximum power output of a new runner.

With a new generator and new runner, G7 will have a high efficiency and will generally be the first unit on / last unit off at the station to maximize generation. The expected annual energy production for SAB 1 will increase by 99 GWh annually on average.

Transformer

The replacement of the 25 Hz generator with a 60 Hz generator necessitates the replacement of the three existing 25 Hz transformers. The existing transformers are in fair condition and the best one will be kept as a spare for Units 1 and 2.

The existing transformer will be replaced with a new 60 Hz, three phase, water-cooled transformer.

Turbine Upgrade

The last significant amount of work on the G7 turbine was carried out in 1975. The normal interval between such work is 25 to 30 years. The turbine upgrade will be performed while the unit is dismantled for the installation of the new runner and new generator. The scope will include the modification of the discharge ring and the installation of greaseless bushings.

Johnson Valve and Headgates

Each generating unit at SAB 1 generating station was built with a Johnson valve to control water flow to the unit. Following the SAB 1 G4 Johnson valve failure in 1999, an engineering study concluded that the Johnson valves had reached the end of their service life and could no longer be relied on to control water flow to the units. A program to remove the internal parts of the Johnson valves and to replace the functionality of the Johnson valves with headgates was initiated. To date, the other 9 units at the station have had this work done.

Other Major Items In Scope

The existing governor control head is at the end of its service life. Replacement parts are not available. The governor head will be replaced with a new digital control head.

A new exciter will be supplied for the new generator.

New switchgear will be supplied for the new generator.

Upgrades to the generator output buswork and to the electrical connections to the Hydro One system are required.

Assessments by both Hydro One and the IESO are required prior to connecting new generation to the Ontario Grid. Agreements have been made with both parties, and

funding provided in the developmental release to carry out the studies in order to maintain the project schedule.

Ongoing Operational and Maintenance Cost Impacts

Ongoing operation of the converted unit will be absorbed in the existing operation and support infrastructure of the facility. Non standard maintenance costs of $5k per year, ½ of maintenance FTE as well as a future unit overhaul have been included in the project NPV calculations. These costs will be included in future Niagara Plant Group Business Plans and budgets.

Qualitative factors

Trades work has been reviewed under the Chestnut Park Accord Addendum, and has been awarded to the Building Trade Unions (BTU).

Project activities will be conducted in accordance with Niagara Plant Group Environment, Health and Safety (EH&S) Management System

Project management

A Project Execution Plan identifying scope, schedule and cost has been developed for this project

The project will be executed by the Niagara Plant Group Project Management Department

Post Implementation Review (PIR)

A comprehensive Post Implementation Review will be conducted within 12 months of the date of the return to service of the unit.

The following unit performance parameters will be measured:

Turbine/ generator output: The Niagara Plant Group Production Department will verify that the generator output is 61.5 MW. Revenue metering equipment will be used to measure the output.

Runner performance: The runner performance with respect to cavitation will be assessed by the Niagara Plant Group Production Department and Hydro Engineering by making an inspection of the runner in accordance with the runner warranty details.

The Project Department will review the project by comparing the planned cost and schedule milestones as outlined in the Project Execution Plan to the actual cost and schedule milestones.

6. QUALITATIVE BENEFITS

Qualitative Factors & Sustainable Energy Development

- Installation of headgates at the top of the penstock provides increased level of safety for the powerhouse, staff, and environment in the event of a penstock failure.
- Combining the generator replacement, runner replacement, headgate installation, and turbine upgrade into one outage reduces total outage time, avoids repetitive dismantling and assembly of the unit.
- Increased production of renewable hydroelectric energy (61.5 MW, 99GWh annually).
- Increased efficiency of water use due to the upgraded runner.
- Environmentally friendly generation with virtually no additional environmental impact which will displace more costly and higher emitting fossil fueled facilities.

7. RISK ANALYSIS

See Appendix 2 for Risk Management Table.

Cost Risk:

There is a high level of confidence in the cost estimate for this project. Over 50% of the project estimate is based on quotes or budget estimates from suppliers and past purchase experience.

- The risk of over expenditure on the headgate work ($2.7M) is low because the work has been done in a satisfactory fashion nine times before by the same contractor.
- The generator design/ supply/ install, the largest single component of the project is a firm bid quotation.
- Preliminary price quotes have been obtained from known suppliers in an effort to develop accurate cost estimates.
- A contingency of 14% is included in the project cost estimate. The overall contingency has been prepared by adjusting contingencies by major item based on its unique risk characteristics.

Assumed Benefits (Generation) Risk:

In order to determine the energy generation potential of G7, historic Niagara River flows were reviewed. The amount of water available at the plant for G7, incorporating water from the new Niagara Tunnel, was determined and the seasonal peak/ off-peak timing of

this water was predicted. Historic water usage at the SAB Complex was extrapolated into the future and the amount of water available for G7 was determined. In order to optimize the water diversion, the Pump Generating station (PGS) was also optimized.

Schedule Risk:

The schedule is aggressive and there will be numerous contractors on site, raising the possibility of interference. This concern will be managed by closely scheduling and coordinating site work.

Supply/ Procurement/ Quality Assurance Risk:

The potential generator suppliers have been pre-qualified to reduce the risk of unsatisfactory contract performance.

Possible manufacture of runner and generator components overseas presents quality risks. Inspection and test plans are being utilized to monitor the product quality through the manufacturing process.

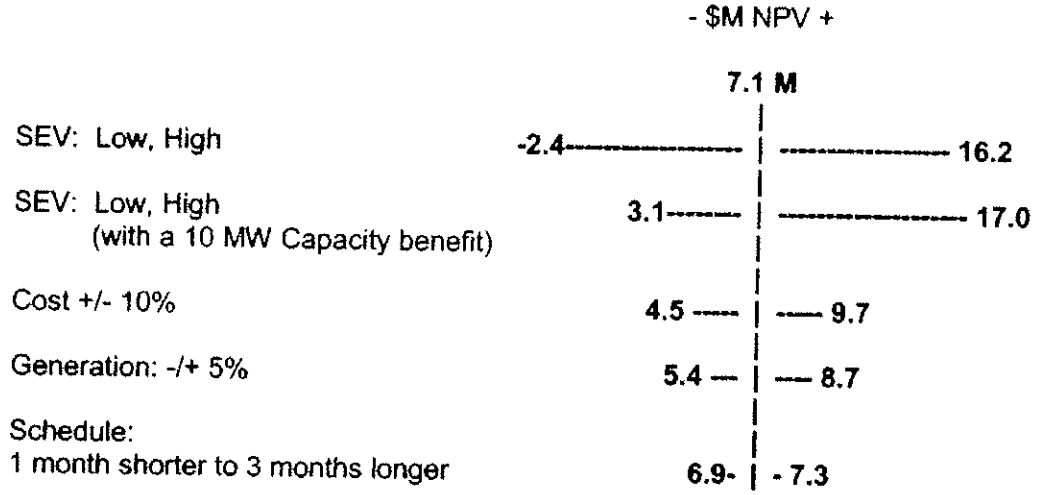
Graphical Representation of Risk using a Tornado Diagram:

The project is considered to be sensitive to the following variables:

SEV
Project cost
Generation
Project in-service date (project schedule)

A Tornado diagram has been constructed to assess the project NPV with the following variables and changes:

- Change to SEV: High and Low values
- Change to SEV: High and Low values, also including a capacity benefit in the NPV calculations equal to 20MW
- Project cost: + / - 10%
- Generation: - / + 5%
- In-service date: schedule shortened by 1 month / extended by 3 months



Schedule has relatively little impact on the NPV due to the seasonal characteristics of the generation from the unit and the timing of the scheduled in-service. Generation also does not have a large impact. The project cost also directly affects the NPV.

The project NPV is most sensitive to a variation in the SEV (market energy price). If a conservative capacity benefit of 20MW is included in the NPV calculation, the impact of low SEV's is greatly reduced, and will result in a positive NPV.

ONTARIO POWER GENERATION

HYDROELECTRIC Summary of Estimate

Date	March 14, 2007
Project #	SAB10032

Facility Name: Beck 1 GS

Project Title: G7 Generator Frequency Conversion from 25 Hz to 60 Hz

Years (k$)	2007	2008	2009	TOTAL	%
Project Mgmt.	446	594	149	1,189	3.4
Engineering	300	400	130	830	2.4
Permanent Materials	2,930	9,568	1,200	13,698	38.9
Construction/ Installation					
- Contractors	2,927	8,230	1,434	12,591	35.8
Interest	307	1,298	433	2,038	5.8
Contingency	990	3,274	600	4,864	13.8
TOTAL	7,900	23,364	3,946	35,210	100%

Notes:
1. Schedule — Start date: May, 2007
   In-service dates(s):
   Headgates, Johnson valve 9 % Jan. 2008
   Generator, balance of work 91% Mar. 2009
2. Interest and Escalation rates are based on current allocation rates provided by Corporate Finance
3. Includes Removal Costs of: 750 k$
4. Includes Definition Phase Costs of: 1,800k$

Prepared by:

Torben Frost
Project Engineer

Approved by:

John Conlon
Project Manager

APPENDIX 1

Assumptions

Financial Model

Following are the key assumptions used during the modeling of the Project:

Project Cost Assumptions:

1. Quotes from suppliers of major components were used if available.
2. Costs for other components and labour were based on costs for similar work carried out in the past with appropriate escalators applied.
3. Competitive bids can be received for the work to be contracted out.

Financial Assumptions:

4. In a non-regulated scenario, energy produced will provide revenue at the 2006 system energy values (SEVs).
5. The September 2006 Hydro FE Model, was used with a 2007 project start year.

Project Life Assumptions:

6. The project can start immediately after approval.
7. The project can be completed in 22 months and the generator can be commissioned in March, 2009.

Energy Production Assumptions:

8. Niagara River flow modeling tool accurately models the water available to the Beck plants.
9. Existing outage plans can be followed.
10. Generation at the Beck plants can be maximized while adhering to the market dispatches.
11. Historical forced outage rates will be typical in the future.

Operating Cost Assumptions:

12. The new unit will increase OM&A costs by 0.5 FTE (or equivalent cost of work contracted out).
13. On-going Non-Standard costs associated with the new unit will be minimal (5k per year)

APPENDIX 2

Risk Management Table for Full Project Release

Risk Category	Risk Description	Implications	Mitigation	Risk After Mitigation
Cost	**Electrical Systems - Hydro 1** - Extent to which OPG is responsible for changes to the Hydro one equipment	Cost: Uncertain – Costs will be firmed up as Hydro One completes their Customer Impact Assessment in November/ December 2007	Due to the uncertainty, include a [redacted] contingency to increase this amount to [redacted]	Low
Schedule	Will Hydro One accept 'E' bus? [redacted]	Schedule: Preliminary schedule from Hydro One indicates no impact, but this requires Hydro One to dedicate adequate engineering and construction effort	Approach Hydro One to start preliminary work on accelerated schedule	Medium
Schedule	**Electrical Systems - Hydro 1** to determine what changes they need to make to their system	Schedule: If changes required to Hydro One system are extensive, this may delay in-service date - by several months?	OPG to participate in outage planning and work coordination	Medium
Schedule	**IESO System Impact Assessment (SIA) and Hydro One Customer Impact Assessment**	Delays in completing the assessments could delay the ability to connect to the Ontario Grid resulting in lost opportunity.	The Developmental release has included funds to start both the IESO and Hydro One assessments	Medium
Schedule	**IESO System Impact Assessment (SIA) and Hydro One Customer Impact Assessment results in insufficient transmission Capacity to allow G7 to connect**	Should the SIA state that it is not possible to connect new generation to the grid, generation from G7 could be bottled.	SAB 1 has a common bus system. When G7 is completed, G9 will be at the end of its service life. Should capacity not be available on the transmission system, G9 will be taken out of service and not rehabilitated. G7 will be connected to the bus. (See appendix 5 for further discussion)	Low
Cost	**Generator removal** - costs currently based on G6 costs - current estimate $535k (not a quote)	Cost: Retaining existing foundation bolts may be challenging	Obtain competitive quotes from contractors Include adequate contingency	Low
Schedule		Schedule: Possible project delay	Schedule work appropriately. The unit is currently not operating, so the removal start is not restricted by outage requirements.	Low
Cost	**Generator foundation** - more work than what GE has anticipated in proposal	Cost: GE will have cost extras if they cannot use the existing foundation bolts as planned $50k - $100 k	Have GE inspect and approve foundation condition as soon as generator is removed Include adequate (50%) contingency on foundation work cost	Low
Schedule		Schedule: May delay in-service date - 3 weeks?		Low

Appendix 3

Major Component Cost Estimates

Unit Runner

American Hydro has been awarded a contract for runner design, runner model development and model testing for new runners for SAB 1 GS. Preliminary engineering indicates that a new runner with an efficiency of approximately [redacted]% and a corresponding output of 58 MW, at efficiency, can be supplied by the runner manufacturer.

OPG has the option to purchase a runner for unit 7 at a cost of $ [redacted]M.

New Generator

The design and build of a new generator is on the critical path for the project. Work must start in early 2007. GE was one of three vendors submitting proposals. Bids were evaluated with Supply Chain's involvement, and GE was selected to supply and install the new generator. A developmental release has been approved to allow GE to commit to this work, and to cover their cost incurred (up to $1M) should the project not proceed. A new generator, supplied and installed, will have a cost of approximately $12M.

Replacement of the existing 25hz Transformer

A new water cooled transformer, will cost $1.3m based on firm quotes received.

Turbine Upgrade

Upgrades to the turbine, to increase the power output, and modifications consistent with a 25 to 30 year maintenance cycle, will cost approximately $3.1M.

Johnson Valves and Head Gates

The removal of the internal components of the Johnson valves and installation of headgates has been completed on the other 9 units resulting in reliable work processes and cost estimates.
The internal components of the G7 Johnson valve will be removed and new headgates will be installed in the G7 headworks at a cost of $3.2M.

Governor Control head

A new governor head, supplied and installed, will cost approximately $460k.

Electrical system and Connection to Hydro One

This work will cost approximately $5.0M to upgrade electrical system up to the connection to Hydro One. [redacted]

[redacted]

IESO System Impact Assessment and Hydro One Customer Impact Assessment

The developmental release (approved) includes $30k funding to have the IESO complete a System Impact Assessment. This assessment is required prior to connecting any new generation to the Ontario Grid. Although G7 is part of the existing SAB1 complex, the unit was deregistered in 2005, and therefore requires this assessment.

In addition, the developmental release (approved) includes $15k funding for Hydro One to complete a Customer Impact Assessment which is required prior to adding additional generation to the transmission system.

New Exciter

A new exciter is required for the new generator and is expected to cost $[redacted]k.

New unit Switchgear

New switchgear is required for the new generator and is expected to cost $[redacted]k.

