CAPITAL EXPENDITURES - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides an overview of the capital expenditures for OPG's regulated hydroelectric facilities for the historical years, bridge year, and the test period, with the exception of the Niagara Tunnel Project, which is addressed in Ex. D1-2-1. This exhibit also provides period-over-period explanations, and an overview of the hydroelectric project management process. Details for regulated hydroelectric capital projects are provided in Ex. D1-1-2.

2.0 OVERVIEW

Over the test period, OPG hydroelectric capital expenditures will primarily focus on sustaining assets in order to ensure the ongoing availability and reliability of OPG's hydroelectric portfolio.

Capital expenditures can vary significantly from year to year based on the number and size of projects being executed. Excluding the Niagara Tunnel project, capital expenditures for the Niagara Plant Group and R.H. Saunders GS over the 2010 to 2015 period remain stable between $30M to $40M per year. For the newly regulated hydroelectric facilities, capital expenditures are consistent over the 2010 – 2013 period and remain in the $60M to $80M per year range, with an increase in 2014 due the start of construction of the Ranney Falls GS Expansion Project.

OPG's capital expenditures for the Niagara Plant Group and R.H. Saunders GS are $34.5M and $38.2M in 2014 and 2015, respectively. The majority of OPG's planned capital expenditures for the test period are for the Sir Adam Beck 1 GS G10 Upgrade; the DeCew Falls I GS Station Upgrade; and the R.H. Saunders Powerhouse Crane Replacement projects. These three projects account for $42.5M of the total test period capital expenditures of $72.8M.
OPG's capital expenditures for the newly regulated hydro facilities are $91.0M and $100.0M in 2014 and 2015, respectively. The largest projects for the newly regulated hydroelectric

facilities in the test period include: the Ranney Falls GS Expansion, Lower Notch GS G1 and G2 Generator Rewinds, Nipissing GS Penstock Replacement, the Ottawa St. Lawrence Plant Group New Headquarters Building, and the Chenaux GS Protections Upgrade projects. These projects account for $93.8M of the total test period capital of $190.9M for the newly regulated hydroelectric facilities.

A summary of the regulated hydroelectric capital expenditures for 2010 - 2015 is provided in Ex. D1-1-1 Table 1.

The remainder of the schedule is structured as follows:
Section 3 – Regulated Hydroelectric Capital Budget
Section 4 – Period-over-period Changes – Test Years
Section 5 – Period-over-period Changes – Bridge Year
Section 6 – Period-over-period Changes – Historical Years
Section 7 – Project Management

3.0 REGULATED HYDROELECTRIC CAPITAL BUDGET

As described in Ex. F1-1-1, Appendix A, the Hydro-Thermal Operations Business Unit (HTO) uses a structured portfolio approach to identify and prioritize projects. Projects are administered using the project management process as described in section 7.0 below. The hydroelectric project portfolio is approved through OPG's business planning process. Most hydroelectric capital projects involve the replacement of end of life equipment or the refurbishment of existing structures. OPG's capitalization policy, at Ex. D4-1-1, is used to determine which projects are capital projects and which projects fall within project OM&A. Project OM&A is discussed in Ex. F1-3-3. Prior to beginning work on a project, funds are released in accordance with OPG's Organizational Authority Register following the approval of a project business case.

Through the 2013-2015 business planning process, excluding the Niagara Tunnel project, OPG's Board has approved $263.7M of capital project expenditures for the 2014 - 2015 test period to sustain or improve the Niagara Plant Group, R.H. Saunders GS, and the newly regulated hydroelectric generating stations. Due to the multi-year nature of many of the capital projects, not all of the capital expenditures planned for the test period will necessarily come into service (and therefore into rate base) during the test period. Exhibit D1-1-2 presents in-service additions for the bridge year and test period, and explains changes from OPG's EB-2010-0008 application.

Capital projects unrelated to the Niagara Tunnel project are summarized in Ex. D1-1-1 Table 1.

The following summarizes the capital budgets for the Niagara Plant Group and R.H. Saunders GS, and newly regulated station segments. Descriptions and listings of the regulated hydroelectric capital projects are provided in Ex. D1-1-2.

3.1 Niagara Plant Group and R.H. Saunders GS Capital Budget

For the Niagara Plant Group, non-tunnel expenditures are dominated by the Sir Adam Beck I GS G10 Upgrade and DeCew Falls I GS Station Upgrade projects which account for $35.1M of the $59.1M in the test period capital expenditures. The Sir Adam Beck GS 1 G10 Upgrade project is in definition phase and the current preliminary cost estimate is $25.6M with an in-service date in 2015. The DeCew Falls 1 GS Station Upgrade project is also in the definition phase and the current preliminary cost estimate is $12.0M with an in service date in 2015. The remainder of the Niagara Plant Group capital expenditures are smaller capital projects.

For R.H. Saunders Generating Station, the planned expenditures are dominated by projects for the replacement of the powerhouse crane and the station service equipment. Together, these two projects account for $11.4M of the $13.6M in test period capital expenditures for this station. The remainder consists of expenditures on a number of smaller capital projects at the station.

3.2 Newly Regulated Facilities Capital Budget

For the Ottawa-St.Lawrence Plant Group, a large portion of the planned expenditures are projects for the Chenaux GS Protections Upgrade, New Plant Group Headquarters Building and Otto Holden GS Sluicegates and Headgates Replacements. Together, these four projects account for $33.0M of the $71.2M in the test period capital expenditures for the Plant Group. The remainder consists of expenditures on a number of small projects and completion of a few larger projects at Des Joachims GS in 2014.

For the Central Hydro Plant Group, a significant portion of the planned expenditures are projects for the Ranney Falls GS Expansion, South Falls GS G2 Unit Turbine and Generator Replacement, and Nipissing GS Penstock Replacement and Spillway projects. Together, these four projects account for $53.2M of the $59.3M in the test period capital expenditures for the Plant Group. The remainder consists of expenditures on a number of smaller capital projects for the Plant Group.

For the Northeast Plant Group, the planned expenditures are dominated by projects for the Lower Notch GS G1 and G2 Capital Upgrades, and G1 and G2 Headgate Upgrades. Together, these four projects account for $31.5M of the $39.9M in the test period capital expenditures for the Plant Group. The remainder consists of expenditures on a number of smaller capital projects for the Plant Group.

For the Northwest Plant Group, a large portion of the planned expenditures are projects for the Cameron Falls and Pine Portage GS Transformer Replacements, Whitedog Falls GS G1 and G3 Generator Rewinds, Kakabeka Falls GS Shebandowan Dam Replacement and the Cameron Falls and Pine Portage GS Unit Breakers Replacements. Together, these projects account for $14.9M of the $20.5M in the test period capital expenditures for the Plant Group. The remainder consists of expenditures on a number of smaller capital projects for the Plant Group.

4.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

<u>2015 Plan vs. 2014 Plan</u>

<u>Niagara Plant Group</u>

In 2015, Niagara Plant Group capital spending is expected to increase by $9.5M to $34.3M due to the start of the DeCew Falls I Trashrack Replacement and Sir Adam Beck I G5 Major

Overhaul & Upgrade projects. In addition, planned expenditures increase for the Sir Adam Beck I G10 Upgrade and Sir Adam Beck Pump Generating Station Protection and Controls Upgrade projects in 2015.

R.H. Saunders Generating Station

In 2015, R.H. Saunders capital spending is expected to decrease by $5.8M to $3.9M due to planned completion of the construction phase of the Powerhouse Crane Replacement in 2014.

Ottawa-St.Lawrence Plant Group

In 2015, Ottawa St. Lawrence Plant Group capital spending is expected to increase by $6.8M to $39.0M due to planned expenditures on the Chenaux GS Protections Upgrade (site installation scheduled for 2015), and timing associated with the execution of approximately 40 other small capital projects.

Central Hydro Plant Group

In 2015, Central Hydro Plant Group capital spending is expected to increase by $7.1M to $33.2M due to the planned expenditures on projects at Nipissing GS for Penstock Replacement and a Spillway Capacity Increase required to meet dam safety requirements.

Northeast Plant Group

In 2015, Northeast Plant Group capital spending is expected to slightly decrease by $0.9M to $19.5M. A significant portion of the planned expenditures in 2015 includes the continuation of the Lower Notch GS Capital Upgrade projects that include generator rewinds and other associated upgrades including headgate and exciter replacements.

Northwest Plant Group

In 2015, Northwest Plant Group capital spending is expected to decrease by $4.0M to $8.3 due to planned completion of the Cameron Falls GS and Pine Portage GS Unit Breakers Replacement projects in 2014.

2014 Plan vs. 2013 Budget

<u>Niagara Plant Group</u>

Niagara Plant Group capital spending is expected to decrease by $3.9M to $24.8M due to the completion of on the DeCew Falls II GS Powerhouse Crane Rehabilitation and Governor Sump & Pump Replacement projects, as well as the Sir Adam Beck I G3 Upgrade and Public Health and Safety Fencing Improvements projects. These decreases will be offset by Sir Adam Beck I G10 Upgrade and DeCew Falls I Station Upgrade which are both starting execution in late 2013.

<u>R.H. Saunders Generating Station</u>

R.H. Saunders GS 2014 capital spending is expected to increase to $9.7M from the 2013 plan of $5.0M. This is a result of several projects ramping up in 2014 including Station Service Replacement, Fire Water System Replacement, and the Powerhouse Crane Replacement.

<u>Ottawa-St.Lawrence Plant Group</u>

In 2014, Ottawa St. Lawrence Plant Group capital spending is expected to slightly increase by $0.4M to $32.2. The Des Joachims Turbine Runner Replacement and the Otto Holden Headgate Replacement are continuing in 2014 with expenditures of $2.4M and $2.5M respectively. The balance of the planned spending in 2014 is associated with the approximately 40 other small capital projects.

<u>Central Hydro Plant Group</u>

In 2014, Central Hydro Plant Group capital spending is expected to increase by $17.1M to $26.1M due to the start of construction on the Ranney Falls GS Expansion project, and expenditures on the South Falls GS Unit G2 Turbine and Generator Replacement.

<u>Northeast Plant Group</u>

In 2014, Northeast Plant Group capital spending is expected to increase by $4.8M to $20.4 due to planned expenditures on the Lower Notch GS G1 Capital Upgrade that includes a generator rewind and other associated upgrades including headgate and exciter replacements.

Northwest Plant Group

In 2014, Northwest Plant Group capital spending is expected to decrease by $3.3M to $12.2 due to decreased expenditures on the Aguasabon GS 13.8 kV Switchgear Replacement and planned completion of the Alexander GS G1 Headgate Replacement in 2013.

5.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2013 Budget vs. 2012 Actual

Niagara Plant Group

In 2013, Niagara Plant Group capital spending is expected to increase by $1.7M to $28.8M mainly due to spending related to the PGS Reservoir Refurbishment project and the start of DeCew Falls II Powerhouse Crane Rehabilitation and Governor Sump & Pump Replacement projects, which are partially offset by reduced spending on the Sir Adam Beck I Unit G3 rehabilitation.

R.H. Saunders Generating Station

R.H. Saunders GS 2013 capital spending is expected to increase to $5.0M from the 2012 plan of $2.7M. The increase is due the ramping up of work for the Powerhouse Crane Replacement project, and the start of work to replace the dewatering system in 2013.

Ottawa-St.Lawrence Plant Group

In 2013, Ottawa St. Lawrence Plant Group capital spending is expected to decrease by $9.2M to $31.7M due to completion of the Mountain Chute GS G1 and G2 Generator Rewinds, Arnprior GS Headgate Replacements, Barrett Chute GS Transformer Replacements and Chenaux GS Headgate Replacements in 2012.

Central Hydro Plant Group

In 2013, Central Hydro Plant Group capital spending is expected to decrease by $0.3M to $8.5M due to substantial completion of the Crystal Falls GS 44 kV Conversion project and deferral of Nipissing GS Turbine and Generator Replacement project in 2012. The project was deferred in 2012 to allow for further investigation into the project scope and cost. The decreases are offset by planned expenditures on the Ranney Falls GS Expansion project.

Northeast Plant Group

In 2013, Northeast Plant Group capital spending is expected to decrease by $6.0M to $15.6 mainly due to the completion of the Matabichuan GS Penstock and Saddle Replacement project in 2012.

Northwest Plant Group

In 2013, Northwest Plant Group capital spending is expected to increase by $6.8M to $15.6 due to commencement of the Pine Portage GS Transformer Replacement and G3 Generator Rewind projects.

6.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2012 Actual vs. 2012 Budget

Niagara Plant Group

Capital spending for the Niagara Plant Group in 2012 was $27.1M, or $3.8M below the OEB approved plan of $30.9M. The variance in expenditures primarily due to the deferral of three projects: the DeCew Falls I GS Electrical and Mechanical Station Upgrade, Sir Adam Beck Pump Generating Station Breaker Replacements, and the Sir Adam Beck I G10 Upgrade. DeCew Falls GS I Electrical and Mechanical Station Upgrade and Sir Adam Beck GS I G10 Upgrade were deferred to allow more planning time to confirm project scope, while the Sir Adam Beck Pump Generating Station Breaker Replacements was deferred due to favorable breaker condition. These reductions are partly offset by higher than planned spending on Sir Adam Beck I G3 Upgrade. The timing for G3 rehabilitation work was delayed to allow for the completion of warranty work on Unit G7 at Sir Adam Beck I GS.

R.H. Saunders Generating Station

In 2012, R.H. Saunders capital spending was $3.2M less than the OEB approved plan of $5.9M. This is a result of several projects being reprogrammed including the reclassification of the Service Water System project as an OM&A project, deferral of the Excitation System replacement following a technical assessment, and deferral of the Fire Water System to determine full scope. These decreases were partially offset by the Powerhouse Crane Replacement project starting in 2012.

Ottawa-St.Lawrence Plant Group

Capital spending for the Ottawa St. Lawrence Plant Group in 2012 was $41.0M, or $0.7M below the approved budget of $41.7M. Work in 2012 included ongoing work for the Des Joachims Main Output Transformer Replacements ($4.6M in 2012), and the remaining balance of 2012 spending was associated with the approximately 40 other capital projects in execution.

Central Hydro Plant Group

Capital spending for the Central Hydro Plant Group in 2012 was $8.8M, or $6.0M under budget. The variance is mainly due to the deferral of the Ranney Falls Expansion project due to delays in obtaining project approvals, in addition to less than planned spending on the Central Hydro Plant Group SCADA Upgrade project, and the deferral of the Nipissing GS Turbine and Generator Replacement.

Northeast Plant Group

Capital spending for the Northeast Plant Group in 2012 was $21.6M, or $4.5M under budget. This under variance was primarily attributed to the deferral of the Otter Rapids GS Runner Upgrade Purchase and Abitibi Canyon GS Station Service Replacement projects due to availability of staff resources that were required on other major projects.

Northwest Plant Group

Capital spending in the Northwest Plant Group in 2012 was $8.7M, or $0.1M under Plan. Several larger projects, such as the Whitedog Falls GS Transformer Replacement, the

Alexander GS Headgate Replacement, and the Caribou Falls GS Sluicegate Replacements and the Pine Portage GS Runner Upgrades, were on budget.

2012 Actual vs. 2011 Actual

Niagara Plant Group

In 2012, Niagara Plant Group capital spending decreased by $0.1M. This is due to the completion of DeCew Falls I GS Penstock Replacement project and reduced spending on Sir Adam Beck I GS G7 Frequency Conversion project.

R.H. Saunders Generating Station

R.H. Saunders GS 2012 capital spending decreased by $5.4M from the 2011 Actual. This was due to the completion of the Protections and Controls project in 2011, partially offset by the timing of the Powerhouse Crane Replacement.

Ottawa-St.Lawrence Plant Group

Ottawa St. Lawrence Plant Group 2012 capital spending of $41.0M was $13.9M more than 2011 spending primarily due to increased project spending on the Des Joachims GS DC Station Service Switchgear, Breakers Replacement, and G1, G3, G5 Generator Rewind projects, and the Mountain Chute GS Generator Rewind, Stewartville GS Protections and Controls and Otto Holden GS Station Service Upgrade projects.

Central Hydro Plant Group

Central Hydro Plant Group 2012 capital spending of $8.8M was $1.3M less than 2011 spending due deferrals of Nipissing GS Turbine and Generator Replacement, Bingham Chute GS Log Lifter, and McVittie GS Sluicegate Repair/Replacement projects, and cancellation of Big Eddy GS Installation of Log Handling Equipment at the Spillway Dam in 2012. This was offset by higher than planned spending on the Ragged Rapids GS and Ranney Falls GS Headgate Replacements, and Gravenhurst Public Safety Upgrades in 2011.

Northeast Plant Group

Northeast Plant Group 2012 capital spending of $21.6M was $11.5M more than 2011 mainly due to the construction phase for Matabichuan GS Penstock and Saddle Replacement project in 2012.

<u>Northwest Plant Group</u>

Northeast Plant Group 2012 capital spending of $8.7M was $5.3M less than 2011 spending due to the completion of the Cameron Falls GS and Whitedog Falls GS Headgate Replacements, and Kakabeka Falls GS G4 Turbine Inlet Valve Replacement projects in 2011.

<u>2011 Actual vs. 2011 Budget</u>

<u>Niagara Plant Group</u>

Capital spending for the Niagara Plant Group in 2011 was $27.2M, or $3.5M below the OEB approved plan of $30.7M. The decrease in expenditures is primarily related to changes in the scope of the Sir Adam Beck I Unit G3 rehabilitation. The original scope was revised as a result of a detailed engineering assessment conducted on the unit which indicated that the major generator components were suitable for an additional 20 to 30 years of service with the planned rehabilitation work. The previous estimate for the Unit G3 project was based on a generator replacement. Overall project savings of $7M will be realized through this scope change. The timing for G3 rehabilitation work was delayed to allow for the completion of warranty work and the installation of the Johnson valve sleeve on Unit G7 at Sir Adam Beck I GS. Overall spending in 2011 on Unit G3 was $10.8M below forecast.

The reduced spending on Sir Adam Beck I Unit G3 was offset by increased spending on the DeCew Falls I GS Penstock Replacement ($1.7M), Sir Adam Beck I Unit G7 warranty work ($3.7M), Sir Adam Beck Pump Generating Station Reservoir Refurbishment definition phase work ($2.2M) and a number of smaller projects.

<u>R.H. Saunders Generating Station</u>

Capital spending at R.H. Saunders in 2011 was $8.1M which was $1.1M less than the 2011 OEB approved plan. This difference was due to several small schedule changes to a number of projects including the Protection and Controls Upgrade project.

Ottawa-St.Lawrence Plant Group

Capital spending for the Ottawa St. Lawrence Plant Group in 2011 was $27.1M, or $9.9M under budget due to less than planned spending on the Mountain Chute GS Generator Rewinds, deferral of the New Plant Group Headquarters Building and small schedule and cash flow changes on a significant number of other projects. The Mountain Chute GS Generator Rewinds outage schedule was updated after the budget was finalized resulting in less than planned spending. The New Plant Group Headquarters Building project was initiated to address the extensive deterioration of the existing building (approx. 45 years old). This project was deferred to allow for a more thorough assessment of options for an headquarters building.

Central Hydro Plant Group

Capital spending for the Central Hydro Plant Group in 2011 was $10.1M, or $0.4M under budget due to less than planned spending on Crystal Falls GS Conversion to 44 kV operations, and the deferral of North Bay Headquarters Renovations. The North Bay Headquarters Renovations ($1.8M budget) was deferred to 2012 to allow for further study of office space requirements and cost effective building construction options. This was offset higher than planned spending on the Ragged Rapids GS and Ranney Falls GS Headgate Replacements.

Northeast Plant Group

Capital spending for the Northeast Plant Group in 2011 was $10.1M, or $4.9M under budget due to less than planned spending for the Matabichuan GS Penstock and Saddles Replacement project due to delays to obtain required permitting and to perform detailed exploratory work, and less than planned spending for the Otter Rapids GS Sluice Hoist Installation and Runner Purchase projects due to issues identified with manufacturer's design.

Northwest Plant Group

Capital spending for the Northwest Plan Group in 2011 was $14.1M, or $0.1M under budget. The largest projects, Alexander GS and Whitedog Falls GS Headgate Replacements and the Caribou Falls GS Sluicegate Replacements were all on budget.

2011 Actual vs. 2010 Actual

Niagara Plant Group

In 2011, Niagara Plant Group capital spending decreased by $1.3M mainly due a reduction in spending on the unit rehabilitation program at Sir Adam Beck I.

R.H. Saunders Generating Station

R.H. Saunders' 2011 capital spending was $3.7M lower than 2010 mainly due to the completion of the St. Lawrence Power Development Visitor Centre project in 2010.

Ottawa-St.Lawrence Plant Group

Ottawa St. Lawrence Plant Group 2011 capital spending of $27.1M was $21.3M less than 2010 due to the completion of the Otto Holden GS Transformers Replacements, the Chenaux GS Limerick Island Dam Sluicegate Rehabilitation, and Chats Falls GS T20 Transformers Replacement projects in 2010.

Central Hydro Plant Group

Central Hydro Plant Group 2011 capital spending of $10.1M was $5.3M more than 2010 spending due to the start of the Ragged Rapids GS and Ranney Falls GS Headgates Replacement projects, as well as, higher than planned spending for the Northbury and Gravenhurst Public Safety Upgrades, the Central Hydro SCADA upgrades, and the Wanapitei Stop Log Replacement projects in 2011. The public safety upgrades consisted of the installation of additional fencing, barriers, safety booms, gates, and signage for generating stations and control structures maintained by the Northbury and Gravenhurst Service Centres. The Wanapitei Control Structure provides water management for the Stinson, Coniston, and McVittie Generating Stations.

Northeast Plant Group

Northeast Plant Group 2011 capital spending of $10.1M was $3.8M more than 2010 spending due to the start of the Matabichuan GS Penstocks and Saddle Replacement project in 2011.

Northwest Plant Group

Northwest Plant Group 2011 capital spending of $14.1M was $5.1M more than 2010 spending due to start of the Cameron Falls GS G7 Headgate Replacement and Silver Falls GS T1 Transformer Replacement projects in 2011.

2010 Actual vs. 2010 Budget

Niagara Plant Group

The Niagara Plant Group's capital spending in 2010 was $7.7M under plan. The capital variance was mainly due to reduced spending on the installation of penstocks at DeCew Falls I ($1.5M), reduced spending on generator rehabilitation work at Sir Adam Beck I for Units G3 ($1.7M) and G9 ($3.5M), and the deferral of protection and control work at Sir Adam Beck Pump Generating Station ($1.0M).

R.H. Saunders Generating Station

R.H. Saunders' capital spending in 2010 was $5.5M under plan ($11.8M versus a plan of $17.3M). This variance was due to: the deferral of the Powerhouse Crane Replacement to 2012 in order to better determine project scope, the deferral of the Projections and Control project to allow for outage scheduling, and for lower than planned contingencies on the St. Lawrence Power Development Visitor project.

Ottawa-St.Lawrence Plant Group

Capital spending for the Ottawa St. Lawrence Plant Group in 2010 was $48.4M, or $2.9M under budget primarily due to less planned spending on the Mountain Chute GS Generator Rewind project. The project scheduled for 2010 was delayed due to a forced outage of Unit 2 in 2009. In addition, there was a deferral the Arnprior GS Headgate Replacement project execution phase to 2011 to accommodate the procurement schedule.

Central Hydro Plant Group

Capital spending for the Central Hydro Plant Group in 2010 was $4.8M, or $2.7M under budget due to the deferral of the North Bay Headquarters Renovations, Nipissing GS Penstock Replacement, and Ragged Rapids GS G1 Runner Replacement and Rewind projects, as well as, less than planned spending on the Central Hydro PG SCADA Upgrades.

Northeast Plant Group

Capital spending for the Northeast Plant Group in 2010 was $6.4M, or $4.8M under budget. As described above, the Matabichuan GS Penstock and Saddles Replacement project was project was delayed in order to perform additional exploratory work and detailed design. Also, there was less than planned spending for the Indian Chute GS G1 Turbine Replacement project.

Northwest Plant Group

Capital spending for the Northwest Plant Group in 2010 was $9.0M , or $1.1M under budget due to less than planned spending on the Kakabeka Falls GS G4 Turbine Inlet Valve Replacement project. As the project progressed in definition phase, it became apparent that there were multiple logistical issues that needed to be addressed, which resulted in postponing the project.

7.0 PROJECT MANAGEMENT

OPG's project management process for regulated hydroelectric facilities is substantially unchanged from EB-2010-0008 with the exception of the addition of a centralized Project Management Office ("PMO"). Capital expenditures for the regulated hydroelectric facilities are planned through the use of a structured portfolio approach, whereby OPG identifies and prioritizes projects. Projects are then administered using a comprehensive project management process. This project management process has been developed by the Hydro

Thermal Business Unit within the framework of, and consistent with, OPG's corporate level investment management processes, which are outlined in Ex. A2-2-1.

The PMO ensures adherence to industry best practice standards for project management. Through planning, training, project management competency, and contractor pre-qualification services, PMO ensures that contractors meet the requirements to perform work on OPG sites. On major strategic projects, a comprehensive Post Implementation Review ("PIR") is conducted by the PMO to ensure that the business and project objectives have met the intended purpose as stated in the Business Case Summary (BCS).

At any point in time, the portfolio of hydroelectric projects may include projects at all stages of the project life cycle, from newly identified opportunities to projects that are in execution or close-out phases and for which funds have been fully released.

The five phases within the project life cycle are as follows:

- Identification - problems or opportunities are identified that are likely to lead to a project;
- Initiation - initial project scope, schedule, and stakeholders are identified, and the project is included in business plans;
- Definition - investigation to determine project scope, verify site conditions, perform preliminary engineering, and produce a release quality estimate and a detailed schedule;
- Execution - management of construction and physical execution of the project;
- Final closing - preparation of project closure report and Post-Implementation Review to document final costs and lessons learned.

The progression of a project from one phase to the next is governed by a management process, which ensures that periodic and systematic reviews are conducted, and that approvals are obtained before OPG proceeds with further investments. Between each phase, a distinct "decision gate" is reached, where a decision is taken on whether the project should proceed to the next phase, revert back to a previous phase, or cease entirely. 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 (as in the case of the replacement of a minor plant component due to breakdown).

Release of funds for hydroelectric projects typically occurs at two stages: definition and execution. For the definition phase, the release of funds is based on a developmental BCS and is limited to 10 per cent of the total project estimate. A full BCS releases all of the funds for the execution phase of the project based on a release quality estimate and a detailed schedule.

Numbers may not add due to rounding.

Table 1

Capital Expenditures Summary - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**	28.5	27.2	27.1	28.8	24.8	34.3
2	**Saunders GS**	11.8	8.1	2.7	5.0	9.7	3.9
3	**Subtotal**	40.4	35.3	29.8	33.8	34.5	38.2
4	**Niagara Tunnel Project**	231.8	265.5	231.2	122.9	2.0	0.0
	Newly Regulated Hydroelectric:						
5	**Ottawa-St.Lawrence Plant Group**[1]	48.4	27.1	41.0	31.7	32.2	39.0
6	**Central Hydro Plant Group**	4.8	10.1	8.8	8.5	26.1	33.2
7	**Northeast Plant Group**	6.4	10.1	21.6	15.6	20.4	19.5
8	**Northwest Plant Group**	9.0	14.1	8.7	15.6	12.2	8.3
9	**Subtotal**	68.6	61.4	80.1	71.4	91.0	100.0
10	**Total**	340.7	362.2	341.0	228.1	127.5	138.2

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 2

Comparison of Capital Expenditures - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved[2]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	**Niagara Plant Group**	36.2	(7.7)	28.5	(1.3)	30.7	(3.5)	27.2	(0.1)	27.1
2	**Saunders GS**	17.3	(5.5)	11.8	(3.7)	9.2	(1.1)	8.1	(5.4)	2.7
3	**Subtotal**	53.5	(13.2)	40.4	(5.0)	39.9	(4.6)	35.3	(5.6)	29.8
4	**Niagara Tunnel Project**	241.8	(10.0)	231.8	33.8	288.0	(22.5)	265.5	(34.4)	231.2
	Newly Regulated Hydroelectric:									
5	**Ottawa-St.Lawrence Plant Group[1]**	51.4	(2.9)	48.4	(21.3)	37.0	(9.9)	27.1	13.9	41.0
6	**Central Hydro Plant Group**	7.5	(2.7)	4.8	5.3	10.5	(0.4)	10.1	(1.3)	8.8
7	**Northeast Plant Group**	11.2	(4.8)	6.4	3.8	15.0	(4.9)	10.1	11.5	21.6
8	**Northwest Plant Group**	10.1	(1.1)	9.0	5.1	14.2	(0.1)	14.1	(5.3)	8.7
9	**Subtotal**	80.2	(11.6)	68.6	(7.2)	76.7	(15.3)	61.4	18.7	80.1
10	**Total**	375.5	(34.8)	340.7	21.6	404.7	(42.4)	362.2	(21.2)	341.0

Line No.	Prescribed Facility	2012 Board Approved[3]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
11	**Niagara Plant Group**	30.9	(3.8)	27.1	1.7	28.8	(3.9)	24.8	9.5	34.3
12	**Saunders GS**	5.9	(3.2)	2.7	2.3	5.0	4.7	9.7	(5.8)	3.9
13	**Subtotal**	36.8	(7.0)	29.8	4.0	33.8	0.8	34.5	3.7	38.2
14	**Niagara Tunnel Project**	199.0	32.2	231.2	(108.2)	122.9	(120.9)	2.0	(2.0)	0.0
	Newly Regulated Hydroelectric:									
15	**Ottawa-St.Lawrence Plant Group[1]**	41.7	(0.7)	41.0	(9.2)	31.7	0.4	32.2	6.8	39.0
16	**Central Hydro Plant Group**	14.8	(6.0)	8.8	(0.3)	8.5	17.7	26.1	7.1	33.2
17	**Northeast Plant Group**	26.2	(4.5)	21.6	(6.0)	15.6	4.8	20.4	(0.9)	19.5
18	**Northwest Plant Group**	8.8	(0.1)	8.7	6.8	15.6	(3.3)	12.2	(4.0)	8.3
19	**Subtotal**	91.4	(11.3)	80.1	(8.7)	71.4	19.6	91.0	9.0	100.0
20	**Total**	327.2	13.8	341.0	(113.0)	228.1	(100.6)	127.5	10.7	138.2

Notes:
1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.
2 For Newly Regulated Hydroelectric, 2011 Budget is provided rather than 2011 Board Approved, as these assets were not regulated in EB-2010-0008.
3 For Newly Regulated Hydroelectric, 2012 Budget is provided rather than 2012 Board Approved, as these assets were not regulated in EB-2010-0008.

CAPITAL PROJECTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides descriptions and listings of capital projects, as well as Business Case Summaries, which support capital expenditures and in-service additions for the OPG's regulated hydroelectric facilities during the test period. These capital expenditures form part of the capital expenditures for the Niagara Plant Group and R.H. Saunders GS, and the newly regulated hydroelectric facilities presented in Ex. D1-1-1. This exhibit does not address the Niagara Tunnel Project ("NTP"), which is covered in Ex. D1-2-1.

2.0 OVERVIEW OF CAPITAL PROJECT DESCRIPTIONS AND LISTINGS

Consistent with the filing guidelines, OPG uses a tiered structure for reporting capital projects. In Section 3.0 below, information is presented for projects with budgeted expenditures during the 2014 and 2015 test period or in-service amounts between 2013 and 2015 as set out below:

- Tier 1 - Projects with a total cost of $20M or greater:
  - Project descriptions are provided in section 3.1.
  - Summary level information is further provided in Ex. D1-1-2 Table 1.
  - Business Case Summaries are provided as attachments to this schedule.

- Tier 2 - Projects with a total cost between $5M and $20M:
  - A description of this category of projects is provided in section 3.2.
  - Project descriptions and summary level information is provided in Ex. D1-1-2 Table 2.

- Tier 3 - Projects with a total cost of less than $5M:
  - A description of this category of projects is provided in section 3.3.
  - Aggregated project information is provided in Ex. D1-1-2 Table 3.

Section 4.0 below presents information on OPG's regulated hydroelectric facilities' capital expenditures that: (a) have gone into service in the historical years, or (b) are expected to go into service either during the 2013 bridge year or during the 2014 and 2015 test period. In-service information is further summarized in Ex. D1-1-2 Tables 4 and 5. These in-service additions are included in the regulated hydroelectric rate base as presented in Ex. B2-3-1 Tables 1 and 2. Exhibit D1-1-2 Table 7 provides a summary of projects greater than $5M that were projected to go into service in 2011 and 2012 in EB-2010-0008.