Appendix 4

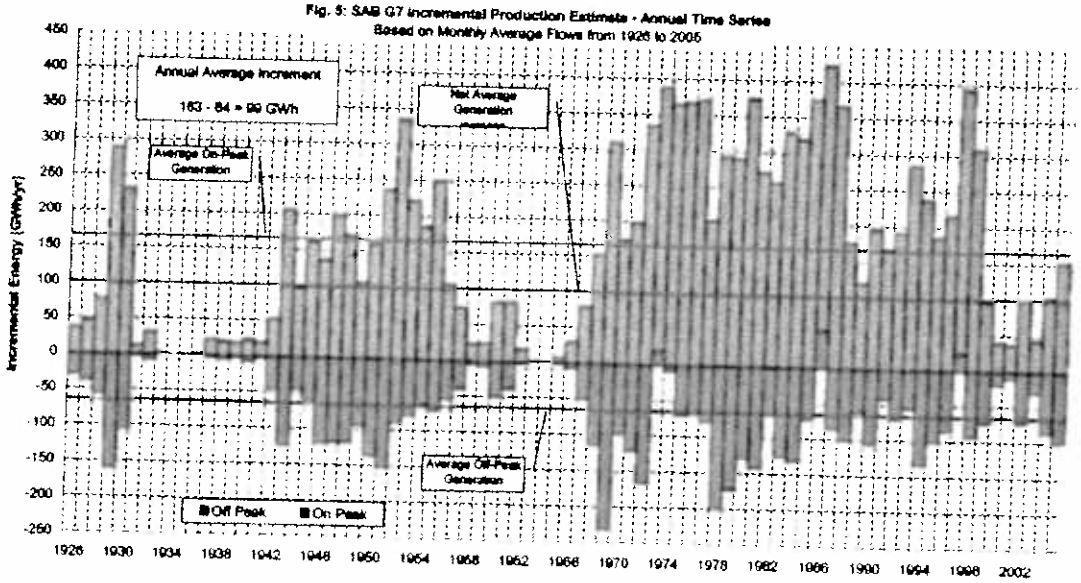
Impact of Tunnel Water on Generation with and without G7

The Niagara Tunnel project assumed the Beck complex will increase its generation on average by 1.6 TWh as a result of increased water diversion. This generation is derived from additional water delivered and an increased ability to utilize PGS to pump. The additional generation would be generated by all the units across the Beck Complex as the tunnel would increase water throughput for a greater period of time. At the time the Niagara Tunnel BCS was presented, G7 was operating as a 25 Hz unit. The Niagara Tunnel BCS was silent on the retirement of the 25hz system and did not contemplate the conversion of any 25 Hz units to 60 Hz. The additional generation was a function of the additional water at the existing station configuration.

To determine the possible generation advantage from the conversion of G7, the generation from the Beck Complex was modeled. Monthly average Niagara River flows from 1926 to 2005, were used to calculate corresponding average tourist and non-tourist hour diversion flows for future diversion capability conditions according to long-term average seasonal restrictions and a DeCew diversion assumption of 200 cms. The model included the new tunnel water as if it were in service for this period. The model was run with G7 not being in service, and with G7 being converted to 60 Hz operation.

Without the G7 conversion, the average annual generation would have been 12,762Gwh. With G7 rehabbed, the average annual generation is 12,861 GWh, for an average annual increase of 99 GWh. This is made up of 163 GWh of on peak generation, offset by -64 GWh of off peak generation, which is the generation required by PGS for pumping.

The graph below indicates the on peak and off peak generation that would have resulted with G7 in service for each of the years since 1926. The green line is the average Net of off-peak (red line) and On-peak (blue line)



Appendix 5

Risk Mitigation Strategy for Queenston Flow West Transmission Limitation.

The outcome of the IESO System Impact Assessment (SIA) will be known in June 2007 and the outcome of the Hydro One Customer Impact Assessment (CIA) will be known in the fall of 2007. There is a potential risk to the viability of the G7 project if the SIA concludes that the system cannot accept the additional station output provided by G7.

The condition of G9 is an important factor when discussing risks to the viability of the G7 project. G9 is currently operating at a reduced output due to its poor mechanical condition. It is scheduled to be removed from service for major repairs, or to be replaced by a new unit, as soon as G7 is placed into service.

G9 will be taken out of service and G7 can be connected to the station output bus and placed in service. The net effect on the transmission system, by this substitution of G7 for G9, will be minor.

Under the current SAB I unit outage strategy, appreciable capacity is not added to the transmission system until the first quarter of 2010 when SAB I G9 is returned to service. Therefore, there is a 3 year period in which the transmission limitation issue can be resolved. The 25 Hz market will also have ended by that time, and it may be possible to utilize the 25 Hz transmission system to help resolve this issue.

If the transmission system capability issue is not resolved by 2010, the timing of the rehabilitation of G9 will be reassessed and the project will be delayed until the transmission constraints are resolved.

The financial risk to the G7 Conversion Project is reduced to the incremental cost of the G7 project over the cost of the G9 project. This incremental cost is in the range of $3M to $10M.

Ontario Power Generation – Project Summary

Project Name:
Sir Adam Beck I Generating Station – Unit G3 Upgrade

Project Number:	Project Category:	Project Type:
SAB10064	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☒ Capital ☐ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
October 2009	January 2012

Project Description:

- This project includes: a new generator (with related excitation and governor equipment), a new transformer, new breakers, and new efficient turbine runner. This project will be coordinated and approved with an overhaul of the remaining turbine components (Project Number: SAB10075) at a cost of $1.0M. The design and work scope is expected to be similar to the frequency conversion of Unit G7, planned for 2008.
- The project is expected to increase the capacity of Unit G3 by 4.5 MW due to the more efficient turbine runner.
- The project is a major mechanical and electrical overhaul that will ensure the unit is capable of sustained production for 25 - 30 years until the next major overhaul.

Project Need (i.e., justification for the project):

- The Sir Adam Beck 1 G3 unit was last overhauled in 1985. Hydroelectric units of this type normally require major overhauls on a 25 - 30 year cycle to ensure continued operation. Unit G3 is in fair condition, but by 2011 will no longer be counted on to provide reliable long-term operation; there are issues with major components of both the generator and the turbine. Although frequent maintenance and attention have enabled continued operation, the equipment issues are substantial enough that unit rehabilitation is required.
- Turbine runner technology has advanced such that additional production may be obtained from the unit.
- Electrical capabilities of this machine are currently sufficient to permit additional production.
- Allowing Unit G3 to fail from service does not permit maximum utilization of Niagara River flows when additional water will become available to the Sir Adam Beck generating stations through the new Niagara Tunnel.

Project Costs:

	LTD Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total
Capital					$ 0.5 M	$ 31.0 M	$ 31.5 M
OM&A						$ 1.0 M	$ 1.0 M

Initial Release Amount:	Current Release Amount:	Variance (Current Release – Initial Release):

Variance Explanation (required if Current Release - Initial Release >10% of Initial Release):
N/A

Ontario Power Generation – Project Summary

Project Name:
Pump Generating Station - Dyke Foundation Grouting and other protective measures

Project Number:	Project Category:	Project Type:
SABP0022	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☒ Capital ☐ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
June 2008	December 2010

Project Description:
- Upgrade protective measures: i.e., foundation grouting, upstream clay blanket, and pressure relief systems which were implemented after the 1958 Pump Generating Station failure of the Dyke in order to sustain production of the Pump Generating asset.

Project Need (i.e., justification for the project):
- The Pump Generating Station dyke is a manmade dam that provides headpond impoundment for the Pump Generating Station station. The foundation at the site is the Lockport dolomite, which is susceptible to sinkhole formation. Sinkholes in turn may lead to piping, a phenomenon where water leaking through a dam begins to remove material from the dam. This process if left unchecked could result in a sudden dam failure. This dyke failed in 1958 as a result of piping through a joint in the bedrock.
- After the 1958 failure, a portion of the dyke was grouted, the upstream clay blanket was enhanced and pressure relief systems were installed. A monitoring program was put in place that continues to this day under the provisions of OPG's Dam Safety Program. Diving inspections carried out as part of this monitoring program have located sinkhole-like features and depressions in the bottom of the reservoir. In addition, the results of the last Dam Safety Periodic Review (2005) recommended that a detailed assessment of the protective measures against piping failure should be carried out at the Pump Generating Station. Detailed inspections and testing are scheduled for 2008 and 2009. At the end of the assessment the extent of the required grouting program will be determined.
- Grouting of a dyke foundation consists of boring a number of holes in the area of concern and then pumping a grouting material into those holes such that they form an impervious barrier to water seepage and particles migration. In general, this technology is complemented by enhancement to upstream clay blankets and pressure relief systems, as required. It is not expected that that the entire dyke requires grouting. The total project costs will be driven in large part by the extent of grouting required.

Project Costs:

	LTD Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total
Capital				$ 0.3 M	$ 0.7 M	$ 19.0 M	$ 20.0 M
OM&A							

Initial Release Amount:	Current Release Amount:	Variance (Current Release – Initial Release):

Variance Explanation (required if Current Release - Initial Release >10% of Initial Release):
N/A

Numbers may not add due to rounding.

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Table 1
Capital Project Listing - Regulated Hydroelectric
Projects >$10M Total Project Cost[1]

Line No.	Project Name	Project Summary Ref. No.	Category	Start Date	Final In-Service Date	Total Project Cost ($M)
	(a)	(b)	(c)	(d)	(e)	(f)
	Project summaries for the following projects are included in this section of the application					
	Niagara Plant Group					
1	Niagara Tunnel Project	EXEC0007	Value Enhancing	2005	2010	985.2
2	Rehabilitate Canal Lining	H-98-0056	Sustaining	2009	2011	51.0
3	Unit G7 Frequency Conversion	SAB10032	Value Enhancing	2007	2008	35.2
4	Unit G9 Upgrade	SAB10047	Sustaining	2008	2009	30.0
5	Unit G10 Upgrade	SAB10050	Sustaining	2009	2010	31.0
6	Unit G3 Upgrade	SAB10064	Sustaining	2009	2011	31.5
7	PGS Dyke Foundatin Grouting	SABP0022	Sustaining	2008	2010	20.0
	Saunders GS					
8	Replace HVAC system	H-97-1864	Sustaining	2007	2008	11.5
9	**Total**					1,195.4

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

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Table 2
Capital Project Listing - Regulated Hydroelectric
Projects $5M - $10M Total Project Cost[1]

Line No.	Project Name	Category	Project Description	Total Project Cost ($M)
	(a)	(b)	(c)	(d)
	Niagara Plant Group			
1	SABP0017 - Main Output Transformer Replacements	Sustaining	Sir Adam Beck Pump Generating Station - Replace Main Output Transformers	8.0
2	SAB10084 - Elevator 1 - Shaft and Tunnel Rehab	Sustaining	Sir Adam Beck #1 - Rehabilitate Elevator #1 Shaft and Entrance Tunnel.	6.1
	Saunders GS			
3	SAUN0047 - Generator Protection & Control Upgrades	Sustaining	R.H. Saunders GS - Generator electrical & mechanical protections,Transformer & LV bus protections, HV Cable protection and Line Protections	8.8
4	**Total**			22.9

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

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Table 3
Capital Project Listing - Regulated Hydroelectric
Projects <$5M Total Project Cost[1]

Line No.	Project Description	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	Niagara Plant Group			
1	**Aggregate Total All Projects <$5M**	9	8.5	0.9
	Saunders GS			
2	**Aggregate Total All Projects <$5M**	6	12.9	2.1
3	**Total**	15	21.3	1.4

1 Projects with expenditures during Test Period

CAPITAL BUDGET – NUCLEAR

1.0 PURPOSE

The purpose of this evidence is to present an overview description of the nuclear capital project budget for the historical year, bridge year, and test period. In addition, a discussion of period-over-period variations is provided for the years 2005 through 2009.

2.0 OVERVIEW OF PROJECT MANAGEMENT PROCESSES

A project, whether OM&A or capital, is defined as a temporary, unique endeavour undertaken outside the routine base activities of the normal work program. The final decision on whether work will be classified as a project will be made based on the complexity and materiality of the work, with consideration of the following characteristics:

- Incremental cost, over and above base OM&A (Ex. F2-T2-S1) is greater than $200k per generating unit.
- Execution duration is limited, with defined start and finish dates.
- Work is clearly incremental to regular ongoing work, non-repetitive in nature, recurring at an interval of greater than once every six years.
- Sponsorship and management accountabilities can be clearly defined.

OPG nuclear projects are developed to meet regulatory commitments (e.g., from the Canadian Nuclear Safety Commission), decrease future base or outage OM&A expenditures, increase system or unit reliability, or increase the output of the station. OPG Nuclear manages all projects, both capital and OM&A, by way of a project portfolio management procedure. This procedure ensures effective coordination and value assessment of all nuclear projects by developing a nuclear project portfolio. Among other things, the nuclear project portfolio facilitates comparative value assessments for project prioritization, and also forms the basis for project budgeting during the business planning process.

The nuclear project portfolio is approved via the OPG business planning process with the OPG Board of Directors approving the OM&A and Capital projects portfolio budget which is then administered via the portfolio management process described below. As part of the

2008 business planning process, the OPG Board of Directors approved $290M ($172 M capital and $118M OM&A) as the appropriate and required level of ongoing project expenditure to maintain the generating assets and associated infrastructure. This funding level was developed in consideration of: historical investment patterns; project execution capabilities; potential beneficial impact of the improved project portfolio management processes; project expenditures in the approved 2007 business plan versus project requirements identified during the 2008 business planning process; and high level comparative data from other nuclear utilities. In addition to this ongoing project portfolio, there are expenditures associated with the P2/P3 Isolation Project and Pickering B Refurbishment Project (see Section 3.0). Total nuclear project costs are presented in Chart 1.

Chart 1: Total Nuclear Project Costs – Project OM&A and Capital

	$ Million	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
1	Total Project Capital	138.9	151.1	186.5	172.0	172.0
2	Total Project OM&A	155.9	140.4	102.1	118.0	118.0
3	**Total Portfolio Costs**	**294.8**	**291.5**	**288.6**	**290.0**	**290.0**
4	P2/P3 Isolation Project	0.0	2.7	18.8	43.6	24.0
	PB Refurbishment	0.0	0.0	0.0	0.0	153.9
5	Total Project Costs	294.8	294.2	307.4	333.6	467.9

At any point in time, the nuclear project portfolio potentially includes projects at all stages of the project life cycle, from newly identified opportunities to fully released projects in execution or close-out phases. The five phases of project life cycle and associated “release” funding normally associated with each phase are indicated here, and discussed below:

- Project identification (using base OM&A, leading to a request for conceptual funding)
- Project initiation (using conceptual funding, leading to a developmental release)
- Project definition (using developmental release, leading to a full or partial release)
- Project execution (leading to a full release if currently partial. Superseding release to be processed if required due to scope change or cost increase)

- Project close-out and post-implementation review

Project progression between phases is governed by a management process, which ensures that a periodic, systematic review is conducted and that approvals are obtained before proceeding with further investment. The recently-formed Asset Investment Screening Committee, discussed below, plays a key role in challenging value at these decision points.

2.1 Project Identification

The purpose of the project identification phase is to identify and assess opportunities for project work.

Potential projects are generally identified by Station Engineering through system health reviews, analysis of component failures, and the life cycle plans prepared for major systems. In addition, projects with an anticipated benefit for multiple sites are identified and sponsored by the support divisions. The life cycle management program is further discussed in Ex. E2-T1-S1.

When an issue or opportunity is identified a “Part A screening form” is completed by the responsible engineer or technical contact in order to characterize the issue and rank the potential impact using standardized prioritization criteria based on probability of occurrence, potential consequences of the issue and the urgency of implementation. If a system modification is required, an engineering change request is also prepared to initiate the engineering change control process. Projects that require engineering change control compliance receive an additional level of scrutiny to ensure that system modifications are consistent with the station design basis, adhere to all codes and standards, and do not compromise the safety of employees or the public.

A project charter, defining the issue or opportunity and the roles of different OPG departments is also prepared by the project sponsor at this stage.