Section 5.0 below presents information on OPG's regulated hydroelectric capital expenditures that were identified in OPG's EB-2010-0008 application but which were subsequently deferred to beyond the 2011 - 2012 test period or cancelled.

3.0 CAPITAL PROJECT DESCRIPTIONS AND LISTINGS

3.1 Tier 1 Capital Projects

Tier 1 projects are those with total costs of $20M or more. There are five Niagara Plant Group regulated hydroelectric Tier 1 projects, four Ottawa St. Lawrence Plant Group hydroelectric Tier 1 projects and one Central Hydro Plant Group Tier 1 project that have planned expenditures at this level during the bridge year or test period. These are described below. Summary information on these projects is provided in Ex. D1-1-2 Table 1.

3.1.1 Sir Adam Beck Pump GS – Reservoir Refurbishment (HDEV0028)

The Pump Generating Station ("PGS") Reservoir is comprised of a 7 km long rock-fill dyke, varying in height from 5 to 21 meters. The reservoir bottom is comprised predominantly of natural materials that provide a low-permeability blanket supplemented by an engineered natural clay blanket in certain areas. The bedrock underlying the reservoir is characterized by open, interconnected, vertical and horizontal joints. These bedrock characteristics could make the foundation and potentially the dyke itself susceptible to sinkhole formation which may lead to a dyke breach. Therefore, in addition to initiating the geotechnical investigation leading to the reservoir refurbishment as described below, OPG has enhanced its existing monitoring of the reservoir and dyke to ensure safe operations.

A preliminary Concept Phase analysis in 2010 recommended the installation of a new liner over for the entire PGS reservoir as the preferred option. As part of the Definition Phase, a detailed geotechnical testing and investigation program was performed to determine the condition of the existing liner and reservoir subsurface, and to develop a detailed scope for the rehabilitation project. Based on the investigation and review by independent experts, it was determined the liner is not in need of a full replacement. Instead, replacement is only required in areas of liner deterioration or those prone to leakage. The estimated cost of $362M in the 2013 to 2015 business plan was based on a full liner replacement. The estimated cost for the partial liner replacement plan is $100M. However, the Definition Phase is continuing to determine the final project scope and cost. The Execution Phase of this project is now planned to begin in 2016. The refurbishment of the reservoir will allow the PGS facility to continue to provide value to the Ontario electricity system over the next 50 to 100 years. The Definition Phase Business Case Summary is provided in Attachment 1.

3.1.2 Sir Adam Beck I Generating Station - Unit G3 Upgrade (SAB10064)

The total cost of the Sir Adam Beck I Generating Station - Unit G3 Upgrade project is estimated to be $23.0M. The outage for the project commenced in 2012 with a planned in service date of March 2013. The unit returned to service in August 2013. The Unit G3 Upgrade project Business Case Summary is provided in Attachment 1 to this schedule.

This project is a complete unit rehabilitation. The design and work scope will draw on experience gained from the completed frequency conversion of Unit G7 and the upgrade of Unit G9. The scope includes: overhauled generator windings with new protections and controls, a new exciter, new switchgear, a new transformer, and a new liner in the area of the removed Johnson valve. It also includes a new more efficient turbine runner.

Unit G3 was last overhauled in 1985. Hydroelectric units of this type normally require major overhauls on a 25 to 30 year cycle to ensure continued operation. By 2012 it could no longer be counted on to provide reliable long-term operation as there were issues with major components of both the generator and the turbine.

Rebuilding of the turbine and generator winding is expected to provide 25 to 30 years of reliable operation before the next unit major overhaul is required. The installation of a new more efficient turbine runner and electrical equipment is expected to increase the capacity of the unit by approximately 9 MW. A new higher rated transformer will be required to handle this additional output.

3.1.3 Sir Adam Beck I Generating Station - Unit G10 Upgrade (SAB10050)

The total cost of the Sir Adam Beck I Generating Station - Unit G10 Upgrade project is estimated to be $25.6M. This project will commence in 2014 and is projected to come into service by June 2015. The Unit G10 Upgrade project is currently in the Definition Phase. The Business Case Summary is provided in Attachment 1.

This project is a complete unit rehabilitation. The design and work scope will draw on experience gained from the frequency conversion of Unit G7, completed in 2009, the rehabilitation of Unit G9, completed in 2011 and the upgrade of Unit 3, completed in 2013. A complete condition assessment of the unit was concluded by OPG engineering staff as part of the project Definition Phase. The expected project scope includes: new generator windings with new protections and controls, a new exciter, new switchgear, and a new transformer. It also includes a new more efficient runner.

Recent inspections have revealed that Unit G10 is near the end of its useful life. It was converted to 60 Hz in 1956. The unit last underwent a mechanical overhaul, including a turbine runner replacement, in 1986. The existing electrical equipment (e.g., breakers, transformer) currently do not have the capability to accommodate the increase in turbine capacity expected from this upgrade project.

Rebuilding of the turbine and generator winding is expected to provide 25 to 30 years of reliable operation before the next unit major overhaul is required. The installation of a new more efficient turbine runner and electrical equipment is expected to increase the capacity of the unit by approximately 10 MW.

3.1.4 Sir Adam Beck I Generating Station - Unit G5 Major Overhaul & Upgrade (SAB10072)

The total cost of the Sir Adam Beck I Generating Station - Unit G5 Major Overhaul & Upgrade project is estimated to be $24.3M. This project will commence in 2015 and is projected to come into service by October 2016. As this project has not commenced the Definition Phase, a Business Case Summary has not been prepared for this project.

A complete condition assessment of the unit is planned for 2014 by OPG engineering staff. The expected project scope includes: a generator overhaul with new protections and controls, a new exciter and new switchgear. It may also include a new more efficient runner depending on the results of the assessment.

Unit G5 was converted to 60 Hz operation in 1985. By 2014 it will have been in operation for 29 years without a major overhaul. Performing a major overhaul on the unit and upgrading components is expected to provide 25 to 30 years of reliable operation before the next unit major overhaul is required.

3.1.5 Sir Adam Beck I Generating Station - Unit G4 Major Overhaul & Upgrade (SAB10086)

The total cost of the Sir Adam Beck I Generating Station - Unit G4 Major Overhaul & Upgrade project is estimated to be $24.3M. A complete condition assessment of the unit is planned for 2015 by OPG engineering staff. The expected scope includes: a generator overhaul with new protections and controls, a new exciter and new switchgear. It may also include a new more efficient turbine runner. The outage for this project is expected to start in 2016 with an in service in October 2017. Performing a major overhaul on the unit and upgrading components is expected to provide 25 to 30 years of reliable operation before the next major unit overhaul is required. As this project has not commenced the Definition Phase, a Business Case Summary has not been prepared for this project.

3.1.6 Des Joachims Generating Station - Replace Main Output Transformers (DESJ0031)

The total cost of the Des Joachims Generating Station - Replace Main Output Transformers project is estimated to be $26.3M. This project was started in 2006 and is projected to be completed by December 2013. The project is currently in Execution Phase. The Business Case Summary is provided in Attachment 1 to this schedule.

The project includes purchasing and installing twelve new main output transformers, one new station spare, and associated equipment at Des Joachims GS. The existing transformers are almost 60 years old, are nearing the ends of their service lives, and the probability of failures is expected to increase dramatically over the next ten years. The four transformer banks are being replaced from 2010 to 2013 (1 bank per year).

3.1.7 Des Joachims Generating Station - Turbine Runner Replacement (DESJ0016)

The total cost of the Des Joachims Generating Station - Turbine Runner Replacement project is estimated to be $22.3M. This project started in 2004 and is projected to be completed by December 2015. The project is currently in its Execution Phase. The Business Case Summary is provided in Attachment 1 to this schedule.

The project includes replacement of eight turbine runners with upgraded runners. The existing runners are damaged and at end of life. Given their condition, there is a significant risk of turbine failure due to the cracking damage which has become more evident in the past few repair cycles. New turbine runners will eliminate the need for excessive weld repairs and related production losses while also increasing turbine runner efficiency and annual energy production.

The expected unit generator improvement performance resulting from the runner program is 2.3% efficiency gain, which results in an increase in station output by 52.6 GWh/yr. The first of eight runners was replaced in 2007, and the last runner is expected to be replaced in 2014.

3.1.8 Otto Holden Generating Station - Replace Sluicegates & Rehabilitate Sluicegates (OTTO0021)

The total cost of the Otto Holden Generating Station - Replace Sluicegates & Rehabilitate Sluicegates project is estimated to be $20.6M. This project was started in 2006 and is projected to be completed by December 2015. The project is currently in Execution Phase. The Business Case Summary is provided in Attachment 1 to this schedule.

The project includes replacement of six sluicegates and rehabilitation of the sluicegates system in order to comply with dam safety requirements and to address operational and reliability needs. Rehabilitation of the sluicegates system occurred in 2009, and replacement of the six gates started in 2010 (one gate per year). The sluicegates can be controlled either locally or remotely from the Chenaux Control Centre. They provide the primary means of discharging excess flow around Otto Holden GS, and are essential in meeting the OPG Dam Safety Program requirements. The existing sluicegates are nearing 60 years of operation and are at the end of their service lives.

This project is part of a program to replace sluicegates that are at the end of their service lives within the Ottawa-St. Lawrence Plant Group, including those at Des Joachims, Chenaux and Chats Falls generating stations.

3.1.9 <u>Otto Holden Generating Station - Replace Headgates and Rehabilitate Gains (OTTO0039)</u>

The total cost of the Otto Holden Generating Station - Replace Headgates and Rehabilitate Gains project is estimated to be $24.6M. This project has started in 2012 and is projected to come into service by December 2021. The project is currently in its partial Execution Phase..A Business Case Summary has been approved to complete one gate to determine scope for the remainder of this project. It is provided in Attachment 1 to this schedule.

Otto Holden GS has eight generating units; each is equipped with two headgates which are installed in the concrete structure of the headworks. The headgates are safety devices used to shut off water supply to the turbines in case of emergency and are the last resort available to stop the generators. They are also used to isolate units during unit repairs and maintenance. It is important that the headgates and gains (i.e. the slots that guide the headgates), including the integrity of the seals and the seal paths, be maintained in good working condition in order to ensure asset protection and worker safety requirements.

The headgates, related embedded components, and the hoist mechanisms are original and were installed in the early 1950's. Since they were installed, the headgates for all 8 units were refurbished once in the 1990's. They are now at end of life. An investigation was completed in 2011 to determine the condition of the headgates and embedded components and to develop the scope for the upcoming project. The inspection revealed that there is significant leakage occurring from headgate seals and sills, and that there are several operational and maintenance issues related to the hoist assemblies. Because it was not possible to access the embedded components, the inspection could not determine their current condition.

As it was not possible to determine the condition of the embedded components during the assessment, a partial release has been approved to determine the complete scope of the repair work required for the embedded components and hoist assemblies and to complete the technical specification and release quality estimate for the remainder of the project. The headgate replacement and the repairs of the embedded components and hoists for the remaining seven units is programmed to be executed during the unit overhauls which are scheduled to begin in 2015. The new headgates will allow for continued safe operation of Otto Holden GS over their expected service life of 50 years.

3.1.10 Ranney Falls GS - Expansion Project (HDEV0024)

The Ranney Falls GS Expansion Project scope is to safely decommission the end-of-life 0.8 MW unit at Ranney Falls GS and construct a new 8 to 10 MW unit which will increase the total station capacity from 10 MW to between 17 to 19 MW. The new unit is expected to increase the station's annual energy production by 30 GWh to 80 GWh. In addition, as a condition of approval from Parks Canada (Trent-Severn Waterway), the project will include construction of a spillway that is designed to improve the management of water at the site by resolving an existing deficiency in spill capacity at their upstream control dam. The addition of a new spillway is needed for the safe bypassing of water flows during emergency situations. The Municipality of Trent Hills Council endorsed this project on September 12, 2012.

The project is currently estimated to cost $42.4M and will take about five years to complete. The Execution Phase of the project is expected to begin in 2013. The project is expected to be completed in 2016. A Definition Phase investigation for the project is currently underway. The Business Case Summary is provided in Attachment 1.

3.2 Tier 2 Capital Projects

Tier 2 projects are those with total costs between \$5M and \$20M. There are a total of four Niagara Plant Group Tier 2 projects that have planned expenditures during the test period. The total cost of these four projects is estimated to be \$37.1M. R.H Saunders has two Tier 2 projects with planned expenditures in the test period. The total estimated cost of these two projects is \$22.2M.

For the newly regulated hydroelectric stations, the Ottawa St. Lawrence Plant Group has ten Tier 2 projects with planned expenditures in the test period. The total estimated cost of these ten projects is \$86.8M. Central Hydro Plant Group has three Tier 2 projects with planned expenditures in the test period. The total estimated cost of these three projects is \$19.2M. Northeast Plant Group also has three Tier 2 projects with planned expenditures in the test period. The total estimated cost of these three projects is \$35.2M. Finally, Northwest Plant Group has one Tier 2 projects with planned expenditures in the test period. The total estimated cost of the one project is \$7.1M. A description of these projects and further summary information is provided in Ex. D1-1-2 Table 2.

3.3 Tier 3 Capital Projects

Tier 3 projects are those with total costs less than \$5M. There are a total of 28 Niagara Plant Group Tier 3 projects that have planned expenditures during the test period. The total cost of these Tier 3 projects is estimated to be \$42.6M. The average cost of a Niagara Plant Group Tier 3 project is \$1.5M. R.H Saunders has a total of four Tier 3 projects with planned expenditures in the test period. The total estimated cost of these projects is \$7.1 M. The average cost of a R.H. Saunders Tier 3 project is \$1.8M.

For the newly regulated stations, there are a total of 47 Ottawa St. Lawrence Plant Group Tier 3 projects that have planned expenditures during the test period. The total cost of these

Tier 3 projects is estimated to be $65.7M with an average cost of $1.4M. The Central Hydro Plant Group has 22 Tier 3 projects that have planned expenditures during the test period. The total cost of these Tier 3 projects is estimated to be $32.0M with an average cost of $1.5M. There are a total of 35 Northeast Plant Group Tier 3 projects that have planned expenditures during the test period. The total cost of these Tier 3 projects is estimated to be $40.2M with an average cost of $1.1M. Finally, there are a total of 26 Northwest Plant Group Tier 3 projects that have planned expenditures during the test period. The total cost of these Tier 3 projects is estimated to be $40.2M with an average cost of $1.5M. Further summary information on these projects is provided in Ex. D1-1-2 Table 3.

4.0 IN-SERVICE ADDITIONS

This section presents information on OPG's regulated hydroelectric capital expenditures that: (a) have gone into service in the historical years at the Niagara Plant Group or R.H. Saunders GS, or (b) are expected to go into service, either during the 2013 bridge year or during the 2014 - 2015 test period for all regulated hydroelectric stations. This information is presented using the tiered reporting structure detailed in section 2 above. In-service information is summarized in Ex. D1-1-2 Tables 4 and 5.

4.1 In-Service Additions in Historical Years (2010, 2011, and 2012)

For Niagara Plant Group and R.H. Saunders GS in 2010, 2011 and 2012, the actual capital in-service amounts were lower in 2010 ($40.9M), higher for 2011 ($20.6M) and lower for 2012 ($36.0M) than the additions forecast in EB-2010-0008. The variances are due to various factors including: delays, deferrals, cancellations, and projects being completed below budget. The projects contributing to in-service variances are detailed below.

In 2010, the Niagara Plant Group in-service variances were due to a one month delay in the in-service of the Sir Adam Beck I Unit G9 Upgrade project ($32.1M), the delayed in-service of the DeCew Falls I penstock replacement ($5.1), and delayed installation of the Sir Adam Beck PGS main output transformers ($3.6M). Sir Adam Beck I Unit G9 was commissioned and began operations in December 2010, but the official in-service did not occur until January 2011. Installation of the DeCew Falls I penstocks were delayed due to contractor safety issues. Transformer installation at Sir Adam Beck PGS was delayed because of increased time required by the manufacturer to construct the transformers and rework required to correct damage that occurred during transportation of the transformers to the station.

R.H. Saunders 2010 in-service variances were due to the Saunders Visitor Centre being placed in service for $1.6M less than planned and the deferral of the Powerhouse Crane project from 2010 to 2014 resulting in $1.5M less than planned in-service. These two projects were slightly offset by the final in service addition of the Iroquois Crane Rehabilitation of $0.2M.

In 2011 the variance to in-service additions was primarily due to a one month delay (December 2010 to January 2011) in the in-service of Sir Adam Beck I G9 ($30.0M). In addition, the delayed in-service of the DeCew Falls I penstock replacement ($5.1M), and delayed installation of the Sir Adam Beck PGS main output transformers ($3.6M), from 2010 contributed to this variance. These increases were partially offset by the deferral of: breaker replacements at Sir Adam Beck PGS ($2.0M), station upgrade work at DeCew Falls I ($2.1M), trashrack cleaning machine at DeCew Falls 2 ($1.0M), and the cancellation of governor replacements at Sir Adam Beck PGS ($2.0M).

The 2011 in service variance for R.H. Saunders of $2.0M less than plan can be attributed to the Powerhouse Crane and other minor projects being deferred to 2012 through 2014. These deferrals were offset by an increase in the in service amount for the Protection and Controls Project by $1.1M to $18.1M due to the project being ahead of schedule.

In 2012, the Niagara Plant Group in-service variances were primarily due to the delayed in-service of the Sir Adam Beck I Unit G3 Upgrade project ($29.4M) and the deferral of DeCew Falls I Station Upgrade ($3.5M). These decreases were partly offset by the additional final in-service amount for Sir Adam Beck I Unit G7 Frequency Conversion project ($4.5M). As described below, the Sir Adam Beck I Unit G3 project was delayed to accommodate the outage for warranty work on Sir Adam Beck I Unit G7.

In 2012, R.H. Saunders GS in service variance of ($1.2M) less than plan is due to the Protection and Controls Project being ahead of schedule and fully in serviced in 2011.

The following three projects, which had costs greater than $20M and were identified in OPG's previous payment amounts application (EB-2010-0008), were completed and went into service in 2010, 2011 or 2012.

4.1.1 Sir Adam Beck I Generating Station – Unit G9 Upgrade (SAB10047)

The project to upgrade Unit G9 was completed on schedule in December 2010 and placed in-service in January 2011. The final project cost was $2.1M less than the approved project estimate of $32.1M. The additional capacity and energy from this project will be 10 MW and 60.8 GWh/year, respectively.

4.1.2 R.H Saunders Generating Station - Generator Protection Replacement and Control Upgrades (SAUN0047)

The Generator Protection Replacement and Control Upgrades project was approved with an estimate of $21.7M. The project was completed in 2011 under budget and ahead of schedule at a total cost of $19.9M, including $0.7M of removal costs which were charged to Base OM&A costs. The final capital in-service amount for the project was $19.1M.

4.1.3 Sir Adam Beck I Generating Station - Unit G7 Frequency Conversion (SAB10032)

The final cost of the Sir Adam Beck I Generating Station - Unit G7 Frequency Conversion project is $32.0M, as compared to the original release of $35.2M. This project was a complete unit rehabilitation, including a frequency conversion from 25 Hz to 60 Hz operation. Prior to this project Unit G7 had been decommissioned and deregistered with the IESO. The additional capacity and energy from this project will be 62 MW and 100 GWh/year, respectively. The unit was declared in-service in June 2009 with a cost of $27.5M. However, as described below, an additional $4.5M was required through February 2012 to complete necessary warranty work. The Unit G7 Frequency Conversion project Business Case Summary is provided in Attachment 1 to this schedule.

This project was originally approved by the OPG Board of Directors in 2007 for $35.2M with a planned in-service date of March 2009. When Unit G7 was commissioned and brought on-line, there were a number of significant operating issues. The unit was not officially accepted for commercial in-service until June 2009 to allow time for some of these issues to be addressed. Two of the major problems with the unit were the ineffectiveness of the turbine runner seal and issues with unacceptable vibration. Efforts were made to address both of these issues. However, these did not yield the required performance changes to ensure reliable service. Therefore, a previously planned outage to install a Johnson Valve sleeve in 2011 was used to remove the runner and correct misalignment issues with the unit, repair damage to wicket gates (caused by the misalignment) and make improvements to the runner seal. This major rework was completed under warranty by Weir American Hydro Corporation in 2012. However, approximately $4.5M of costs, including the disassembly and reassembly of the unit, were not covered by the warranty and was funded under the original project approval.

4.2 In-Service Additions in 2013 Bridge Year and 2014-2015 Test Period

Summary information for capital in-service additions is provided in Ex. D1-1-2 Tables 4 and 5. For the bridge and test years, additional detail by project is provided on Ex. D1-1-2 Tables 1, 2 and 3.

The largest in-service addition over these three years is the Niagara Tunnel project, which is described in Ex. D1-2-1. For the Niagara Tunnel Project, $1,474.2M will be placed in-service in 2013, and $2.0M in 2014. These amounts are in addition to the previous in-service amount of $19.2M for the accelerator wall at the International Niagara Control Works structure (also known as International Control Dam) that was completed in 2007.

Other than the Niagara Tunnel project, five Tier 1 projects have amounts that come into service in the bridge year, including: the Sir Adam Beck 1 GS G3 Unit Rehabilitation ($22.7M in 2013), Des Joachims GS Main Output Transformer Replacements ($4.3M in 2013), the Otto Holden GS Headgate Replacement and Gain Rehabilitation ($3.0M in 2013), the Des Joachims GS Turbine Runner Replacements ($2.8M in 2013), and the Otto Holden GS Sluicegate Replacement and Sluicegate System Rehabilitation ($2.5M in 2013).

During the test period, four Tier 1 projects have amounts that are expected to come into service during the test period, the Sir Adam Beck 1 Unit G10 Rehabilitation ($25.4M in 2015), the Des Joachims GS Turbine Runner Replacements ($2.8M in both 2014 and 2015), the Otto Holden GS Sluicegate Replacement and Sluicegate System Rehabilitation ($2.5M in both 2014 and 2015), and the Otto Holden GS Headgate Rehabilitation and Gain Replacement ($2.0M in 2015).

5.0 DEFERRED PROJECTS AND CANCELED PROJECTS

The following three Tier 1 projects identified in OPG's previous payment amounts application (EB-2010-0008) have been deferred or cancelled.

5.1 Sir Adam Beck I Generating Station – Unit 10 Upgrade (SAB10050)

This project was identified as a part of the Sir Adam Beck I Generating Station unit upgrade program with work planned between 2012 and 2014. However, during the Definition Phase of the project, a detailed condition assessment was conducted and completed in 2011. The unit was discovered to be in better condition than had been anticipated. Therefore, as described above, the unit upgrade was deferred and the project is not expected to commence until 2014.

5.2 Sir Adam Beck I Generating Station – Rehabilitate Canal Lining (SAB10056)

This project was originally identified during a condition assessment of the canal liner above the waterline. The upper portion of the canal lining was found to be deteriorated and in need of eventual repair work. In September 2007, a comprehensive inspection of the canal below the water line was completed. During this inspection, it was revealed that the canal was in better condition than previously believed and, as part of 2009 business planning, the project was deferred from the 2011 in-service date that was indicated in EB-2007-0905. The project cost estimates have been updated to $126.5M. This project is now expected to start in 2017 with an in-service date in 2020. The scope reflects the repair work specified in the more comprehensive condition assessment. The project is currently programmed to be completed after the Niagara Tunnel project and Sir Adam Beck Pump GS Reservoir Rehabilitation projects in order to minimize production losses and the overlapping of major projects at the Sir Adam Beck complex.

5.3 Sir Adam Beck Pump Generating Station – Dyke Foundation Grouting (SABP0022)

This project was cancelled as its scope of work has been included in the Sir Adam Beck Pump Generating Station Reservoir Refurbishment and Expansion project (HDEV0028) described above.

LIST OF ATTACHMENTS

ATTACHMENT 1

Business Case Summaries

Provided below is a list of projects with total project cost of $20M or greater, and their associated Business Case Summaries. Paper copies of the Business Case Summaries are provided.

Tab	Business Case Summaries	Project No.
1	Sir Adam Beck Pump GS – Reservoir Refurbishment (Definition Phase)	HDEV0028
2	Sir Adam Beck I Generating Station – Unit G3 Rehabilitation	SAB10064
3	Sir Adam Beck I Generating Station – Unit G7 Frequency Conversion	SAB10032
4	Sir Adam Beck I Generating Station – Unit G9 Rehabilitation	SAB10047
5	Sir Adam Beck I Generating Station – Unit G10 Upgrade – New Runner and Generator Rewind (Developmental Release)	SAB10050
6	Des Joachims Generating Station - Replace Main Output Transformers	DESJ0031
7	Des Joachims Generating Station - Turbine Runner Replacement	DESJ0016
8	Otto Holden Generating Station - Replace Sluicegates & Rehabilitate Sluicegates	OTTO0021
9	Otto Holden Generating Station - Replace Headgates and Rehabilitate Gains	OTTO0039
10	Ranney Falls GS Expansion Project (Definition Phase)	HDEV0024

SIR ADAM BECK PUMP GENERATING STATION (SAB PGS) RESERVOIR REFURBISHMENT – DEFINITION PHASE - HDEV0028

1. RECOMMENDATION:

Approve the release of $9.3 M for Definition Phase work to assess and finalize the design for the refurbishment of the Sir Adam Beck Pump Generating Station (SAB PGS) reservoir.

OPG's economic assessment shows that there is substantial value, estimated at $470 million NPV (2011$), to the Ontario electricity system from continued operation of the SAB PGS.

A Concept Phase assessment has been completed and it concluded that sealing the base of the reservoir with a liner was the preferred option. Definition Phase work relating to refurbishment includes finalizing the design for a reservoir liner system, including assessing whether a partial, or full, liner system and which type of liner system will most cost-effectively allow the facility to continue to provide value to the Ontario electricity system over the next 50-100 years.

Request for this Current Release:	$ 9.3 M
Expenditure Type:	Capital
Release Type:	Definition Phase Release
Release Date:	Q3 2011
Completion Date:	Q4 2013
Investment Type - Refurbishment	Sustaining
Estimate Quality:	Release

Release History ($M)	Pre-2011	2011	2012	2013	2014	2015	Total
Previous Releases - Concept OM&A	1.5	2.0					3.5
Current Release - Definition Capital		3.5	3.5	2.3			9.3
Future Release - Execution Capital					131.5	143.0	274.5
Total Estimated Project Costs	**1.5**	**5.5**	**3.5**	**2.3**	**131.5**	**143.0**	**287.3**

The Execution Capital estimates are preliminary and reflect the AACE Class 4 standard with an expected accuracy of [redacted] to [redacted]. More accurate Class 3 estimates will be prepared during the Definition Phase.

The Definition Phase Refurbishment work will be done in conjunction with other work, if approved, to benefit from synergies, including work to assess the expansion of the reservoir. Business cases for the other work will be provided separately.

Managing the risks around the Project will be important in achieving success. To manage the risk, OPG has engaged an independent panel of international experts to provide technical advice to OPG on the project. Management believes that the issues and risks associated with this project are manageable.

2. SIGNATURES

Submitted by:

Carlo Crozzoli

Carlo Crozzoli
VP, Hydroelectric Development — Date

Recommended by:

14 Sept 2011

John Murphy
Executive Vice President, Hydro — Date

Finance Approval :

Sept 16/2011

Donn Hanbidge
SVP and Chief Financial Officer — Date

Line Approval :

Sept 19, 2011

Tom Mitchell
President & CEO — Date

3. SCOPE, BACKGROUND & ISSUES

3.1 Scope of Definition Phase

The scope of the Definition Phase of the refurbishment work is to finalize the design of a reservoir liner system, including assessing whether a partial, or full, liner system and which type of liner system will most cost-effectively allow the facility to continue to provide value to the Ontario electricity system over the next 50-100 years.

3.2 General Background

The SAB PGS is a six unit reversible pump-turbine plant capable of pumping water from the outlet of the tunnels and canal of the SAB complex, into a storage reservoir, and generating (174 MW) from that reservoir by discharging the stored water back into the SAB Complex head pond. The station was constructed between 1953 and 1957. It is the only pump generation station in Canada.

The SAB PGS supports the peaking operation of the SAB Complex. It stores water in off-peak times and uses it to generate during higher priced on-peak hours. Its operation is integrated with the Sir Adam Beck 1 (SAB1) and Sir Adam Beck 2 (SAB2) stations and water stored in the reservoir is used to generate peaking power at all three stations. As a result, the operation of SAB PGS provides a significant summer peaking value to the Ontario electricity system. The SAB PGS is also used to: 1) improve the overall efficiency of operations at the SAB Complex, 2) assist SAB1 and SAB2 in the provision of Automated Generation Control (AGC) services and Operating Reserve services to the Ontario electricity system.

3.3 Background Issues and Opportunities

The PGS Reservoir is comprised of a 7 km long rock-fill dyke, varying in height from 5 to 21 meters. The reservoir bottom is comprised predominantly of natural materials that provide a low-permeability blanket supplemented by an engineered natural clay blanket in certain areas.

The bedrock underlying the entire reservoir is thought to be characterized by open, interconnected, vertical and horizontal joints. Such joints could result in seepage from the reservoir over long distances and cause migration of fine grained soils into the open joints. Such bedrock characteristics could make the foundation and potentially the dyke itself susceptible to sinkhole formation which could potentially lead to dyke breach.

There is some uncertainty in the extent and nature of the jointing in the bedrock, which, if significant, could lead to more prevalent sinkhole development over time and the shutdown of the facility in the near term. Past performance combined with more recent observations indicates that further investigation is warranted at this time. The reservoir has performed satisfactorily over the last 50 years. A detailed investigation is now required to assess its performance and determine any potential mitigative measures to ensure its ongoing operations.

A Concept Phase analysis has been completed and assessed two main options for refurbishment:

1. Sealing the base of the reservoir with a liner.

2. Installation of a concrete cut off wall through the overburden soils and into the bedrock under most of the reservoir perimeter.

The assessment concluded that sealing the base of the reservoir with a liner was the preferred option because it is more cost effective and has less risk. The preferred option will be refined during Definition Phase by determining the extent of the liner and the type of liner.

4. DEFINITION PHASE ALTERNATIVES AND PRELIMINARY ECONOMIC ANALYSIS

I. Status Quo Alternative (leading to Potential Shutdown in 2014): Not Recommended

The status quo is not recommended. This alternative would result in the potential shutdown and removal of the SAB PGS from operations in the near future. An economic analysis shows that there is substantial value to the Ontario electricity system from continued operation of the SAB PGS. There is a substantial cost associated with shutting down the PGS and putting it in a safe state. Preliminary estimates indicate the cost could be $50 M.

II. Delay Definition Phase for the Project: Not Recommended

Delaying the Definition Phase work is not recommended. OPG's assessment shows that it is prudent to continue investigations into the geological condition of the site, including the extent and nature of the jointing in the bedrock under the reservoir. It is also prudent to further investigate potential mitigative measures, such as whether installation of a partial liner, or a full liner over the entire reservoir base, is warranted.

III. Proceed to the Definition Phase of the Refurbishment Work: Recommended Case

It is recommended that the work proceed to Definition Phase immediately to ensure that investigations into the geological conditions of the site and into potential mitigative measures are completed in a timely way.

Economics of Recommended Alternative:

The economic assessment shows that there is an approximately $470 M net present value to the Ontario electricity system based on OPG's evaluation of the capacity value and the peaking energy value of the ongoing operation of the SAB PGS, compared to the shut-down of the facility.