During the project identification phase, project funding is preliminarily classified as either OM&A or capital based on the nature of the work. The rules for classification of a project as OM&A or capital are the same for all expenditures as described in Ex. A2-T2-S1. All contemplated project expenditures for existing assets are considered OM&A unless they qualify for capitalization as per corporate policy as outlined therein. Expenditure classification decisions are made independent of the impact to either the OM&A or the capital budgets, and all decisions are verified by the Finance organization.

The Part A screening form and the project charter are presented to the appropriate station Project Approval Committee. The Project Approval Committee consists of key management and supervisory staff within Station Engineering, Maintenance, Operations, and Support Services organizations. The members of Project Approval Committee challenge the justification for a project, perform a preliminary screening and make a decision on whether to proceed further with project definition or to cease further activity on the project. Projects approved by each Project Approval Committee will normally receive limited project OM&A funding ("conceptual funding", typically in the order of $50k to $100k) in order to proceed to the project initiation phase.

2.2 Project Initiation

Using the conceptual funding discussed above, the first step in the project initiation phase is a review of the alternatives to solve the identified problem or to pursue the identified opportunity. If this review concludes that a project is in fact not required (e.g., improved maintenance procedures will address the problem), then project analysis terminates at this point.

If the review concludes that undertaking a project is the recommended solution, the next step for most projects is completion of a developmental business case summary ("BCS"). The developmental BCS provides cost estimates for each of the viable project alternatives, recommends a preferred alternative, outlines project-specific funding required to progress the project to the next decision phase, and provides a cost estimate for the entire project with an accuracy of + 60 percent/ - 25 percent (consistent with industry standards).

In addition to the developmental BCS, the following documents are also produced during the project initiation phase:

- A "Part B screening form", outlining the alternatives considered and the costs for each alternative.
- A level 1 schedule, which is created to define completion dates for specific project milestones and deliverables, to the degree that they are understood in the developmental BCS.

The developmental BCS and the Part A and Part B screening forms are submitted to the Asset Investment Screening Committee.

The Asset Investment Screening Committee was created in late 2006. The Asset Investment Screening Committee consists of members from all Nuclear sites and Nuclear Finance. This Committee has the mandate to review project recommendations and evaluate acceptance of new projects to be added into the Nuclear project portfolio from an OPG nuclear fleet perspective. The Committee evaluates the project value, relative priorities, schedules, and cost estimates of the submitted projects and the do-ability constraints on the organization as a whole. If the Asset Investment Screening Committee supports the proposal, the developmental BCS will be routed as per the organizational authority register, see Ex. A2-T2-S1 Section 5.0 for approval of the associated funding. This approval, and all subsequent references to organizational authority register approval, requires both line management and Finance signoff, with the project cost determining the organizational approval level required. Upon approval of the developmental BCS and of the associated release of funds, the project moves to the project definition phase, and the project-specific funding is released. The project (with identification of sponsoring division) is then considered added to the portfolio.

2.3 Project Definition

The purpose of the project definition phase is to fully define the scope of the project, complete approximately 40 percent of the expected engineering work and, from that, to develop a preliminary project execution plan and a full release BCS to seek approval for

project execution. In some cases, in lieu of a full release BCS, a partial release BCS will be prepared as discussed below.

A project team of OPG regular staff (supplemented by external resources as required) is assembled during this phase. Work completed during this phase includes the following:

- A review of the documentation associated with the plant systems to be modified.
- A "walk-down" of the plant systems to identify potential issues with respect to construction, operation, maintenance, and safety of the associated systems.
- A review of the major material needs of the project, with consideration for long lead items requiring extended delivery schedules from suppliers.
- Completion of a more detailed work activity schedule (level 2), identifying significant milestones, engineering, and execution work and resources required to support the project.
- Completion of up to 40 percent of the design engineering work.
- Development of a cost estimate for the entire project with an accuracy in the range of
- + 30 percent/ - 15 percent.
- Drafting of a partial or full release BCS.

<u>Approval of Project Releases</u>

For a developmental release, project approval is based on the dollar value of the developmental release work as a stand-alone project. If an investment of > 10 percent of total project estimate had been required at this stage, or project staff recommend conducting some execution activities in advance of a full release, a partial release BCS will be prepared and approved as per the organizational authority register on the basis of total project estimate. This approach ensures effective management involvement and oversight in these instances to minimize financial commitment while providing management with adequate additional information to decide on proceeding with execution.

With reference to a partial BCS, this approach may be used to allow execution of the first unit of a multi-unit project or the first stage of a large (multi-stage) project. A phased approach is

used to allow confirmation of costs and benefits from the first unit installation, prior to committing to undertake work for the balance of units with a full release BCS.

The appropriate BCS is routed for funding approval as per OPG's organizational authority register. Upon approval of the funding associated with the BCS and associated project change request authorization form, the project moves forward to the project execution phase.

2.4 Project Execution

During the project execution phase, design engineering is completed, a detailed project execution plan is prepared, and requests for proposal of bids from prospective contractors are reviewed for contract award (as applicable). A level 3 schedule (task level detail) and an updated cost estimate for the entire project with an accuracy of + 15 percent/ - 10 percent are also prepared, and detailed installation instructions are issued for implementation in the field.

For multiple unit projects, installation then proceeds on the first unit. Identified tasks are incorporated into station work schedules and resources are assigned to execute identified tasks in the field. Installation activities are followed by commissioning activities (measurements, checks, and tests) and, upon completion, the system is declared in-service. If work on the first unit (or first stage) has been funded via a partial release, a full release BCS is prepared for release of the balance of funding for the remaining units, and approval of funds is requested as per the organizational authority register.

Projects are continuously scrutinized during the execution phase. In addition to operational reviews within Project and Modifications Department of Engineering and Modifications Division, monthly station Project Approval Committee meetings and Asset Investment Screening Committee reviews, the major project status review meeting provides a forum for key finance, project management, engineering staff, and senior management to review and challenge all Nuclear projects with a total project estimate $\geq$ $5M. Project status, issues, and proposed corrective actions are then formally reported to senior management.

If, during the execution of a project, the cost projection at completion is forecast to exceed approved funding, a superseding BCS is prepared to document the status of the project, the causes for forecast over-expenditure, the management actions taken to-date to control costs, and all viable options for cost control or scope adjustment for management consideration. The funding request as identified in the superseding BCS is routed for approval as per the organizational authority register; approval is required before exceeding the previously approved full release amount.

2.5 Project Close-Out and Post-Implementation Review

Upon completion of all execution and commissioning activities, project close-out is performed. This phase involves:

- Closure of engineering activities, including drawing updates.
- Procedure update, as required.
- Financial activities, such as cost account closure and in-service declaration for capital projects.
- Contract closeout activities.

These process steps ensure proper completion of all project, engineering and financial activities, and sharing of project experience for future benefit. At this point, regular employees are assigned to other projects within the Nuclear project portfolio, and contractors are released.

As outlined in Ex. A2-T2-S1, following project completion, a post-implementation review should be completed, to review the success of the project in achieving the objectives defined in the BCS and to promote continuous improvement and maximum future economic benefit to OPG through dissemination of “lessons learned”.

Final post-implementation review reports are approved by the project sponsor, and Nuclear Finance. To date, OPG Nuclear has not reached full compliance in this area, in that there is a backlog of post-implementation reviews to be completed that is being addressed aggressively.

3.0 OVERVIEW OF CAPITAL EXPENDITURES

Exhibit D2-T1-S1 Table 1 presents Nuclear capital project expenditures by sponsoring division and category for the period 2005 - 2009.

Exhibit D2-T1-S1 Table 1 presents the following information for facility projects:

- "Released Facility Projects" includes the value of completed work (2005 - 2007) and the planned expenditures for released projects (2008 - 2009) for each facility, The values include the approved release amounts for all projects with a developmental, partial or full release. These projects have been added to the Nuclear project portfolio, as described in section 2.2.
- "Facility Projects to be Released" includes the balance of the total project estimate for projects with a developmental or partial release. At the completion of the developmental or partial release phase, a BCS will be produced for funding approval, at which time management will assess the value of continuing with the proposed balance of the work scope ("balance to be released").
- "Listed Work to be Released" reflects funding available to undertake project work that is currently in the project identification or project initiation phases (D2-T1-S2 Table 4a/4b for capital projects, and F2-T3-S3 Table 4a/4b for OM&A projects). This reflects the difference between the project portfolio envelope approved by the OPG Board of Directors during business planning, and the cost of identified facility projects that are either 'Released' or 'To Be Released' at the time of filing. Where Listed Work to be Released is a negative amount, it indicates that planned work exceeds approved funding, and will be addressed through the portfolio management process.
- "P2/P3 Isolation Project" reflects work to achieve operational isolation of Pickering A Units 2 and 3 (i.e., those units in the safe storage state), as well as modifications to common system controls which are currently located on Unit 2. This project enables continued operation of remaining Pickering A Units 1 and 4, and Pickering B, upon completion of the safe storage project as discussed at Ex. A1-T4-S3. This work is listed separately from ongoing Nuclear portfolio work due to its extraordinary nature. In addition to amounts in Ex. D2-T1-S1 Table 1, there is an OM&A component discussed in Ex. F2-T3-S2.

- "Pickering B Refurbishment Project" reflects potential capital expenditures as described in Ex. D2-T1-S3, should the OPG Board decide to proceed with life extension options as outlined further in that exhibit.

In addition, capital project expenditures have been categorized in Ex. D2-T1-S1 Table 2 by the categories of regulatory, sustaining or value enhancing/strategic as defined in Ex. A2-T2-S1.

Exhibit D2-T1-S1 Table 1 presents the following trends in capital expenditures:

- "Released Facility Projects" work decreases in the test years (from $186.5M in 2007 to $37.7M in 2009), reflecting completion of currently ongoing project work while some 2008/2009 work is yet to be released. As the data presented reflects 2008 business planning information, this is consistent with industry experience, where up to two years of released work is the norm.
- "Facility Projects To be Released" work increases in the test years (complementary to the trend for "released" work above), reflecting expected further release of funds to complete project work currently in the project definition phase, or undertaking any of the numerous projects currently in the project identification or initiation phases.
- "Listed Work to be Released" increases in 2009, consistent with expectations that listed projects will move from the project identification and initiation phases into project development phase during 2008.
- "P2/P3 Isolation Project" work increases in 2007 and 2008 reflecting peak project activity, then ramps down to completion in 2009.
- Pickering B Refurbishment Project reflects potential expenditures if the OPG Board decides to proceed with one of the life extension options. See Ex. D2-T1-S3.

Exhibit D2-T1-S2 presents further details of capital projects included in these expenditures.

3.1 Capital Project Drivers

Regulatory projects have been a major factor in capital project expenditures over the 2005 - 2009 period, with fire protection, security and auxiliary power system issues (in response to the loss of the bulk electric system on August 14, 2003) predominating. Due to its sensitive nature, limited information is available for security projects.

For projects with cash flows in the test period, additional project information can be found in Ex. D2-T1-S2.

In 2005, the security optimization projects ($47.2M), Darlington fire protection phase 3 ($16.8M) and Pickering B auxiliary power system installation ($10.2M) required the most significant effort.

In 2006, the major capital initiatives were again regulatory in nature, with the Pickering B auxiliary power system installation ($57.9M) and the security optimization project ($22.8M).

In 2007, there are again major regulatory capital expenditures associated with the Pickering B auxiliary power system installation ($36.3M) and security fence project ($18.5M). Major sustaining initiatives included the Darlington used fuel dry storage in-station modifications ($15.0M). In addition, there is significant effort on the P2/P3 Isolation Project ($9.3M), as noted above.

In 2008, major capital items include regulatory-driven security projects at all stations (totalling ~$36M). There are significant expenditures associated with sustaining projects such as the Darlington used fuel dry storage in-station modifications ($12.3M) and the Darlington second full scope simulator installation ($10.2M). In addition, there is continued effort on the P2/P3 Isolation Project ($17.0M).

In 2009, major capital initiatives are influenced by security fence project, security hardening project, controlled area improvements (security) and security doors (totalling $22.4M), continued effort on the Darlington D_2O storage facility improvements ($7.2M), and ramp up of Darlington maintenance facilities replacement ($14.5M).

There are seven major sustaining capital projects planned to come fully into service during the test period (reference Ex. D2-T1-S2 Table 1), the largest of which is the Darlington used fuel dry storage in-station modifications project ($43.9M). In addition, there are 11 major regulatory capital projects planned to come fully into service during the test period (Ex. D2-T1-S1 Table 1), including six security-related projects, the major auxiliary power system project for Pickering B and the Darlington fire protection upgrade phase 3 program.

4.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

Year-over-year variances are broken down by facility in Ex. D2-T1-S1 Table 3b and are explained below. Where projects have cash flows in the test period, more detailed project information is contained Ex. D2-T1-S2.

2009 Plan versus 2008 Plan

The increase in planned spending in 2009 compared with 2008 plan (Ex. D2-T1-S1 Table 3b, $141.9M) reflects the planned purchase of long lead-time materials for the Pickering B refurbishment project ($148.8M), partly offset by planned reductions in P2/P3 Isolation Project work as this projects moves to completion in 2009 (-$6.9M).

2008 Plan versus 2007 Actual

The decrease in planned spending in 2008 compared with 2007 actual (Ex. D2-T1-S1 Table 3b, -$6.8M) is a result of reducing project portfolio capital to the Board of Directors approved level of $172M (-$14.5M), partly offset by P2/P3 Isolation Project work deferred from 2007 ($7.7M).

5.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

Year-over-year variances are presented by facility in Ex. D2-T1-S1 Table 3b and are explained below. Where projects have cash flows in the test period, and only for those projects, more detailed project information is contained Ex. D2-T1-S2.

2007 Actual versus 2007 Budget

Capital is under spent in 2007 (-$54.7M), primarily due to deferral of potential 'Listed Work to be Released' (-$22.6M), no requirement to draw on planned contingency (-$5.0M), and the net impact of project-specific variances associated with the 118 capital projects that were managed in 2007 (-$12.8M). The establishment of more achievable target capital expenditure levels in the test period (as outlined in Section 2.0 above) is expected to significantly reduce such variances in future. The balance of the under-expenditure results from delays in the P2/P3 Isolation Project (-$14.3M), reflecting deferral of construction and maintenance ramp-up (to allow greater progress on engineering/assessing activities), and the new CNSC requirement for an environmental assessment (with conservative deferral of potentially-impacted activities).

2007 Actual versus 2006 Actual

The increase in spending in 2007 compared with 2006 actual (Ex. D2-T1-S1 Table 3a, $43.5M) was due to increased work on the security fence project ($16.9M), Darlington used fuel dry storage facility in-station modifications ($9.1M), Pickering A switchyard relay building cable replacement ($9.4M), Pickering A calandria vault inspection tooling development ($7.2M) and the P2/P3 Isolation Project ($8.2M). These increased efforts are partly offset by reductions in spending due to the Pickering B auxiliary power system installation (-$21.6M) and the security optimization project (-$15.5M).

6.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

Year-over-year variances are broken down by facility in Ex. D2-T1-S1 Table 3a, and explained here. Where projects have cash flows in the test period, and only for those projects, more detailed project information is contained Ex. D2-T1-S2.