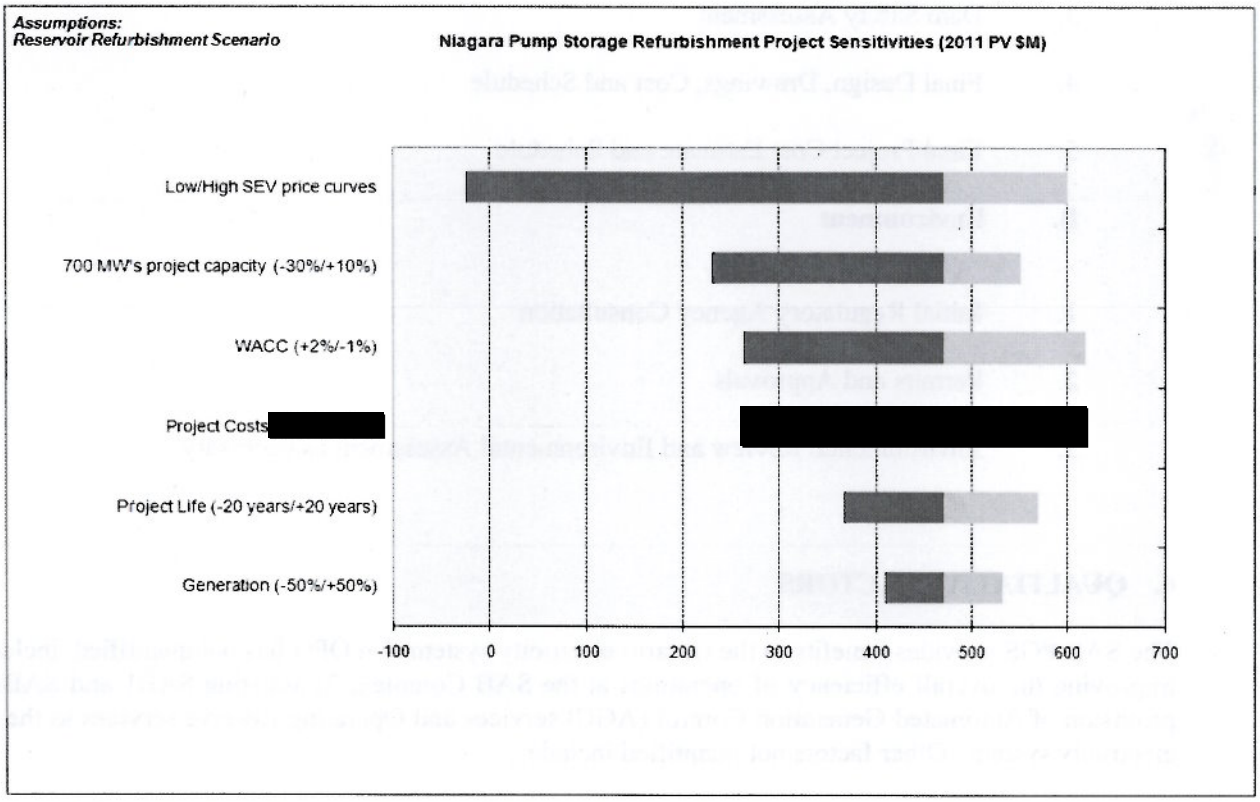
Net Present Value (NPV) calculations have used forecast market prices of electricity and System Economic Values for economic evaluation purposes. This demonstrates that the investment is beneficial to the electricity system.

The SAB PGS is a regulated hydroelectric asset and as such will receive the regulated rate for energy. The impact on regulated Hydro rates to recover the cost of this project is estimated to be approximately 2.5% in 2016, or about $1.3/MWh based on current assumptions.

The economic assessment is based on the estimated cost of an engineered liner over the base of the entire reservoir. At this preliminary stage of the project, cost estimates of Execution Phase work reflect the AACE Class 4 standard and therefore, have an expected accuracy of [redacted] to [redacted]

The results were tested for sensitivity to key inputs, as shown in the graph below. The sensitivity analysis shows that the expected economic value to the electricity system is insensitive to such key factors as the cost of the incremental work, project life, project capacity value, and electricity generation performance.

It is sensitive to electricity prices. An assumed low electricity price curve results in an estimated project NPV of about -$25 M, while a high price curve results in an estimated project NPV of about $600 M.



Key Assumptions used in the economic analysis are provided in Appendix A.

While at this preliminary stage of the project there are significant uncertainties associated with the assessment, the preliminary economic analysis shows that the Refurbishment work is economic when compared to the Status Quo alternative. Therefore, the analysis justifies moving to the Definition Phase for the Refurbishment work.

5. THE PROPOSAL

Definition Phase work relating to refurbishment includes finalizing the design for a reservoir liner system, including assessing whether a partial, or full, liner system and which type of liner system will most cost-effectively allow the facility to continue to provide value to the Ontario electricity system over the next 50-100 years.

Major tasks to be completed during the Definition Phase will include:

A. Engineering

1. Comprehensive Geotechnical Investigation
2. Preliminary Design, Drawings, Cost and Schedule
3. Dam Safety Assessment
4. Final Design, Drawings, Cost and Schedule
5. Final Project Cost Estimate and Schedule

B. Environment

1. Initial Regulatory Agency Consultation
2. Permits and Approvals
3. Environmental Review and Environmental Assessment as necessary

6. QUALITATIVE FACTORS

The SAB PGS provides benefits to the Ontario electricity system that OPG has not quantified, including: 1) improving the overall efficiency of operations at the SAB Complex, 2) assisting SAB1 and SAB2 in the provision of Automated Generation Control (AGC) services and Operating Reserve services to the Ontario electricity system. Other factors not quantified include:

Improving the Unit Efficiencies and Removing Operation Limitations on Existing PGS Units

OPG is assessing the potential to improve the efficiency of existing SAB PGS units through unit overhauls and runner replacement. OPG is also assessing the potential to improve operations by removing existing limitations on the units. The work has the potential to improve the benefit of the SAB PGS to the electricity system. Further work to assess the issues will be done during the Definition Phase of the Reservoir Refurbishment work and will be separately approved.

Refurbishment of SAB1 G1 and G2

SAB1 G1 and G2 were 25Hz units that were shut down in 2009. They have not been refurbished pending review of the business case. Analysis to date shows that refurbishment of the units could add about 110 MW of new capacity to the Beck Complex and could add to the value of the SAB PGS to the electricity system. Further work to assess the issues will be done during the Definition Phase of the Reservoir Refurbishment work and will be separately approved.

Wind and Solar Integration

Energy storage, including pumped storage, has been widely discussed in recent years due to its potential to assist in integrating intermittent renewables, such as wind and solar, into the electricity system and maximizing their contribution. There is the potential for additional value, including new sources of value to the electricity system for pumped storage in the future as the share of wind and solar increases in Ontario's electricity system. The Directive of February 17, 2011, from the Minister of Energy to the OPA to guide the OPA in development of the Plan requires the OPA to consider the potential for storage technologies.

In addition to the work described above, OPG is assessing expanding the volume of the reservoir which could provide additional benefits to the Ontario electricity system. Further work to assess expansion, if approved, will be done jointly with the reservoir refurbishment work to capture synergies and will be separately approved.

7. RISKS

A key risk for the work stems from the geological conditions at the site. To mitigate the risks OPG has engaged a qualified Owner's Representative to assist OPG through the remaining phases of the project, including developing and implementing a comprehensive geotechnical investigation of the site. In addition, OPG has engaged an independent panel of international experts to provide advice to OPG on the project. Overall, risks to the project fall into three main categories:

1. Technical Risks: e.g. the risk that unexpected findings from the planned geotechnical investigations result in delays and design changes.

2. Regulatory Risks: e.g. the risk that issues relating to regulatory requirements result in unexpected delays and costs.

3. Economic Risks: e.g. the risk that unexpected findings during the Definition Phase assessments lead to design changes that increase the cost of the project.

The top risks are included in Appendix B.

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

Type of PIR	Target Definition Phase Completion Date	Target PIR Completion Date
Simplified	(31/Dec/2013)	(31/Mar/2014)

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)	When it will be measured
Quality assessment of the feasibility of the Project	N/A	Work is well managed and done to a high standard of quality.	Technical feasibility to be confirmed by Independent Panel	Independent Panel and Sponsor	At completion of Definition phase
Provincial and/or Federal Environmental Approvals	N/A	Receive all necessary approvals on schedule	Receive all necessary approvals on schedule	Project Team	At completion of Definition phase
Full Business Case Summary for OPG Board approval	N/A	Quality BCS prepared on schedule	Quality BCS prepared on schedule	Sponsor	At completion of Definition phase

APPENDIX A: Modeling Assumptions for Economic Analysis

Financial Model – Assumptions

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

1. Definition Phase costs of $8.4M which includes [redacted] for contingency.
2. Interest during Construction (IDC) for Definition Phase of $0.9M
3. Execution Phase costs of $255.0M which includes [redacted] for contingency.
4. Interest during Construction (IDC) for Execution Phase of $19.5M.

Financial Assumptions:

1. For NPV calculations a Weighted Average Cost of Capital (WACC) of 7% was used.
2. Debt Rate of 6.75%.
3. Return on Equity (ROE) of 9.3%.
4. Debt Ratio of 53%.

Project Life Assumptions:

1. SAB PGS Reservoir life extended 50 years.

Energy Production Assumptions:

1. Average 50 years of production from the SAB PGS will be 128 GWh's.
2. Average 50 years of production from the Beck Complex resulting from the SAB PGS will be 728 GWh's.

Operating Cost Assumptions:

1. Average 50 years of pumping generation from the SAB PGS will be 178 GWh's.
2. Average 50 years of uplift charges of $1.4M (2011$'s) which include rural rate assistance, debt retirement charge and charging energy.
3. Average 50 years of pumping generation associated with the Beck Complex resulting from the SAB PGS will be 779 GWh's.
4. Average 50 years of standard and non standard OM&A of $4.5M (2011 $'s).
5. Average 50 years of sustaining capital expenditures of $7.1M (2011$'s).

Appendix B: Risk Register

Category	Risk	Contributing Factors	Mitigation / Monitoring / Refurbishment	Residual Risk
Site Investigation (Geotechnical)	Geotechnical investigations cause damage to existing clay liner, dyke or tongue (test-pitting/ drilling, etc.).	- Lack of experience and/or controls - Poor workmanship and materials - Compressed schedule - Working conditions (weather, temp., etc)	- Prepare and implement rigorous quality assurance program which includes engineering oversight over all field activities (including possible repairs) - Identify liner integrity and repair requirements in investigation plan - Monitor reservoir during re-filling activities and maintain frequent monitoring for first year of operation after work completed	Based on experience, the probability of a defect developing as a result of the investigation work is likely very low. However, if a defect develops it can be repaired in the future.
Site Investigation (Environmental)	Issues related to aquatic species relocation arise during dewatering process and cause delays to the geotechnical investigation.	- Greater number of fish and mussels found in the reservoir than anticipated - Discovery of species at risk	- Prepare detailed plans for aquatic species relocation - Retain contingent systems (additional personnel and equipment) for fish rescue and salvage operations will be available	If the relocation process takes longer than expected, available time for the geotechnical investigations would be reduced. This could result in an extension of the planned outage or a need to schedule another outage in 2012.
Site Investigation (Environmental)	Inability to dewater reservoir in specified timeframe (e.g sediment discharge exceeds allowable limits) causes delays to the geotechnical investigation.	- Existing reservoir conditions are likely to produce sediment laden water during complete reservoir drawdown.	- Utilize sediment control (flocculants, settling ponds, filter tubes, etc.) - Maintain a controlled drawdown rate	If the dewatering process takes longer than expected, available time for the geotechnical investigations would be reduced. This could result in an extension of the planned outage or a need to schedule another outage in 2012.
Construction	The reservoir bottom conditions are not as expected (e.g., soft bottom conditions, bedrock joints, sand seams, etc.) resulting in logistical issues, schedule delays, cost increase, and quality issues	- The geotechnical investigation may not detect all deficiencies in the overburden and bedrock	- Delineate and characterize sediment (bearing capacity) during site investigations - Invite general contractors to view reservoir in dewatered state - Install temporary working platforms - Allow sediment to be dried and removed prior to liner placement - Repair any deficiencies detected during construction	Additional cost and time may be required to repair any deficiencies detected during construction.
Construction	The dyke "tongue" does not exist in all areas or to extent expected, resulting in cost & schedule increases	- Lack of as-built verification/ records. - May be difficult to differentiate "tongue" material from surrounding material.	- Determine the extent of the "tongue" during the site investigations - Develop alternative designs to tie-in to dyke core.	Additional cost and time may be required for excavation work to tie-in to dyke core.
Regulatory	Cost Recovery	Recovery of project costs is subject to regulatory review before the Ontario Energy Board	Effective project management processes and execution	All such regulatory reviews include uncertainty and as such, some inherent risk.

Appendix C: Summary of Definition Phase Cost Estimates ($M)

	2011	2012	2013	Total
Internal Expenses	0.2	0.6	0.6	1.4
External Expenses	[redacted]			
Interest	[redacted]			
Escalation	0.0	0.1	0.1	0.1
Contingency	[redacted]			
Total Release	**3.5**	**3.5**	**2.3**	**9.3**

Prepared by:

Mahir Aydin
Project Manager
Sept 13, 2011
Date

Approved by:

Tim Gigliotti
Project Director,
Sept. 13, 20
Date

SIR ADAM BECK 1 GS

G3 Upgrade - New Runner & Generator Rewind

Project Number: SAB10064

Niagara Plant Group

SCI #: NPG-08707.021-0001

SIR ADAM BECK 1 GS

G3 Upgrade - New Runner & Generator Rewind

SAB10064

1. RECOMMENDATION

Approval is recommended for the release of $24,057k (CAP), including a preliminary release of $650k, to rehabilitate and upgrade Sir Adam Beck 1 (SAB1) G3. Work will include a generator rewind and an upgraded runner resulting in improved unit efficiency and a maximum continuous rating (MCR) increase of approximately 9 MW. This project is a sustaining investment required to ensure continued reliable operation of G3 and to maximize the use of water available from the Niagara River when the third tunnel is placed in-service.

The rehabilitated G3 unit is expected to produce 59 GWh annually, including an incremental increase of 13 GWh due to the installation of higher capacity stator windings, a Johnson Valve sleeve, and more efficient runner and transformer.

This sustaining investment is consistent with the approved Life Cycle Plan (LCP) for SAB1 and OPG's objective of continuing to increase clean, renewable generation from its existing fleet of hydroelectric assets.

$000's	LTD 2010	2010	2011	2012	2013	Total
Currently Released	650					650
Requested Now (This Release)			3,426	19,222	759	23,407
Future Funding Required						
Total Project Costs	287	11	3,778	19,222	759	24,057
Investment Type	**Class**	**NPV**	**IRR**	**LUEC**	**Discounted Payback**	
Sustaining	17	26,654 (using SEV's)	14.3% (using SEV's)	$47.65 / MWh	12 years (using SEV's)	

Funding:
- A developmental release was approved on October 15, 2009 for $650k
- The funding for the project is included in the Niagara Plant Group's annual business plan
- Capital funding of $29,400k was included in the rate application EB-2010-0008

2. SIGNATURES

Submitted by:

19 JAN 11

Mike Martelli Date
Plant Group Manager, Niagara Plant Group

Recommended by:

3 Feb 2011

John Murphy Date
Executive Vice President - Hydro

Finance Approval:

Donn Hanbidge Date
Senior Vice President and
Chief Financial Officer

Line Approval:

27 Feb 2011

Tom Mitchell Date
President and CEO

3. BACKGROUND AND ISSUES

Sir Adam Beck 1 (SAB1) GS is a ten unit station located on the Niagara River. The units were placed in service during the years 1921 to 1930. Two of the units (G1 and G2) are 25Hz generators and were decommissioned in 2009. The approved LCP for SAB1 considered the water available to the station, including that provided by the third Niagara Tunnel, and concluded that an eight unit configuration will optimize the water available to the station and the corresponding station revenues. The LCP established an orderly program of unit rehabilitation involving G7, G9, G10 and G3 for SAB1. G7 was rehabilitated and placed in service in 2009 and G9 was rehabilitated and placed in service in December 2010. In 1970 SAB1 G3 was converted from 25 Hz to 60 Hz and upgraded to a 55 MVA machine.

SAB1 G3 was originally placed in service in 1922 and has not had a major rehabilitation since 1985. Hydroelectric units of this type normally require overhauls on a 25-30 year cycle to ensure reliable operation and to maintain revenue. In the rate regulation submission case number EB-2007-0905, OPG laid out a schedule whereby SAB1 units would be rehabilitated in order G7, G9, G10 then G3. A decision was made in April of 2009 to rehabilitate G3 ahead of G10, due to the condition of the stator core. G10's stator core was known to be acceptable for extended service while the condition of the core for G3 was unknown and a significant potential source of operational risk.

A condition assessment was completed by Hydro Engineering Division (HED) on G3 in August 2010. The assessment report indicated that the following components are at end of life:

- Surface air coolers
- Bearing coolers
- Stator windings
- Excitation system
- 15 kV bus and insulators
- Main output transformer
- Switches
- Protection and control system

The report recommended: a major overhaul of the turbine and related equipment, a major generator overhaul which included rewinding the stator, replacement of many main output power delivery system components, refurbishment of the excitation system, replacement of the main output transformer and modernization of the unit protections and controls. The existing excitation system does not meet current IESO requirements for reactive power capability, response time and ceiling levels. Many of the end-of-life components including the exciter, switches and bus work are original 1920's vintage equipment.

Based on previous rehabilitation and upgrade work completed on both units G7 and G9 at SAB1, there is an opportunity to replace the runner and install a Johnson Valve sleeve increasing the overall efficiency and energy production from the unit. The Johnson Valves were original station equipment installed in the 1920's. The sleeve is installed in the enlarged section of the penstock which reduces turbulent flow and thereby increases unit efficiency by 4 GWh for G3.

The runner on G3 is suitable for extended service, based on the Engineering condition assessment, however; replacement of the runner on G3 is justified because of the significant efficiency and capacity gains that can be achieved. The runner design used for G3 will be the same design used on both G7 and G9. The new runner will increase unit MCR by approximately 9 MW, and represents approximately 8 GWh of the total 13 GWh of incremental energy that will be generated by upgrading G3. Replacing the runner represents $[redacted] million of the total project costs and provides excellent value to the ratepayer as the LUEC is approximately $26/MWh, the NPV is $11M and the payback period is approximately 8 years.

The total estimated cost for the recommended upgrade alternative is $24.1M. This is $5.3M less than the previous cost estimate used in both the 2010 – 2014 Business Plan and the EB-2010-0008 Payment Amounts submission for 2011 and 2012 to the Ontario Energy Board. The reduced costs are primarily due to the favourable condition of the generator found during the Engineering condition assessment of the unit. The G3 generator is expected to last for another 30 to 40 years with just a rewind and major overhaul work. During previous unit upgrades on G7 and G9 the generator needed to be replaced which significantly increased project costs.

Business Objectives:

Rehabilitate or overhaul G3 to provide 30 years of reliable service in the most cost effective manner possible to sustain the capacity of the eight unit (SAB1) station recommended by the approved Life Cycle Plan. Where it is cost effective, introduce both unit efficiency and capacity increases to expand the ability of existing hydroelectric generation to meet demand. Ensure that adequate generation capacity is available at Sir Adam Beck Generating Complex to maximize the use of water that will be delivered by the third Niagara Tunnel.

ALTERNATIVES & ECONOMIC ANALYSIS

Base Case (Do Nothing):

Do Nothing. ($0k Capital)

This alternative does not address the increasing risk of equipment failure on G3. There were a number of systems that were identified as end-of-life during the engineering assessment. There is a risk of general cooling failures, bearing failures, excitation system failure in addition to numerous other electrical system failures on G3 due to the age and condition of the equipment. Not making appropriate sustaining investments to correct these conditions and deficiencies will lead to increasing unit unreliability and lost production. This alternative does not address the stated business objective and is not consistent with the approved Life Cycle Plan for SAB1.

- **This alternative is not recommended.**

Alternative 1:

Rewind Generator and Replace Turbine Runner ($24,057k Capital)

This alternative upgrades the existing generator and runner MCR from 55 MVA (46 MW) to 63.25 MVA (55 MW). A new, efficient runner will be installed, the turbine will be rehabilitated and a liner installed in the Johnson valve. This alternative includes performing miscellaneous safety and ergonomic improvements to work areas and equipment associated with the G3 unit. An Uprate Study to establish the maximum electrical and mechanical limits of the unit up to 68.5 MVA, 61.65 MW will be performed. If the unit can be successfully up-rated, additional generation of 5 GWh annually may be possible. With appropriate maintenance and overhauls, the expected service life of the components is 50 years.

This alternative is recommended because it provides the most cost effective manner in which the unit reliability will be restored and maintained for the next 30 years while delivering an additional 13 GWh of incremental energy annually. This alternative delivers the most preferable NPV and provides the best overall value to the Ratepayer of all of the alternatives considered. Performing safety and ergonomic upgrades will improve the work environment and reduce health and safety risks to workers. Performing an Uprate Study will ensure maximum utilization of the upgraded unit based on the existing scope of work.

- **This is the recommended alternative**

Alternative 2:

Replace Generator and Turbine ($39,954k Capital)

This alternative replaces the 46 MW generator with a new 61.6 MW generator. A new, efficient runner would be installed, the turbine would be rehabilitated and a liner installed in the Johnson valve. This alternative includes performing miscellaneous safety and ergonomic improvements to work areas and equipment associated with the G3 unit. The scope of work for this alternative is the same as the rehabilitation work recently completed on G7 and G9 at SAB1. With appropriate maintenance and overhauls, the expected service life of the components is 50 years.

This alternative is rejected because improvement in unit performance resulting from the replacement of the generator does not yield enough incremental generation to justify the extra expenditure. The 50 year NPV for this alternative is over $6M lower than the recommended alternative despite additional incremental generation of 5 GWh annually. A full generator replacement is not required and there are few benefits that would result from this significant expenditure.

- **This is not the recommended alternative**

Alternatives Considered But Rejected:

1. Minor Overhaul

This option involves repairing only the equipment that requires immediate attention. It does not include upgrading the generator, the installation of a new runner, or overhauling the turbine. The expected reliable service life is only 5 years where 30 years of reliable service is required to meet the business objectives. This option does not make full use of the water that will be provided by the third tunnel. This alternative also does not address the stated business objectives and is not consistent with the approved LCP. Furthermore, pursuing this alternative does not provide the best value to the Ratepayer as this alternative ignores the value enhancing investments in the Johnson Valve sleeve and runner.

2. Major Overhaul

This option involves making necessary repairs to existing equipment and overhauling the turbine. It does not include upgrading the generator or the installation of a new runner. The expected reliable service life is only 15 years where 30 years of reliable service is required to meet the business objectives. Since many of the unit components are at end of life there is no guarantee of reliable long term performance of the generator. This option does not make full use of the water that will be provided by the third tunnel. This alternative does not address the stated business objectives and is therefore rejected. Furthermore, pursuing this alternative does not provide the best value to the Ratepayer as this alternative ignores the value enhancing investments in the Johnson Valve sleeve and runner.

Financial Analysis:

$ Millions	Base Case	Alternative 1 (recommended)	Alternative 2 (Not recommended)
Project Cost	0	24.06	39.95
NPV (after tax)	0	26.65	20.56
IRR %	0	14.3	10.4
Discounted Payback (Yrs)	n/a	12	18

The financial analysis was based on a 50 year study period. Major overhauls are included 30 years into the study for both alternatives considered.

Annual generation for G3 is expected to be 59 GWh; 88% of which is expected to be delivered during the winter peak. MCR for G3 is expected to increase to 55 MW providing an incremental increase of approximately 9 MW over the previous unit configuration.

Net Present Value (NPV) calculations have used forecast market prices of electricity (SEV's) for economic evaluation purposes. This demonstrates that the investment is prudent from a commercial perspective. However, this generator is part of OPG's regulated hydroelectric assets and as such will receive the regulated rate for energy. This project was included in OPG's 2010 rate submission for the rate years 2011 and 2012.

The breakeven levelized unit energy cost (LUEC) over 50 years for this project is $47.65/MWh. This is significantly lower than the OPA's published prices of $122/MWh for waterpower projects over 10MW under the Feed in Tariff (FIT) program. The impact on regulated rates to recover the cost of this project is estimated to be approximately 0.2%.

THE PROPOSAL

Results to be Delivered

Completing this project will result in the following:

1. 30 years of reliable service for G3
2. An upgraded runner providing increased efficiency ([redacted]) and greater unit capacity (9 MW)
3. A more efficient main output transformer ([redacted])
4. Increased unit MCR (9 MW)
5. Increased overall generation from the unit (13 GWh incremental annual generation)
6. Improved unit control
7. Improved work conditions
8. Excitation system will meet IESO requirements for reactive power capability and response

Execution Phase Work Overview

The work to be done in this stage will include the execution of the Project Execution Plan based on the project scope. The general scope of work for the project is as follows:

1. Upgrade existing generator and runner MCR from 55 MVA (46 MW) to 63.25 MVA (55 MW)
2. Perform an overhaul of the turbine system components
3. Upgrade the electrical output systems associated with the generator to 68.5 MVA
4. Perform miscellaneous safety and ergonomic improvements to work areas and equipment associated with the G3 unit
5. Perform an Uprate Study to establish maximum electrical and mechanical limits of the unit up to 68.5MVA, 61.65 MW

A draft Project Execution Plan (PEP) identifying scope, schedule and cost has been developed for this project. A final PEP will be in place prior to the mobilization of the contractor.

A comprehensive scope of work can be found in the Execution Phase Project Charter and the detailed Sir Adam Beck 1 – G3 Upgrade Scope of Work document.

Electricity Grid and System Connection Requirements
A Customer Impact Assessment (CIA) will be initiated by OPG and completed by Hydro One based on the scope of work for the project. A System Impact Assessment (SIA) will also be requested by OPG and completed by the IESO based on the scope of work.

Execution Phase Work Milestones

- Award Installation and Major Equipment Procurement contracts – **September 2011**
- In-service the upgraded unit – **December 2012**

Labour Strategy
Trades work assignment has been completed via the Chestnut Park Accord (CPA) Addendum based on recommended alternative scope of work.

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

6. QUALITATIVE BENEFITS

Sustainable Development
Since Hydroelectric generation is a renewable source of energy, the loss of a hydroelectric generating unit will increase the environmental impact of meeting Ontario's electricity demands. This will potentially necessitate the supply of energy from other less sustainable sources; therefore, increasing the reliability and production of SAB1 will potentially reduce the environmental impact of meeting Ontario's electricity demands.

Station Enhancement
Upgrades performed on the unit such as the modernization of the excitation system, unit protections and controls will improve the unit response and ensure compliance with Electricity market rules. This will enhance the overall station performance.

Health and Safety Issues
The work will be completed in a manner that ensures G3 and associated equipment will be compliant with all current corporate and provincial health and safety standards. Efforts will also be made to ensure that any new equipment installed is ergonomic. Enhancements such as upgraded lighting will improve the work environment and reduce health and safety risks to workers.

Environmental Issues
An Environmental Assessment is not required for this project as the scope of this upgrade does not extend the operational parameters for SAB1 past the parameters associated with the original 10 unit station configuration.

7. RISK ANALYSIS

Risk Type	Issue Category	Description		
Cost	Description	Final Execution Phase cost is higher than estimated		
	Consequences	Release funding insufficient to complete work		
	Mitigating Activity	RQE is based on recent G7 and G9 projects as well as recent DeCew Falls GS2 overhauls. A contingency allowance is included in the estimate		
	Before Mitigation	Medium Risk	**After Mitigation**	Low Risk
Scope	Description	Planned Execution Phase scope of work not complete		
	Consequences	Could lead to cost overruns		
	Mitigating Activity	Detailed scope provided for Execution Phase work is based on condition assessment of existing equipment. Stakeholders' requirements and expectations have been obtained upfront. A PEP will be completed prior to project execution.		
	Before Mitigation	Medium Risk	**After Mitigation**	Low Risk
Scope	Description	Generator stator core is in poor condition		
	Consequences	Stator core requires replacement		
	Mitigating Activity	The decision to rewind the generator is based on recommendations derived from the core assessment, testing, inspection, maintenance records, history and sound engineering judgment		
	Before Mitigation	High Risk	**After Mitigation**	Low Risk
Performance	Description	Expected unit performance after the upgrade may not be achieved		
	Consequences	Unit operation does not meet operational targets		
	Mitigating Activity	Runner and Johnson Valve efficiency improvement targets are based on OEM model testing. MCR and MVA targets are based on unit assessment and engineering data. The performance targets stated are conservative.		
	Before Mitigation	High Risk	**After Mitigation**	Low Risk
Schedule	Description	Delay in completion of construction will result in lost generation revenue.		
	Consequences	Reduced revenue.		
	Mitigating Activity	Preliminary estimates of hours required to complete the work are based on recent G7 and G9 projects as well as recent DeCew Falls GS2 overhauls. Scheduled outage provides a float and is longer than the obtained estimates		
	Before Mitigation	High Risk	**After Mitigation**	Low Risk
Schedule	Description	Delays in delivery of long-lead items		
	Consequences	Delays in the start-up of installation work. This can delay the completion of construction work resulting in lost generation revenue		
	Mitigating Activity	Delivery estimates are based on recent G7 and G9 projects as well as recent experiences in the hydro fleet		
	Before Mitigation	Medium Risk	**After Mitigation**	Low Risk

Risk Type	Issue Category	Description		
Quality	Description	Poor quality of workmanship		
	Consequences	Poor equipment/ unit reliability after return to service and possible damage to equipment and personnel. Equipment/ unit operation does not meet operational targets		
	Mitigating Activity	Include onsite quality assurance monitor during construction and support from the manufacturer during commissioning period. Develop and follow site inspection plans to ensure quality		
	Before Mitigation	High Risk	After Mitigation	Medium Risk
Regulatory	Description	Delays in obtaining outage approval		
	Consequences	Delay in start of construction work		
	Mitigating Activity	Prior approval and condition guarantee will be obtained for the outage from Hydro One and IESO		
	Before Mitigation	Medium Risk	After Mitigation	Very Low Risk
Environment	Description	Hazardous material may exist in obsolete equipment		
	Consequences	Improper disposal of hazardous material		
	Mitigating Activity	NPG Environmental policies will be followed		
	Before Mitigation	Medium Risk	After Mitigation	Low Risk
Health & Safety	Description	Risk of Injury to workers		
	Consequences	Worker Injury		
	Mitigating Activity	NPG Safety policies will be followed		
	Before Mitigation	Low Risk	After Mitigation	Very Low Risk
Health & Safety	Description	Hazardous material may exist in obsolete equipment		
	Consequences	Exposure to hazardous material		
	Mitigating Activity	NPG Safety policies will be followed		
	Before Mitigation	Low Risk	After Mitigation	Very Low Risk
Health & Safety	Description	Working near live equipment		
	Consequences	Worker Injury due to electrical shock		
	Mitigating Activity	Minimum clearances will be maintained		
	Before Mitigation	High Risk	After Mitigation	Low Risk
Other	Description	Lag time between delivery of large components and installation		
	Consequences	Storage space issues		
	Mitigating Activity	Prior arrangement and coordination between Projects and Production will need to be made to store equipment in the powerhouse area		
	Before Mitigation	Medium Risk	After Mitigation	Low Risk

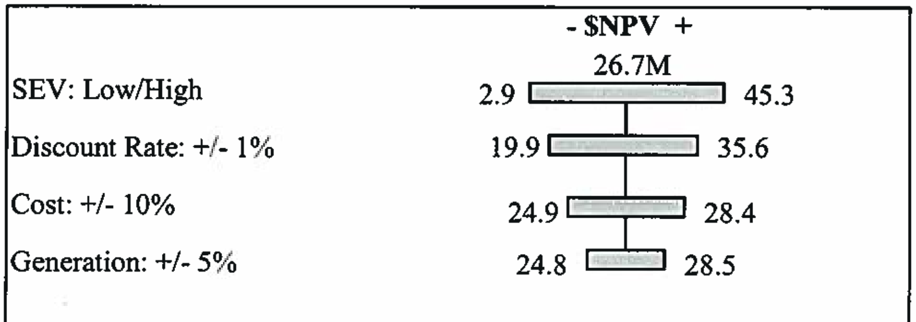
<u>Graphical Representation of Risk using a Tornado Diagram</u>:

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

SEV
Discount Rate
Capital Cost
Generation

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

- Change to SEV: Low and High values
- Discount Rate: + / - 1%
- Project cost: + / - 10%
- Generation: - / + 5%



TORNADO DIAGRAM

The result of the sensitivity analysis indicates that all NPV's are positive and project economics are fairly robust.

This project is most sensitive to the set of system economic values (SEV's) used in the analysis. If SEV's are low, than the economics of this project are less positive, but still attractive. If high SEV's are used, this project looks extremely attractive yielding a very high NPV and a quick payback. Base SEV's are used in the Financial Analysis delineated on page 7 and 8.

If the uprate study proves that the machine is capable of 68 MVA with a capacity of 61 MW than additional generation of 5 GWh would be expected annually. The corresponding NPV for the project would be $30.4 million or $3.7M more than the stated project NPV of $26.7M.

8. <u>POST IMPLEMENTATION REVIEW</u>

A simplified Post Implementation Review Report will be submitted by the Asset Management department 12 to 18 months after G3 is placed in service. Due to difficulties scheduling the Gibson test and outages to facilitate the cavitation inspection, the PIR completion deadline may be extended. The following table provides the criteria for this PIR.