2006 Actual versus 2006 Budget

The variance to budget in 2006 (Ex. D2-T1-S1 Table 3a, -$117.3M) reflects primarily delays in various security projects (-$27.8M), Darlington used fuel dry storage in-station modifications (-$13.2M), Pickering B auxiliary power system installation, 49104 (-$11.8M), Pickering A calandria vault inspection tooling development, 46537 (-$6.3M), cancellation of

the Pickering B lunch/shower/change room facility (-$5M), unspent contingency (-$5M) and minor delays in a large number of other projects (- $1M to - $4M each).

2006 Actual versus 2005 Actual

The change in spending 2005 - 2006 (Ex. D2-T1-S1 Table 3a, $13.3M) reflects primarily a major ramp-up in work on the Pickering B auxiliary power system installation, 49104 ($47.7M increase over 2005), partly offset by winding down of the security optimization project (-$24.4M) and Darlington fire protection phase 3 project (-$14.1M).

2005 Actual versus 2005 Budget

The variance to budget in 2005 (Ex. D2-T1-S1 Table 3a, -$92.1M) reflects primarily material delays for the Pickering B auxiliary power system installation (-$34.7M), unutilized contingency and balancing adjustment (-$25.4M), delays in the security optimization project and security fence project (-$19M) and delays in the Pickering B lunch/shower/change room facility (-$4.9M).

It should be noted that significant improvements have been made to the project management process to reduce the variances due to project delays noted during the historic period.

Numbers may not add due to rounding.

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Exhibit D2
Tab 1
Schedule 1
Table 1

Table 1

Capital Expenditures Summary - Nuclear ($M)

Line No.	Sponsoring Division/Category	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Facility Projects (Released)					
1	**Darlington NGS**	43.2	27.0	45.4	63.5	20.4
2	**Pickering A NGS**	2.7	6.8	35.4	25.4	5.1
3	**Pickering B NGS**	40.2	82.5	55.1	15.6	5.8
4	**Engineering & Modifications**	0.1	0.0	3.5	9.0	1.4
5	**Programs & Training**	52.5	29.6	37.7	21.1	3.3
6	**Supply Chain**	0.1	0.4	1.3	2.2	0.5
7	**Inspection & Maintenance Services**	0.0	4.8	8.1	7.3	1.3
8	**Total Facility Projects (Released)**	138.9	151.1	186.5	144.0	37.7
9	**Facility Projects to be Released**	0.0	0.0	0.0	30.4	78.5
10	**Contingency**	0.0	0.0	0.0	0.0	0.0
11	**Listed Work to be Released**	0.0	0.0	0.0	(2.4)	55.8
12	**Subtotal Project Capital (Portfolio)**	138.9	151.1	186.5	172.0	172.0
13	**P2/P3 Isolation Project**	0.0	1.1	9.3	17.0	10.0
14	**Pickering B Refurbishment Project**	0.0	0.0	0.0	0.0	148.8
15	**Total Project Capital**	138.9	152.2	195.7	189.0	330.9

Numbers may not add due to rounding.

Updated: 2008-03-14
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Exhibit D2
Tab 1
Schedule 1
Table 2

Table 2
Capital Expenditures Summary - Nuclear ($M)
By Project Category

Line No.	Project Category	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Facility Projects (Released)					
1	**Regulatory**	102.8	100.9	78.9	30.9	3.6
2	**Sustaining**	36.1	50.2	107.6	113.2	34.1
3	**Value Enhancing / Strategic**	0.0	0.0	0.0	0.0	0.0
4	**Total**	138.9	151.1	186.5	144.0	37.7

Numbers may not add due to rounding.

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Exhibit D2
Tab 1
Schedule 1
Table 3a

Table 3a
Comparison of Capital Expenditures - Nuclear ($M)

Line No.	Sponsoring Division/Category	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Facility Projects (Released)									
1	**Darlington NGS**	49.9	(6.7)	43.2	(16.2)	27.0	(42.4)	69.4	18.4	45.4
2	**Pickering A NGS**	4.4	(1.7)	2.7	4.1	6.8	(19.9)	26.7	28.6	35.4
3	**Pickering B NGS**	79.4	(39.2)	40.2	42.3	82.5	(20.3)	102.8	(27.4)	55.1
4	**Engineering & Modifications**	3.6	(3.5)	0.1	(0.1)	0.0	(5.8)	5.8	3.5	3.5
5	**Programs & Training**	67.7	(15.2)	52.5	(22.9)	29.6	(18.5)	48.1	8.1	37.7
6	**Supply Chain**	0.5	(0.4)	0.1	0.3	0.4	(0.1)	0.5	0.9	1.3
7	**Inspection & Maintenance Services**	0.0	0.0	0.0	4.8	4.8	(10.6)	15.4	3.3	8.1
8	**Total Facility Projects (Released)**	205.5	(66.6)	138.9	12.2	151.1	(117.5)	268.6	35.4	186.5
9	**Facility Projects to be Released**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Contingency**	25.4	(25.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Listed Work to be Released**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Subtotal Project Capital (Portfolio)**	231.0	(92.1)	138.9	12.2	151.1	(117.5)	268.6	35.4	186.5
13	**P2/P3 Isolation Project**	0.0	0.0	0.0	1.1	1.1	0.2	0.9	8.2	9.3
14	**Pickering B Refurbishment Project**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Project Capital**	231.0	(92.1)	138.9	13.3	152.2	(117.3)	269.5	43.5	195.7

Numbers may not add due to rounding.

Updated: 2008-03-14
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Exhibit D2
Tab 1
Schedule 1
Table 3b

Table 3b
Comparison of Capital Expenditures - Nuclear ($M)

Line No.	Sponsoring Division/Category	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Facility Projects (Released)							
1	**Darlington NGS**	44.3	1.1	45.4	18.1	63.5	(43.1)	20.4
2	**Pickering A NGS**	40.6	(5.2)	35.4	(10.0)	25.4	(20.3)	5.1
3	**Pickering B NGS**	54.3	0.8	55.1	(39.5)	15.6	(9.8)	5.8
4	**Engineering & Modifications**	4.8	(1.3)	3.5	5.4	9.0	(7.6)	1.4
5	**Programs & Training**	38.0	(0.3)	37.7	(16.6)	21.1	(17.8)	3.3
6	**Supply Chain**	0.6	0.7	1.3	1.0	2.2	(1.7)	0.5
7	**Inspection & Maintenance Services**	16.7	(8.6)	8.1	(0.8)	7.3	(6.0)	1.3
8	**Total Facility Projects (Released)**	199.3	(12.8)	186.5	(42.4)	144.0	(106.3)	37.7
9	**Facility Projects to be Released**	0.0	0.0	0.0	30.4	30.4	48.1	78.5
10	**Contingency**	5.0	(5.0)	0.0	0.0	0.0	0.0	0.0
11	**Listed Work to be Released**	22.6	(22.6)	0.0	(2.4)	(2.4)	58.2	55.8
12	**Subtotal Project Capital (Portfolio)**	226.9	(40.4)	186.5	(14.5)	172.0	0.0	172.0
13	**P2/P3 Isolation Project**	23.6	(14.3)	9.3	7.7	17.0	(6.9)	10.0
14	**Pickering B Refurbishment Project**	0.0	0.0	0.0	0.0	0.0	148.8	148.8
15	**Total Project Capital**	250.5	(54.7)	195.7	(6.8)	189.0	141.9	330.9

DETAILS OF CAPITAL PROJECTS – NUCLEAR

1.0 PURPOSE AND OVERVIEW

The purpose of this evidence is to provide project listings and supporting information to support planned capital expenditures for the nuclear facilities.

2.0 CAPITAL PROJECTS LISTING

A tiered reporting structure consistent with OEB filing guidelines has been used to present the evidence for all capital projects which have budgeted expenditures during the test period.

- Tier 1: Projects with a total cost of $10M or greater, for which summary level information is provided as well as a project summary form.
- Tier 2: Projects with a total cost of $5M to $10M, for which summary level information is provided.
- Tier 3: Projects with a total cost of less than $5M for which aggregated information is provided.

Consistent with the definitions presented in Ex. D2-T1-S1, information on facility projects in the following tables is categorized as released amount, balance to be released and listed work to be released. The information is then further sorted by sponsoring division.

As per Ex. D2-T1-S2 Table 1, there are 28 released projects with a total project cost > $10M, that have expenditures in the test period, and 12 of these projects have a future balance to be released during the test period. Generally, the future balance reflects requesting approval to proceed to project execution phase following successful completion of the project definition phase. Project summary forms are provided for each of these projects in the Appendix, with variance explanations provided for completed projects where actual project costs exceed the initial full release by 10 percent or more.

As per Ex. D2-T1-S2 Table 2, there are 15 released projects with a total project cost between $5M and $10M that have budgeted expenditures in the test period, and five of these projects

have a future balance to be released during the test period. Generally, the future balance is associated with requesting approval to proceed to project execution phase following successful completion of the project definition phase.

As per Ex. D2-T1-S2 Table 3, there are 35 projects with a total project cost less than $5M that have budgeted capital expenditures in the test period, 13 of which have a balance to be released. Summary level information is provided in Ex. D2-T1-S2 Table 3.

As per Ex. D2-T1-S2 Table 4a/4b, there are a total of 47 projects categorized as "Listed Work to be Released". This potential work is currently in the project identification or project definition phases, and could be started in the test period as a result of the portfolio management process.

LIST OF ATTACHMENTS

Appendix A: Ontario Power Generation – Project Summary Forms

- Project Number 25908 - Security Doors Upgrade
- Project Number: 28452 – Darlington Second Full Scope Simulator
- Project Number: 31555 – Darlington D_2O Storage Facility
- Project Number: 31717 – Improve maintenance Facilities at Darlington
- Project Number 33293 - Main Control Room Heating, Ventilation & Air Conditioning
- Project Number: 33631 - Darlington Chiller Replacement to Reduce Chlorofluorocarbon Emissions
- Project Number: 33815 – Darlington Fuel Handling Computer Replacement
- Project Number: 33925 – Darlington Used Fuel Dry Storage in Station Modifications
- Project Number: 33955 – Darlington Shutdown System Computer Aging Management
- Project Number: 33973 – Darlington Standby Generator Controls Replacement
- Project Number: 33977 – Darlington Digital Control Computer Replacement/Refurbishment/Upgrades
- Project Number: 34000 – Darlington Auxiliary Heating System
- Project Number: 34008 - Darlington Feeder Replacement As Low As Reasonably Achievable Optimization
- Project Number: 40543 – Pickering B Chlorofluorocarbon Replacement (Freon Removal)
- Project Number: 46537 – Pickering A – Reactor Structures – Calandria Vault Inspection
- Project Number: 49104 – Pickering B Auxiliary Power System
- Project Number: 49109 – Pickering B Standby Generator Governor Upgrade

- Project Number: 49251 – Pickering site (A and B) – Heavy Water (D_2O) Storage Facility
- Project Number: 49266 – Pickering A Switchyard Relay Building Cable Replacement
- Project Number 62558 - Security Optimization (Capital)
- Project Number 62567 - Additional Feeder Cut and Weld Tooling
- Project Number 79016 - Darlington Fire Protection Phase II
- Project Number: 79147 – Pickering B Chemistry Standards (CH-002)
- Project Number 79148 - Darlington Fire Protection Phase III
- Project Number: 25609 – Nuclear Programs and Training Security Fence Project
- Project Number: 25901 – Nuclear Programs and Training Security Hardening Project
- Project Number: 25902 – Nuclear Programs and Training Controlled Area Improvements
- Project Number: 25905 – Nuclear Programs and Training Security Monitoring Room

APPENDIX A

Ontario Power Generation - Project Summary

Project Name: Nuclear Programs & Training Security Doors Upgrade		
Project Number: 25908	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): August 2006	In-Service Date (month, year): December 2009	

Project Description:

Improve physical security provisions within Pickering A, Pickering B, and Darlington stations.

Project Need (i.e. justification for the project):

This project is required to meet Canadian Nuclear Safety Commission security requirements.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	480	2,241	5,792	4,000	754	13,267
OM&A							

Initial Full Release (A): N/A – Partial Release	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Second Full Scope Simulator		
Project Number: 28452	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): September 2006	In-Service Date (month, year): July 2009	

Project Description:

Complete engineering, procurement, installation, and commissioning of a second full-scope main control room simulator in the Darlington Learning Center Facility.

Project Need (i.e., justification for the project):

The current Darlington full-scope simulator located at the Pickering Learning Center cannot meet the demand for hands-on initial and refresher training of authorized staff due to the following:

- Demographics of the authorized staff complement will result in higher attrition rates in coming years and result in higher initial training demand than is currently accommodated.
- Changes in the Darlington Power Reactor Operating License conditions require more authorized operators per shift, further increasing demand for initial and refresher training.
- Regulatory expectations that the recommended amount of hands-on refresher training be increased from 30 to 35 hours per year to a minimum of 60 per industry best-practice recommendations.

The current simulator is in operation 16 hours per day, 5 to 7 days per week (depending on time of year) and cannot be operated further without significantly compromising required maintenance time.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	47	3,750	7,818	2,041	546	14,202
OM&A							

Initial Full Release (A): $16,204k	Actual or Forecasted Project Completion Cost (B): $14,202k	Variance (B-A): -$2,002k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington D_2O Storage Facility		
Project Number: 31555	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): November, 2006	In-Service Date (month, year): December, 2010	
Project Description: Construct an addition to the existing Heavy Water Management Building to house multi-purpose storage tanks, a drum storage area, and drum testing facility.		
Project Need (i.e., justification for the project): OPG needs to improve its overall ability in managing its D_2O (heavy water) inventories to support continuous station operations in a safe and cost efficient manner, and support efficient detritiation services that are located at Darlington. The existing facility is inadequate to meet current demand. The business objectives of this project are therefore as follows: • Improve detritiation capability (removal of radioactive tritium from D_2O) within OPG. • Improve operational flexibility and ability to segregate different streams/qualities of D_2O. • Improve the management of drum inventories. • Allow OPG to pursue new business opportunities associated with detritiation services.		

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital		22	1,542	1,320	7,155	18,161	28,200
OM&A							

Initial Full Release (A): N/A – Developmental Release	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A): N/A
Variance Explanation (if Variance >10% of Initial Full Release): N/A		

Ontario Power Generation – Project Summary

Project Name: Improve Maintenance Facilities at Darlington		
Project Number: 31717	Project Category: ☐ Regulatory ☐ Sustaining ☒ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): January 2002	In-Service Date (month, year): December 2010	

Project Description:

Construct a new 57,300+ sq. ft. Maintenance Facility, including:

- Mechanical maintenance monitoring and test equipment lab
- Control maintenance monitoring and test equipment lab
- Mechanical maintenancer valve shop
- Mechanical maintenance seal lapping shop
- Reactor maintenance shop
- Breaker shop
- Inspection and maintenance services quality control labs and offices
- Control maintenance/mechanical maintenance valve shop
- Inspection and maintenance services pressure tube area
- Civil first line manager offices
- Mechanical maintenance first line manager offices

Project Need (i.e., justification for the project):

This project is designed to address the current inadequate maintenance facilities at Darlington which are leading to overcrowding, inefficiencies, outage extensions, and non-code compliant work areas.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	141	8	359	3,245	14,563	26,104	44,420
OM&A							

Initial Full Release (A): N/A – Developmental Release	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A): N/A

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation - Project Summary

Project Name: Darlington Main Control Room Heating, Ventilation & Air Conditioning System Modifications		
Project Number: 33293	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): May 2001	In-Service Date (month, year): September 2008	

Project Description:
Implement modifications to the Main Control Room Heating, Ventilation & Air Conditioning (HVAC) system:

- Install new, larger cooling coils to lower the design temperature setpoint.
- Install changes to air distribution in Digital Control Computer Equipment Rooms to eliminate hot spots and lower average temperature in the rooms.
- Install improved filtration.
- Install improved humidity and pressure controls as well as system monitoring and diagnostic tools.
- Install additional equipment to separate the Brine Chillers to eliminate common elements that could lead to common mode failures.
- Improve pressure relief capacity on condenser cooling water system.