Type of PIR		**Target Project In Service date**		**Target PIR Completion date**
Simplified		2012		2013/2014
Measurable Parameter	**Current Baseline**	**Target Result**	**How will it be measured?**	**Who will measure it? (person/group)**
1. MCR	45.9 MW	55 MW	Unit Metering	SAB1 Production
2. Apparent Power	55 MVA	63 MVA	Unit Metering	SAB1 Production
3. Runner and Johnson Valve Efficiency Improvements	1986 Gibson Test	[redacted] to [redacted] efficiency improvement over 1986 Gibson Test ([redacted] expected improvement with +/- 2% error on Gibson Test)	Gibson Test	NPG Asset/Projects
4. Runner Cavitation	N/A	As per model testing results (cavitation guarantee is 59 MW)	Visual Inspection	NPG Asset/Projects

ONTARIO POWER GENERATION

HYDROELECTRIC
Summary of Estimate (k$)

Date: 30-Nov-10
Estimate #: SAB10064-01

Facility Name: Beck 1 GS

Project Title: G3 Upgrade, New Runner and Generator Rewind

Estimated Cost Distribution (k$)

Years	2010	2011	2012	2013	TOTAL	%
Engineering & Project Mgmt	8	200	764	75	1,047	4.4
Permanent Material	[redacted]					[redacted]
Consultant			450		450	1.9
Construction/Installation						
- OPG	174	25	123	30	352	1.5
- Others	[redacted]					[redacted]
Interest	5	53	1,151	30	1,239	5.1
Contingency	[redacted]					[redacted]
TOTAL	298	3,778	19,222	759	24,057	100.0

Notes: 1. Schedule: Start date: Oct-11
In-Service Date(s) Dec-12 100.0%
(include % for partial in-service)

2. Interest and Escalation rates are based on current allocation rates provided by Corporate Accounting.
3. Includes Removal cost of: $ 200 k in 2011
4. Incl. Definition Phase costs of: N/A

Prepared by: Tobe Frost
Project Engineer

Approved by: Gord Allan
Gord Allan
Project Manager

APPENDIX 1

Assumptions

Financial Model

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

Project Cost Assumptions:

1. Overall project cost estimates were heavily based on G7 and G9 rehabilitations where appropriate
2. The cost for a new generator has increased significantly (approximately $[redacted]) from the G7 contract price (which also allowed the purchase of the G9 generator)
3. Estimates for the generator rewind were based heavily on actual labour requirements from SAB2 overhaul work
4. Quotes from suppliers of major components were used if available
5. Costs for other components and labour were based on costs for similar work carried out in the past with appropriate escalators applied
6. Competitive bids can be received for the work to be contracted out

Financial Assumptions:

7. Discount rate of 7%
8. The new generator and associated equipment will have a useful service life of 50 years
9. Extensive overhauls will be carried out after 30 years of service
10. For Alternative 1 a generator replacement is assumed to be required after 30 years of service
11. Costs for overhauls are built into the stream of cash flows for the analysis on both alternatives 1 and 2
12. SEV's will be used for financial analysis

Project Life Assumptions:

13. The project can start immediately after approval
14. The project can be completed and the generator can be commissioned by the end of Q4 2012
15. The useful service life of both the alternatives is 50 years
16. The study period used for the analysis is 50 years

Energy Production Assumptions:

17. Energy forecasts were based on Niagara River flow models
18. Existing outage plans can be followed
19. Generation at the Beck plants can be maximized while adhering to the market dispatches
20. Historical forced outage rates will be typical in the future

Operating Cost Assumptions:

21. There will be minimal incremental operating costs associated with the upgraded G3 unit

ONTARIO POWER GENERATION	Project: SAB10032	Review Routing Slip
	SIR ADAM BECK 1 – GS Unit 7 FREQUENCY CONVERSION FROM 25Hz TO 60Hz	

Niagara Plant Group Review:

Craig Smellman
Niagara Plant Group Controller — Date: May 9/07

Dave Heath
Niagara Plant Group Manager — Date: May 9/07

Hydroelectric Generation Review

Mario Mazza
Manager Hydroelectric Programming & Regulatory Affairs — Date: May 11/07

Don Brazier
Controller
Hydroelectric Generation — Date: May 10/07

John Murphy
Executive Vice President
Hydroelectric Generation — Date: May 22/2007

Corporate Finance Review

Don Power
Vice President
Corporate Investment Planning — Date: June 4/07

Donn Hanbidge
Senior Vice President and
Chief Financial Officer — Date: June 7/07

Recommended by:

Pierre Charlebois
Senior Vice President and
Chief Operating Officer — Date: June 8/07

Line Approval:

Jim Hankinson
President and CEO — Date: 11/6/07

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:

22 May 2007

John Murphy
Executive Vice President - Hydro

Date

Recommended by:

Aug 13/07

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 [redacted] 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

- $M NPV +

		7.1 M	
SEV: Low, High	**-2.4**	|	**16.2**
SEV: Low, High (with a 10 MW Capacity benefit)	**3.1**	|	**17.0**
Cost +/- 10%	**4.5**	|	**9.7**
Generation: -/+ 5%	**5.4**	|	**8.7**
Schedule: 1 month shorter to 3 months longer	**6.9**	|	**7.3**

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	[redacted]				
Construction/ Installation					
- Contractors	[redacted]				
Interest	307	1,298	433	2,038	5.8
Contingency	[redacted]				
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

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 Schedule	**Electrical Systems - Hydro 1** - Extent to which OPG is responsible for changes to the Hydro one equipment Will Hydro One accept 'E' bus? [redacted]	Cost: Uncertain – Costs will be firmed up as Hydro One completes their Customer Impact Assessment in November/ December 2007 Schedule: Preliminary schedule from Hydro One indicates no impact, but this requires Hydro One to dedicate adequate engineering and construction effort	Due to the uncertainty, Include a [redacted] contingency to increase this amount to [redacted] Approach Hydro One to start preliminary work on accelerated schedule	Low 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 Schedule	**Generator removal** - costs currently based on G6 costs - current estimate $535k (not a quote)	Cost: Retaining existing foundation bolts may be challenging Schedule: Possible project delay	Obtain competitive quotes from contractors Include adequate contingency Schedule work appropriately. The unit is currently not operating, so the removal start is not restricted by outage requirements.	Low Low
Cost Schedule	**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 $[redacted] - $[redacted] Schedule: May delay in-service date - 3 weeks?	Have GE inspect and approve foundation condition as soon as generator is removed Include adequate ([redacted]) contingency on foundation work cost	Low 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

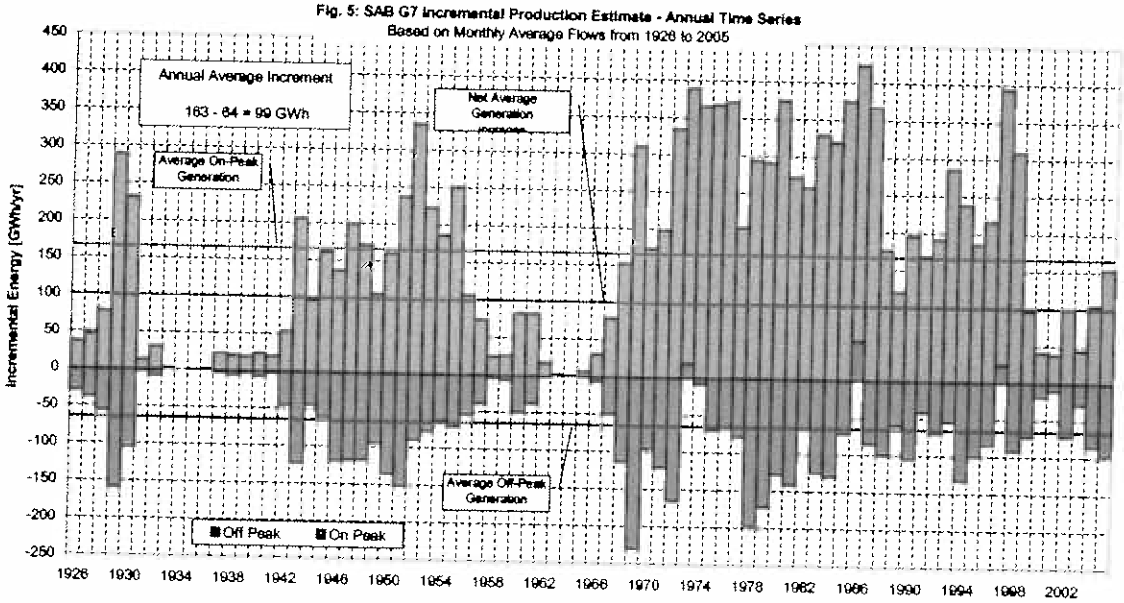
The Niagara Tunnel project assumed the Beck complex will increase its generation on average by 1.6 TWh as a result of increased water diversion. This generation is derived from additional water delivered and an increased ability to utilize PGS to pump. The additional generation would be generated by 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)

Fig. 5: SAB G7 Incremental Production Estimate - Annual Time Series
Based on Monthly Average Flows from 1926 to 2005



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.

SIR ADAM BECK 1 GS

G9 REHABILITATION

Project Number: SAB10047

Niagara Plant Group

SIR ADAM BECK 1 GS

G9 REHABILITATION

SAB10047

1. RECOMMENDATION

Approve the release of $ 32.0 million (includes a previously approved developmental release of $300k) for the replacement of the Sir Adam Beck 1 (SAB1) G9 generator with a new generator, the rehabilitation and upgrade of the turbine, the installation of a new runner, a liner in the Johnson valve and a new transformer and the upgrade of the associated electrical equipment. The upgraded G9 is scheduled to be commissioned and placed into service by the end of 2010.

The new G9 generator will have an electrical rating of 61.6 MW, increasing the installed capacity of the SAB1 Generating Station by 10.8 MW. The project has been incorporated into the station Life Cycle Plan. The rehabilitated and upgraded G9 will optimize energy production by efficiently utilizing the water available to the SAB complex, including water available from the Niagara Tunnel. The Pump Generating Station (PGS) will be used to shift energy from off-peak to on-peak, increasing capacity output of the SAB facility. The resulting incremental peaking capability for SAB1 is about 10 MW and incremental energy is 60.8 GWh per year. This incremental output has a market value of ~$4 to 6 million (2008$).

This project is consistent with OPG's objective of maintaining its assets and optimizing production from its existing hydroelectric generating assets. The project is identified in the current approved business plan in 2008, 2009 and 2010 and cash flows will be managed by the Plant group.

$000s	LTD 2007	2008	2009	2010	Later	Total
Currently Released	0	300				300
Requested Now (This Release)		1,700	15,520	14,490		31,710
Future Funding Required						
Total Project Costs		2,000	15,520	14,490		32,010
Investment Type	**Class**	**NPV**	**IRR**		**Discounted Payback**	
Sustaining/Value Enhancing	17	17,600 (using SEVs)	11.0% (using SEVs)		16 years (using SEVs)	

2. SIGNATURES

Submitted by:

7 Aug 2008.

John Murphy
Executive Vice President - Hydro

Date

Recommended by:

Aug 11/08

Pierre Charlebois
Executive Vice President and
Chief Operating Officer

Date

Finance Approval:

August 10/08

Donn Hanbidge
Senior Vice President and
Chief Financial Officer

Date

Line Approval:

Aug 21/08

Jim Hankinson
President and CEO

Date

3. BACKGROUND AND ISSUES

SAB 1 GS is a ten unit hydroelectric station located on the Niagara River. The units were placed in service during the years 1921 to 1930. Two of the units (G1 and G2) have 25 Hz generators and they are scheduled to be decommissioned in 2009. The SAB1 Life Cycle Plan considered the water available to the station, including that provided by the Niagara Tunnel, and concluded that an eight unit station will optimize the use of the water available to the station. An orderly program of unit rehabilitation involving G7, G9, G10 and G3 was proposed in the Life Cycle Plan. After the completion of the G7 conversion project currently underway, this G9 project and the Niagara Tunnel, the eight 60 Hz units at the station (G3 to G10) will have a total capacity of 427 MW and will have an annual energy production of approximately 2,149 GWh. This energy generates annual revenue of $81.4 million at the proposed regulated rate of $37.90/MWh but over $100 million if valued at current market prices.

The G9 generator was installed in 1925 and converted to 60 Hertz in 1956. The 50.8 MW generator is in poor mechanical condition. It is currently limited to operating at a maximum of 70% wicket gate opening due to significant vibrations that occur at greater gate openings. Under this operating restriction, the maximum generator output is 37 MW. The bearing lubrication system is unreliable and prone to causing bearing failures. It is suspected that the upper guide bearing is partially wiped. The unit may fail at any time and it is possible that it may not be able to be brought back into service. The generator is at the end of its service life. Consideration has been given to correcting the problems with the generator, but this will require significant re-design and re-work within the physical constraints of the current generator. It is unlikely that a generator manufacturer other than the original designer would be prepared to undertake the major re-design required. It is expected that the cost of the re-design and the repairs will be significant compared to the cost of a new generator. Any attempt at undertaking the re-design and repairs will yield a unique repair with uncertain long term reliability.

When the SAB1 G7 generator was purchased from GE Hydro in 2007, OPG negotiated an option, valid until the end of 2008, to purchase a second, similar generator at the same base cost, modified by an escalator clause for the cost of labour and material. This represents an attractive option to OPG. GE Hydro has since been acquired by Andritz VA Tech and the takeover was concluded at the end of June, 2008. Discussions with Andritz VA Tech have been initiated and Andritz VA Tech has indicated that it will honour OPG's option for a second generator.

The installation of a new, larger G9 generator necessitates the replacement of associated electrical components. The existing rotating exciter has a "dead zone" and is not fully functional. A new static exciter is required to complement the new generator. Upgrades to the buswork and a new, larger capacity transformer are required to handle the increase in generator output.

The existing runner and turbine are physically unable to fully utilize the water available through the G9 water conveying structures. A new efficient runner and an upgrade to the turbine are required to utilize this water. It has been identified that there are significant hydraulic losses through the G9 Johnson valve. A liner installed in the Johnson valve will reduce these losses.

4. ALTERNATIVES & ECONOMIC ANALYSIS

Base Case (Status Quo): Continue to Operate G9 in its Current Condition

This alternative does not address the fact that the unit is in poor condition, restricted to 70% wicket gate opening due to vibration problems and may have a partially wiped upper guide bearing. The unit may fail at any time and may not be able to be brought back into service, resulting in the total loss of generation from the unit.

- **This alternative is not recommended.**

Alternative 1:

Install a new 61.6 MW Capacity Generator, Transformer, Runner, Johnson Valve Liner and Upgrade the Turbine

This alternative replaces the end of life 50.8 MW G9 generator with a new 61.6 MW generator that optimizes the use of the water available. It includes a new exciter, new protections and controls and a new transformer. A new, efficient runner will be installed, the turbine will be rehabilitated and a liner installed in the Johnson valve. With regular maintenance, the useful service life of the components is expected to be 50 years or more.

- **This is the recommended alternative**

The following options were considered and rejected:

1. **Repair the Existing Generator, Upgrade to 61.6 MW, Install a New Transformer, Runner, Johnson Valve Liner and Upgrade the Turbine**

This option involves undertaking a major re-design and re-work of the generator. The upgrade of the generator, the installation of a new transformer and runner and the upgrade to the turbine would optimize the use of the available water. However, the generator re-work would be a unique rehabilitation and there will be a significant risk that the rehabilitation will not guarantee reliable long term performance of the generator. This option was rejected for technical reasons.

2. **Repair the Existing Generator (50.8 MW), Install a New Runner and Overhaul the Turbine.**

This option involves repairing, but not up-grading, the generator and installing a new runner and overhauling the turbine. The same problems identified in the option above would be present, with no guarantee of reliable long term performance of the generator. This option does not make full use of the available water. This option was rejected for technical and financial reasons.

Financial Analysis:

$ Millions	Base Case	Alt 1 (recommended)
Project Cost	0	32.0
NPV (after tax)	0	17.6
IRR %	0	11.0
Discounted Payback (Yrs)	n/a	16

The financial evaluation assumes incremental peaking capability of 10 MW and annual energy of 60.8 GWh for G9. Generation estimates were developed using detailed water and energy modeling based on 80 years of historical Niagara River flows. Peaking capability is estimated based on the unit's average capacity factor during peak periods in the summer and winter seasons.

The Beck complex is often operated for operating reserve and paid through an Operating Reserve revenue stream. The financial evaluation calculations do not include this benefit as this value is determined at the time of operation and is dependant on system requirements and how the units are required to be operated.

Net Present Value (NPV) calculations have used forecast market prices of electricity for economic evaluation purposes. This demonstrates that the investment is prudent from a commercial perspective. However, this generator is part of OPG's regulated Hydroelectric assets and as such will receive the regulated rate for energy. This project was included in OPG's 2008 rate submission for the rate years 2008 and 2009.

The levelized unit energy cost (LUEC) over 50 years for this project is approximately $54/MWh. This is significantly lower than published prices of $110/MWh in OPA's standard offer for renewable energy projects. The impact on regulated rates to recover the cost of this project is estimated to be approximately 0.2%.

5. THE PROPOSAL

Results To Be Delivered:

The existing SAB1 G9 generator will be replaced with a new 61.6 MW generator and the turbine will be rehabilitated and upgraded. Also included are a new exciter, new protections and controls, upgraded buswork and a new transformer. The turbine rehabilitation will incorporate a new, efficient runner and greaseless bearings. A steel liner will be constructed inside the Johnson valve to reduce hydraulic losses.

The generator is scheduled to be commissioned by the end of 2010. The new generator will utilize the water made available to the Beck complex by the Niagara Tunnel and through the use of the Pump Generating Station. It will contribute 60.8 MWh annually to the station output. As well, it will increase the Beck complex's ability to provide operating reserve and provide assistance with managing excess baseload generation (EBG) on the system.

Runner

The existing runner is the original runner installed in 1925. It was last inspected in March 2007 and found to have some minor cavitation and pinholes in the stainless steel overlay.

The design, model development and model testing for new runners for SAB 1 GS have been completed as part of a runner replacement program. A new runner for G9 with an efficiency of approximately [redacted] can be supplied by the runner manufacturer.

Generator:

A new 61.6 MW capacity generator can be installed to match the maximum power output of a new runner.

With a new generator and new runner, G9 will have a high efficiency rating and will generally be one of the first units on / last units off at the station to maximize efficient generation.

Transformer

The existing 55 MVA transformer will be replaced with a new 68.5 MVA transformer to match the output of the generator.

Turbine Upgrade

The last significant amount of work on the G9 turbine was carried out in 1956 at the time of conversion to 60 Hertz. Stator repairs were made in 1974. The normal interval between major overhauls is 25 to 30 years and the turbine is overdue for rehabilitation. Modifications will be made to the turbine to increase the maximum output to approximately 61.6 MW, from the current 50.8 MW output. The scope will include the modification of the discharge ring and the installation of greaseless bushings. The upgraded turbine will maximize the efficient use of the available water.

Johnson Valve Liner

The G9 water conveying structures include a Johnson valve located at the end of the penstock. The internal components of the Johnson valve have been removed to address a concern that the valve could not be relied on to function safely. The ribs and projections remaining inside the valve casing cause significant hydraulic losses. A steel liner will be installed to create a smooth transition from the penstock to the scroll case, thereby reducing the hydraulic losses. Installation of the liner will also alleviate concerns regarding the long term integrity of the cast steel Johnson valve casing.

Other Major Items In Scope

The existing faulty rotating exciter will be replaced with a new static exciter to match the requirements of the new generator.

Upgrades to the generator output buswork and to the electrical connections to the Hydro One system will be made to handle the increase in generator output.

A System Impact Assessment by the IESO and a Customer Impact Assessment by Hydro One are required because the project will connect additional generation capacity (10.8 MW) to the Ontario Grid. The developmental release (approved) provides funding to carry out these studies.

Ongoing Operational and Maintenance Cost Impacts

The incremental effort to maintain the unit is minimal and will be managed in the Plant Group business plan. A unit overhaul after 25 years of operation has been included in the financial analysis.

Qualitative Factors

The Project was classified by OPG as Rehabilitation and therefore was presented to the Chestnut Park Accord Steering Committee for trades work assignment. The Committee assigned operation of the powerhouse overhead crane, inspection of scroll case and stay vane repairs, transformer testing and oil handling, and commissioning to the Power Workers Union. The balance of the work was assigned to the Building Trades unions.

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

Project Management

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

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

Post Implementation Review (PIR)

A Post Implementation Review (PIR) 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 61.6 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 Niagara Plant Group Project Department will review the project by comparing the planned cost and schedule milestones outlined in the Project Management Plan to the actual cost and schedule milestones.

6. QUALITATIVE BENEFITS

Qualitative Factors & Sustainable Energy Development:

- Sustained generation from an existing hydro generating station with a 10.8 MW increase in capacity (from 50.8 MW to 61.6 MW).
- Increased efficiency of water use due to the efficient runner, turbine upgrade and installation of the Johnson valve liner.
- Combining the generator replacement, electrical equipment replacement, runner replacement, turbine upgrade and Johnson valve liner installation into one outage reduces total outage time and avoids repetitive dismantling and assembly of the unit.

7. RISK ANALYSIS

Risk Category	Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Residual Risk
Cost	Cost over-run / Cost under-run	Plant Group cash flow issues	medium	Estimates refined by obtaining budget quotes where possible	low to medium
Scope	Scope not complete, or accurate	Could lead to cost over/ under runs	low	Compared scope with similar project underway (G7)	low
Schedule	Delays to the delivery / installation of the generator	G9 return to service delayed	medium	Initiate discussions with preferred generator vendor to secure delivery schedule, commit to generator purchase as soon as possible	medium
Resources	Insufficient commissioning resources to complete critical tasks on schedule	G9 return to service delayed	medium	Where possible, schedule and complete activities throughout project life	low to medium
Technical and Quality Assurance	Incorporating new technology and equipment	Unproven technology or equipment may prove unacceptable	low	Where possible, apply OPG standards. Ensure adequate specifications and engineering reviews of proposals	low
	Poor quality components from unknown/ overseas suppliers	Detrimental to the long term performance of the component	medium	Arrange site surveillance, develop and follow inspection test plans to ensure quality	low
Generation	Inaccurate estimation of energy production from unit	Over estimate of energy production	medium	Use detailed water modeling incorporating 80 years of historical Niagara River flow	low
Regulatory	G9 not compatible with grid / system requirements	G9 not permitted to be connected to grid	low	Ensure applications to IESO and Hydro One are complete and accurate	low
Environmental	Spill	Reportable spill	low	Plant Group Environmental policies will be followed	low
Health & Safety	Unsafe working procedures	Worker injury	medium	Plant group Safety Policies will be followed	low

Cost Risk:

There is a medium to high level of confidence in the cost estimate for this project.

- The cost of the generator design/ supply/ install, the largest component of the project, is based on the purchase option obtained from GE Hydro at the time of the purchase of the SAB1 G7 generator. A defined escalation clause for labour and material will be applied to the G7 base cost. However, negotiations with Andritz VA Tech, the new owners of GE Hydro, for the purchase of the new generator have not been concluded.

- Preliminary price quotes have been obtained from the exciter, runner, transformer and Johnson valve liner suppliers in an effort to develop accurate cost estimates.

- Much of the work associated with the G9 project is similar to the work presently being undertaken on the G7 project. G9 project costs were developed with this knowledge.

- An overall contingency of [redacted] is included in the project cost estimate. The contingency has been determined by assessing the unique risk factors for each of the items in the estimate.

Schedule Risk:

- Discussions with Andritz VA Tech indicate that they will honour OPG's option to purchase a 61.6 MW generator similar to the SAB1 G7 generator currently being installed by GE. OPG has not concluded discussions with Andritz VA Tech regarding OPG's schedule for the installation of the generator. It is not known if the G9 generator can be slotted into the Andritz VA Tech manufacturing queue such that it can be manufactured and installed to meet the project schedule. If the Andritz VA Tech generator production plant is booked, the generator in-service date will be delayed.

- The project schedule is such that there may be numerous contractors on site at any given time, creating the possibility for interference. This concern will be managed by scheduling and coordinating site work appropriately.

Supply and Procurement Quality Assurance Risk:

- Supply Chain and Hydro Engineering will exercise due diligence and assess the capabilities of Andritz VA Tech prior to entering an agreement.

- Possible manufacture of runner and generator components overseas presents quality risks. Contracts for source surveillance will have to be put in to place. Inspection and test plans will be utilized to monitor the product quality throughout the manufacturing process.

- Quality assurance for the generator assembly at site will be addressed by hiring a Quality Control monitor to oversee the generator assembly.

<u>Graphical Representation of Risk using a Tornado Diagram</u>:

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

SEV (forecast market prices)
Discount Rate
Capital Cost
Generation

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

- Change to SEV: Low and High values
- Discount Rate: + / - 1%
- Project cost: + / - 10%
- Generation: - / + 5%

- $M NPV +

17.6 M

	-	+
SEV: Low, High	1.8	35.4
Discount Rate: +/- 1%	11.4	25.7
Cost: +/- 10%	15.3	19.9
Generation: -/+ 5%	15.4	19.7

The result of the sensitivity analysis indicates that the project economics are fairly robust with the NPV remaining positive for the range of variables tested.

ONTARIO POWER GENERATION

HYDROELECTRIC Summary of Estimate

Date	July 15, 2008
Project #	SAB10047

Facility Name: Sir Adam Beck 1 GS

Project Title: G9 Rehabilitation

Years (k$)	2008	2009	2010	2011	TOTAL	%
Project Mgmt.	75	500	594		1,169	3.7
Engineering	[redacted]					
Permanent Materials						
Construction/ Installation						
- Contractors		[redacted]				
Interest	25	540	1,477		2,042	6.4
Contingency	[redacted]					
TOTAL	2,000	15,520	14,490		32,010	100%

Notes:

1 Schedule — Start date: September, 2008
In-service dates:
Generator: December, 2010

2 Interest rate provided by Corporate Finance

3 Includes Removal Costs of: 1,100 k

4 Includes Definition Phase Costs of: 300 k

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. VA Tech will honour OPG's option to purchase a generator similar to G7 at the price negotiated in the contract with GE Hydro.
2. Quotes from suppliers of major components were used if available.
3. Costs for other components and labour were based on costs for similar work carried out in the past with appropriate escalators applied.
4. Competitive bids can be received for the work to be contracted out.

Financial Assumptions:

5. The July 2008 Hydro FE Model was used with a 2008 project start year.
6. The new generator and associated equipment will have a useful service life of 50 years.

Project Life Assumptions:

7. The project can start immediately after approval.
8. The project can be completed and the generator can be commissioned by December, 2010.

Energy Production Assumptions:

9. Energy forecasts were based on Niagara River flow models.
10. Existing outage plans can be followed.
11. Generation at the Beck plants can be maximized while adhering to the market dispatches.
12. Historical forced outage rates will be typical in the future.

Operating Cost Assumptions:

13. Other than a unit overhaul after 25 years of operation, there will be minimal incremental operating costs associated with the new generator.

NIAGARA PLANT GROUP BUSINESS CASE SUMMARY

Project No.: SAB10050
Project Title: G10 Upgrade
Facility Name: Sir Adam Beck 1

Expenditure Type:	☐ OM&A Project	☒ Capital Project		
Release Type:	☒ Developmental	☐ Partial	☐ Full	☐ Superseding
Work Category:	☒ Sustaining	☒ Value Enhancing		☐ Regulatory

Prepared by: Mark Armstrong, Cost & Schedule Analyst

1. RECOMMENDATION

Approval is recommended for the release of 600k$ CAP to fund the preliminary engineering work necessary to identify the SAB1 G10 Upgrade preferred alternative which will be developed in the Definition Phase. This work will include a detailed equipment condition assessment, engineering analysis and a detailed report.

This course of action will address the business needs of this project as outlined in the Niagara Plant Group's Business Plan of sustaining our generating resources and is consistent with the strategic plan for Sir Adam Beck 1 Generating Station (SAB1) and OPG's mandate to increase its portfolio of hydroelectric generating capacity.

(k$)	2011	2012	2013	2014	2015	Total
Cash Flows For This Release	600					**600**
Future Funding (Full Release)		1,700	15,253	12,153		**29,106**
Total Project Cost	**600**	**1,700**	**15,253**	**12,153**		**29,706**
Business Plan (BP2011-15)	400	1700	15253	12153		29,506
Business Plan Variance	200	0	0	0		200

Funding:
This project includes removal costs of $1,500k OM&A in 2013 which has been included in the full release amount.

2. SIGNATURES

Submitted by:

Nov/30/10

Robby Sohi Date
Asset & Technical Services Manager

Finance Approval:

Nov 30 10

Cynthia Domjancic Date
Site Controller

Approval by:

1 DEC 10

Mike Martelli Date
Plant Group Manager

3. BACKGROUND & ISSUES

Sir Adam Beck (SAB) 1 GS is a ten unit station located on the Niagara River. The units were placed in service during the years 1921 to 1930. Two of the units (G1 and G2) are 25 Hz generators and were decommissioned in 2009. Analysis and modelling work for SAB1 considered the water available to the station, including that provided by the 3rd Niagara Tunnel, and concluded that an eight unit configuration will optimize the water available to the station. An orderly program of unit rehabilitation involving G7, G9, G3 and G10 was proposed going forward as the strategic plan for the station.

SAB1 G10 has not had a major rehabilitation since 1986. Hydroelectric units of this type normally require overhauls on a 25-30 year cycle to ensure reliable continued operation. A degraded unit condition, due to end of life, will lead to increasing unreliability, lost production and lost revenue. Since Hydroelectric generation is a renewable source of energy, the loss of a hydroelectric generating unit will increase the environmental impact of meeting Ontario's electricity demands. This will necessitate the supply of energy from other less environmentally friendly sources or generators external to Ontario.

While the G10 unit is being rehabilitated, there is an opportunity to replace the existing runner with a higher capacity and more efficient runner allowing maximum utilization of the Niagara River flows during peak generation hours and increasing the turbine output by approximately 8-10 MW.

Business Need

Complete a comprehensive unit condition assessment and conduct preliminary engineering and analysis to clearly identify the scope of work for the SAB1 G10 Upgrade Project. This will minimize project risk by better identifying the necessary project scope to achieve the overall project business needs identified in the Initiation Phase Project Charter.

4. ALTERNATIVES and ECONOMIC ANALYSIS

Base Case — **Status Quo (Not Recommended)** - This alternative is not recommended as it does not address the stated business need of minimizing risk and may result in unnecessary financial exposure. A comprehensive equipment condition assessment is needed to determine which unit components need to be replaced or overhauled and which components can be repaired and reused in addition to those components that are still capable of 25 to 30 years of reliable service.

Alternative 1 — **Perform Initiation Phase Assessment Work (Recommended)** - carry out the preliminary engineering work necessary to clearly define the scope of work for SAB1 G10 Upgrade and identify the preferred project alternative prior to proceeding with the Definition Phase. A detailed equipment condition assessment is the preferred way to minimize overall project cost by replacing only those components that cannot be repaired or rehabilitated to achieve the expected unit service life as indicated in the Business Needs in the Initiation Phase project charter.

This alternative assesses the condition of the existing generator, turbine and associated unit components. Project alternatives will be developed for the optimum rehabilitation and upgrade of the unit, consistent with the strategic plan for the station. Alternatives will consider:

- The installation of a new generator,
- The re-wind of the existing generator,
- The installation of new equipment to optimize the unit output,
- The optimal use of the available water.

Alternative 2 **Proceed to Definition Phase Immediately (Not Recommended) –** this alternative is not recommended as there are uncertainties relating to the exact work scope and optimal equipment configuration that need to be resolved. Proceeding directly to Definition Phase work may result in the approval of an inappropriate scope of work with a higher degree of uncertainty, risk and overall project cost.

5. PROPOSAL

Results to Be Delivered

The overall objective of this project is to provide 25 to 30 years of reliable operation of G10 in the most cost effective manner possible. In addition, replace or introduce new components to improve both efficiency and unit output where it is economically advantageous to do so. This developmental release will be used to deliver the following results:

- Accurately identify the scope of work required to meet the stated business needs and objectives.
- Minimize financial risk by identifying a clear and well defined scope of work, allowing a higher degree of control over cost & schedule.
- Ensure the project plan is achievable from a practicality and resourcing point of view.
- Recommend the preferred alternative to be developed in the Definition Phase.
- Critically examine capacity and efficiency improvements to ensure that they are economically sound investments

Proposal Overview

The work to be done in this stage will include preliminary engineering work necessary to clearly identify the scope of work for the Definition phase and recommend the preferred alternative consistent with the strategic plan for SAB1.

6. QUALITATIVE FACTORS

Sustainable Development

Since Hydroelectric generation is a renewable source of energy, the loss of a hydroelectric generating unit will increase the environmental impact of meeting Ontario's electricity demands. This will necessitate the supply of energy from other less environmentally friendly sources; therefore, an increase in the reliability and production of G10 unit will reduce the environmental impact of meeting Ontario's electricity demands.

Technical Considerations

Upgrading and rehabilitation of the G10 unit and its components will increase its reliability over the next 30 years. Unplanned maintenance due to aging equipment is expected to be reduced following rehabilitation or replacement of the existing equipment with new equipment.

7. RISK ANALYSIS

This risk analysis only addresses the Definition Phase work for this project.

Risk Category	Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost	Final Initiation Phase cost higher then estimated.	Release funding insufficient to complete work.	Medium.	Preliminary price quotes have been obtained from known suppliers for external resources in an effort to develop accurate cost estimates. The risk of over expenditure is low because the field work has been done in a satisfactory fashion before by the staff involved. A contingency allowance is included in the estimate.	Low.
Scope	Poor Definition of Scope of Work.	Increased Cost.	Medium.	Detailed scope provided for Initiation Phase work based on equipment condition, maintenance records as well as previous experience with other similar projects.	Low.
Schedule	Delay in completion of outage work will result in lost generation revenue.	Reduced revenue.	Low.	Scheduled outage provides a float and is longer than what is needed to do the Initiation Phase site work because this outage is also being utilized to install G10 Governor Control Head which should have no impact on this work.	Very Low.
Resources	No available resources to do the work.	Delays in schedule. Work not getting done.	Medium.	Based on earlier discussions, Internal and external resources have been committed from OPG and service providers for the work. The project engineer will coordinate project resourcing.	Low.
Regulatory	Delays in obtaining outage approval.	Delay in start of outage inspection work.	High.	Prior approval has been obtained for the outage.	Very Low.
Environmental	Spill.	Reportable Spill.	Low.	NPG Environmental policies will be followed.	Very Low.
Health &Safety	Risk of Injury to workers.	Worker Injury.	Low.	NPG Safety policies will be followed.	Very Low.

8. POST IMPLEMENTATION REVIEW

A simplified Post Implementation Review Report will not be needed for this Initiation Phase. A comprehensive Post Implementation Review Report will be submitted within twelve months of the date of the completion of Execution Phase work, which is projected to be 2014.

ONTARIO POWER GENERATION	Project Number: DESJ0031	Facility: Des Joachims GS	Page: 1 of 8
	BUSINESS CASE SUMMARY Replace Main Output Transformers		

1. RECOMMENDATION

Recommend full release approval of $27.9M (which includes Definition Phase release of $80k) to purchase and install 12 new main output transformers, 1 new station spare, and associated equipment at Des Joachims GS. The existing transformers are almost 60 years old, are nearing the ends of their service lives, and the probability of failures is expected to increase dramatically over the next ten years. Since the indicated time required to manufacture a transformer is approximately 90 weeks, it is recommended that a transformer replacement program be initiated now to ensure transformers at Des Joachims GS are replaced in an orderly and timely fashion over the 2010 to 2013 period (1 bank per year).

Total Investment Cost: $28M

Recommended Alternative	LTD 2007	2008	2009	2010	2011	2012	2013	Total
Project - Capital	$54k	$1,749k	$1,771k	$6,982k	$6,412k	$6,580k	$4,337k	$27,874k
Proposed 2008-12 BP	$83k	$2,016k	$3,400k	$3,477k	$6,483k	$6,543k	$6,141k	$28,143k

Expenditure Type: Capital
Investment Type: Sustaining
Release Type: Full release under OAR element 1.1
Funding: The total project cash flows have been programmed in the 2008 Budget Version of the Work Program Catalogue.
Investment Financial Measures: NPV: $6,542 k (Relative to the Base Case)

2. SIGNATURES

Submitted by:

28 Jan 2008.

EVP - Hydro | date

Recommended by:

Feb 5/08

EVP & COO | date

Finance Approval:

Feb 1/08

SVP & Chief Financial Officer | date

Line Approval per OAR 1.1:

Feb. 11/08

President & CEO | date

3. BACKGROUND & ISSUES

- Des Joachims GS is an eight unit, hydroelectric station located on the Ottawa River, 20km north of Deep River. The facility was placed in service in 1950 and 1951. The station is controlled from the Chenaux Control Centre. The station capacity (MCR) and average annual energy production are 428.8 MW and 2,247 GWh respectively, with 2006 revenue of $121.4M. The ten year average of the station Capacity Factor is 58%.
- The asset classification of this station is "Flagship" and is ranked 4th in both capacity and energy production in Hydroelectric. The Life Cycle Plan expenditure strategy for this station includes planned investments, over the next 30 years, totalling about $100 million. Major projects include the turbine replacement and overhaul program ($40M), transformer replacement program ($28M), rehabilitation of sluice gates ($17M) and generator rewind program ($6M).
- Reliability has been excellent over the past 10 years with an Incapability Factor (ICbF) in the 7% range. The Equivalent Forced Outage Rate (EFOR) is less than 1%.
- Due to its asset classification, Des Joachims receives high priority for sustaining investments to maximize return on investment. The recommended preferred alterative will ensure that similar reliability will be sustained.
- Originally all eight units produced 45 MW each. In the late 70's and early 80's new runners were purchased as replacements for the original runners to increase the output of the units. The unit output was increased by 9.0 MW. The transformers were never upgraded or replaced. All cables have recently been replaced; have no visible signs of leaks in the floor penetrations and will not need to be changed.
- The transformers are water cooled original installations (1950 vintage) and have previously experienced a failure in 1981. The T2 Blue Phase transformer ruptured and oil entered the tailrace area.
- The Des Joachims Generating Station consists of four transformer banks, each supplied by two generators. Each bank is made up of three single phase transformers plus one single phase spare transformer for the station. (Total of thirteen transformers). The nameplate sizes of the in-service transformers are rated at 33 MVA each but are operating at 110 MVA per bank or 10% above rated capacity.
- Due to 20+ years of operation at 10% above rated capacity, the life expectancy of the transformers has been reduced to where they are now approaching the ends of their service lives. Oil test results show elevated concentrations of carbon monoxide and moisture. High carbon monoxide levels are a symptom of elevated thermal stress within the transformer that results in accelerated ageing of the critical insulation system. Moisture in a transformer is also a major accelerant of insulation deterioration, particularly when combined with elevated operating temperatures, and moisture levels are now approaching recommended ASTM limits for reliable operation. No field process can remove the moisture from deep within the insulation system; therefore, rehabilitation is not practicable.
- Transformer reliability can be characterized by the "bathtub curve", which correlates the risk of failure with equipment life. The curve suggests that a long period of low failure risk operation is followed by a relatively shorter period of escalating probability of failure as the equipment approaches its end of life. The recent test results indicate that the transformers are now approaching the ends of their service lives and the risk of failure can be expected to dramatically increase.
- There are additional operational concerns due to:

- The 30º C transformer operating temperature. Cooling pump use must be restricted during winter operation to avoid over-cooling the oil, which has resulted in gasification problems.
- Lower level flooding of the powerhouse due to PVC cooling water piping failures
- The risk of oil spills due to leaking oil-filled Low Voltage Box connections
- Signs of deterioration in the concrete beams that support the Ring Gaps

- The first transformer replacements will not occur until 2010 due to the 90 week lead time for delivery, with the planned in-service date of the final bank of transformers occurring in 2013. Due diligence dictates that a prudent, orderly transformer replacement program be initiated to avoid transformer failures.
- The failure of one of the main output transformers in any transformer bank could result in the loss of energy output from two units. Although the spare transformer could be used to replace the first failed transformer, replacement would still require a dual unit outage of at least one month. If a second transformer failure occurred before the spare was replaced, it would result in a dual unit outage of up to 2 years. The probability of this occurrence is expected to escalate over the next few years as the transformers approach end of life.
- The manner in which a transformer could fail is not predictable. A catastrophic failure could result in an uncontrolled loss of oil, presenting a risk to station personnel, the environment, and to the station itself. (Each transformer contains approximately 5,100 imperial gallons (23,000 litres) of oil).

4. ALTERNATIVES & ECONOMIC ANALYSIS

Approval was attained during the project Definition Phase in 2006 for $80k to retain a transformer consultant in order to prepare a Technical Specification and request proposals for the supply of 13 transformers over the period of four years. (One bank per year) The transformer consultant performed a performance evaluation for each of the four proposals received and recommended the preferred supplier.

Base Case:
Do nothing – Replace upon failure

- The existing transformers are operating at 10% above rated capacity with oil test results indicating unacceptable oil moisture and gasification levels. This indicates these transformers are approaching end of life and an escalating risk of failure, jeopardizing production.
- The results of a previous transformer refurbishment program have been unsatisfactory and the service lives of these transformers will not be extended through refurbishment. The Plant Group strategy is a transformer replacement program.

For asset equipment protection and personnel safety concerns in the event of a transformer failure, this alternative is unacceptable.

Alternative 1: (13 Transformers)
Replace with Single Phase – Water Cooled

- Water cooled transformer will require ongoing maintenance costs, which are not required by the **Alternative 3** air cooled design.
- There is a risk of cooling water failures which could result in flooding of the powerhouse, and a risk of cooling water freeze up conditions.

The financial cost of this alternative is very similar to the preferred alternative, but due to the cooling risks identified and ongoing maintenance costs this alternative was rejected.

Alternative 2: (5 Transformers)

Replace each bank (3 single phase transformers) with (1) three phase transformer

- The loading capacity of the existing concrete structure will require major civil upgrades. The 3 phase transformer weight is 130 tons, while the existing single phase transformer weighs 60 tons. The runway, transformer base and moving trolley will not withstand the increased load.
- A transformer rotation mechanism will be required to rotate the transformer 90 degrees at the corner of the runway due to the increase in outside dimensional size.
- The transformer deck door opening is not sufficient in size to move the transformer in and out of the powerhouse erection bay to the transformer deck area.
- The installation of radiators must be conducted outside the powerhouse; therefore, a mobile crane is required for these installations.
- The existing oil containment system will require major civil modifications due to the extensive difference in size vs. a single phase transformer.
- There is a marginal efficiency gain for three phase over single phase transformers.

Although the procurement of three phase transformers (5) is less expensive than single phase transformers (13), the lower cost is more than offset by the need for major civil modifications.

Alternative 3: (13 Transformers)

Replace with Single Phase – Air Cooled

- Single phase air cooled transformers will require minimal civil modifications due to the similar structural dimensions as the existing.
- The transformer increased output capacity will provide sufficient capability intended for the existing turbine replacement program, plus an additional 10% capacity for future unit upgrades.
- Major civil oil containment and structural modifications will not be not required.
- The spare transformer cost is 1/13 of the total supply cost vs. 1/5 for three phase design.
- No additional major adaptation will be required for low voltage cable modifications.

This is the recommended alternative.

Other alternatives considered but discounted

- Refurbish – Past refurbishment efforts did not produce the expected end result.
- Like-for-like capacity replacement - The existing transformers are under-capacity; therefore, an increase in transformer output is required.
- Partial bank replacement – All transformers are approaching end of life. Partial replacement would also require two sets of spare transformers; one for the new and one for the existing.

Financial Analysis

	Base Case	Alt. 1	Alt. 2	Alt. 3
Initial or Remaining Costs (k$)	$30,824	$29,227	$34,555	$27,874
NPV (2007 PV (k$) 40 years	($30,319)	($24,446)	($27,870)	($23,777)
Impact on Economic Value (2007 PV k$)		$5,873	$2,449	$6,542

5. THE PROPOSAL

Results to be delivered

- Prepare installation engineering specification.
- Purchase and install twelve 30/40/50 MVA ONAN/ONAF1/ONAF2 transformers plus one station spare.
- Dispose of existing transformers
- Modify existing deluge system
- Modify oil containment system and perform minor civil modifications
- Provide spare parts
- Provide operation and maintenance training
- This investment is linked to the Turbine replacement project to avoid duplicating outages. Installation of the transformers will be coordinated with the outages for the Turbine replacement and major overhauls.

Project Management

- A Project Execution Plan (PEP) will be used to monitor the project progress.
- Lessons Learned meetings will be conducted following the first bank outage and a list of actions developed an implemented on the subsequent outages. The PEP will be revised and issued by Q2 of each outage year.

Project Execution Outage Schedule

Station	Transformer Bank Outage	Turbine Replacement	Execution Date
Des Joachims GS	T1	G4	2010
Des Joachims GS	T3	G8	2011
Des Joachims GS	T2	G1	2012
Des Joachims GS	T4	G5	2013
Des Joachims GS		G3	2014

6. QUALITATIVE FACTORS

- Transformer replacement will reduce the risk of injuries to personnel in the vicinity of the transformer deck in the event of a failure, environmental impact (oil spillage, vapour/particulates in the event of transformer fire, etc.), and collateral damage to adjacent structures and the facility.

7. RISK ANALYSIS

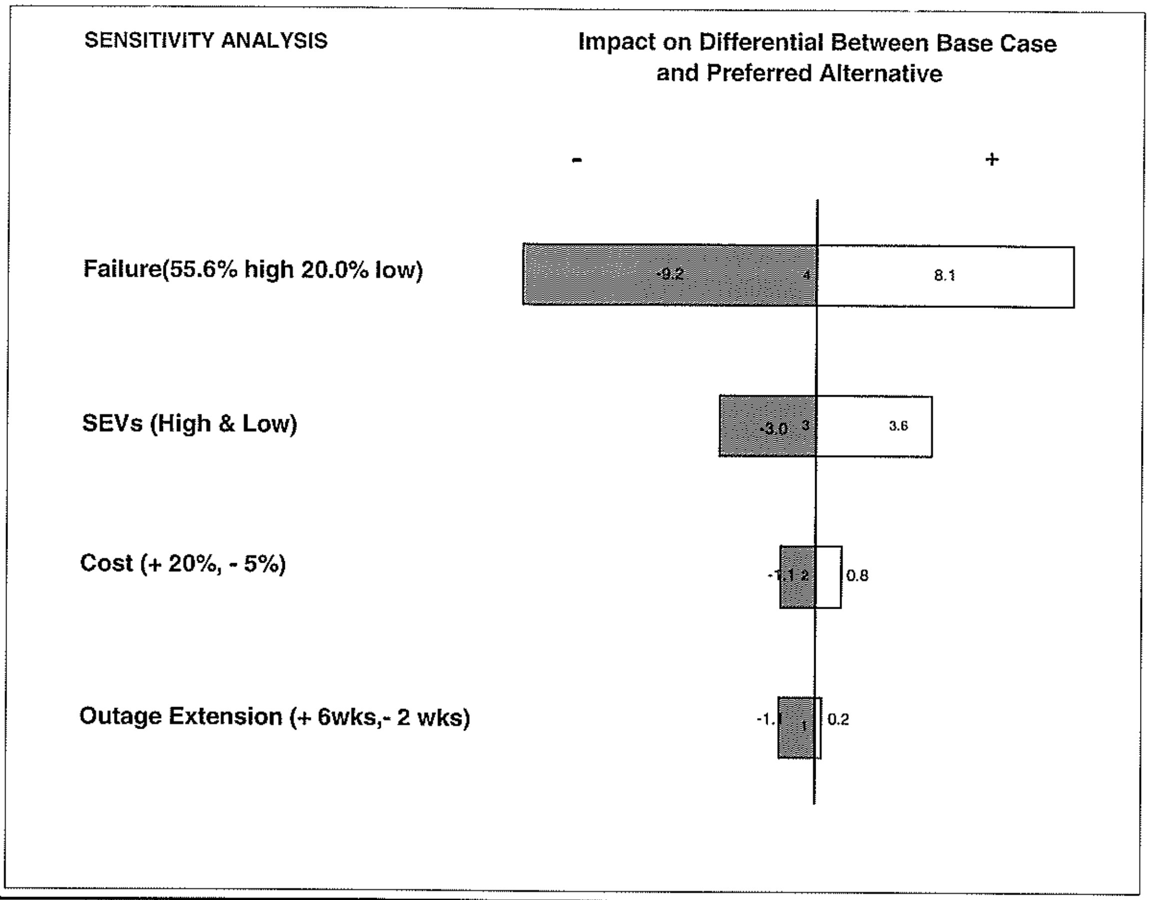
Risk Description	Impact	Initial Risk (before Mitigation) (H,M,L)	Mitigating Activity	Residual Risk (after Mitigation) (H,M,L)
Cost				
1. Project costs escalation.	1. Exceeding release amount.	1. M	1. Estimated costs associated with the procurement of the transformers were obtained from four proposals to supply thirteen transformers over the period from 2010 to 2013.	1. L
2. Unknown installation costs.	2. Exceeding release amount.	2. M	2. Cost estimates provided by [redacted] and [redacted] were used to fully develop the costs for procurement and installation.	2. L
3. Material escalation costs.	3. Exceeding release amount.	3. M	3. Project Contingency included covering the anticipated copper steel price increases. If the price of copper escalates beyond the anticipated amount, a superseding BCS release may be required.	3. L
Scope				
1. Unknown civil modifications required prior to transformer installation.	1. Increased project cost due to design changes.	1. M	1. Air cooled transformers are similar in size as the existing transformers The suppliers were given station drawings of the existing structure and station components (E.g. high voltage connections) that the transformers must be designed to.	1. L
Schedule				
1. Unable to remove transformer from service.	1. Delays the start of each outage and shifts costs to future years.	1. M	1. The transformer outages will be coordinated with the Turbine replacement program outages.	1. L
2. Exceeds outage request.	2. Outage would extend into the following year.	2. M	2. Transformers will be delivered to site three months prior to the scheduled outage commencement date. This is sufficient time to prepare the transformers for installation.	2. L
3. Defer one year due to expected 90 week delivery window.	3. Outage would extend into the following year.	3. M	3. The transformer outage will still continue to be coordinated with the Turbine replacement program the following year. No additional transformer outages would be required.	3. L
Resources				
1. Lack of PWU resources on site.	1. Lengthens the transformer outage. There is a risk that the PWU portion could be higher depending on the CPA assignment.	1. L	1. Transformer installation will adhere to the Chestnut Park Accord process.	1. L
Technical				
1. Replacement transformers and associated equipment	1. Additional future outages required to repair equipment.	1. M	1. Pre-approved qualified transformer manufacturers were asked to bid on a Request for Proposal as per	1. L

will not meet expected performance or reliability standards. 2. Insufficient scope of work.	2. Future outages required to complete additional scope items.	2. M	the Transformer specification. Technical data and standards will be measured during factory acceptance and in-service testing. 2. Numerous Stakeholder meetings, component assessments, engineering reviews, life cycle planning and equipment needs exercise in developing the project scope of work.	2. L

The results of the sensitivity analysis are shown in the diagram below. This shows the variance from the Base Case to the preferred option (Alt. 3) resulting from changes to Failure Probability, Cost, Outage Time and SEV's. Difference from the Base Case to the preferred option is ($8.1M) based on a 55.6% failure rate assumption. The diagram illustrates that Probability of Failure represents the greatest risk of influencing the NPV value with Cost and Outage Time expected to present the least risk.

VARIABLE/RISK	HIGH/LOW RANGES	NPV (2007 $M) Base Case	NPV (2007 $M) Preferred Alternative	+/- From Initial Difference Between Base Case & Pref. Alt. (2007 $M)
Probability of failure	HIGH 55.6% Failure	-67.5	-52.9	8.1
	LOW 20% Failure	-17.5	-20.1	-9.2
Cost	HIGH 20% increase	-32.4	-26.9	-1.1
	LOW 5% decrease	-29.8	-22.4	0.8
Outage Extension	HIGH 10 weeks (add'n 6weeks)	-30.7	-25.3	-1.1
	LOW 2 weeks (reduce 2 weeks)	-30.2	-23.5	0.2
SEVs	High SEVs	-36.3	-26.1	3.6
	Low SEVs	-25.8	-22.3	-3.0

Initial Difference Between Base Case & Preferred Alt. (2007 $M) 6.5



8. POST IMPLEMENTATION REVIEWS

- Project management will conduct a Lessons Learned exercise following the first bank outage and review:
  - Transformer purchase and installation cost variances
  - Outage duration variances
  - Coordination complexity associated with the turbine/overhaul and transformer outages

  The lessons learned will be incorporated into the subsequent transformer bank installations.
- Project Management will provide results of the Factory Acceptance and In-service Test reports to verify that the transformers have met specified performance criteria:
  - The manufacturer shall perform all tests, before transformer shipment, in accordance with CAN/CSA-C88-M requirements.
  - OPG will repeat some low voltage tests at site, such as core insulation, sweep frequency response analysis, and insulation dissipation factor tests. The basis for acceptance at site will be the same as the Factory Acceptance tests performed before shipment.
- The final PIR report will be completed by the Ottawa/St. Lawrence Plant Group Asset Management Department by the end of December 2013

ONTARIO POWER GENERATION

HYDROELECTRIC
Summary of Estimate CAPITAL

Date	**Dec. 2007**
Project #	**DESJ0031**

Facility name: **Des Joachims GS**

Project Title: **Replace Main Output Transformers**

	LTD	2008	2009	2010	2011	2012	2013	TOTAL	%
Project Management/Engineering **(012)**	$8k	$20k	$20k	$20k	$20k	$20k	$20k	$128k	.4
Consultant/Engineering **(310)**	$33.5k	$220k	$20k	$20k	$20k	$20k	$20k	$353.5k	1
Construction/Installation									
Hydroelectric (PWU labour) **(010)**		$10k	$10k	$20k	$20k	$20k	$20k	$100k	3
Contractor/ (BTU labour)/EPSCA **(310)**	[redacted]								
Materials **(200)**	[redacted]								
Interest **(700)**	$0.5k	$99k	$100k	$395k	$359k	$364k	$238k	$1,555.5k	5
Contingency **(998)**	[redacted]								
TOTAL (GROSS)	$42k	$1,749k	$1,771k	$6,982k	$6,412k	$6,580k	$4,338k	$27,874k	100

Notes: 1 Full Release: **Y2008**
In-service Date: T1-2010, T3-2011, T2-2012, T4-2013
2 Interest and escalation rates are based on current allocation rates provided by Corporate Finance
3 Includes removal costs of: $500k
4 Includes Definition Phase Cost of: $80k

Prepared by:	Approved by:
Project Engineer	Production/Project Manager
Date: Dec 11/07	Date: Jan 2/08

BUSINESS CASE SUMMARY

Project No.: DESJ0016
Facility Name: Des Joachims G.S.
Project Title/Description: Turbine Runners – Replace runners

1. RECOMMENDATION

Full release approval of $22.7M (Phase 2) to replace the eight turbine runners with modern runners designed to match the site specific hydraulic characteristics of Des Joachims G.S. These runners are at end of life and have suffered from severe and excessive cavitation damage since installation due to the mismatch of the runner and the hydraulic characteristics of the station. There is a significant risk of catastrophic failure due to the cracking damage which has become more evident during the past few repair cycles. New turbine runners will eliminate excessive cavitation damage, weld repairs and related production losses while also increasing turbine efficiency and annual energy production.

Definition Phase approval (Phase 1) was attained in 2004 of $1.1M to develop and test a model turbine runner and obtain proposals to supply eight turbine runners over the period from 2007 to 2014. American Hydro Corporation was the successful bidder (of five turbine manufacturers) on a Request for Proposal (RFP # EP-HBU-2004-001). To date, model development is complete with model testing and OPG independent lab testing to be conducted from March – June 2006 at IMHEF Ecole Polytechnique (Lausanne Switzerland).

Total project cost (including $91k spent to date of the $1,100k previously released) is $23,800k

M$	Pre 2006	2006	2007	2008	2009	2010	2011-15	Total
Recommended Alternative	$77k	$2.2M	$2.6M	$2.8M	$2.7M	$2.7M	$10.7M	$23.8M
2006-2010 WPC Final Budget	$110k	$1.2M	$1.6M	$2.2M	$2.2M	$2.2M	$9.7M	$19.1M
Variance to Business Plan	$33k	(1.0)	(1.0)	($0.6)	($0.5)	($0.5)	($1.0)	($4.7)

Expenditure Type: Capital
Investment Type: Sustaining/Value Enhancing
Release Type: Full release under OAR element 1.1.2

Funding: 2006 - 2010 Work Program Catalogue (WPC) Final Budget: $19,147k is the current estimate for project costs in the 2006-2010 WPC Final Budget. Definition Phase release of $1,100k was approved in 2004 to develop, construct and test a model runner designed to match the site specific hydraulic characteristics of Des Joachims G.S. The increased cost of this release includes additional unit components that directly relates to the operation and performance of the new turbines and require rehabilitation. This increased funding will be managed within the OSPG Capital budget envelope. Subsequent years will be re-programmed into the Work Program Catalogue during the next business planning cycle. Total overall project costs including definition phase will be $23,800k

Investment Financial Measures: NPV: $3,862k (Relative to the Base Case)

2. SIGNATURES

Submitted by:

Apr 26/06
Plant Group Manager – OSPG date

Recommended by:

May 3/06
EVP – Hydro date

Finance Approval:

SVP & Chief Financial Officer date

Line Approval per OAR 1.1.2:

May 13/06
President & CEO date

3. BACKGROUND & ISSUES

- Des Joachims GS is an eight unit, hydroelectric station located on the Ottawa River, 20km north of Deep River. The facility was placed in service in 1950 and 1951. The station is controlled from the Chenaux Control Centre. The station capacity (MCR) and average annual energy production are 428.8 MW and 2,247 GWh respectively. The ten year average of the station Capacity Factor is 58%.
- The asset classification of this station is a Flagship. It is ranked 4th in both capacity and energy production in Hydroelectric. The Life Cycle Plan capital expenditure strategy for this station includes planned investments, over the next 30 years, totalling about $75 million: $50 million for capital and $25 million for Non-Standard OM&A. Major projects include the turbine replacement program ($24M), rehabilitation of sluice gates ($17M), generator rewind program ($6M), replacement of generator and transformer protections ($3M), replacement of switchgear ($2.6M), replacement of station service transformers ($1.6M), repair main dam concrete ($1.2M), replacement of stoplogs ($1M) and roof replacements ($0.6M).
- Reliability has been excellent over the past 10 years with an Incapability Factor (ICbF) in the 7% range. The ICbF is expected to increase to about 10% from 2007 to 2015 during these planned outages. After 2015, the ICbF is expected to average 6%.
- The Equivalent Forced Outage Rate (EFOR) is near excellent and any delay of the turbine replacement program could negatively impact the current EFOR rate.
- The main driver of this project is runner cavitation protection and the need to replace the end of life runners and reduce the current runner repair program. In addition to the cavitation protection, the contract obligations expect a [redacted] efficiency gain.
- This facility participates in the Independent Electricity System Operator (IESO) Automatic Generator Control (AGC) program which acts to match total system generation to total system load as required on the electricity grid, and helps correct variations in power system frequency. This service causes the unit outputs to vary automatically within a specified range, in response to control signals from the IESO's Energy Management System (EMS). The average weighted efficiency of the existing turbines is less than the proposed design of the new turbines. In other words, there will be a greater band of unit efficiency with the new design that the operations of these generators are subjected to due to AGC control.
- There is a need to restore the integrity of the turbine runners at Des Joachims G.S. to ensure reliable operation of the unit generators. The existing Francis runners at Des Joachims G.S. were purchased in 1975 as replacements for the original runners to increase the output and efficiency of the units. The efficiency was increased by [redacted] and the unit outputs were increased by [redacted] (best efficiency) and [redacted] (full load). These new runners were not custom designed for Des Joachims G.S.; they were "off the shelf" runners with no homologous model testing and are near end of life. Sustaining the present conditions will become more and more difficult with outage repairs increasing approx. 20% per year.
- The runners can be repaired based on the existing 4 year maintenance cycle of 12 weeks for two units but the following will occur:
    - Cavitation damage will worsen.
    - Additional blade cracking will occur in the transitional area at the crown and runner band due to blade profile changes.
    - Maintenance outages will be longer with each repair as runner condition worsens.
    - Increased damage and repairs will change the hydraulic profile of the blades and further accelerate the aging of the runners.
    - Loss of efficiency.
- Maintenance outages for runner repairs are no longer technically viable and economically limiting. Due to their very poor condition, the runners will require extensive repair work to keep them operational until they are replaced. The additional runner repair work will significantly increase base maintenance costs by $150k to $250k per year (or by 15% per cycle) until the runners are replaced. This welding has resulted in distorting the runner blades and recently, significant fatigue cracks have been identified at the runner crown/blade transition and the runner band/blade interface. Unit 7 (2001) had 10 of 15 blade cracks. Unit 1 (2002) revealed 3 of 15 blades with cracks. The cracking is resulting from the blades fluttering which in turn is caused by the distorted blade profile.

- This cavitation and cracking damage will determine the schedule of the replacement runners.
- Due to IESO unit outage restrictions and Plant Group experience, it is virtually impossible to schedule two outages per year. OSPG has experienced difficulty in obtaining outages from the IESO. In the recent past, the IESO frequently requested delays of the start dates of planned outages for runner replacement. Each day of delay compromises the completion date and the return to service of each unit.
- The position of OPG and OSPG is to avoid commercial losses associated with water spill during spring freshet. Generating units will not be removed from service during periods of high water flow. Units will be made available, during this period, to generate all potential energy.
- During the runner replacement program, other work, classified as OM&A (Mechanical/Electrical Overhauls - DESJ0008) is required to return units to satisfactory service. In other words, while the units are disassembled, it is an opportune time to repair and realign various parts of the units.
- Five of the eight generators recently had stator winding replacements. It is recommended the remaining three units (G1, 3 & 5) be scheduled to coincide with the last three turbine outages. Risk associated with this deferral is fairly low due to the fact that Partial Discharge (PD) test results are proving that these winding are in fair condition for their age. This will extend the life of the winding of these units to approximately 40 years.
- IMHEF Ecole Polytechnique (Lausanne Switzerland) will be conducting a full homologous model test to guarantee the performance of a new runner. If the test results indicate that the new runners are not as good as guaranteed of the Phase 1 bid, liquidated damages ([redacted]) could be awarded as per contract obligations.
- The time required to attain BCS approval, generate the Purchase Order and manufacture a new turbine following the acceptance of the model test results, is limited. The approval of this release will proceed with expectation that the turbine model tests results will meet the contract guarantees and Phase 2 of the turbine project will proceed. If funding approval is not acquired by May 2006, the schedule of the first unit outage will be compromised as describe below in the Risk table.
    - **Design and Manufacture Model** – Start Sept. 1, 2005 / Complete March 17, 2006
    - **Install and Test Model** – Start March 27, 2006 / Complete June 20, 2006
    - **Manufacture Proto-type Turbine** – Start July 7, 2006 / Complete Sept. 21, 2007
- All costs associated with the unit disassembly, re-assembly, testing and commissioning to return the unit back to service will be charged against the capital portion of each outage.

- **Phase 1 -** Design, development, testing and demonstration of performance by witness test of a Francis turbine runner model (including the existing stationary parts: penstock, spiral casing with stay ring, turbine wicket gate mechanism, turbine bottom ring, discharge ring and complete draft tube) and delivery of the complete model to an independent laboratory for acceptance tests. Total cost $1,100k - completion date June 20, 2006

- **Phase 2 -** Upon successful completion of the model development phase and final acceptance testing at the independent laboratory, American Hydro Corporation to manufacture 1 prototype runner - completion date Sept. 21, 2007, and supply up to (8) full size Francis turbine runners, including the proto-type runner, nose cones and 8 sets of runner to shaft coupling bolts for Des Joachims GS.

4. ALTERNATIVES & ECONOMIC ANALYSIS

Base Case: (Status Quo)
Do nothing - Continue with present four year runner maintenance repair cycles and operate the generating units as is.
This alternative is not recommended since runner maintenance repair outages will be longer with each repair. The repair regime on these runners has accelerated the aging of the runners and they are quickly approaching their end of life. The present repair strategy will not resolve the cavitation problems but accelerate the damage, blade cracking, blade profile distortion and reduction in turbine efficiency. Possibility of catastrophic turbine runner failure could occur resulting in significant lost production.
This alternative rejected due to the efficiency loss, asset protection and the extended outage durations required for runner welding repairs.

Alternative 1: Perform Major Repairs and Defer Runner Replacement to Start in 2018
A program to rehabilitate the runners would be undertaken between 2007 & 2014 and the runner replacement program would be implemented starting in 2018. Each runner would be removed from the unit and extensive repairs performed in a controlled environment on the generating station floor or machine shop, one runner per year with an outage length of 22 weeks and a cost of $514k. This alternative will not bring the runner blades back to their design profile nor relieve the built-in stress from welding repairs. Long term use of the existing runners will also jeopardize the throat ring.
This alternative is considered but rejected. NPV calculations indicate that this alternative is not economically beneficial.