Project Need (i.e. justification for the project):

The business objective of this project is to address the following deficiencies in the Main Control Room and adjacent Computer Equipment Rooms' HVAC systems:

- high temperature excursions that threatened reliable operation of the units
- health and safety concerns with the lack of proper filtration and humidification

Project Costs :

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	9,304	446	600	515	30	0	10,895
OM&A							

Initial Full Release (A): $6,040k	Actual or Forecast Project Completion Cost (B): $10,895k	Variance (B-A): $4,855k

Variance Explanation (if Variance >10% of Initial Full Release):
Initial full release was approved prior to full scoping of the project and completion of any detailed engineering. Engineering costs were $1.7M higher than in the initial release due to additional scope (modifications to brine chillers), field conditions not matching design documents, and design

quality activities not included in the original design plan. Installation costs increased by $2.2M due to increased scope, underestimation of installation costs, labour rate increases, and a transition away from internal hiring of trades. The delay in the completion of the work from the original schedule increased interest by $0.96k.

Ontario Power Generation – Project Summary

Project Name: Darlington Chiller Replacement to Reduce Chlorofluorocarbon Emissions		
Project Number: 33631	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): January 2004	In-Service Date (month, year): December 2011	

Project Description:

- Replace the following chillers which cannot be converted to non-ozone depleting refrigerants:
  - Two chillers in central services area which provide cooling to the central services area and the main control room.
  - Eight chillers in the reactor auxiliary bay that provide process cooling for shutdown system instrumentation and the reactor auxiliary bay.
  - One chiller that provides cooling to the Tritium Removal Facility/Heavy Water Management Building.
- Install new three-way control valves and controllers for the new chillers.

Project Need (i.e., justification for the project):

Federal Halocarbon Regulations issued in 2003 have mandated that any chiller (air conditioning unit) containing chlorofluorocarbon refrigerants, such as R-11, shall not be maintained and recharged after January 1, 2010 and not operated past January 1, 2015. Darlington site has 11 chillers that use R-11 as refrigerant to provide the cooling for the buildings of central services area, reactor auxiliary bay and Tritium Removal Facility/Heavy Water Management Building.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	1,077	1,812	772	2,596	2,600	4,443	13,300
OM&A							

Initial Full Release (A): N/A – Partial Release	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A): N/A

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Fuel Handling Computer Replacement		
Project Number: 33815	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): August 2005	In-Service Date (month, year): February 2012	

Project Description:

Provide qualified replacement for the fuel handling system control computers using emulator based systems to address obsolescence and spare parts issues for the expected balance of station life. The project will also address obsolescence issues involving printers, monitors, video generators, and computer interface modules.

Project Need (i.e., justification for the project):

The obsolescence of control computers is a generic problem, and also applies to the digital control computers, sequence of events monitoring and common process computer systems. Projects have been initiated to deal with these issues. A system health report has indicated that the supply of spare parts for the fuel handling computers systems is poor and declining. A significant decrease in fuel handling control computer reliability will be experienced as non-repairable components fail, which will negatively impact fuel handling operations and ultimately production.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	233	546	643	2,892	1,883	4,225	10,422
OM&A							

Initial Full Release (A): $10,422k	Actual or Forecasted Project Completion Cost (B): $10,422k	Variance (B-A): $0

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Used Fuel Dry Storage In Station Modifications		
Project Number: 33925	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): January 2001	In-Service Date (month, year): December 2008	

Project Description:

- Complete modifications to the truck bays, decontamination areas, and wet cask bays to allow dry storage containers to be loaded with spent fuel for transfer to the Darlington waste management facility.
- Complete installation of equipment, platforms, and services to permit the loading of dry storage containers and preparing for shipment to the Darlington Waste Management Facility.

Project Need (i.e., justification for the project):

Darlington's used fuel bundles are currently stored underwater in the West and East irradiated fuel bays. The West pool is projected to become full in 2009, and the East pool in 2010. The purpose of the Darlington used fuel dry storage project is to install in-station modifications to permit transfer of used fuel to interim dry storage to allow continued use of the pools to support station operation.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	9,549	5,880	14,988	12,291	1,589		44,297
OM&A							

Initial Full Release (A): $47,790k	Actual or Forecasted Project Completion Cost (B): $44,297k	Variance (B-A): -$3,493k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Shutdown System Computer Aging Management		
Project Number: 33955	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): November 2006	In-Service Date (month, year): December 2011	

Project Description:

- Determine detailed material condition and component failure rate for shutdown system one and shutdown system two trip computers, shutdown system one and shutdown system two display/test computers and shutdown system monitoring computer.
- Initiate replacement of critical components (monitors, hard disks, etc.)
- Determine and implement replacement strategy for shutdown system computers to ensure reliability is sustained.

Project Need (i.e., justification for the project):

The Darlington shutdown system computers comprise a network of 14 computers per reactor unit connected to one shutdown system monitor computer that is common to all four reactor units. The shutdown system computers are classified as part of a special safety system that is to:
(a) Automatically initiate a reactor shutdown.
(b) Display shutdown system parameters at the main control panels.
(c) Provide a facility where by the trip measurements, logic and reactivity devices can be tested.
(d) Monitor the shutdown system routinely to detect and notify the operator of conditions which adversely affect production, reliability, or shutdown system availability.

The computers in the systems are obsolete with no original equipment manufacturer support (original equipment manufacturer no longer in existence) and critical spare parts inventory is being depleted. Without mitigating action by 2011, shutdown system one and shutdown system two will not be functional, requiring shutdown of the units.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	0	244	1,150	1,000	62,156	64,550
OM&A							

Initial Full Release (A): N/A – Developmental Release	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A): N/A

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Standby Generator Controls Replacement		
Project Number: 33973	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): December 2006	In-Service Date (month, year): December 2011	

Project Description:

Replace the control and monitoring systems for the Darlington standby generators including:

- Governor system
- Vibration monitoring system
- Annunciation system
- Over-speed protection system
- Electrical protection relays

Project Need (i.e., justification for the project):

Standby generator control system components are over 20 years old, are increasingly susceptible to unpredictable failure and are no longer supported by the original equipment manufacturer. Current trends indicate the stock of critical spares will be depleted in an estimated three to five years and the risk of concurrent standby generator failures leading to unit and/or station shutdown will increase significantly.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	0	371	1,000	4,300	8,679	14,350
OM&A							

Initial Full Release (A): N/A – Developmental Release	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A): N/A

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Digital Control Computer Replacement/Refurbishment/Upgrades		
Project Number: 33977	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): September 2003	In-Service Date (month, year): December 2012	

Project Description:

Provide qualified replacement for the unit digital control computers, common process computer and sequence of events monitoring computers with emulator based systems that will ensure reliable operation for the current life of the station, address obsolescence, and avoid a shortage of spare parts. The project scope will address identified life cycle management actions.

Project Need (i.e., justification for the project):

Digital control computers reliability issues were identified as the cause for plant shutdowns, transient events, and unnecessary challenges to the operators, primarily due to aging technology. This project ensures a proactive approach to addressing the issues that naturally arise with aging technology, specifically; hardware obsolescence, diminishing support from the industry, shortage of qualified in-house engineering resources, and decreasing maintenance capabilities for this aging technology.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	1,080	2,593	2,768	3,344	4,705	4,692	19,182
OM&A							

Initial Full Release (A): $22,058k	Actual or Forecasted Project Completion Cost (B): $19,182k	Variance (B-A): -$2,876k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Auxiliary Heating System		
Project Number: 34000	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): March 2006	In-Service Date (month, year): December 2009	
Project Description: Replace the existing construction boilerhouse with a facility that can, in the event of a four unit shutdown, maintain the temperature inside the Powerhouse and Tritium Removal Facility/Heavy Water Management Building above 10°C.		
Project Need (i.e., justification for the project): The business objective of this project is to provide a reliable back-up supply of heating steam to prevent major equipment damage and thereby support the safe return of Darlington units to service following a four unit shutdown during the winter months. The current construction boilerhouse is reaching the end of service life and needs to be replaced. Unacceptably low powerhouse temperatures would impair both safety and non-safety related systems due to heavy water freezing.		

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	265	508	3,896	14,916	913	20,498
OM&A							

Initial Full Release (A): N/A – Developmental Release	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A): N/A
Variance Explanation (if Variance >10% of Initial Full Release): N/A		

Ontario Power Generation - Project Summary

Project Name: Darlington Feeder Replacement As Low As Reasonably Achievable Optimization		
Project Number: 34008	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): January 2006	In-Service Date (month, year): December 2008	

Project Description:

Design, fabricate, install and commission physical modifications to feeder replacement systems and components.

Project Need (i.e. justification for the project):

Provide tooling and capability in order to optimize feeder replacement durations and reduce radiation dose associated with feeder replacements. The tooling and capability developed under this project will also improve efficiency of the fuel channel reconfiguration and single fuel channel replacement executions.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	859	6,488	3,434	0	0	10,781

Initial Full Release (A): $11,700k	Actual or Forecasted Project Completion Cost (B): $10,781k	Variance (B-A): -$919k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering B Chlorofluorocarbon Replacement (Freon Removal)		
Project Number: 40543	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): October 2003	In-Service Date (month, year): December 2009	

Project Description:

Replace seven chillers at Pickering containing chlorofluorocarbon refrigerant (R-11) with chillers using an approved non-ozone depleting refrigerant by 2010, in order to comply with environmental regulations.

Project Need (i.e., justification for the project):

Federal Halocarbon Regulations issued in 2003 have mandated that any chiller (air conditioning unit) containing chlorofluorocarbon refrigerants, such as R-11, shall not be maintained and recharged after January 1, 2010 and not operated past January 1, 2015. Pickering B has seven such chillers that use R-11 as refrigerant to provide required cooling within the station.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	3,896	2,142	3,196	6,705	2,133	907	18,979
OM&A							

Initial Full Release (A): $22,377k	Actual or Forecasted Project Completion Cost (B): $18,979k	Variance (B-A): -$3,398k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering A - Reactor Structures - Calandria Vault Inspection		
Project Number: 46537	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): August 2006	In-Service Date (month, year): December 2009	

Project Description:

Develop the capability for inspection and repair of all the specified calandria vault components.

Project Need (i.e., justification for the project):

Due to structural configuration, access to the interior of the Pickering A calandria vaults for inspection or repair is limited. The vaults have been exposed to moist corrosive environments since shortly after the reactors were placed in service, which has the potential to impact the calandria vault structure and systems passing through the vault. Development of inspection capability and specialized repair tooling (geared to the limited access) will facilitate development of a comprehensive life cycle management plan for the calandria vault and affected systems.

Project Costs :

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	1,752	8,955	10,400	845	0	21,952
OM&A							

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$23,874k	$21,952k	-$1,922k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering B Auxiliary Power System		
Project Number: 49104	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): March 2005	In-Service Date (month, year): February 2008	

Project Description:

Restore Pickering A and B within their design basis by enhancing standby power to:

- Start a high pressure emergency coolant injection pump within 30 minutes of a loss of the bulk electrical system event with no surviving units.
- Cool down all six reactors to less than 90 degrees Celsius within 24 hours of a loss of the bulk electrical system event with no surviving units.

The above are the minimal regulatory requirements of the auxiliary power system. The business objective will be met by providing a cost effective and reliable aero-derivative combustion turbine power generation facility that will provide back-up power immediately following a loss of the bulk electrical system event, should no units survive the transient.

Project Need (i.e., justification for the project):

On August 14, 2003, during the province-wide blackout, Pickering A and B experienced a loss of the bulk electrical system for approximately five hours. None of the three operating units at Pickering B survived the event leading to a total loss of class IV power across the two stations (Pickering A and B) and the site electrical system was unavailable. It is a Canadian Nuclear Safety Commission commitment to ensure that suitable provisions are in place to mitigate against potential future events of this nature.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	10,217	57,899	36,284	333	0	0	104,733
OM&A							

Initial Full Release (A): $116,700k	Actual or Forecasted Project Completion Cost (B): $104,733k	Variance (B-A): _-$11,967k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering B Standby Generator Governor Upgrade		
Project Number: 49109	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): October 2005	In-Service Date (month, year): July 2008	

Project Description:

- Replace the existing Woodward governors and fuel governor controls with programmable logic controllers, fuel metering valve and Lucas fuel pumps.
- Replace majority of control/start logic relays with programmable logic controllers.
- Install independent over-speed protection rack.
- Replace timers and speed switches with programmable logic controllers software.

Project Need (i.e., justification for the project):

Standby generator governor components are showing increased potential for failure. Proactive strategic improvement initiative to prevent standby class III power reliability/availability degradation due to aging of obsolete components.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	2,212	7,664	9,237	2,880	0	0	21,993
OM&A							

Initial Full Release (A): $22,872k	Actual or Forecasted Project Completion Cost (B): $21,993k	Variance (B-A): -$879k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering Site (A and B) – Heavy Water (D_2O) Storage Facility		
Project Number: 49251	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): November 2006	In-Service Date (month, year): July 2010	
Project Description: Design and construct additional facilities for D_2O storage as well as drum handling, cleaning and testing facilities.		
Project Need (i.e., justification for the project): Pickering A and B need to improve their overall ability to manage D2O inventories, to address a series of operational issues with respect to D_2O storage and handling, and to support continuous station operation in a safe and cost effective manner. The ability to allow large volume bulk swap of heavy water, and also allow segregation of different steams of D_2O is required, as well as the need for management, handling, and washing of D_2O drums.		

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital		13	363	898	2,166	9,829	13,269
OM&A							

Initial Full Release (A): N/A – Developmental Release	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A): N/A
Variance Explanation (if Variance >10% of Initial Full Release): N/A		

Ontario Power Generation – Project Summary

Project Name: Pickering A Switchyard Relay Building Cable Replacement		
Project Number: 49266	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): Dec 2006	In-Service Date (month, year): June 2010	

Project Description:

Replace the existing relay building with new redundant (A and B) relay buildings in the Pickering A switchyard, and install new cabling between the Pickering A powerhouse and the Pickering A switchyard.

Project Need (i.e., justification for the project):

As a result of a fire in early 2006, the protection, control, and telecom equipment in Pickering A switchyard relay building was damaged beyond repair. Further investigation revealed a significant number of fire-damaged cables inside cable trenches in the relay building. The extent of the damage forced Hydro One and OPG to bypass the damaged relay building equipment with a temporary protection and control solution in order to maintain connection of Pickering A units to the grid. Subsequent investigation into the health of the existing cables connecting the station with the switchyard also showed significant degradation as a result of aging and submersion in water for extended durations. The modification will fix the identified problem in the switchyard, improve security of the bulk electricity system, and provide independent and fully separated dual protection channels, thereby enhancing reliability.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	124	9,519	2,577	1,436	854	14,510
OM&A							

Initial Full Release (A): $15,772k	Actual or Forecasted Project Completion Cost (B): $14,510k	Variance (B-A): -$1,262k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation - Project Summary

Project Name: Security Optimization		
Project Number: 62558	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): April 2002	In-Service Date (month, year): December, 2008	
Project Description: Improve physical security provisions within Pickering A, Pickering B, and Darlington stations.		
Project Need (i.e. justification for the project): This project is required to meet Canadian Nuclear Safety Commission security requirements.		

Project Costs :

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	140,729	22,811	7,310	1,100	0	0	171,950
OM&A							

Initial Full Release (A): $160,858k	Actual or Forecasted Project Completion Cost (B): $171,950k	Variance (B-A): $11,092k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation - Project Summary

Project Name: Additional Feeder Cut and Weld Tooling		
Project Number: 62567	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): June 2007	In-Service Date (month, year): December 2008	

Project Description:

Specification and acquisition of two additional, improved feeder cut and weld tooling systems to facilitate concurrent feeder replacements.

Project Need (i.e. justification for the project):

Feeder replacement is expected to be the critical path item for all Pickering A and Darlington outages in the 2008-2017 timeframe. The three sets of tools will make the following currently unachievable results possible:

- Conducting feeder replacement execution at two reactor faces in parallel when it is required.
- Completing concurrent training or one face execution at another Nuclear station, if it is required
- Reducing feeder replacement time by using the new and improved tools

DNGS has indicated the requirement for additional tooling to perform a concurrent 2-face campaign. We estimate that similar conditions can be expected regularly at both PNGSA and DNGS in the 2008-2017 timeframe. Outage delays are possible if there is a shortage of tools due to an overlap in feeder replacement campaigns for OPG and Bruce Power stations.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	0	0	2,261	8,469	1,404	0	12,134
OM&A							

Initial Full Release (A): $15,763k	Actual or Forecasted Project Completion Cost (B): $12,134k	Variance (B-A): -$3,629k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation - Project Summary

Project Name: Darlington Fire Protection Upgrade Program Phase 2		
Project Number: 79016	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): October 1997	In-Service Date (month, year): December 2007	

Project Description:

Complete fire protection improvements at Darlington, specifically:

- Install turbine-generator fire suppression upgrades per (REGC AR 28023793) commitment to CNSC.
- Install fire detection upgrades in the main control room & associated areas (REGC A/R 28023739)
- Construct a emergency response team (ERT) Facility
- Install containment dyking around each turbine-generator set.

Project Need (i.e. justification for the project):

To satisfy CNSC requirements regarding fire protection provisions at Darlington.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	18,412	306	55	47	0	0	18,820
OM&A							

Initial Full Release (A): $15,400	Actual or Forecasted Project Completion Cost (B): $18,820k	Variance (B-A): $3,420k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

- The Emergency Response Team Facility was originally constructed as a commercial modification, as opposed to the more rigorous nuclear design and quality standards that should have been applied. This resulted in increased costs ($0.7M) associated with re-engineering, and interest due to in-service delays.
- The Fire Detection Alarm Upgrade package increased ($1.0M) due to increased use of premium time to meet the regulatory commitment date arising from slippages in design work and resource shortages as well as the design and construction of a training mock-up.
- During the Available for Service review for the Turbine Generator Fire Suppression system, it was identified that there was insufficient pressure relief capability in the system and the piping was routed such that it interfered with the maintenance of other equipment. Redesign and installation work required to resolve these deficiencies increased costs ($1.8M).

Ontario Power Generation – Project Summary

Project Name: Pickering B Chemistry Standards (CH-002)		
Project Number: 79147	Project Category: ☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): February 1998	In-Service Date (month, year): June 2008	

Project Description:

Implement the capital modifications necessary for compliance with the OPG standardized chemistry program:

- Install ultraviolet oxidation system to improve D2O upgrader feed purification.
- Replace the gas chromatographs in the helium cover gas sampling system.
- Install new boiler water and steam sampling panels.
- Install heat transport system hydrogen control improvements.
- Install individual isolation valves on the heat transport system ion exchange columns.
- Install hydrazine addition system to permit wet lay-up of the condensers.
- Install an inductively coupled plasma spectrometer.

Project Need (i.e., justification for the project):

An internal review identified the need for improved chemistry standards at OPG Nuclear stations to more effectively address plant chemistry control, and its potential impact on operational performance and potential equipment degradation. The program includes standards, procedures and system improvements to achieve this result. Similar projects have been completed at Pickering A and Darlington.

Project Costs):

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	11,117	4,072	1,056	1,501	0	0	17,746
OM&A							

Initial Full Release (A): $16,772k	Actual or Forecasted Project Completion Cost (B): $17,746k	Variance (B-A): $974k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation - Project Summary

Project Name: Fire Protection Upgrade Program Phase 3		
Project Number: 79148	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): August 2001	In-Service Date (month, year): December 2008	

Project Description:

This project was undertaken to:

- Resolve deviations to the Fire Code Compliance Review (CCR), Fire Safe Shutdown Analysis (FSSA) and Fire Safety Assessment (FSA)
- Complete the Fireworks alarm system installation

Project Need (i.e. justification for the project):

To meet our CNSC commitment to become compliant with CCR, FSSA and FSA, and complete the Fireworks alarm system installation.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Budget	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	24,143	2,653	1,915	151		0	28,862
OM&A							

Initial Full Release (A): $21,000k	Actual or Forecast Project Completion Cost (B): $28,862k	Variance (B-A): $7,826k

Variance Explanation (if Variance >10% of Initial Full Release): N/A

- Underestimation of scaffolding & labour costs for the CCR/FSA fire detection work package, including recommissioning a part of the fire detection system, increased costs by $8 million.
- Underestimation of scaffolding & labour costs for the Sprinkler & Standpipe work package, including resolution of lack of overpressure relief for the booster pump, increased costs by $1.3 million.
- Reduction of scope through new approaches to meeting regulatory commitments and minimizing the number of devices installed reduced costs by $1.4 million.

Ontario Power Generation – Project Summary

Project Name: Nuclear Programs and Training Security Fence Project		
Project Number: 25609	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): November 2005	In-Service Date (month, year): September 2010	
Project Description: Install improved perimeter fencing system at Pickering A, Pickering B, and Darlington, including lighting, perimeter monitoring, and other required functions.		
Project Need (i.e., justification for the project): This project is required to meet Canadian Nuclear Safety Commission security requirements.		

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	2,064	1,612	18,511	13,800	6,300	4,613	46,900
OM&A							

Initial Full Release (A): N/A – Partial Release	Actual or Forecast Project Completion Cost (B): N/A	Variance (B-A): N/A
Variance Explanation (if Variance >10% of Initial Full Release): N/A		

Ontario Power Generation – Project Summary

Project Name: Nuclear Programs and Training Security Hardening Project		
Project Number: 25901	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): November 2005	In-Service Date (month, year): December 2010	
Project Description: Improve physical security provisions within Pickering A, Pickering B, and Darlington stations.		
Project Need (i.e., justification for the project): This project is required to meet Canadian Nuclear Safety Commission security requirements.		

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	123	41	195	3,015	5,151	5,335	13,860
OM&A							

Initial Full Release (A): N/A – Partial Release	Actual or Forecast Project Completion Cost (B): N/A	Variance (B-A): N/A
Variance Explanation (if Variance >10% of Initial Full Release): N/A		

Ontario Power Generation – Project Summary

Project Name: Nuclear Programs and Training Controlled Area Improvements

Project Number:	Project Category:	Project Type:
25902	☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	☒ Capital ☐ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
November 2005	September 2009

Project Description:

Reconfigure site access, such that all access to the Pickering or Darlington sites is through a single secure entrance.

Project Need (i.e., justification for the project):

This project is required to meet Canadian Nuclear Safety Commission security requirements.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	26	216	2,051	5,727	6,068	0	14,088
OM&A							

Initial Full Release (A):	Actual or Forecast Project Completion Cost (B):	Variance (B-A): N/A
N/A – Partial Release	N/A	

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Nuclear Programs and Training Security Monitoring Room		
Project Number: 25905	Project Category: ☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): November 2005	In-Service Date (month, year): December, 2008	
Project Description: Replace security monitoring rooms at Pickering site and Darlington to meet current requirements.		
Project Need (i.e., justification for the project): This project is required to meet Canadian Nuclear Safety Commission security requirements.		

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital	1,951	2,622	6,882	6,930	848		19,233
OM&A							

Initial Full Release (A): N/A – Partial Release	Actual or Forecast Project Completion Cost (B): N/A	Variance (B-A): N/A
Variance Explanation (if Variance >10% of Initial Full Release): N/A		

Table 1
Capital Project Listing - Nuclear
Facility Projects - Released Amount and Balance to be Released
Projects >$10M Total Project Cost[1]

Line No.	Project Name	Project Summary Ref. No.	Category	Start Date	Final In-Service Date	Released Amount ($M)	Balance To Be Released ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Project summaries for the following projects are included in this section of the application						
	Darlington NGS						
1	Second Darlington Full Scope Simulator	28452	Sustaining	Sep-06	Jul-09	14.2	0.0
2	D2O Storage Facility	31555	Sustaining	Nov-06	Dec-10	2.8	25.4
3	Improve Maintenance Facilities at Darlington	31717	Sustaining	Jan-02	Dec-11	1.4	43.0
4	Main Control Room HVAC	33293	Sustaining	May-01	Sep-08	10.9	0.0
5	Chiller Replacement to Reduce CFC Emissions	33631	Regulatory	Jan-04	Dec-11	6.6	6.7
6	FH Computer Replacement	33815	Sustaining	Aug-05	Feb-12	10.4	0.0
7	Used Fuel Dry Storage In Station Modifications	33925	Sustaining	Jan-01	Dec-08	44.4	0.0
8	Shutdown System Computer Aging Management	33955	Sustaining	Nov-06	Dec-11	1.6	63.0
9	Standby Generator Controls Replacement	33973	Sustaining	Dec-06	Dec-11	1.2	13.1
10	DN DCC Replacement / Refurbishment / Upgrades	33977	Sustaining	Sep-03	Dec-12	19.2	0.0
11	Auxiliary Heating System - Phases 1 & 2 Alternative Heating	34000	Regulatory	Mar-06	Dec-09	2.0	18.5
12	Feeder Replacement As Low As Reasonably Achievable Optimization	34008	Sustaining	Jan-06	Dec-08	10.8	0.0
13	Fire Protection Upgrade Program Phase 2	79016	Regulatory	Oct-97	Dec-07	19.0	0.0
14	Fire Protection Upgrade Program Phase 3	79148	Regulatory	Aug-01	Dec-08	28.9	0.0
	Pickering A NGS						
15	Calandria Vault Inspection Tooling	46537	Sustaining	Aug-06	Dec-09	22.0	0.0
16	Pickering Site - D2O Storage Facility	49251	Regulatory	Nov-06	Jul-10	1.9	11.4
17	Switchyard Relay Building Cable Replacement	49266	Sustaining	Dec-06	Jun-10	14.5	0.0
	Pickering B NGS						
18	CFC Replacement (Freon Removal)	40543	Regulatory	Oct-03	Dec-09	19.0	0.0
19	Auxilliary Power System for PB	49104	Regulatory	Mar-05	Feb-08	104.7	0.0
20	Standby Generator Governor Upgrade	49109	Sustaining	Oct-05	Jul-08	22.0	0.0
21	Chemistry Standards (CH-002) at PB	79147	Regulatory	Feb-98	Jun-08	17.8	0.0
	Engineering & Modifications						
22	Additional Feeder Cut and Weld Tooling	62567	Sustaining	Jun-07	Dec-08	12.1	0.0
	Nuclear Programs & Training						
23	Security Fence Project	25609	Regulatory	Nov-05	Sep-10	39.3	7.6
24	Security Hardening Project	25901	Regulatory	Nov-05	Dec-10	4.9	9.0
25	Controlled Area Improvements	25902	Regulatory	Nov-05	Sep-09	1.9	12.2
26	Security Monitoring Room	25905	Regulatory	Nov-05	Dec-08	11.6	7.7
27	Security Doors Upgrade	25908	Regulatory	Aug-06	Dec-09	3.1	10.1
28	Security Optimization (Capital)	62558	Regulatory	Apr-02	Dec-08	172.0	0.0
29	**Subtotal Facility Projects**					620.1	227.8

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D2
Tab 1
Schedule 2
Table 2

Table 2
Capital Project Listing - Nuclear
Facility Projects - Released Amount and Balance to be Released
Projects $5M - $10M Total Project Cost[1]

Line No.	Project Name	Category	Project Description	Released Amount ($M)	Balance To Be Released ($M)
	(a)	(b)	(c)	(d)	(e)
	Darlington NGS				
1	Darlington Learning Center Modifications	Regulatory	Modify the Darlington Learning Centre to accept a Darlington full scope simulator and provide the supporting building infrastructure.	9.8	0.0
2	Replacement of Obsolete Computer Components	Sustaining	Replace obsolete digital control computer components.	9.1	0.0
3	New Change Room Facility	Sustaining	Replace life-expired change room facilities used by temporary staff.	1.3	7.6
4	Reactivity Mechanism Replacement Tooling	Sustaining	Develop tooling for the replacement of reactivity mechanisms.	8.0	0.0
5	Turbine Generator Vibration Monitor System Replacement	Sustaining	Upgrade the turbine generator vibration monitoring system. Current system has already reached end of life and uses obsolete hardware & software with no spares.	1.1	5.8
6	Fuel Handling Power Track Improvement	Sustaining	Modify Fuel Handling Power Track to improve reliability and add condition monitoring capability.	0.9	5.6
7	Liquid Chlorination System Upgrade	Sustaining	Improve reliability of chlorination system to more effectively combat zebra mussel infestation.	5.1	0.0
	Pickering A NGS				
8	Unit 2 and 3 D2O Storage Tanks	Sustaining	Install storage tanks to store the Primary Heat Transport D2O drained from Units 2 and 3. Excess capacity in tanks sourced from Bruce Heavy Water Plant to be used for additional site storage.	8.6	0.0
9	Administration Building Cafeteria Modifications	Sustaining	Refurbish Cafeteria to address health & safety concerns, improve functionality and upgrade systems to current requirements.	8.3	0.0
10	Redundant Calandria Vault Dryer	Sustaining	Improve reliability of calandria vault dryers to minimize corrosion of structures, systems and equipment in the calandria vault.	5.6	0.0
11	Modular Buildings 1,2 & 3 Refurbishment	Sustaining	Carry out major renovation of the existing modular buildings to address issues relating to aged building structure and health & safety concerns arising from potential mold infestation.	5.0	0.0
	Pickering B NGS				
12	Reactor Controller Upgrades	Sustaining	Improve reliability of reactor and safety system controllers, which have reached design life.	9.6	0.0
13	PB Emergency Power Generator Control Upgrade	Sustaining	Improve reliability of Emergency Power Generators by replacing obsolete components.	4.0	1.7
14	Radioactive Emission Reduction	Regulatory	Improve the Radioactive emissions monitoring and control performance per CNSC Operating License requirements (Project EV-005)	6.1	1.3
	Inspection & Maintenance Services				
15	CIGAR Control System Replacement Obsolescence/Configuration Management (Channel Inspection, Gauging and Relocation System)	Sustaining	Upgrade the CIGAR control system by replacing obsolete PDP computer hardware, drive system hardware and software.	6.7	0.0
16	**Subtotal Facility Projects**			89.1	22.0