Alternative 2: Replace 8 Runners Over 5 Years 1, 2,2,2,1 (2007-2011)
Install 1 runner in years 2007 and 2011, and 2 per year between 2007 and 2011. The second outage is scheduled to allow for performance testing of the first runner and verify performance guarantees. Once the efficiency of the new turbine has been measured the program is accelerated to two runners per year.
This alternative is unacceptable due to IESO outage restrictions and scheduling conflicts with spring freshet conditions and summer/winter peak demands as discussed in section 3. Background and Issues.

Alternative 3: Replace 8 Runners 1 per Year (2007- 2014)
The primary deliverable is the supply and installation of 8 new Francis Turbine Runners (1 per year between 2007 and 2014), nose cone and coupling bolts, designed to match the site specific hydraulic characteristics of Des Joachims GS. Components directly relating to the Turbines and require inspection or rehabilitation are as follows; Throat Ring, Headcover Wearing Plates and Seals, Turbine Bearing and Journal, Runner Shaft Seal and Turbine Shaft coupling faces. Unit disassembly, re-assembly, set up and in service testing needed to return the unit generator back to service will all be charged against this release. Also included; Final Report - A description of the work done including all measurements taken during the outage and commissioning test results, Post upgrade Performance test and report.
Highest probability of obtaining IESO approval for unit outages is during Aug.-Nov. period. This outage period will avoid units being out of service during spring freshet and summer/winter peak demands.
This is the recommended alternative

Financial Analysis

	Base Case	Alt. 1	Alt.2	Alt.3
Initial (k$)	4,286	32,151	22,255	22,437
NPV (2006 PV (k$) 30 years	(8,691)	(10,156)	(5,383)	(4,829)
Impact on Economic Value (2006 PV k$)		(1,465)	3,308	3,362

5. THE PROPOSAL

Results to be delivered

- Install eight new turbine runners to improve unit efficiency and enhance runner cavitation protection thus resulting in less maintenance outage time required to repair the turbine runners. Eliminate in place welding repair costs per unit @ $150k - $250k each and total commercial losses estimated at $490k to conduct repairs for two runners per year.
- The new runners are designed to be virtually cavitation free, thus eliminating in place welding repairs.
- Expected unit generator improvement performance resulting in the runner program is [redacted] efficiency gain, which results in an increase in station output by 52.6 GWh/yr
- One additional performance test (post upgrade) will be completed in 2008 and efficiency curves will be produced.
- PIR will be conducted in 2008 following the first turbine replacement outage and prior to commencement of second outage.

Milestone	Turbine Replacement Completion Date	Turbine Manufacturer Completion Date
Runner Model Development & Independent Lab Test	2005/2006	
G3 Pre upgrade Performance Test	2005 (Complete)	
G7 Pre upgrade Performance Test	September 2006	
G7 Runner Replacement	November 2007	G7 September 2007
G7 Post upgrade Performance test	March 2008	
G7 Simplified PIR	June 2008	
G2 Runner Replacement	November 2008	G2 September 2008
G6 Runner Replacement	November 2009	G6 September 2009
G4 Runner Replacement	November 2010	G4 September 2010
G8 Runner Replacement	November 2011	G8 September 2011
* G1 Runner Replacement	December 2012	G1 September 2012
* G5 Runner Replacement	December 2013	G5 September 2013
* G3 Runner Replacement	December 2014	G3 September 2014
Comprehensive PIR	2015	

* Last three runner outages will include a stator rewind, extending the outage window approx. 8 weeks.

Project Management

- A Project Execution Plan (PEP) will be used to monitor the project progress.
- Lessons Learned meetings will be conducted following each outage and a list of actions developed will be implemented on the subsequent outages. The PEP will be revised and issued by Q2 of each outage year.

6. QUALITATIVE FACTORS

- The new turbine runners should be designed to be "virtually maintenance free", E.g. excessive cavitation damage elimination and increase turbine efficiency and annual energy production.
- Resource feasibility study conducted in 2005 determined the availability of a combination of experienced Des Joachims and other OSPG staff supplemented with BTU labour working two ten hour shifts would reduce the outage time from 20 weeks to 13. The Project Engineer will co-ordinate work between PWU staff and any contractors.
- The work assignment will be as per Chestnut Park Accord process.
- The stations reliability will be sustained by reducing future forced outages caused by runner failures.
- Economic viability and continued availability of revenue of the asset will be maintained and protected.

- The project will comply with Ottawa/St.Lawrence Plant Group Environmental Managed System/Occupational Health and Safety Managed System and related Ottawa/St.Lawrence Standing Instruction/Station Specific Standing Instruction Procedures.

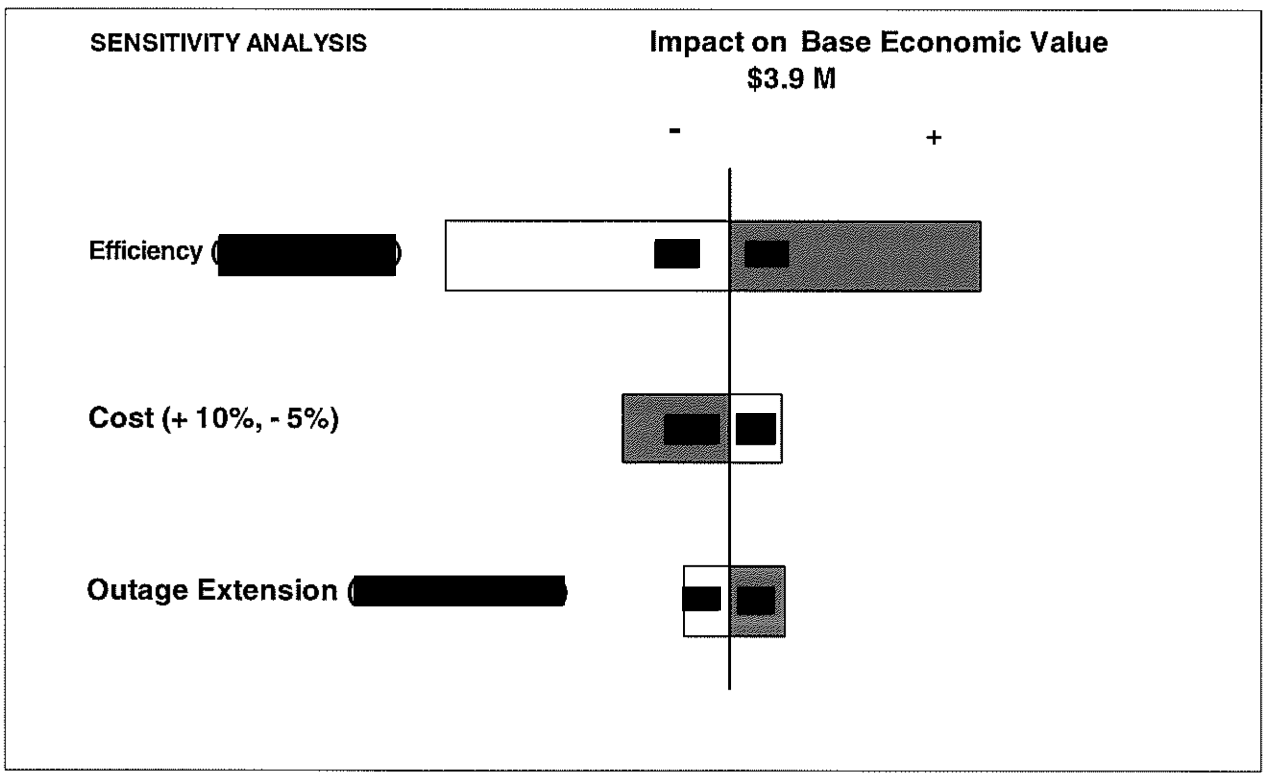
7. RISK ANALYSIS

Risk Description	Impact	Initial Risk (before Mitigation) (H,M,L)	Mitigating Activity	Residual Risk (after Mitigation) (H,M,L)
Cost				
1. Runner costs increase including steel cost escalation.	1. Exceeding release amount.	1. M	1. The financial risk for the runner costs is minimal since runner cost escalation has been identified and included in the cash flows.	1. L
2. Escalation to PWU/BTU labour rates.	2. Exceeding release amount.	2. M	2. An OPG/PWU contract obligation for the following 3 years guarantees the labour rates for the first 3 outages. Contingency funds will protect against future contact labour rate increases.	2. L
Scope				
1. Emergency repair of damaged equipment upon disassembly.	1. Increase in cost to repair damaged equipment.	1. M	1. Have the staff experience with the previous runner changes, therefore know what to expect.	1. L
2. Units become unavailable due to existing runner failure.	2. Loss of generation and revenue	2. M	2. Runner failure will be evident throughout the runner change program. Runner welding maintenance will continue throughout the runner change program. Inspections of the remaining runners will determine the priority of the outage schedule taking into account units that have higher probability of failure.	2. L
3. Deficiencies to equipment unknown until unit is dismantled and inspected.	3. Exceeding release amount and outage schedule.	3. M	3. [redacted] project contingency will be included for the first unit (excluding the runners) to cover the cost of these items. A [redacted] reduction in contingency each year down until year 2011 and will remain at [redacted] for the remainder of the project. The runners will have a [redacted] contingency for the life of the project. **Stationary runner seals -** These seals shall be inspected upon removal of the runner from the unit. One new set of seals will be pre-machined and ready for final machining. The new runners will dictate the sizing and allowable tolerances. **Throat ring** - Inspect upon removal of the runner with welding/machining repairs as required. Past throat ring inspections have indicated only minor welding repairs required.	3. L
4. Accelerate the runner replacement program and conduct two runner replacements a year due to catastrophic failure of an existing runner.	4. Second runner not available.	4. M	4. Runner supplier could revise the manufacturing schedule and produce two runners per year at a cost premium.	4. L

Schedule				
1. Unable to remove unit from service.	1. Delays the start of each outage and shifts costs to future years.	1. M	1. Start the outage as requested to follow timeline of critical path.	1. L
2. Delay acquiring Businesses Case Summary approval.	2. If the approval of the Business Case is hindered, delivery date of the new runners may be delayed and the outage schedule will be at jeopardised.	2. M	2. Approval of the BCS will be obtained based on the contract guarantees. If the model tests results do not meet the performance guarantees liquidated damages [redacted] could be awarded and the F.E's will be re-calculated based on the model test efficiency results.	2. L
3. Critical path of the project extended.	3. Exceeds outage request and delays the return to service date.	3. M	3. Long lead time items identified in the project charter and will be purchase prior to the commencement of the outage.	3. L
4. Runner delivery date not met.	4. Exceeds outage request and delays the return to service date.	4. M	4. Repair original runner and place back in service.	4. L
Resources				
1. Lack of PWU resources	1. Lengthen the unit outage	1. M	1. Resource feasibility study conducted in 2005 determined a combination of Des Joachims and other OSPG staff supplemented with BTU labour would reduce the outage from 20 weeks to 13.	1. L
Technical				
1. Will not meet expected performance guarantees.	1. Less than expected revenue due to reduced efficiency gains.	1. M	1. There is the potential that the full-scale prototype runner may not meet its performance guarantees and in this case, liquidated damages can be applied. ([redacted]. G7 pre-upgrade performance test results will be used as the baseline for the remainder of all units. Post upgrade performance test conducted on G7 will verify the efficiency gains.	1. L
2. Catastrophic failure of an existing runner	2. Unit unavailable for approx. 12 months due to the time required to manufacture a new runner.	2. M	2. Current runner repair cycle will continue during the runner replacement program	2. L
Health & Safety				
1. Fall protection	1. Extended outage time	1. M	1. Falling hazards have been eliminated or controlled as part of the project with installation of scaffoldings, improving employee safety.	1. L
2. Regulatory requirements.	2. Work stoppage.	2. M	2. A detailed inventory of all manufactured, and/or engineer approved OPG/OSPG fabricated lifting device have been approved for use at Des Joachims GS.	2. L
Investment				
1. Guaranteed cavitation protection of a new runner will not be met.	1. Cavitation performance will not be met. There is no capacity increase for the units but there is increased cavitation protection that results in significantly reduced maintenance costs.	1. M	1. Runners shall be guaranteed against cavitation for a period of 15,000 hours of operation. The full cost of repair and any modifications required to reduce or eliminate subsequent cavitation damage will be the responsibility of the runner manufacturer.	1. L
2. Runner defects	2. Unforeseen outages and associated costs required to repair or replace a defective runner.	2. M	2. Except for cavitation damage the runner will be safeguarded against defective parts, design, material or workmanship up to five years as per the contract document.	2. L

The results of the sensitivity analysis are shown in the diagram below. This shows the variance from the preferred option (Alt. 3) NPV ($3,862M) resulting from changes to Efficiency, Cost and Schedule. Differences in NPV from the preferred option assumptions (plus and minus) have been plotted. The diagram illustrates that Efficiency represents the greatest risk of influencing the NPV value with Cost and Schedule expected to present the least risk.

VARIABLE/RISK	HIGH/LOW RANGES	+/- FROM BASE ECONOMIC VALUE (2006 $M)
Efficiency Gain	HIGH [redacted] **TARGET** [redacted] LOW [redacted]	[redacted] [redacted]
Cost	HIGH 10% increase LOW 5% decrease	[redacted] [redacted]
Outage Extension	HIGH 20 weeks LOW 8 weeks	[redacted] [redacted]



8. POST IMPLEMENTATION PLAN:

- Pre-Upgrade Performance tests on G7 will be used as a baseline to verify the efficiency gains of all the units. Post-upgrade performance tests on G7 will be conducted in 2008 and the efficiency improvement for the new runner will be derived from the G7 post-upgrade tests.
- The new runners will be inspected annually for cavitation damage by OSPG staff.
- Warranty cavitation inspections will be conducted following 15,000 hours of operation (Approx. 3 years) and witnessed by American Hydro as outlined in the Contract Terms and Conditions.
- Four year cycle of current runner welding repairs will be reduced and the decrease in costs associated with these repairs will be verified at the conclusion of the program.
- Simplified PIR will be conducted following the first turbine replacement outage - Q1 2008.
- The final PIR report will be completed by the Ottawa/St. Lawrence Plant Group Asset Management Department - May 2015.

ONTARIOPOWER GENERATION **HYDROELECTRIC Summary of Estimate**

Date	April 2006
Project #	**DESJ 0016**

Facility name: Des Joachims Generating Station

Project Title: Turbine Runners – Replace runners

Years	Pre-2006	Y2006	Y2007	Y2008	Y2009	Y2010	Y2011	Y2012	Y2013	2014	2015	TOTAL	%
Project Management and Engineering **(012)**	$31k	$50k	$51k	$52k	$53k	$54k	$55k	$56k	$57k	$59k	$60k	$578k	2
Materials **(200)**	[redacted]												
Consultant **(310)**	$38k	$150k		$104k								$292k	1
Construction/Installation													
Hydroelectric (PWU) **(010)**	$8k	$10k	$326k	$333k	$340k	$346k	$353k	$360k	$368k	$375k	$30k	$2849k	12
Others (BTU) **(310)**	[redacted]												
Interest **(700)**		$113k	$139k	$146k	$142k	$145k	$148k	$150k	$153k	$116k	$11k	$1263k	5
Contingency **(998)**	[redacted]												
TOTAL (GROSS)	$77k	$2200k	$2623k	$2800k	$2700k	$2700k	$2700k	$2800k	$2800k	$2200k	$200k	$23800k	**100%**

Notes: 1 Schedule Start Date Aug. 2007
Final In-service Date Feb. 2015
2 Interest (6%) and escalation (2%) rates are based on current allocation rates provided by Corporate Finance
3 Includes removal costs of: $80k
4 Includes Definition Phase Cost of: $1,100k

Prepared by: Ron Gorell	Approved by:
Project Engineer RON GORELL	Project Manager
Date: APRIL 11/06	Date: APRIL 25/06

ONTARIO POWER GENERATION	Project Number: OTTO0021	Facility: Otto Holden G.S.	Page: 1 of 8
	BUSINESS CASE SUMMARY Replace Sluicegates & Rehabilitate Sluicegates System		

1. RECOMMENDATION

Approve the full release of $23.9M (including previous Developmental Phase release of $215k) to replace the six sluicegates and rehabilitate the sluicegates system in order to comply with dam safety requirements and to address operational and reliability needs.

The sluicegates can be controlled either locally or remotely from the Chenaux Control Centre. They provide a primary and effective means of discharging excess flow around Otto Holden G.S., and are essential in meeting the OPG Dam Safety Program requirements on expeditious discharge of large volumes of water in the event of a dam safety emergency. These sluicegates are nearing 60 years of operation and are at the end of their service lives. Failure of the sluicegates to operate could result in dam safety hazards to employees and the public, long term production losses and extensive property damage. In the recent past similar sluicegates at other stations (e.g. Chenaux) have jammed during operation, resulting in an uncontrolled loss of water. This project is part of an OSPG sluicegate replacement program to replace sluicegates within the plant group that are at the end of their service lives, including those at Des Joachims, Chenaux and Chats Falls. The plan at Otto Holden is to rehabilitate the sluicegates system in 2009, and replace the gates at a rate of one gate per year starting in 2010.

$215k was released in 2006 to perform definition phase work on this project. The definition phase work results and experience learned from recent sluicegate replacement projects provide a high confidence level for this full project release, with no need for a partial release.

Total Investment Cost: $23.8M (includes $215k previously approved for Developmental Phase work)

Recommended Alternative	LTD 2008	2009	2010	2011	2012	2013	2014	2015	Total
Project - Capital	194k	$4,730k	$2,855k	$2,971k	$3,097k	$3,222k	$3,324k	$3,463k	$23,856k
2008 Final budget Version WPC	172k	$4,572k	$4,887k	$2,590k	$2,667k	$2,747k	$2,830k	0	$20,465k

Expenditure Type: Capital
Investment Type: Regulatory – Dam Safety
Release Type: Full Release under OAR element 1.1.2
Funding: The 2008 Budget Version WPC includes $20.5M for this project. The new higher project cost reflects material cost increases in the last year and some scope changes, and will be re-programmed in the 2009 – 2013 Business Plan.
Investment Financial Measures: NPV = ($14,168k).

2. SIGNATURES

Submitted by:

15 Oct 2008
EVP - Hydro — date

Finance Approval by:

Nov /08
SVP & CFO — date

Recommended by:

Dec 3/08
EVP & COO — date

Approved by:

Dec 4/08
President & CEO — date

ONTARIOPOWER GENERATION	Project Number: OTTO0021	Facility: Otto Holden G.S.	Page: 2 of 8
	BUSINESS CASE SUMMARY Replace Sluicegates & Rehabilitate Sluicegates System		

3. BACKGROUND & ISSUES

Plant:

Otto Holden G.S. is an eight unit hydroelectric station located on the Ottawa River 9 km north of Mattawa. It was placed in service in 1952. The station has a total capacity of 243 MW with an average annual energy production of 990 GWh, and production revenue of $52.8 Million in 2007.

The station is classified as a "Workhorse" in Hydroelectric's portfolio management system. Planned investments over the next ten years total approximately $71.4 Million, including concrete growth mitigation, sluicegates rehabilitation, headgates replacement, fire protection, and main output transformers replacement. The 2000 Otto Holden GS LCP includes a recommendation to rehabilitate the sluicegates in 3 to 7 years.

The facility is equipped with 6 sluicegates and 41 stoplog sluices for water management (flow control). To ensure timely response and satisfy dam safety emergency preparedness requirement, all 6 sluicegates and 15 stoplog sluices need to be available at all times. If one sluicegate is unavailable, the loss of flow capacity may be replaced with 4 stoplog sluices. However it takes approx. 4/8 hours (summer/winter) to strip 4 stoplog sluices with two three-man crews on site versus approx. 15 minutes to open a sluicegate with one crew. The stoplog sluices operation time will also be substantially longer outside normal working hours. For dam safety emergency preparedness purpose it is therefore much more efficient, effective and desirable to have all sluicegates available.

Issues:

The 6 existing sluicegates are 56 years old and near the end of their service life. In 1996 and 1998, gates #4 and #3 respectively were refurbished with new downstream cladding, sandblast and paint work, new internal heaters, lights, and access ladders, electrical work, bubbler system, etc. in an attempt to extend their service life. However without addressing the structural integrity, drive train mechanisms and civil aspects of the gates, the relatively minor rehab work did not extend the gates' service life significantly. The six gates have exhibited major operating difficulties in the past and Gate #1 has been impacted to the point where it is not used as it is not guaranteed to be able to close.

The monorail crane used to install sectional service gates has been forced out of service pending major repair requirements. Since the monorail crane is used very infrequently and only for gate maintenance, a technical/economic review concluded that it is much more cost effective to employ mobile rental crane to move the service gates than to replace the monorail crane. To improve safety in and access to the area, the out-of-service monorail system will be removed and properly disposed of under this project.

The 6 sluicegates are often used for routine water management operations, and are the primary flow control equipment at the facility because they can be fully opened in a much shorter time than a stoplog sluice, and each sluicegate provides flow capacity equivalent to about 4 stoplog sluices. The sluicegates are integral to Otto Holden fulfilling the OPG Dam Safety Program requirement in discharging Incremental Design Flood during a dam safety emergency. Failure and unavailability of one or more sluicegates will impact on the capability of Otto Holden to meet dam safety water control requirements.

The gates were inspected in 2003 as part of the Dam Safety Periodic Review (DSPR) and items were identified that need addressing, such as the structural integrity of the skinplates and the buckling safety factors of some of the beams. Visual inspections of the gates carried out in 2004 revealed that the skinplates on all the gates have deflected from 1/16" to ½", indicating that the skinplates have been loaded beyond their yield strength. An Engineering Assessment performed in 2006 by OSPG Asset Management/Technical Services Dept. concluded that the gates are showing signs of structural failure and also do not meet modern strength requirements. The assessment recommended replacement of these sluicegates to prevent such failures.

Other sluicegate system deficiencies and recommendations from the DSPR and assessment include:

1. The embedded parts (roller paths and seal paths) are deteriorated and need to be refurbished. The concrete surrounding the roller path (secondary concrete) is also in poor condition and needs to be replaced.
2. The sluicegate electrical distribution system was updated in 1996, but will need modification/replacement in order to support new gates, control systems, correct existing design deficiencies, and to be consistent in design with other OSPG sites undergoing similar sluicegate systems rehabilitation programs.
3. The sluicegate bridge and tower structure are recommended to be sandblasted and have new protective coating applied.

Lessons-learned from recent sluicegates replacement projects at other OSPG plants show that it is more cost effective to replace the sluicegates rather than refurbishing them. A Developmental Phase Release was approved in 2006 to prepare detailed design specs and obtain release-quality cost estimates to replace the sluicegates and rehabilitate the sluicegates system. The Developmental Phase work was completed and the cost estimates used for the basis of this Full Release are consistent with recent similar sluicegate replacement projects. The slightly higher costs for this project (over other sluicegate projects) reflect recent material cost increases and the more extensive concrete repair required in the roller path/gain areas at Otto Holden.

4. ALTERNATIVES & ECONOMIC ANALYSIS

Base Case: Status Quo. Initial Cost = $189k. NPV = 0.

- Do not replace the sluicegates, rehabilitate sluicegates system, and repair concrete in the sluicegate areas.
- Failure of sluicegates to operate would create unacceptable hazards in facility operation and dam safety due to the risk of gate overtopping and the consequent safety concerns to employees and the general public.
- To not proceed with this project exposes OPG to dam safety non-compliance risk, in that timely, reliable water flow control through these sluicegates is necessary in the event of normal spill requirements, unexpected plant shutdowns, or a dam failure.
- OGP would not realize the benefits of already expended funds if it does not proceed with this project.

To conform to dam safety requirements, personnel and public safety concerns in the event of a dam safety incident, this alternative is unacceptable.

Alternative 1: Rehabilitate 6 sluicegates and the sluicegates system now. Initial Cost = $54,042k. NPV = ($16,080k).

- In this alternative the 6 sluicegates will be rehabilitated rather than replaced.
- New gates would need to be installed in 2035 at $29.5M (escalated). This cost is reflected in the $54,042k above.

Rehabilitation provides an extension life of 25 years maximum with gate replacement required in 2035. There will also be higher on-going maintenance expenses associated with rehabilitated gates. There is a high risk of budget overrun from as-found defects and discovery work during rehabilitation of over 50-year old sluicegates. This alternative is not recommended.

Alternative 2: Replace 6 sluicegates and rehabilitate the sluicegates system. Initial Cost = $23,856k. NPV = ($14,168k).

- Rehabilitate the sluicegates system, and remove and dispose of the monorail crane system in 2009.
- Replace the 6 sluicegates with new gates at a rate of one per year starting in 2010. As each gate is being replaced, rehabilitate gate hoist drive and concrete in roller path/gain areas of the gate.
- New gates are technically superior to rehabilitated gates. New gates incorporate the benefits of technology progress made over the past 50 years, are engineered and fabricated to modern standards, and have life expectancies of up to 50 years.
- The environmental risk is less with a replacement gate, with no in-situ abrasive blasting/containment/painting operations over water.
- The risk to on-site worker safety is less for gate replacement than for the in-situ gate rehabilitation.
- Cost projections are subject to a lower degree of uncertainty for new gates than for rehabilitated gates. Typically it is the bid price.

This is the recommended alternative.

Financial Analysis

	Base Case	Alt. 1	Alt. 2 (recommended)
Initial or Remaining Costs (escalated k$)	194	54,042	23,856
NPV (2008 k$)	0	(16,080)	(14,168)

5. THE PROPOSAL

Replace the 6 sluicegates and rehabilitate the associated systems with results delivered as per the following schedule:

Year 2009

- Remove and properly dispose of existing electrical distribution system and gain heaters. Replace with new upgraded electrical system.
- Integrate gate control and telemetry into plant RTU.
- Sandblast and paint the entire sluiceway superstructure.
- Remove and properly dispose of the monorail hoist, beam and crane.
- Design, construct and install a stair tower on the Ontario end of the sluice structure using grating style stair treads and bar grating for the landings.
- Where applicable and required, install proper lighting and kickboards, repair/replace bridge deck grating.

From Year 2010 through Year 2015, remove and properly dispose of existing sluicegates, replace with new gates, refurbish hoist drive, repair concrete downstream of the gains, commission and return the specific gate in service on a one gate per year basis, under the following schedule:

Year	2010	2011	2012	2013	2014	2015
Gate to be replaced	#1	#6	#5	#2	#4	#3

Gate replacement sequence is prioritized by gate condition and with poorer conditioned gates given higher priority. The above sequence reflects current condition of the 6 gates. This sequence may be modified during the 6-year project period as dictated by any gate condition changes. Lessons learned from the recent Des Joachims sluicegate replacement project has shown that replacing more than one gate per year is too aggressive a schedule and impractical.

A Project Execution Plan (PEP) will be used to monitor the project progress.

Lessons-learned meetings will be conducted in Q4 of each year following each gate replacement and a list of actions developed and implemented on the subsequent replacement. The PEP will be updated and issued by Q2 of each year and prior to the start of installation of the next gate.

6. QUALITATIVE FACTORS

- Public safety risk due to uncontrolled spill will be minimized.
- Environmental Risk will be minimized, as there will be no in-situ sluicegate repairs near open water with the installation of new gates.
- The sluicegate replacements will be of modern design and latest technology, and have a life expectancy of 50 years.
- New gate seals will minimize water losses currently experienced with the 1950's technology and aged gate seal installations.

7. RISK ANALYSIS

Risk Description	Impact	Initial Risk (before Mitigation) (H,M,L)	Mitigating Activity	Residual Risk (after Mitigation) (H,M,L)
Cost				
1. Project costs escalation. 2. Material escalation costs.	1. Exceeding release amount. 2. Exceeding release amount.	1. M 2. M	1. Estimated costs were obtained from 2006 contractor estimate and adjusted for inflation. They are also consistent with actual costs from recent similar sluicegate rehab projects at other OSPG facilities. 2. Project contingency included covering the anticipated steel price increases.	1. L 2. L
Schedule				

Risk Description	Impact	Initial Risk (before Mitigation) (H,M,L)	Mitigating Activity	Residual Risk (after Mitigation) (H,M,L)
1. Equipment installations delayed due to weather.	1. Delays in-servicing of equipment.	1. M	1. Strategy to install only one gate per year reflects experience from other similar projects. Also start work each year as soon as spring flows permit. Extend hours of work as required to maintain schedule.	1. L
2. Gate replacement delayed due to longer than anticipated spring freshet.	2. Sluicegate outage commencement start date deferred.	2. M	2. See #1 above.	2. L
Operational				
1. Sluicegates unavailable during outage for approx. 4 months.	1. Loss of flow control equipment.	1. L	1. Remaining five sluicegates will remain operational plus the additional flow control available with the 41 log sluices during traditional low flow periods within the 4 months of construction.	1. L
2. Sluicegate freezes in open position if commissioned during winter months.	2. Loss of flow control equipment and production losses.	2. M	2. Sluicegate commissioning to be conducted during favourable weather conditions. e.g. prior to late fall or winter months.	2. L
Environmental				
Debris and contaminants entering the water course during demolition and construction.	Violation of the Environmental Protection Act resulting in fines and works stoppages to OPG and contractor.	M-H	An environmental assessment will be incorporated into the tendered documents to ensure environmental requirements are met. Execution plan, based on previous similar gate replacement project experience, will be implemented to minimize the impact to the environment. Sectional gates will allow installation to be performed in a dry environment.	L
Resources				
Labour disputes resulting in strikes by BTU trades.	Defers the outage commencement date.	L	Work is in Quebec and a labour process similar to the Chestnut Park Accord process will be followed. Verify BTU trades contracts prior to initiating yearly construction work.	L

Risk Description	Impact	Initial Risk (before Mitigation) (H,M,L)	Mitigating Activity	Residual Risk (after Mitigation) (H,M,L)
Technical				
1. Discovery work during gate replacement.	1. Lengthens outage period.	1. M	1. Experience and lessons learned from other PG sluicegate replacement projects will be fully utilized in advanced work planning to avoid/mitigate this risk. Total replacement of gate minimizes this risk.	1. L
2. Commissioning tests indicate gate does not operate according to Technical Specification.	2. Unavailable flow control capability	2. L	2. Project strategy and technology are proven in recent other PG sluicegate replacement projects. Pre-approved vendor/contractor will be used to ensure work quality.	2. L

8. POST IMPLEMENTATION REVIEWS

- Project management will conduct a lessons-learned exercise following each gate replacement and revise the PEP for the next gate replacement.
- Project Management will demonstrate functionality and commissioning tests following each installation, witnessed by Production and Asset Management/Technical Service Department representatives.
- Project Management will provide commissioning test report.
- Commissioning will be in accordance with the following documents:
  - Periodic Review of Mechanical Equipment Used for Flow Control (DS-STD-09 R03)
  - Periodic Review of Electrical Equipment Used for Flow Control (DS-STD-10 R01)
- Project Management will provide actual costs vs. estimated Q4 of each installation year and rationale of any variances incurred
- The PIR report will be completed by the Ottawa/St. Lawrence Plant Group Asset Management Department 6 months after final in-service report is completed - 2013.

ONTARIO POWER GENERATION

HYDROELECTRIC
Summary of Estimate - Capital

Date	September 10, 2008
Project #	OTTO0021

Facility name: Otto Holden G.S.

Project Title: Replace Sluicegates & Rehabilitate Sluicegates System

	LTD	2009	2010	2011	2012	2013	2014	2015	TOTAL	%
Project Management/Engineering **(012)**	20k	40k	40k	40k	45k	45k	45k	45k	320k	1.3
Consultant/Engineering **(310)**	170k								170k	0.7
Construction/Installation										
Hydroelectric (PWU labour) **(010)**		60k	30k	30k	30k	35k	35k	35k	255k	1.1
Contractor/ (BTU labour)/EPSCA **(310)**	[redacted]									
Materials **(200)**	[redacted]									
Interest **(700)**	4k	120k	73k	76k	79k	82k	85k	89k	607k	2.5
Contingency **(998)**	[redacted]									
TOTAL	**194k**	**4,730k**	**2,855k**	**2,971k**	**3,097k**	**3,222k**	**3,324k**	**3,463k**	**23,856k**	**100**

Notes: 1 Schedule: Start Date: January 2009 (Execution Phase)
In-service Date: November 2015

2 Interest and escalation rates are based on current allocation rates provided by Corporate Finance

3 Includes removal costs of: $457k

4 Includes Definition Phase Cost of: $194k

Prepared by:	Approved by:
Project Engineer/Officer	Production/Project Manager
Date: Sept 23, 2008	Date: Sept 29/08

Type 2 Business Case Summary

Final Security Classification of the BCS: **Internal Use Only**

To be used for investments/projects meeting Type 2 criteria in OPG-STD-0076.

Part A: Project Information					
Project #:	OTTO0039	**Title:**	Replace Headgates and Rehabilitate Gains		
Phase:	Definition and Execution	**Release:**	Partial	**Records File:**	
Facility:	Otto Holden GS	**Class:**	Capital	**Investment Type:**	Sustaining

Business Need:

The business need is a reliable headgate system to provide asset protection for the generators. To meet this business need, the recommendation is to replace the end of life headgates and restore the associated headgate equipment.

Otto Holden has eight generating units; each is equipped with two headgates which are installed into gains embedded into the concrete structure of the headworks. The headgates are asset protection devices used to shut off water supply to the turbines in case of emergency and are the last resort available to stop the generators. They are also used to isolate units during unit repairs and maintenance. It is important that the headgates and gains, including the integrity of the seals and the seal paths, be maintained in good working condition in order to ensure asset protection and work protection requirements.

The headgates, embedded components and the hoist mechanisms are original from the early 1950's. Between 1990 and 2003, the headgates for all 8 units received life extension work. The work was conducted on Units 1-6 and 8 from 1990-98, while the work for Unit 7 was in 2003. The repairs were expected to extend the service life of the gates by approximately 15-20 years and to restore operating reliability to the headgates until the headgate replacement and embedded components rehab project initiates in 2014. Our experience is that the headgates were at end of life and was confirmed by the assessment (R-NA6-29550-0001) in 2011 (21 years after the previous repairs began), however the condition of the embedded parts was not ascertained. The inspection results revealed that there is significant leakage occurring from headgate seals and sills and also revealed several operational and maintenance issues related to the hoist assemblies. The resources required to examine the embedded components prior to the partial release would not be feasible recognizing the there will be a unit outage to replace the headgates. The headgates' full functionality needs to be re-established by bringing the leakage rate within the acceptable range. In addition, previous drop tests results have revealed that at least one headgate does not drop to the sill under full load conditions and other units are experiencing significant leakage.
This Partial Release of $3,910k will fund the installation of new headgates and the required restoration or replacement of embedded components and hoist assemblies to new condition on one unit (G1) in 2014. The estimated total project cost at completion is $24,599k. As it was not possible to determine the condition of the embedded components during last inspection, this partial release is also required to determine the complete scope of the repair work required for the embedded components and hoist assemblies, validate our assessment of the hoist assemblies and to complete the technical specification and release quality estimate for the remainder of the project. The headgate replacement and the repairs of the embedded components and hoists for the remaining seven units are programmed to be executed during the Otto Holden unit overhauls which are scheduled to begin in 2015.

Preferred Alternative: Replace headgates with new headgates and rehabilitate gains and hoists. Advance one unit to 2014 and execute the remaining unit headgate replacements during the unit overhaul outages beginning in 2015.

The preferred alternative includes the replacement of all of Otto Holden's headgates with new headgates as well as the required repairs to the embedded components and the hoist assemblies. One unit will be completed in 2014 in advance of the unit overhauls and the remaining seven units will be completed during the unit overhauls between 2015 and 2022.

The replacement of all of the headgates with new headgates is recommended due to the improved performance and increased life expectancy of new gates over the alternatives to refurbish the gates, delay the work, or to do nothing. Currently the headgates are past their end of life, including the life extension that was provided by previous refurbishments, and drop tests on two units have revealed performance issues. Improved performance and reliability of the headgates and components will ensure that the units can be dewatered for inspections and maintenance as well as provide additional asset protection if required in an emergency.

The 2012-16 plan includes aligning all headgate replacements with the unit overhauls. The preferred alternative will require one additional planned outage above those planned for the unit overhauls. Due to the potential for discovery work, this alternative will provide the opportunity to determine the extent of the discovery work on the first unit and will reduce the financial and schedule risks associated with discovery work for the remaining seven units. There has been no known impact on the operations of the headgates from the concrete growth (AAR) issue at Otto Holden although it is present in the headworks area. Discovery work could also impact the schedule and cost of the unit overhauls. Completing the replacement and repairs on one unit in advance of the overhauls will provide the information necessary to ensure that the scope and costs of executing the work on the remaining units can be determined with higher confidence and will allow for the necessary coordination between this project and the upcoming unit overhauls.

Base Case: Status Quo – No Project

The headgates are currently 60 years old. The initial expected service life was 50 years. They have been refurbished once; however they are showing signs of deterioration and leakage. Doing nothing is not recommended as the headgates' performance could deteriorate to the point where they are not able to shut off water supply to the turbines in case of an emergency or be used for dewatering the units for maintenance and/or inspection purposes. Previous drop tests results have revealed that at least one headgate does not drop to the sill under full load conditions and other units are experiencing significant leakage. This increases the risk of damage to the unit and/or other equipment, should an emergency require automatic isolation of the water passage.

Alternative 2: Delay Work – Replace headgates and rehabilitate gains and hoists after unit overhauls

The headgates are currently past their end of life. Delaying the work could lead to increased leakage and further deterioration to the gains and hoists assemblies. Drop tests were completed on two units since the rehabilitation program in the 1990s. One headgate did not close all the way, while the others exhibited significant leakage. Based on these tests and the known age and condition of the headgates, it is not recommended to wait until after the unit overhaul program to initiate the headgate replacement. If the headgates are not replaced until after the unit overhauls, the headgates will be 20 years past their end of life before the replacement even begins.

This alternative is not recommended as it does not provide the asset protection required and may lead to increased costs due to further deterioration of the embedded components and the hoist assemblies. In addition, this alternative would require taking eight additional unit outages following the unit overhaul program which could be avoided by combining the headgate replacement with the overhauls for seven of the units.

Alternative 3: Replace headgates and rehabilitate gains and hoists in advance of unit overhauls

The replacement of the headgates is the preferred option. Completing the unit headgate work in advance of the overhauls, however, will require additional planned outages and is not recommended. Replacing all of the headgates in advance of the unit overhauls would provide new headgates for each overhaul, however it would also result in 8 additional outages over the same period as the unit overhauls. The unit overhauls are approximately eight months in duration while an outage for headgate replacement and hoist/gain rehabilitation would require approximately 4-5 months. In order to minimize the outage time and maximize unit availability, completing the headgate replacement project in advance of the unit overhaul outages is not recommended.

Alternative 4: Refurbish headgates and rehabilitate gains and hoists

Due to the age of the headgates, their design and the fact that the headgates have been refurbished previously, this option is not recommended. The headgates are original from the 1950s and have an estimated service life of 50 years. The headgates are approximately 60 years old and have exceeded their design life that was extended by previous refurbishments. Refurbishment is estimated at approximately 75% of the cost to replace the headgates with new headgates. In addition, headgate replacement would still need to be completed once the benefits of the refurbishment deteriorate. Since this would be the second time that the headgates were refurbished, it would likely not provide the same life extension. There is also a risk that major refurbishments will be required, beyond what was completed on previous refurbishments, which could increase the costs to the equivalent of replacing the headgates with new, without providing the benefits associated with new headgates such as improved design, performance, warranty and increased life expectancy.

Deliverables:	Milestones:	Target Date:
Definition and Partial Execution Phase Release deliverables will include: - Technical Specification for Headgates and Sectional Gates - Purchase of additional Sectional Service Gates required for executing headgate replacement project. - Purchase of headgates and execution of headgate replacement and gain/hoist repair for one unit in 2014 - Technical Specification to complete scope identified in Charter for remaining seven units - Release Quality Estimate for executing the remaining seven units	• Technical Specification for service gates and headgates • Contract awarded for 1st unit • Execution of one unit headgate replacement and gain/hoist repairs • Full Release for execution of	• March 2013 • May 2013 • June 2014 - September 2014

Full Execution Phase Release deliverables will include: - Replacement of headgates and rehabilitation of the embedded components and hoists for the remaining seven units at Otto Holden in conjunction with the unit overhauls planned for 2015-2022.	seven remaining units • Project Completion	• Q3 2014 • Q4 2021

References:

- OTTO0039 – Headgates Investigation (R-NA6-29550-0001 – R000)
- Project Execution Plan – OTTO0039 – Replace Headgates and Rehabilitate Gains
- Project Definition Charter – OTTO0039 – Replace Headgates and Rehabilitate Gains

Part B: Project Cash Flows

k$	LTD	2012	2013	2014	2015	2016	2017	Future	Total
Currently Released	0	0	0	0	0	0	0	0	0
Requested Now	-	410	1,048	2,452	0	0	0	0	3,910
Future Required	-	0	0	0	2,863	2,894	2,924	12,008	20,689
Total Project Cost		410	1,048	2,452	2,863	2,894	2,924	12,008	24,599
Ongoing Costs	-								
Grand Total		410	1,048	2,452	2,863	2,894	2,924	12,008	24,599

Estimate Class[1]:	Class 3	**Estimate at Completion[1]:**	$24,599	**OAR Approval Amount:**	$24,599

Additional Information on Project Cash Flows (optional):

Part C: Financial Evaluation

k$	Preferred Alternative	Base Case	Delay Work	Alternative 3	Alternative 4
Project Cost	24,599	N/A	30,357	24,599 ?	62,822
NPV (after tax)	(14,303)	N/A	(14,713)	(17,901)	(16,452)
Other (e.g., LUEC)	N/A	N/A	N/A	N/A	N/A

Summary of Financial Model Key Assumptions (see Guidance on this Type 2 BCS Form):

- Outage required for headgate replacement is 5 months and will be scheduled during off-peak time.
- New headgates have an expected service life of 50 years.
- Refurbishment will extend the life of the gates 15 years, after which replacement would be required.
- Refurbishment costs are approximately 75% of replacement costs.
- Delay work (Alt 2) NPV includes probability of one headgate failure between 2013 and 2022. Costs to replace failed gate are included. Costs associated with potential equipment/unit damage resulting from a gate failure are difficult to quantify and were not included.
- Base Case (Status Quo) – NPV not calculated. Potential consequences include damage to equipment, lost production, and action required to regain control of flow through the units, however the cost of these consequences has not been quantified. Based on drop test results to date, performance indicates that replacement is recommended.

[1] Estimate Class and Estimate at Completion are to be stated if known. Other supporting documentation such as a Summary of Estimate (SoE) may be attached. The SoE template can be found on the Finance BCS Toolkit website.

Part D: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	Discovery work related to embedded components results in exceeding release amount	The partial release includes allowances for the scope recommended in the investigation report as well as discovery work. Contingency ([redacted]) is also included. The partial release will fund the execution on one unit in order to finalize the scope and costs for the full execution release to complete the remaiming units. Current costs estimates are based on budget estimate from vendor.	Medium	Low
Scope	Discovery work related to the imbedded components could increase the project scope	Discovery work is expected for the first unit which is to be completed with this partial release. The results from the first unit will be used to develop a detailed scope for the remaining units. Allowances and contingency have been made for the discovery work, and the schedule will be planned to ensure significant outage time is available to complete any discovery work.	Medium	Low
Schedule	Delay in ordering/receiving new headgates could impact execution	PEP and contract will include a schedule which will be the basis for the execution planning. Based on the estimated lead time of the headgates, sufficient time has been provided to order the headgates so that they are delivered prior to the start of the outage.Since the headgate replacement on the first unit does not coincide with a unit overhaul, the outage will be planned to ensure that the new headgates will be on site when required.	Low	Medium
Resources	Lack of resources	Labour assignment will be completed prior to awarding the contract for this project. Outage duration for the first unit can be adjusted to accomodate any delays.	Low	Medium
Quality/ Performance	New gates not performing as expected	A technical specification will be developed for the new headgates and the supplier will have experience with similar work at other OPG sites.	Low	Medium
Technical	Gate design does not meet technical requirements	A technical specification will be provided by OPG Hydro Engineering and the proposals will be reviewed by OPG to ensure that the propsed designs meet the technical specifications requested prior to awarding the contract.	Low	High
Other				

Part E: Post Implementation Review (PIR) Plan

Type of PIR	Target Project In Service Date	Target PIR Completion Date
Simplified	2014-10-31	2014-12-31

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Improve headgate performance for emergency closure and maintenance isolation when dewatering the unit. Reduced leakage on first unit completed.	Current leakage has not been measured but was observed (visually) in the investigation and described as significant.	Leakage reduced as per requirements listed in the technical specification.	Leakage will be measured during commissioning and established as a new baseline.	Production, Project Management
Develop firm scope of work and costs for remaining units.	Current scope and costs based on estimates from vendor for replacement and assumed condition of embedded components.	Firm scope and execution phase costs estimates for remaining units.	Updated Project Scope documented in the Full Execution Phase Release Project Charter. Release Quality Estimate developed based on revised scope.	Asset Management & Technical Services - Programming
Scope	The scope for this Partial Release is outlined in the Project Definition Charter	Execute scope detailed in Project Charter.	Project officer to confirm the approved scope was completed as per the Charter.	Asset Management & Technical Services - Programming
Cost	The cost estimates for this phase of the project are included in the cash flow table of this BCS.	Execute the scope within the approved funding.	Actual costs to be compared to approved funds in this release.	Asset Management & Technical Services - Programming

Part F: Review/Approvals

	Signature	Comments	Date
This BCS represents the best option to meet the validated business need in a cost effective manner.			
Recommended by: Frank Chiarotto SVP Hydro-Thermal Operations Project Sponsor	[signature]	funds for 2012 and 2013 are sufficient in the BP.	Sept 25 2012
I concur with the business decision as documented in this BCS.			
Finance Approval: Donn Hanbidge SVP & Chief Financial Officer	[signature]		Oct 9/12
I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Tom Mitchell President & CEO, per OAR 1.1	[signature]		OCT 16/12

ONTARIO POWER GENERATION

Project Summary of Estimate

Date: August 29, 2012

Project #: OTTO0039

Facility name: Otto Holden GS

Project Title: Replace Headgates and Rehabilitate Gains

CAPITAL ($K)	LTD	2012	2013	2014	2015	2016	2017	Future (2018-2021)	TOTAL	%
Project Management/Engineering **(010)**	0	28	48	65	63	64	66	275	609	2
Consultant/Engineering **(310)**	0	0	0	0	0	0	0	0	0	0
Construction/Installation										
Hydroelectric (Plant Group Labour) **(010)**	0	12	24	69	70	71	73	306	625	3
Contractor/ (BTU labour)/EPSCA **(310)**	0	[redacted]								
Materials **(200)**	0	[redacted]								
Interest **(700)**	0	9	40	112	65	66	66	272	630	3
Contingency **(998)**	0	[redacted]								
TOTAL (GROSS)	**0**	**410**	**1,048**	**2,452**	**2,864**	**2,894**	**2,924**	**12,007**	**24,599**	**100**

2012 Budget	**0**	**25**	**100**	**200**	**1,950**	**1,964**	**2,000**	**10,000**	**16,239**	

Notes: 1 Schedule: Start Date: October 2012

In-service Date: December 2014 (first gate), December 2021 (all gates)

2 Escalation rates are based on current allocation rates provided by Corporate Finance

3 Includes Partial Execution Phase Cost of: $3,910k

4 Includes Removal Costs of: $150k

Prepared by: Caley Griener	Approved by: Roy Van Clieaf
Project Engineer/Officer	Production/Project Manager
Date: Aug 29/2012	Date: Aug 30/12

Ranney Falls GS G3 Project (Project Number HDEV0024)

1 Recommendation

Approve the release of 6.1 $M (contingency included) to allow the Ranney Falls G3 Project (the **Project**) to proceed to the Definition Phase. The purpose of the Project is to safely decommission the end-of-life 0.8 MW unit at Ranney Falls Generation Station (**Ranney GS**) and construct a new 8 to 10 MW unit. This addition will increase the total station capacity from 10 MW to about 18 to 20 MW. Installing the G3 upgraded unit will result in an increase of 30 GWh in average annual energy from 50 GWh to 80 GWh. This Project compares favourably with other renewable electricity supply options and is aligned with OPG's mandate and the Ontario government's renewable energy and climate change policies. This Project also aligns with OPA direction as an opportunity to redevelop existing infrastructure. The released amount will be spent in 2012 to 2013 to complete the Definition Phase activities.

The Definition Phase deliverables include securing Environmental Assessment approvals, completing civil and water-to-wire designs, perform required technical investigations, complete the process of selecting the construction and installation contractors required to execute the Project. Deliverables will also include securing and arranging for completing Hydro One connection; and obtaining Project approval (Site License and Work Permit) from the Trent-Severn Waterway (TSW).

Following the Definition Phase, construction is currently targeted to commence by mid-2013, and requires about 30 months with a tentative in-service date by the end of 2015 at a total Project cost of about 48.7 $M (including [redacted] contingency), [redacted] to [redacted]. This estimate has been developed by the project team and is based on consultants' and contractors' budgetary estimates. This Project is in the 2012-2016 Hydro Business Plan.

The total Project cost of 48.7 $M includes about 5 $M for the engineering, design and construction of a new spillway adjacent to the new powerhouse. The TSW has indicated that their approval for redeveloping the site requires the contribution to resolve an existing deficiency in spill capacity at their upstream control dam. A spillway not only increases flexibility and efficiency in operating existing Ranney GS but also enhances TSW's limited spill capacity and mitigates the risk of flooding residential areas along the intake canal of the existing Ranney GS site. About 3 $M of the 5 $M cost for the spillway is attributed to mitigating the existing flooding risk, which would cost about 10 $M if undertaken independent of the Project.

The economic analysis of the Project is presented in Appendix E, and summarized in Table 4-1. The Base Case financial analysis includes the full cost of the spillway. It is considered an opportunistic capital expenditure that would otherwise be a cost prohibitive measure for mitigating the existing station flooding risk. The Base Case equivalent Feed-in-Tariff (FIT) rate is about 13.3 ¢/kWh including [redacted] contingency. The equivalent Feed-in-Tariff (FIT) rate excluding the 3 $M cost attributing to enhancing the public safety of the existing station would be 12.1 ¢/kWh. The current OPA FIT rate is 13.1 ¢/kWh for hydroelectric Stations under 10 MW.

Total Investment Cost: 48.7 $M (including 1.5 $M previously approved released OM&A fund for Conceptual Phase. 6.1 $M Definition Phase funding is requested for this release)

	Funding Type	2010 & prior	2011	2012	2013	2014	2015	Later	Total
Previously Released	OM&A	0.6	0.9						1.5 $M
Requested Now	Capital			3.8	2.3				6.1 $M
Future Request	Capital				21.2	14.0	5.9		41.1 $M
TOTAL		**0.6**	**0.9**	**3.8**	**23.5**	**14.0**	**5.9**	**0**	48.7 $M

2 Signatures

Submitted by: G. Elliott Dec. 12/11
Glen Elliott — Date
Acting Director, Business Development

Recommended by: Carlo Crozzoli Dec 13/11
Carlo Crozzoli — Date
VP, Hydroelectric Development

Reviewed by: Don Brazier Dec 12/11
Donald Brazier — Date
Director of Finance

Approved by: for John Murphy Dec 15/11
John Murphy — Date
EVP, Hydroelectric

3 Background and Issues

Ranney Falls Generating Station (**Ranney GS**) was formerly leased by the federal government to the Seymour Power Company and acquired by Hydro-Electric Power Commission in 1916. The site is now owned by OPG and the generating station is managed by the Central Hydro Plant Group (CHPG) with remote operation from the North Bay Control Centre and maintained by the Campbellford Service Centre.

OPG engineers reached the proposed most economical conceptual design of the preferred alternative in response to CHPG requirement of adding a site spillway to the project.

3.1 Description of Existing Ranney Falls Generating Station

Ranney GS is located on the Trent Canal at the south end of the Town of Campbellford, Ontario. The existing Ranney GS consists of two powerhouses, with the main powerhouse housing two operating units (G1 and G2) running at 5 MW each. These units were upgraded from 4 MW between 2005 and 2007. The second powerhouse, commonly referred to as the "Pup", has a 0.8 MW unit (G3) that has reached its end-of-life.

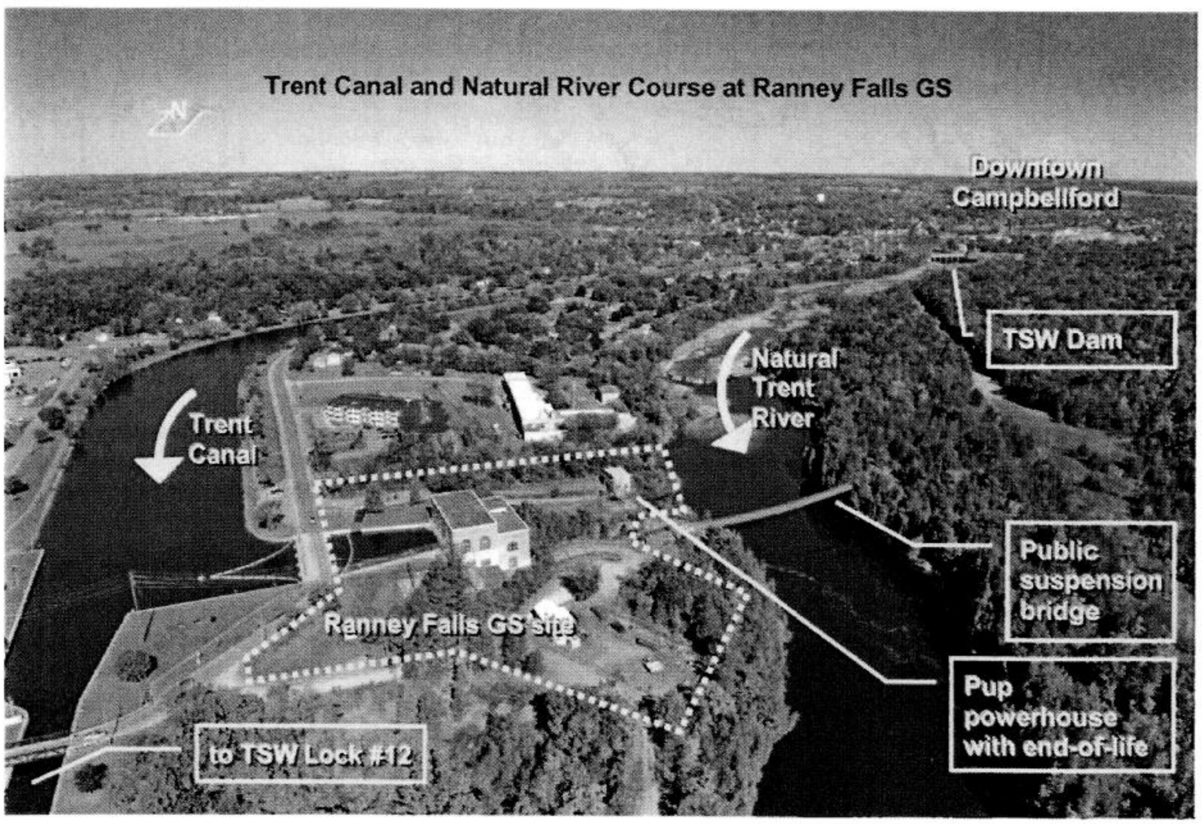


Figure 3-1 Existing Ranney Falls Generating Station – Aerial View

Both powerhouses share a common intake structure from the Trent Canal (Figure 3-2), with G3 being fed by a penstock from a channel that branch off the forebay. The average gross head is around 14.4 m. The average available flow is around 167 m^3/s. The total existing site maximum flow consumption is about 100 m^3/s.

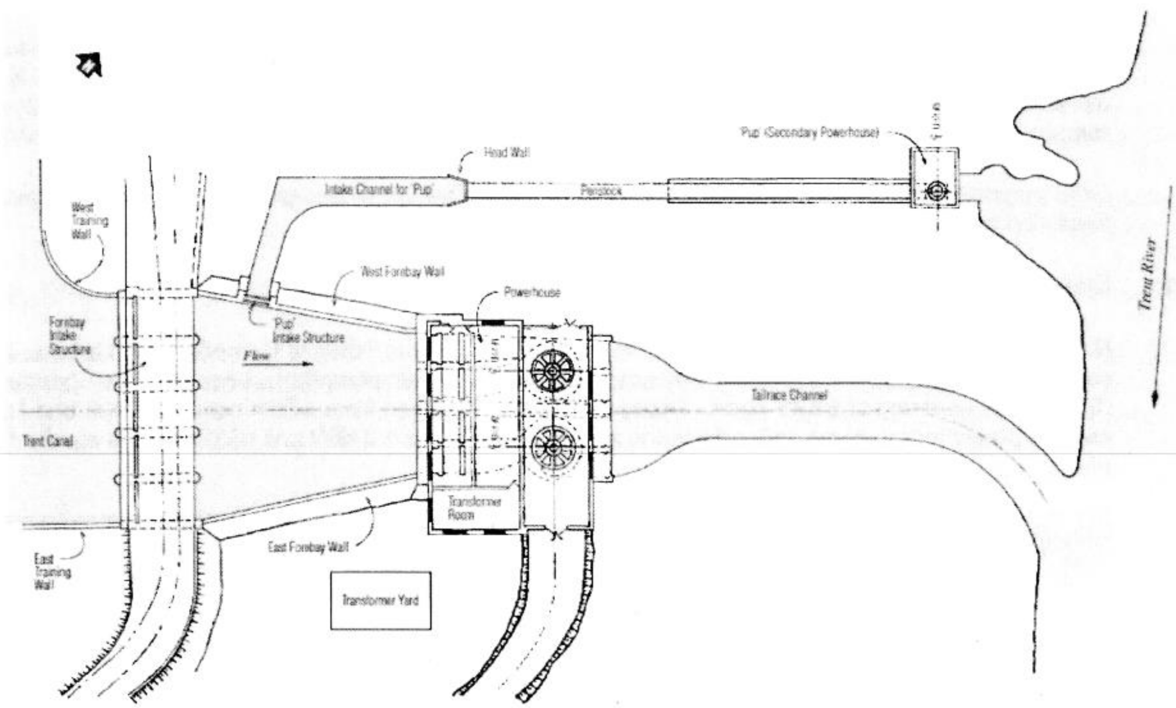


Figure 3-2 Existing Ranney Falls Generating Station - Plan View

The existing G3 unit is undersized for the available flow compared to other sites on the river. Installing in a bigger G3 unit will expand the capacity of Ranney GS making optimal use of the available flow.

3.2 First Concept Study by KST Hydroelectric Engineers

The first Concept Phase Study for the Project carried out by KST Hydroelectric Engineers (KST) in 1992 identified the potential to increase total station capacity to about 24.5 MW and almost double the station energy production. A redevelopment proposal which involved retaining the existing main powerhouse and adding a 16.5 MW unit beside it was recommended.

The KST Study proposed to construct a second forebay just north of the existing one (Figure 3-3). The proposal employed a new, dedicated intake from the Trent Canal and a new public road bridge (Trent Drive) over the new forebay. The existing Pup powerhouse would be demolished and replaced with a larger powerhouse. The existing Pup's penstock would be replaced with two larger penstocks taking flow from the second forebay to the new powerhouse.

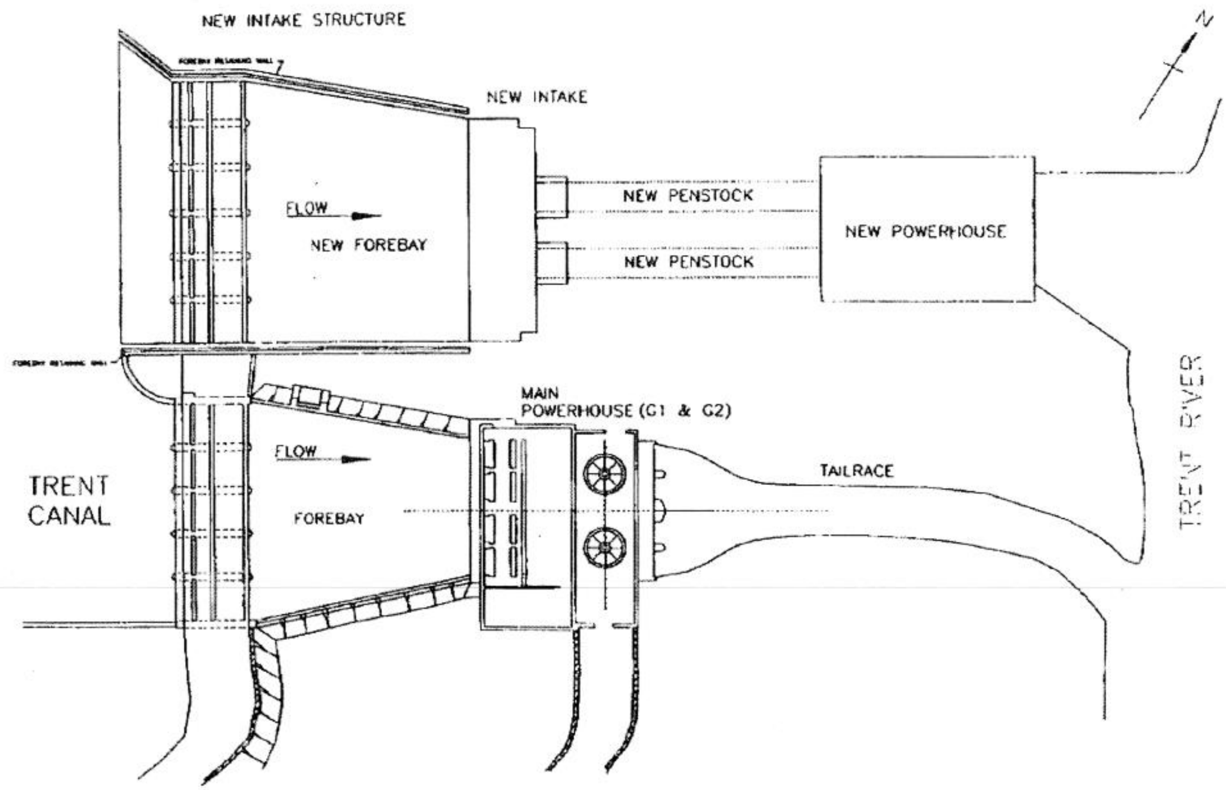


Figure 3-3 KST Hydroelectric Engineers' 1992 recommendation

The redevelopment proposal was not pursued due to unfavourable economics at the time. KST's redevelopment proposal continues to be not feasible at this time due largely to the following reasons:

- In 2006, Aquatic Ecosystem Impacts Research Division, Environment Canada, conducted a field experiment to determine the erosion potential in the Trent Canal leading to Ranney GS. The experiment recommended the maximum flow rate without affecting the stability of the canal to be 172 m^3/s, which is enough for only a total station capacity of about 20 MW.

- In 2006, Hatch Acres International determined that the existing conveyance (i.e., existing intake and forebay configuration) would be adequate with minimal head losses. Accordingly, the envisaged head loss advantage associated with an entirely new intake could not justify the expense of building a completely new road bridge and intake along with the land purchase that would be required from TSW and the municipality.

3.3 Second Concept Study by Hatch Acres International

The second Concept Phase Study for the Project, carried out by Hatch Acres International (HAI), in 2006 utilized the existing forebay and its intake structure for the increased flow and recommended to replace only the existing Pup's powerhouse, penstock, and the penstock head works (Figure 3-4), without the need for a new intake and forebay. Modifications to the existing forebay and its intake would be required for expanding the intake channel of the new penstocks.