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D2
Tab 1
Schedule 2
Table 3

Table 3
Capital Project Listing - Nuclear
Projects <$5M Total Project Cost[1]

Line No.	Project Description	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	Facility Projects (Released Amount)			
1	Darlington NGS	11	21.7	2.0
2	Pickering A NGS	9	16.3	1.8
3	Pickering B NGS	5	8.6	1.7
4	Engineering & Modifications	2	2.3	1.1
5	Programs & Training	3	6.6	2.2
6	Supply Chain	2	5.5	2.8
7	Inspection & Maintenance Services	3	2.5	0.8
8	Subtotal Facility Projects (Released Amount)	35	63.5	1.8
	Facility Projects (Balance to Be Released)			
9	Darlington NGS	6	11.5	1.9
10	Pickering A NGS	4	9.5	2.4
11	Pickering B NGS	2	2.1	
12	Engineering & Modifications	1	2.5	2.5
13	Subtotal Facility Projects (Balance to be Released)	13	25.7	2.0
14	**Total**	35	89.1	2.5

1 Projects with expenditures during Test Period

Table 4a
Capital Project Listing - Nuclear
Facility Projects -- Listed Work to be Released[1]

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Facility Projects (Listed Work to be Released)		
	Darlington NGS		
1	Turbine-Generator Control Upgrade or Replacement	Sustaining	2008
2	Secondary Control Area Air Conditioning Unit Replacement	Sustaining	2008
3	Operations Support Building Refurbishment	Sustaining	2008
4	Replacement of Emergency Power System Uninterruptible Power Supply	Sustaining	2008
5	Feeder Freezing Penetration on the South Side of the Reactor	Sustaining	2008
6	Darlington Station Fire Detection System Upgrades	Sustaining	2009 or Future
7	Water Treatment Plant Control Room & Sludge Press Upgrade	Sustaining	2009 or Future
8	Universal Delivery Machine Fuel Push	Sustaining	2009 or Future
9	Alternative to Vault Vapour Recovery System	Sustaining	2009 or Future
10	Intake Structure Zebra Mussel Anti-Fouling Covers	Sustaining	2009 or Future
11	Condenser Efficiency Modifications	Sustaining	2009 or Future
12	Site Facilities Maintenance Building	Sustaining	2009 or Future
13	Suit Communication System Replacement	Sustaining	2009 or Future
14	Public Address System Upgrade	Sustaining	2009 or Future
15	Shutdown System 2 Radiation Reduction Tooling	Sustaining	2009 or Future
16	Transport Fuel Storage and Dispensing Facility	Sustaining	2009 or Future
	Pickering A NGS		
17	Replacement of Standby Boilers (Note 2)	Regulatory	2008
18	Inter-Station Transfer Bus Permanent Cabling	Regulatory	2008
19	Fuel Channel East Shift Tooling	Sustaining	2008
20	Channel Isolation and Draining Tool for Feeder Replacement	Sustaining	2008
21	Calandria Vault Component Repair Tooling	Sustaining	2008
22	Liquid Zone Control System	Sustaining	2009 or Future
23	New Parking Lots	Sustaining	2009 or Future
24	Ion Exchange Cleanup Vent Line Replacement	Sustaining	2009 or Future
25	Decommission/Decontruct Pickering Upgrader A Towers	Sustaining	2009 or Future
26	Sulzer B Online Feed and Sampling System Upgrade	Sustaining	2009 or Future
27	Ion Exchange Cleanup Oil/Water Separation Upgrade	Sustaining	2009 or Future
28	Miscellaneous D2O Building Liquid Recovery Collection Direct to Ion Exchange Cleanup	Sustaining	2009 or Future
29	Pickering Incoming/Outgoing Transfer System Loading Arms Upgrade	Sustaining	2009 or Future
30	Liquid Waste Management System PP&E Upgrade	Sustaining	2009 or Future
31	Service Wing H3 Off Gas Dryer Installation	Sustaining	2009 or Future
32	Feeder Replacement As Low As Reasonably Achievable Optimization	Sustaining	2009 or Future
33	Core Physics Reconfiguration	Sustaining	2009 or Future
	Table continues on Ex. D2, Tab 1, Sch 2 Table 4b		

1 Projects with potential expenditures during Test Period
2 Projects with potential cost > $10M

Table 4b
Capital Project Listing - Nuclear
Facility Projects -- Listed Work to be Released[1]

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Facility Projects (Listed Work to be Released) - Continued		
	Pickering B NGS		
34	Upgrade Fire Detection System for Standby Generator & Emergency Power Generator Buildings	Sustaining	2009 or Future
35	Replacement of Turbosupervisory Equipment Vibration Instrumentation	Sustaining	2009 or Future
36	Feeder Replacement As Low As Reasonably Achievable Optimization	Sustaining	2009 or Future
37	Install Aluma Seismic Platforms in Boiler Room	Sustaining	2009 or Future
38	Transport Fuel Storage and Dispensing Facility	Sustaining	2009 or Future
	Engineering & Modifications		
39	Feeder Integrity - Weld Overlay Tooling Development	Sustaining	2008
	Nuclear Programs & Training		
40	Armed Responder Training Facility	Regulatory	2008
41	Security Water Side Detection (Note 2)	Regulatory	2008
42	Reactor Cooling Security Enhancement	Regulatory	2008
43	Changes in Roads	Sustaining	2009 or Future
44	Engineering Desktop Simulators	Sustaining	2009 or Future
45	Certification Training Classroom Refurbishment	Sustaining	2009 or Future
46	Certification Training Desktop Simulator Upgrade	Sustaining	2009 or Future
	Nuclear Supply Chain		
47	Pickering Warehouse Refurbishment	Sustaining	2008

1 Projects with potential expenditures during Test Period
2 Projects with potential cost > $10M

REFURBISHMENT AND NEW GENERATION – NUCLEAR

1.0 PURPOSE

The purpose of this evidence is to present an overview description of the nuclear plant refurbishment projects and new nuclear generation development projects (new nuclear build) for the historical and bridge years and test period.

2.0 PROJECT OVERVIEW

Based on current inspection and maintenance plans, Pickering B units are expected to reach the end of their production life over 2014 - 2016 while Darlington units are predicted to come to the end of their production life over 2018 - 2020. Collectively, this represents 5600 MW of electricity generation in the province of Ontario and approximately 25 percent of OPG's installed generating capacity. Similar timelines for potential refurbishments are facing other Canadian Deuterium Uranium ("CANDU") reactors in Canada, as well as other nuclear generators in North America.

Nuclear unit production life is primarily determined by life-limiting components, the replacement or refurbishment of which would require a multi-year outage. Specifically, these components are the fuel channels, steam generators and feeders at Pickering B, and fuel channels and feeders at Darlington. The production life of other station components can be extended through ongoing maintenance or less extensive replacement activities, which would be integrated with normal outage schedules or, if more efficient, be carried out as part of the major outage duration driven by refurbishment of life-limiting components.

Given the long lead times to procure critical components and the need to properly plan and prepare for execution of such major projects, OPG began exploratory work in 2005 to evaluate the feasibility of refurbishing and continuing to operate the Pickering B and Darlington units beyond their currently expected production lives.

In June 2006, the Ontario government directed OPG to begin feasibility studies on refurbishing its existing nuclear plants, and to begin an environmental assessment ("EA") on

refurbishing Pickering B's four nuclear units. In the same directive, OPG was directed by the Ontario government to begin a federal approvals process, including preparation of an EA, for building new nuclear generating units at an existing site. Refurbishment and new nuclear build accountabilities were assigned to the newly-formed Nuclear Generation Development and Services Division.

The need for refurbishment and new build is also being addressed in the Ontario Power Authority's Integrated Power System Plan ("IPSP"). In that context, the Ontario Power Authority, in response to a Directive from Ontario's Minister of Energy, is planning for up to 14,000 MW of nuclear generation to meet Ontario's requirement for base load energy. The IPSP recognizes that refurbishment decisions rest with facility operators and owner (see EB-2007-0707, exhibit D-6-1 page 20 - 21). However, the IPSP "reference plan" and all scenarios analyzed include substantial nuclear refurbishment (EB-2007-0707, exhibit G-1-1 page 2). In addition, given that the lead times associated with a new nuclear unit (EA process and approvals, combined with construction and commissioning of a new nuclear unit) range from nine to twelve years, the IPSP Supply Discussion Paper supports activities to expeditiously proceed with the development of new nuclear units (see EB-2007-0707, exhibit C-8-1 page 76).

2.1 Refurbishment

The goal of a major nuclear unit refurbishment is extension of production life to provide an additional 25 to 30 years of generation following completion of refurbishment. A major nuclear unit refurbishment project would involve a multi-year outage for replacement of life-limiting critical components as noted above, as well as maintenance/replacement of other components which are most cost-effectively done during the extended outage period. Such refurbishment could be carried out as part of a full station outage, or on a unit by unit basis with other nuclear units continuing to operate.

OPG envisages a major refurbishment project being managed in three phases, specifically:

- Phase 1: Assessment and viability recommendation
- Phase 2: Outage planning and preparation

- Phase 3: Refurbishment outage execution

Phase 1 of a refurbishment project is typically funded by base OM&A. Phases 2 and 3, if approved, would typically be funded as capital projects.

Phase 1 is an assessment phase, aimed at determining feasibility and financial viability of the refurbishment options. This involves:

- Engineering studies, including a plant condition assessment to assess the condition of the plant, with special focus on the life-limiting components. Studies would be conducted to assess the condition of all major station systems and components. In addition, the logistics/methods/timing for carrying out refurbishment on a multi-unit station would be assessed.
- An EA as required by the *Canadian Environmental Assessment Act*. Identified issues or deficiencies would be assessed for inclusion in the refurbishment project scope.
- An integrated safety review ("ISR") to address key safety factors against modern safety standards. The basis for this study is discussed with the Canadian Nuclear Safety Commission ("CNSC"), and the results used in the preparation of the integrated implementation plan. Identified issues would be assessed for inclusion in the refurbishment project scope.
- An integrated implementation plan that incorporates results of the ISR and EA. The integrated implementation plan requires CNSC acceptance for incorporation into the operating licence.
- Concept studies for replacement of critical life-limiting components (i.e., feeders and fuel channels and for Pickering B, steam generators).
- Generation and assessment of a variety of refurbishment and non-refurbishment scenarios based on the results of the plant condition assessment, ISR, EA, and integrated implementation plan.
- A phase 2 and 3 project schedule and resourced cost estimate, and a recommendation for the Board of Directors consideration, based on an assessment of the business case of all alternatives.

Should the OPG Board decide to proceed with refurbishment of Pickering B, phase 2 of the project is the planning and preparation phase, which involves:

- Project management staff hiring and training, and decision on internal versus external project management.
- Letting of contracts for long lead materials such as steam generator components and fuel channel replacement tooling.
- Procurement of other required material.
- Completion of detailed engineering.
- Site preparation.
- A project schedule and resourced cost estimate for the refurbishment outage execution, to support request for phase 3 approval by the Board of Directors.
- Selection of direct work contractors to execute the major component replacement packages (fuel channels and feeders, steam generators).

Phase 3 of a major refurbishment project is the execution and close-out phase, completing all planned aspects of refurbishment, as well as associated re-commissioning (as required), obtaining licensing approvals and all other activities to return the units to production.

2.1.1 Pickering B Refurbishment

Pickering B Units 5, 6, and 7 are expected to reach end of their production lives in 2014. Phase 1 work is well underway. A recommendation with respect to Pickering B refurbishment options is expected to be provided to the Board of Directors no later than early 2009. The decision with respect to the Pickering B refurbishment option was delayed to allow OPG to assess the results of the environmental assessment and integrated safety review processes currently under way.

Work that is underway is as follows:

- A plant condition assessment was completed in July 2007, the results of which are being incorporated into the ISR referenced below. The plant condition assessment included a review of approximately 60 major systems and their components, across the station, to ensure that requirements for inspections, repairs, replacement and/or modification are

appropriately incorporated into the refurbishment outage or station work programs before and after the refurbishment outage.

- As of August 2007, OPG has assessed all twelve safety factors against modern standards, and has prepared and submitted eleven of the required twelve safety factors reports to the CNSC for approval. The one remaining safety factor report is in the process of being completed and is expected to be submitted in Q2 2008.
- A draft EA report was submitted to the CNSC in June 2007. Preliminary findings are that there are no significant adverse effects, and the majority of the potential effects from a refurbishment project are similar to those of the Pickering A return to service project. Following review by the CNSC and other federal authorities, a final EA study report was submitted to the CNSC in December, 2007. During 2008, the CNSC staff will prepare an environmental screening report for public review and presentation to the Commission for their approval.
- The integrated implementation plan is a compilation of the activities which will be undertaken to address findings of the ISR and EA processes and, as such, cannot be finalized until the EA and ISR are completed. The integrated implementation plan is currently expected to be filed by early 2009, for approval with the CNSC.
- Public Consultations: OPG has conducted stakeholder workshops, held three rounds of open houses across Durham Region and in Toronto, participated in numerous community events and mailed out newsletters and open house invitation cards to approximately 150,000 homes in order to seek public input on the potential refurbishment project.

Phase 1 costs are outlined in Chart 1.

Chart 1

Pickering B Refurbishment Costs, 2005 - 2009, Base and Project OM&A

OM&A Cash Flows (M$)	Category		2005	2006	2007	2008	2009
Refurbishment – Phase 1	Base OM&A	Actual	1.3	11.3	23.3		
		Budget	3.0	8.9	22.0	6.2	
Planned Projects on Hold[1]	Project OM&A	Actual					
		Budget					5.1

[1] In Charts 1 and 2, planned projects on hold reflects previously-identified projects that were put on hold pending a refurbishment decision. Following the OPG Board decision on a refurbishment option, the associated projects would be taken off hold and re-assessed as appropriate based on the OPG Board's decision.

This filing also includes, very preliminary phase 2 (capital) costs associated with undertaking a major refurbishment project. These are presented in Chart 2, and will be confirmed and revised as necessary as part of the phase 1 work.

Chart 2

Pickering B Refurbishment Costs, 2005 - 2011, Capital Projects

Capital Cash Flows (M$)	Category		2005	2006	2007	2008	2009
Refurbishment - Phase 2	Project Capital	Actual					
		Budget	0	0	0	0	126.1
Planned Projects on Hold	Project Capital	Actual					
		Budget	0	0	0	0	22.7

Refurbishment - Phase 2 cost estimates for 2008/2009 in Chart 2 are associated with first unit refurbishment (expected to commence around 2013, if approved), and will be primarily directed to issuing contracts for long-lead items (primarily associated with steam generators, fuel channel tooling) and issuing a contract for a project management partner (should the external project management option be selected).

Base OM&A, project OM&A and project capital budgets as noted in Chart 1 and 2, have been approved by the OPG Board. In this regard, section 6 (2) 4 of O. Reg. 53/05 specifically contemplates recovery of costs for refurbishment activities. A description of the associated deferral account and confirmation of OPG's compliance with the conditions is discussed in Ex. J1-T1-S1, and is applicable to both Pickering B and Darlington refurbishment activities.

2.1.2 Darlington Refurbishment

As the first Darlington unit is expected to reach end of production in 2018 which is later than Pickering B. Phase 1 Darlington refurbishment work is scheduled to start in 2008, with an expected Board of Directors decision on refurbishment options in 2010.

In 2008 and 2009, Darlington Phase 1 work will include a screening level economic assessment (providing a very preliminary assessment of refurbishment option viability),

subsequent commencement of engineering studies including a plant condition assessment, an Integrated Safety Review, and a public communications and consultation program.

Major activities associated with an EA for Darlington refurbishment are currently scheduled to occur after the test period following the completion of environmental assessment work for new nuclear build, although expenditures for EA work will be incurred in 2008/2009 for preparatory activities and some preliminary data collection.

Phase 1 costs are outlined in Chart 3 below.

Chart 3

Darlington Refurbishment Costs, 2005 - 2009

OM&A Cash Flows (M$)	Category		2005	2006	2007	2008	2009
Refurbishment – Phase 1	Base OM&A	Actual			0.4		
		Budget			0.7	18.5	22.7

As the Board of Directors decision on refurbishment options for Darlington is not anticipated until 2010**,** there are no phase 2 (capital) costs for Darlington in this filing.

Base OM&A budgets as presented in Chart 3 were approved by the Board of Directors as part of the business planning process. Recovery of costs is discussed above (section 2.1.1).

2.2 New Nuclear Build

The planning for new nuclear units is a complex and significant undertaking. Substantial work must be done in support of:

- Evaluating possible technologies and selecting a preferred alternative.
- Defining the overall project scope and execution strategy.
- Obtaining necessary regulatory approvals.
- Developing and executing a procurement strategy for the chosen technology, and the vast amount of supporting materials and equipment.

- Consulting with the public on the potential impacts of new nuclear construction and operations, and maintaining an informed local community throughout the planning process.
- Preparing the site for construction and arranging for infrastructure necessary to support the station.
- Constructing and commissioning the generating unit and supporting systems.
- Recruiting and training staff operate the station.

The upfront work includes extensive effort related to:

- Activities for carrying out an EA under the *Canadian Environmental Assessment Act*.
- Activities for obtaining required governmental licences, authorizations, permits or other approvals.
- Activities for evaluating the available nuclear plant technology options in support of selecting the technology to be deployed in Ontario.
- Activities supporting project definition and the eventual procurement of the plant and/or related components.

The Ontario Power Authority, through the IPSP has indicated its planning assumptions with respect to the amount and required timing of new nuclear generation. The IPSP recognizes the potential for up to four new nuclear generating units and up to 4,800 MW being developed (EB-2007-0707, exhibit D-6-1 page 17 - 18) with potential in-service dates starting as early as 2018 for a first unit.

In response to the June 2006 directive, OPG began planning the work required to obtain the necessary federal approvals, including planning for preparation of the EA. In addition, OPG initiated the review of available reactor designs in 2007 (collaboratively with Bruce Power), and completed the review in December 2007. As noted in Chart 4, there were only nominal expenditures in the historic years ($0.3M in 2006), associated with: retaining staff and consulting support for the new nuclear project; submission of site preparation licence application (September 2006), and initial public consultation and communication sessions (November 2006).

A preliminary base OM&A budget of $10M per year was established in the 2007 – 2011 business plan for new nuclear build activities in the Nuclear Generation Development and Services Division, and approved by the Board of Directors as part of the business planning process. Work undertaken in 2007 included:

- EA Activities
    - Submission of a project description to the CNSC, in support of establishing EA guidelines
    - Commencement of baseline studies and data collection in support of the EA
    - Development and implementation of a public consultation and community communications program
- Governmental licence, permit and authorization activities
    - Commencement of site preparation planning studies
- Technological assessment activities
    - Assessment of the nuclear technology options for possible deployment at the Darlington site

The funding requirements and key deliverables were reviewed and further refined in the 2008 - 2010 business plan. Some of the drivers for revising the work schedule and cost estimates were the federal approvals process, available technology, and experience in other countries that are also engaged in development of new nuclear power generation. In 2008 and 2009, the following major work activities are expected to be undertaken:

- Completion of the environmental assessment baseline study (2008)
- Preparation of draft environmental assessment guidelines and terms of reference (2008)
- Preparation of final environmental assessment guidelines and terms of reference (2009)
- Site evaluation completion (2008)
- Preliminary construction application submission (2009)

- Final site preparation license application submission (2009)
- Various procurement and planning activities, such as vendor assessment and selection

Chart 4 below, provides the actual costs for 2006 and 2007 along with cost estimates resulting from the 2008 - 2010 business planning process:

Chart 4

Pre-development New Nuclear Build Costs, Base OM&A (2008-2010 Business Plan)

OM&A Budget (M$)		2005	2006	2007	2008	2009
New Nuclear Build	Actual		0.3	11.2		
	Budget			10.0	75.3	67.2

Base OM&A costs as noted in Chart 4 has been approved by the OPG Board. In this regard, O. Reg. 53/05, as recently amended, specifically contemplates recovery of costs incurred and firm commitments made in the course of planning and preparation for the development of new nuclear generation facilities. A description of the associated deferral and variance account and confirmation of OPG's compliance with the conditions is discussed in Ex. J1-T1-S1, and is applicable to the new nuclear build activities.

3.0 EXPENDITURE SUMMARY

Chart 5 below, sets out actual (2005 - 2006) and forecast (2007 - 2009) base OM&A, project OM&A, and capital expenditures on the Pickering B refurbishment, Darlington refurbishment, and new nuclear build initiatives.

Chart 5

Program Cost Summary

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Line No.	Program ($M)	Cost Category	2005 Budget	2005 Actual	2006 Budget	2006 Actual	2007 Budget	2007 Actual	2008 Plan	2009 Plan
			(a)	(b)	(c)	(d)	(e)		(f)	(g)
1	**Base OM&A**	Pickering B Refurb	3.0	1.3	8.9	11.3	22.0	23.3	6.2	0.0
2		Darlington Refurb	0.0	0.0	0.0	0.0	0.7	0.4	18.5	22.7
3		New Nuclear Build	0.0	0.0	0.0	0.3	10.0	11.2	75.3	67.2
4		**Total Base OM&A**	**3.0**	**1.3**	**8.9**	**11.6**	**32.7**	**35.0**	**100.0**	**89.9**
5	**Project OM&A**	Pickering B Refurb	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**5.1**
6	**Project Capital**	Pickering B Refurb	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**148.8**

CAPITAL BUDGET – CORPORATE GROUPS

1.0 PURPOSE AND OVERVIEW

This evidence provides an overview of the capital budgets of OPG's corporate groups for the historical years, bridge years, and the test period, and provides explanations for period-over-period variances.

2.0 CAPITAL EXPENDITURES SUMMARY

Capital expenditures by OPG's corporate groups for the prescribed facilities are presented in Ex. D3-T1-S1 Table 1. OPG's business planning and budgeting process (described in Ex. A2-T2-S1) provides detailed information about the process through which expenditures are classified as capital in nature and how such projects are managed. Once these projects are completed, the assets associated with them are declared to be in service. In the case where the assets can be directly assigned to either regulated hydroelectric or nuclear facilities or business units, they are in service additions to the rate base for the respective business units. If the assets are held centrally, the regulated business units are charged a service fee for the use of these assets (as described in Ex. F3-T3-S1).

3.0 PERIOD-OVER-PERIOD VARIANCES

Period-over-period comparisons of capital expenditures by OPG corporate groups are presented in Ex. D3-T1-S1 Table 2.

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D3
Tab 1
Schedule 1
Table 1

Table 1
Capital Expenditures Summary - Corporate Groups ($M)
(Capital Expenditures in Corporate Groups impacting Prescribed Facility Rate Base or Asset Service Fee)

Line No.	Corporate Group	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**CIO**	13.3	13.5	15.7	16.6	16.5
2	**Real Estate**	3.3	4.2	12.7	7.3	5.5
3	**Other**	0.0	0.0	0.0	0.0	0.0
4	**Total**	16.6	17.7	28.4	23.9	22.0

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D3
Tab 1
Schedule 1
Table 2

Table 2
Comparison of Capital Expenditures - Corporate Groups ($M)
(Capital Expenditures in Corporate Groups impacting Prescribed Facility Rate Base or Asset Service Fee)

Line No.	Corporate Group	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**CIO**	15.1	(1.8)	13.3	0.2	13.5	(3.6)	17.1	2.2	15.7
2	**Real Estate**	3.1	0.2	3.3	0.9	4.2	1.6	2.6	8.5	12.7
3	**Other**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Total**	18.2	(1.6)	16.6	1.1	17.7	(2.0)	19.7	10.7	28.4

Line No.	Corporate Group	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
5	**CIO**	16.3	(0.6)	15.7	0.9	16.6	(0.1)	16.5
6	**Real Estate**	7.3	5.4	12.7	(5.4)	7.3	(1.8)	5.5
7	**Other**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Total**	23.6	4.8	28.4	(4.5)	23.9	(1.9)	22.0

CAPITAL EXPENDITURES – CORPORATE GROUPS

1.0 PURPOSE AND OVERVIEW

The purpose of this evidence is to provide detailed information about the capital expenditures by OPG's corporate groups for the prescribed facilities during the test period.

2.0 CAPITAL PROJECTS LISTING

OPG has used a tiered structure for reporting on all capital projects which have budgeted expenditures during the 2008 and 2009 test period. The projects in each tier are shown in the attached tables, with supporting project documentation presented in Appendix A, as required.

Based on the tiered reporting structure, the following information is provided for capital projects being undertaken by OPG's corporate groups:

- Tier 1: Projects with a total cost of $10M or greater, for which summary level information as well as a project summary form are provided.
- Tier 2: Projects with a total cost of $5M to $10M, for which summary level information is provided.
- Tier 3: Projects with a total cost of less than $5M for which aggregated information is provided.

There is one project with a total cost of $10M or greater, which is being undertaken by the Real Estate group and relates to nuclear office expansion. The project summary form is provided in Appendix A.

There are four projects with a total cost of $5M to $10M each, three of which are being undertaken by the CIO group and one is being undertaken by the Real Estate group. Summary information related to these projects is provided in Ex. D3-T1-S2 Table 2.

There are 71 projects with a total cost of less $5M each, the majority of which (by dollar value) are being undertaken by the CIO group. Aggregated information for these projects is provided, by corporate group, in Ex D3-T1-S2 Table 3. Examples of some of these capital

projects include, under the CIO, an upgrade to the Passport application (Nuclear's integrated software system), telecom infrastructure upgrades for hydroelectric (Ottawa St. Lawrence Plant Group), IT systems applications upgrades for certain corporate groups, and, under the Real Estate group, roofing-related projects at the Kipling Building Complex and the Bruce site.

LIST OF ATTACHMENTS

Appendix A: Ontario Power Generation – Project Summary Form

- Project Number: 632.2-1016 Clarington – OPG Clarington Energy Park Development Project

Ontario Power Generation – Project Summary

Project Name: OPG Clarington Energy Park Development Project		
Project Number: 632.2-1016 Clarington	Project Category: ☐ Regulatory ☐ Sustaining ☒ Value Enhancing	Project Type: ☒ Capital ☐ OM&A
Project Start Date (month, year): March 2007	In-Service Date (month, year): Land purchase – July 2007 Phases 1 and 2 – 2012 Phase 3 – To be determined	

Project Description

OPG purchased a 61 acre property (the "Site") in the Clarington Energy Park to meet possible future Nuclear office space needs in Clarington area. The land acquisition and subsequent proposed development within the Clarington Energy Park are strategic for OPG to maintain flexibility in its delivery of space options for the Nuclear business. Such space needs would include consolidation of existing leases and replacement of existing owned buildings.

The Site is vacant and un-serviced and needs to be prepared for development by bringing in municipal services (i.e., water and sanitary sewer mains and storm water management system, an internal road system to subdivide the Site into building parcels, and improvement of existing roads). Due to timeline risks for securing municipal approvals, the project has been structured in the following phases: Land Purchase, Phase 1 - Municipal Approvals and Design Work, and Phase 2 - Execution of the Servicing and Subdivision Agreement and the construction of servicing infrastructure. The final phase of the project, Phase 3 - Construction of Office Building, is excluded from Real Estate's business plan as it will only proceed at such time as the building needs are more fully defined, a lease versus own business decision has been made and a separate business case approval has been obtained.

Project Costs (as per current Business Plan): $000

New Office Building	LTD 2007 Actual	2008	2009	2010	2011	2012	Total Costs
Land Purchase	5,200						5,200
Phases 1 and 2		4,200	4,100	3,100	3,100	1,900	16,400
Phase 3							*TBD*
Total Project Costs							**21,600**

Initial Full Release (A):	Actual Completion Cost (B):	Variance (B-A):

Variance Explanation (if Variance >10% of Initial Full Release):
N/A

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D3
Tab 1
Schedule 2
Table 1

Table 1
Capital Project Listing - Corporate Groups
(Capital Projects in Corporate Groups impacting Prescribed Facility Rate Base or Asset Service Fee)
Projects >$10M Total Project Cost[1]

Line No.	Project Name	Project Summary Ref. No.	Category	Start Date	Final In-Service Date	Total Project Cost ($M)
	(a)	(b)	(c)	(d)	(e)	(f)
	Project summaries for the following projects are included in this section of the application					
	CIO					
1	No projects in this category					
	Real Estate					
2	OPG Clarington Energy Park Development Project	632.2-1016 Clarington	Value Enhancing	2007	2012[2]	21.6
	Total					21.6

1 Projects with expenditures during Test Period
2 Final in-service date refers to Phases 1 and 2 of the project. Final in-service date for Phase 3 is to be determined. Refer to Ex. D3-T1-S2 Appendix A for details.

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D3
Tab 1
Schedule 2
Table 2

Table 2
Capital Project Listing - Corporate Groups
(Capital Projects in Corporate Groups impacting Prescribed Facility Rate Base or Asset Service Fee)
Projects $5M - $10M Total Project Cost[1]

Line No.	Project Name	Cost Assignment	Project Description	Total Project Cost ($M)
	(a)	(b)	(c)	(d)
	CIO			
1	Supplier Relationship Management ("SRM")	Value Enhancing	Deliver an environment that allows users to purchase materials via a self service portal, analyze spend, and send documents to suppliers. This procurement environment also allows material analysts to perform daily functions within SRM.	7.8
2	Cost Schedule Improvement	Value Enhancing	Purchase, integrate, and implement software, processes and organization changes to improve Nuclear Engineering & Modifications Division's ability to obtain timely and accurate information in order to effectively select and manage projects.	7.7
3	Day Ahead Market Program	Value Enhancing	Provide greater assurance of adequate and reliable electricity supply in the operational timeframe, improve day-ahead price certainty, and lead to more efficient use of resources. Upon direction from the IESO to implement the Day Ahead Market, this project would be re-classified as Regulatory.	6.2
	Real Estate			
6	Bruce B21 Buildling Renovation	Sustaining	Renovation of Building B21 on Bruce site for use as office space by Nuclear Waste Management Division and IMS.	6.1
	Total			27.8

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit D3
Tab 1
Schedule 2
Table 3

Table 3
Capital Project Listing - Corporate Groups
(Capital Projects in Corporate Groups impacting Prescribed Facility Rate Base or Asset Service Fee)
Projects <$5M Total Project Cost[1]

Line No.	Project Description	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	CIO			
1	**Aggregate Total All Projects <$5M**	44	51.4	1.2
	Real Estate			
2	**Aggregate Total All Projects <$5M**	27	6.8	0.3
	Other			
3	**Aggregate Total All Projects <$5M**	0	0.0	0.0
4	**Total**	71	58.2	0.8

1 Projects with expenditures during Test Period