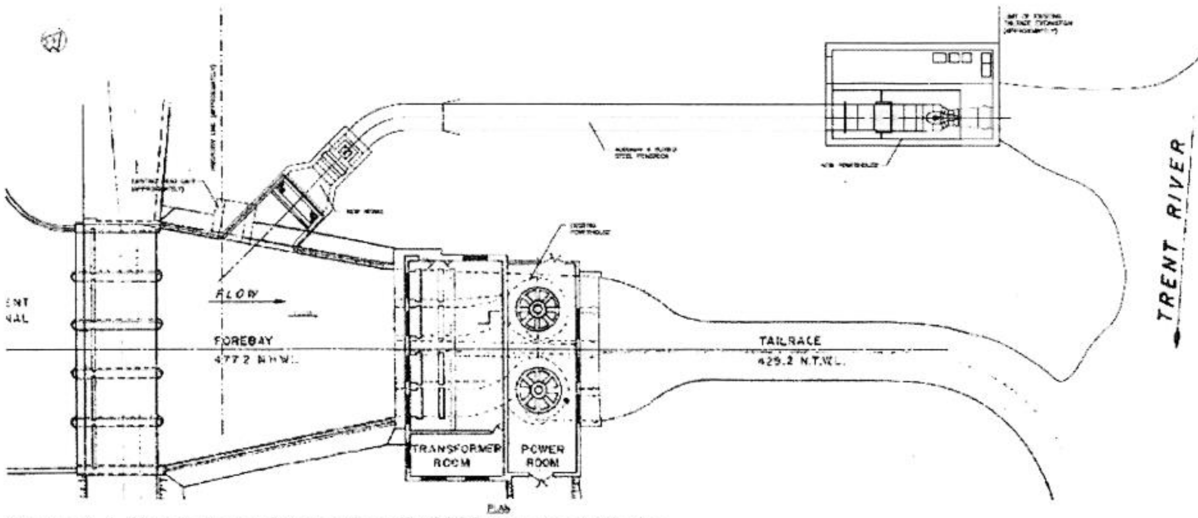


Figure 3-4 Hatch Acres International's 2006 recommendation

3.4 Third Concept Study by OPG Hydro Engineering

In 2011, OPG Hydro Engineering (HED) conducted a third Concept Phase Study in 2011. The Study included the review of the geotechnical investigation carried out by Knight Piesold in 2010. Extensive geotechnical investigation performed at the site to meet CDA - Dam Safety requirements and to better estimate the work required during construction at the site compared with a recent project in the area that needed grout injection in order to complete construction. The Study also encompassed a number of hydraulic models (HEC-RAS and 3-dimentational computational fluid dynamic) and field measurements, which were later used in the calibration of the hydraulic models. Based on the hydraulic models, the addition of a spillway would be required to minimize flooding risk associated with operating the new unit. Consultation with CHPG and TSW later required the size of the spillway to be doubled to minimize the flooding risk associated with the operation of not only the new but also the existing units.

HED study considered numerous configurations for the Project with different types of turbine (CAT, SAXO, Pit, and conventional Kaplan). Based on direct construction cost and space limitation of the site, two-unit configurations were eliminated. Some one-unit configurations were also eliminated based on space limitation, leaving the Project with three schemes for consideration.

In all three schemes, the existing end-of-life G3 would be mothballed with its turbine and generator remaining in place. The existing forebay would be expanded northward feeding the flow directly to the new unit, eliminating the needs for penstocks. With the powerhouse being near the forebay, a long tailrace would have to be excavated. All three schemes included a submerged spillway that was not in the first and second concept studies by KST and HAI, respectively.

The differences between the three schemes are described as follows:

- Scheme A: a long but shallow powerhouse would be constructed for one CAT unit. The new tailrace for Unit 3 is separated from the existing tailrace for Units 1 and 2.
- Scheme B: a short but deep powerhouse would be constructed for one SAXO unit. The new tailrace for Unit 3 is separated from the existing tailrace for Units 1 and 2 like Scheme A.
- Scheme C: a short but deep powerhouse would be constructed for one SAXO unit, like Scheme B. Unlike Scheme B, however, the existing tailrace for Units 1 and 2 would be expanded northward to accommodate flows from all (existing and new) units.

4 Alternatives and Economic Analysis

Economic and sensitivity analysis has been performed for the Project for a total of 48 scenarios with different combinations of powerhouse configurations, unit sizes, project execution situations, revenue alternatives, and financial situations. Significant scenarios are summarized below.

Table 4-1 shows that the proposed Project falls within the FIT Program current rate using the actual Incremental Energy. Using the Incremental Energy according to the FIT Program yields a much lower cost/kWh than the FIT allowed rate. The Project is aiming to secure either a FIT contract or an equivalent HESA revenue agreement with OPA.

Table 4-1 Economic and sensitivity analysis

	Sensitivity Analysis Of PPA recommended *Alternative 2* New 8 to 10 MW unit with extended tailrace canal				***Alternative 3* New 8 to 10 MW unit with penstocks**	***Alternative 2 Base Case* excluding the portion of the spillway enhancing public safety of the existing station**
Capacity (MW)*	9	**9 Preferred Alternative Base case**	9	**9 Preferred Alternative**	9	**9 Preferred Alternative**
Assumption about construction duration (months)	24	**30**	36	**30**	30	**30**
Project cost ($M) (including Escalation and IDC) - $/kw - $/MWh	39.0 4,3335 1,286	**47.2** 5,239 1,555	60.3 6,697 1,987	**47.2** 5,239 1,555	55.8 6,201 1,923	**42.8** 4,750 1,409
Cost associated with mitigating existing flooding risk not included in project cost above and financial analysis ($M)	0	0	0	0	0	0
Annual Incremental Energy (GWh)	30.3	**30.3 Actual Incremental Energy**	30.3	**46.5 FIT Incremental Energy**	29.0	**30.3 Actual Incremental Energy**
Assumption about water availability after in-service date	average water years	average water years	average water years	average water years	average water years	average water years
Minimum revenue required for break-even (¢/kWh)	10.7	**13.3**	15.8	**8.9**	15.6	**12.1**
Current Feed-in-Tariff rate (¢/kWh)	13.1					

Note: * The project is considering the new capacity of 8 MW to 10 MW. Economic analysis is based upon 9 MW unit

4.1 Alternative 1: Status Quo

The status quo alternative is not recommended because it represents a lost opportunity in expanding OPG's hydroelectric generation portfolio and continues to expose OPG to risk of flooding the residential areas along the Trent Canal leading to Ranney GS.

4.1.1 Lost Opportunity

With the Status Quo Alternative, the 0.8 MW Pup unit (G3) that has reached its end-of-life and will be run until failure, leaving Ranney GS with two larger units (G1 and G2) with a reduced total station capacity of 10.3 MW. Average annual energy production by G1 and G2 combined is about 50 GWh.

This Status Quo Alternative under utilizes the available flow during the non-navigation period (between the long weekends of Thanksgiving in October to Victoria Day in May), which if economically utilized could produce on average an additional 30 GWh of electricity in a typical water year. Figure 4-1 shows the percentage of available flow spilling at the site for different new unit sizes.

This Project compares favourably with other renewable electricity supply options and is aligned with OPG's mandate and the Ontario government's renewable energy and climate change policies. This Project also aligns with OPA direction as an opportunity to redevelop existing infrastructure for longer term.

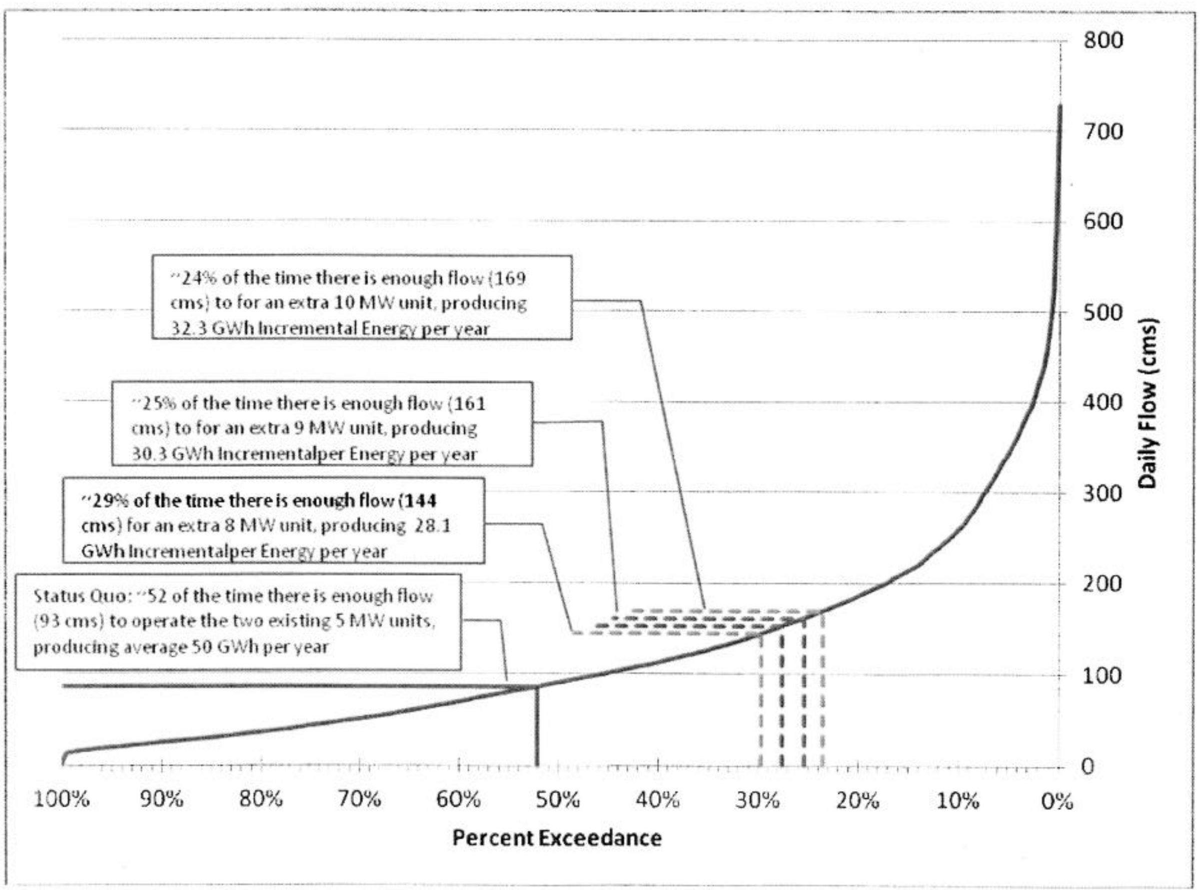


Figure 4-1 Comparison of Unit Size and Incremental Energy

4.1.2 Continued Exposure to Flooding Risk

Trent Canal is sensitive to Ranney GS operations because it is a run-of-the-river station with a very small storage capacity (3 m^3/s-day) with no spilling capacity. The TSW owned and operated control dam is 1.4 km upstream of the station. Therefore, timely diversion of the flow away from Ranney GS is important in emergency shutdown situations. However, there are inevitable delays associated with mobilizing external staff to manually operate TSW Dam #10 to divert the flow.

A major issue with the Status Quo Alternative is that CHPG will continue to be exposed to the risk of flooding the residential areas along the Trent Canal leading to Ranney GS. This risk is credible when an incident of overtopping event occurred. Although TSW is responsible for operating the control dam when the station is down for any reason including the outages imposed by Hydro One, the reputation of OPG is and will be associated with any delay or failure to perform this critical operation in a timely manner.

Including the spillway as integrated part of the new powerhouse is a major enhancement to public safety for the newly developed Ranney GS site. The new spillway will allow for passing the flow from the new unit and also from any or both of the two existing units at the site.

4.2 Alternative 2: Mothball End-of-Life 0.8 MW unit and Construct new 8-10 MW Unit (Recommended Alternative)

In this alternative, an 8-10 MW unit is recommended to be installed in a new, smaller powerhouse, next to the existing main powerhouse. The existing forebay structure will also need to be expanded. This alternative does not require a penstock because the expanded forebay will feed the flow directly to the new unit. In addition, the existing tailrace will have to be expanded to handle the additional discharge from the new unit and spillway.

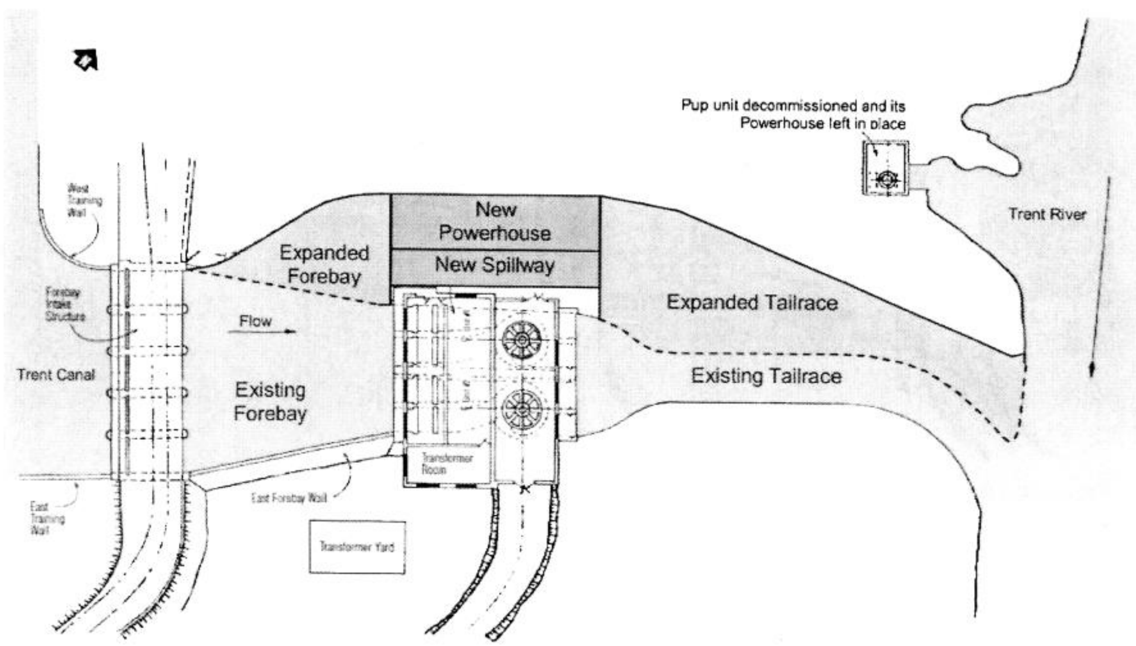


Figure 4-2 Ranney Falls G3 Project with no penstock and long tailrace

In this alternative also, the end-of-life 0.8 MW unit in the Pup powerhouse will be mothballed and its penstock will be partially removed and capped to make space for the new powerhouse. The superstructure of the 'Pup' powerhouse itself will be left in place for heritage and cultural purposes.

In addition, a new spillway will be installed to mitigate the dam and public safety risks associated with operating flow from the existing and new units. The spillway will be capable of passing 172 m^3/s; the combined flow of all (existing and new) generating units.

Table 4-1 shows the results of the economic analysis for Alternative 2. At the total Project cost of 47.2 \$M, this would require a revenue rate of 13.3 ¢/kWh to break even. However, when considering the fact that about 3 \$M of the total Project cost is a license-required expenditure that would provide value-added public safety benefits for the existing station, the Project would require a revenue rate of only 12.1 ¢/kWh. This is estimated after considering the portion of the spillway expenditure as adding value to public safety of the existing station. The current Feed-in-Tariff would provide a rate of 13.1 ¢/kWh.

4.3 Alternative 3: Replace End-Of-Life 0.8 MW with 10 MW Unit with Penstocks

For this alternative, the end-of-life 0.8 MW unit, the Pup powerhouse and its penstock will be demolished and replaced with an 8-10 MW unit housed in a new powerhouse and utilizing two larger penstocks to convey the flow from the expanded forebay to the new unit. Similar to Alternative 2, the existing forebay structure will be expanded to provide water to the new unit. Unlike Alternative 2, this alternative requires two large penstocks, each capable of passing 40 m^3/s of flow but less excavation would be required for the tailrace canal in order to increase its discharge capacity.

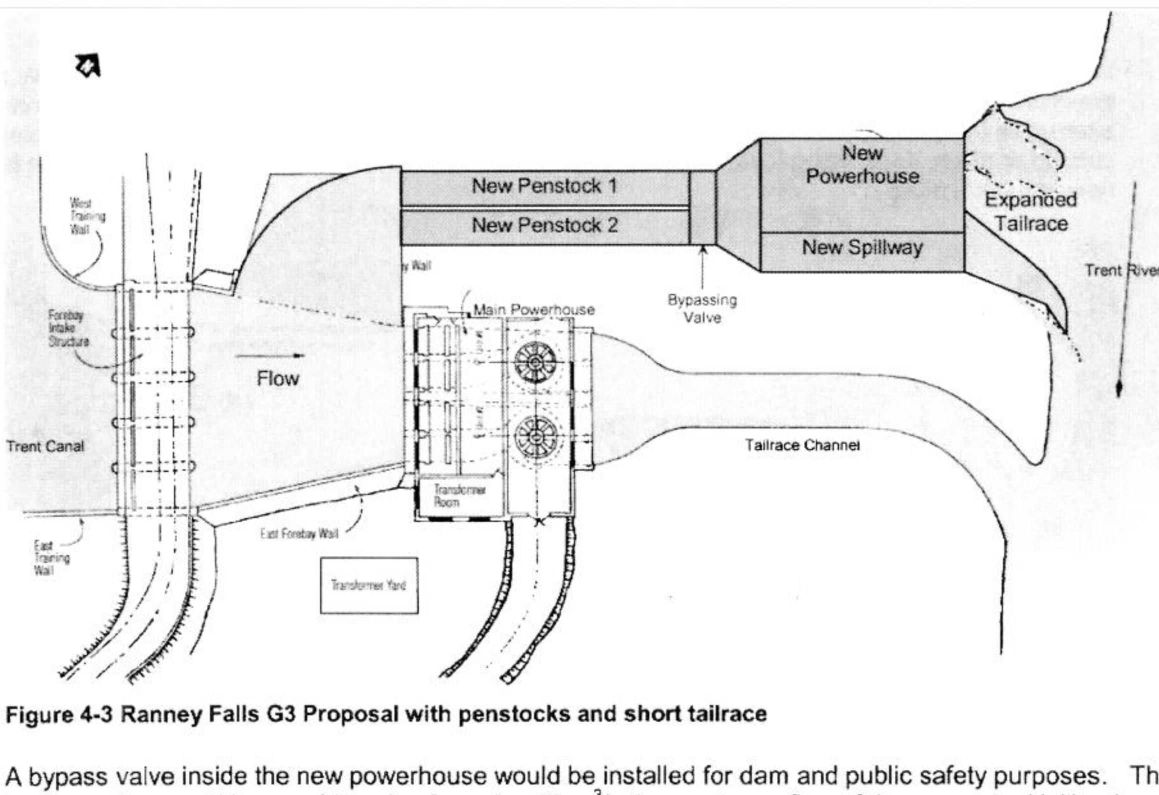


Figure 4-3 Ranney Falls G3 Proposal with penstocks and short tailrace

A bypass valve inside the new powerhouse would be installed for dam and public safety purposes. The bypass valve would be capable only of passing 80 m^3/s the maximum flow of the new unit. Unlike the spillway discussed in Alternative 2, the bypass valve in this alternative would not be able to bypass the combined flow of all (existing and new) units at Ranney GS. As a result the flooding risk at the site is not mitigated when the station operates above the new unit maximum capacity.

A bypass valve inside the new powerhouse would be installed for dam and public safety purposes. The bypass valve would be capable of passing only 80 m^3/s – the maximum flow of the new unit. Unlike, the spillway discussed in Alternative 2, the bypass valve in this alternative would not be able to pass the combined flow of all (existing and new) units at Ranney GS. As a result, the flooding risk at the site would not be fully mitigated when the station operates above its new maximum capacity.

The Project also would require a revenue rate of 15.6 ¢/kWh to break even (Table 4-1, Alternative 3) while the current Feed-in-Tariff would provide a revenue rate of only 13.1 ¢/kWh.

5 The Proposal

The requested release of 6.1 $M covers the Definition Phase for the recommended alternative (Section 4.2). The release amount will be utilized during 2012 and 2013 to cover costs associated with: OPG project management and other labour; Environmental Consultant for assessments and approvals; Owner's Engineer studies, design, and support; Hydro One fees; negotiation of construction and installation contracts; revenue contract negotiations; and' preparation of an approved business case for the Execution Phase.

Specifically, the work scope will include the following deliverables and activities with the support of the Owner's Engineer and the Environmental Consultant:

- Contracting strategy;
- Finalize technical and commercial documentation and obtain ready to sign civil and water-to-wire contracts;
- Civil and water-to-wire designs;
- Design for connection with Hydro One's distribution system;
- Dam safety assessment;
- Environmental Assessment and approvals obtained;
- Revenue agreement (the Project fits within the FIT program rules);
- Execution Phase BCS and approval; and
- Project Execution Plan for the Execution Phase.

The project Definition Phase is expected to start in Q1 2012 and be completed by Q2, 2013. Construction is targeted to start in Q3 2013 and the plant is targeted to be in service in Q4 of 2015. Key Project milestone are listed below.

Milestone	Target Completion Date
Definition Phase Milestones (to be delivered as part of this funding request)	
Contract for Environmental Consultant Awarded (Completed)	Q4, 2011
Finalize Contracting strategy (Report is in progress)	Q4, 2011
Contract for Owner's Engineer/Representative Awarded	Q1, 2012
Contract for Water-to-Wire supplier selected and Design Package Awarded	Q2, 2012
Water-to-Wire Design Complete	Q3, 2012
Civil Design Complete	Q4, 2012
Selection of Civil Work Contractor	Q1 2013
Environmental Assessment Complete	Q2, 2013

Execution BCS Approved	Q2, 2013
Execution Phase Milestones (to be delivered as part of future funding request)	
Contract for Civil Works Awarded	Q3, 2013
Construction Permits Obtained	Q3, 2013
Contract for Water-to-Wire Equipment Fabrication and Installation Awarded	Q3, 2013
Civil Works Construction Started	Q3, 2013
Civil Works Construction Complete	Q3, 2014
Water-to-wire Installation Started	Q4, 2014
Water-to-Wire Installation Complete	Q2, 2015
In-Service date without schedule contingency	Q2, 2015
In-Service date with schedule contingency	Q4, 2015

6 Qualitative Factors

The Preferred Alternative will:

- Confirm OPG's commitment to public safety and demonstrates good corporate citizenship. The inflow design flood of the TSW control Dam is 1,110 m^3/s and the current flood passing capacity of TSW control dam is much less, at only 776 m^3/s. The Project will increase the site capacity to pass flood water by 170 m^3/s. The new flood passing capacity will be 946 m^3/s.

- Strengthen OPG's relationship with TSW by reducing demand of their day-to-day operations of TSW Control Dam when units shut down. Currently, and after the development of this project, TSW is and will remain in water control of the site and responsible for operating the water control structure (Dam #10). With the project increasing site flow intake, TSW will only be in water control for about 2 months in a year, meaning they are able to re-assign their field staff to activities other than operating Dam #10. This will also reduce call-out costs for OPG-CHPG.

- Demonstrate that at OPG, we strive to meet our obligation to produce power in a manner that reflects our commitment to the environmental dimension of sustainable development. The new unit will add to OPG's green energy portfolio 30 GWh per year, equivalent to removing more than 4,100 passenger vehicles from the roads annually.

- The estimated Ranney 30 GWh incremental energy assessed against the overall OPG fleet 2010, will result in the avoiding the following emissions:

  - CO_2 Emissions (tonnes) 4,298
  - SO_2 Emissions (tonnes) 12.8
  - NO_x Emissions (tonnes, as NO_2) 5.4

- Increase operational flexibility and efficiency at the existing Ranney GS. Without the spillway, the station is currently operated at a head water level that is much lower than permitted because of the lack of the ability to timely pass the water flow when the units are shutdown in emergency situations. The new spillway will provide this ability and enable the units to be operated at the permitted water level. This is part of the ongoing communication process with TSW.

- Enables OPG to meet its mandate from the Government of Ontario to expand hydroelectric generation on existing sites. This Project also aligns with OPA direction as an opportunity to redevelop existing infrastructure for longer term.
- Have limited environmental impact as the Project does not involve new inundation that is often seen in other hydroelectric development projects. In-stream construction is limited in scope and poses minimal concerns that will be fully addressed by the project. A coordinated federal-provincial environmental assessment will be completed. The Project requires only screening level assessments..
- Boost local economic activity during construction. About hundred man-year jobs are expected to be created during the three year duration of this project.
- Have limited Employee/Public Safety risks with any potential risks being assessed and addressed through a site and project-specific Public Safety Risk Assessment and Action Plan.

7 Risks

The Project's Risk Management Plan (RMP) establishes how risks associated with the Project are identified, assessed, mitigated, controlled, and tracked until they are adequately resolved. The RMP employs a Risk Register which is periodically updated as new risks are identified and existing risks are resolved. Table 7-1 is a summary of risks from the Risk Register.

Table 7-1 Summary of Risks

Risk Rating before Mitigation	Risk Description	Risk Mitigation	Residual Risk
High	The Regulators could require the Project to provide an eel ladder or a new fish passage even though there is currently no eel or fish passage through the site	The Project will mitigate this risk by starting the environmental assessment process early to identify the regulator requirements. The business case of the Project will evaluate the cost impacts of those requirements before going into the Execution Phase.	Low
Medium	Serious or fatal accident may occur during the construction	To reduce OPG's liability, the Project will set up the contracting strategy such that: 1. The Project will only work with pre-qualified contractors with high safety records. 2. An Owner's Representative will be employed to monitor the contractors' safety program and compliance. 3. OPG will be in the Owner-only role and the contractor will be the Constructor as per Ontario's *Occupational Health and Safety Act*. 4. In additional, OPG will perform Health and Safety auditing during construction.	Low

Risk Rating before Mitigation	Risk Description	Risk Mitigation	Residual Risk
High	The submerged spillway either contains design flaws or does not operate as designed causing the Trent Canal to be flooded or drained depending on the failure state of the spillway gate (failed opened or failed closed)	The Project will minimize this risk by having three separate teams (HED, CHPG-Engineering Support Services, and CHPG-Operations at CSC) review the spillway design. A formal commissioning plan for the spillway will also be developed and executed prior to placing the unit in service. All HED and Dam Safety standards and guidelines will be followed for the spillway from design to maintenance. Regular gate testing will be mandated after commissioning the gate as per OPG Standard guidelines.	Low
High	The Project is unable to secure a revenue agreement that provides a revenue rate of more than the project's break-even rate	The Project is mitigating this risk by aligning itself for the application with the Ontario Power Authority through the Feed-in-Tariff Program which would provide a current revenue rate of 13.1 ¢/kWh. The Project would not proceed to the Execution Phase until an acceptable revenue agreement is secured.	Low
High	With the increased flow, the increase in water velocity may have adverse impacts on boaters experience and wildlife	The Project is mitigating this risk by having developed a hydraulic model to estimate the new water velocity. The predicted water velocity will be provided and discussed with the regulator as part of the environmental assessment process.	Medium
Medium	The Project cost and schedule may increase because the bedrock conditions are unfavourable for supporting the powerhouse or dewatering during construction.	The Project has partially mitigated this risk by having conducted an extensive geotechnical investigation to confirm rock mass as foundation and identify dewatering requirements during construction. Although the results of the investigation are favourable, the risk remains because as with any geotechnical investigations, the results are based on only the core samples. The true conditions of the entire bedrock are not known until excavation is complete.	Low
High	The Project could not secure distribution capacity from Hydro One	The Project has mitigated this risk by executing a Connection Cost Agreement with Hydro One to reserve a capacity of 10 MW on their existing R8S line.	Very Low
High	The increased flow in the Trent Canal could introduce unacceptable levels of erosion	The Project has mitigated this risk by hiring Environment Canada's Aquatic Ecosystem Impacts Research Division to perform a detailed investigation for the canal integrity at a flow up to 171.4 m^3/s. The investigation has concluded that no erosion would take place up to this flow level.	Very Low

Risk Rating before Mitigation	Risk Description	Risk Mitigation	Residual Risk
High	Consultation with Aboriginal Communities in the area takes longer than anticipated schedule	The Trent River is located in an area covered by the 1923 Williams Treaty. In this Treaty area, the Aboriginal Communities gave up all their rights along the Trent River. No impact on Aboriginal Communities is expected from the project, as the existing station is already in operation since 1922. Consultation will start as early as possible in the environmental assessment process, with the guidance and assistance of the Ministry of Energy and TSW.	Medium
High	Environmental Assessment requires longer than targeted schedule while coordinating with Federal and Provincial agencies. For example data collection needs a season or more to satisfy agencies.	OPG retained an experienced consultant (SENES Consultants Limited) to perform the EA activity. Extensive field data collection completed by Q4 2010. Mitigation plan studies regarding endangered map turtle species started in 2007. Contingency fund is available for any additional studies or data collection if requested by any involved agency. OPG will also propose additional work to be done after the EA as a condition of approval.	Medium

8 Post Implementation Review (PIR) Plan

Type of PIR: Simplified

Target Project In-Service Date: Q4, 2015

Target PIR Completion Date: 18 months after the project's In-Service date

Measureable Parameter	Current Baseline	Target Results	How will it be measured?	Who will measure it (person/group)?
Station annual energy production (GWh)	50 GWh annually	80 GWh annually	Production records for 12 months or 6 months rolling	CHPG – Asset & Technical Services Manager
Performance Guarantee	As per the specification of the water-to-wire supplier (to be selected in the Definition Phase)	Meets or exceeds the specification of the water-to-wire supplier (to be selected in the Definition Phase)	Performance testing	Independent performance and testing consultant (to be selected in the Execution Phase)
Total Project Cost ($M)	40.0 to 60.0 $M (This range will be refined before the start of the Execution Phase)	47.2 $M for the capital cost of the recommended alternative for the Project	Project accounting	Project Manager

Measureable Parameter	Current Baseline	Target Results	How will it be measured?	Who will measure it (person/group)?
Project In-Service Date	Q4, 2015 (This date will be revised and refined before the Execution Phase)	Q4, 2015	Commercial production	Project Manager
Report of Equipment In-Service (REIS)	1 month after In-Service date	1 month after In-Service date	REIS fully approved	Project Manager and CHPG senior Managers
Turn-over documentation	- As-built drawings - Operating and maintenance (O&M) manuals	- As-built drawings - O&M manuals	- As-built drawings electronically available in SAP - O&M manuals available in the station, Campbellford Service Centre, North Bay Control Centre	CHPG – First Line Manager, Campbellford CHPG – Engineering Manager, North Bay

9 Appendix B – Glossary

BCS	Business case summary
CHPG	Central Hydro Plant Group
EA	Environmental Assessment
FIT	"Feed-in-Tariff" Program managed by OPA
HAI	Hatch Acres International
HED	Hydro Engineering
IRR	Internal rate of return
KST	KST Hydroelectric Engineers
NPV	Net present value
PCA	Parks Canada Agency
PIR	Post implementation review
Project	Ranney Falls G3 Project
Ranney GS	Ranney Falls Generating Station
REIS	Report of Equipment In-Service
RFP	Request-for-proposal
RPM	Risk Management Plan
TSW	Trent-Severn Waterway

10 Appendix C – Cost Variances from Business Plan

	2010 & prior	2011	2012	2013	2014	2015	2016 & beyond	Total
Previously Released	**584**	**873**						**1,457**
Spent Life-to-Date (up to month-end August, 2011)	584	700						1,284
Remaining to Spend		173						173

Previously Released	584	873						1,457
Request Now			3,839	2,262				6,101
Future Request				21,160	14,039	5,900		41,099
Superseding Release								
Revised Project Total	**584**	**873**	**3,839**	**23,422**	**14,039**	**5,900**		**48,657**

OM&A	584	873						1,457
Capital			3,839	23,422	14,039	5,900		47,200
Revised Project Total	**584**	**873**	**3,839**	**23,422**	**14,039**	**5,900**		**48,657**

11 APPENDIX D – Summary of Estimate for Definition Phase

	2012	2013	Total
Internal Labour	**540**	**670**	**1,210**
- Hydroelectric Development	400	500	900
- Hydro Engineering and CHPG	140	170	310
Internal Expenses	**70**	**70**	**140**
- Hydroelectric Development	50	50	100
- Hydro Engineering and CHPG	20	20	40
External Expenses	[redacted]		
- Owner's Engineer Services			
- Geotechnical Investigation			
- Environmental Assessment Consultant			
- Hydro One connection and allocation deposit			
- FIT deposits and TSW deposit			
- Turbine/Generator final design (5% of W2W cost)			
- Map turtle fence - 1 year before construction starts			
Interest ([redacted])	[redacted]		
Contingency ([redacted]	[redacted]		
Escalation (3%)	**86**	**47**	**133**
Total Release for Definition Phase ($k)	**3,839**	**2,262**	**6,101**

12 APPENDIX E – Financial Analysis and Assumptions

Numbers may not add due to rounding.

Table 1
Capital Project Listing - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric
Projects ≥ $20M Total Project Cost[1,2]

Line No.	Project Name	Project Summary Ref. No.	Category	Changes from EB-2010-0008	Start Date	Final In-Service Date	Total Project Cost ($M)	In-Service 2013 ($M)	In-Service 2014 ($M)	In-Service 2015 ($M)	2010 Actual ($M)	2011 Actual ($M)	2012 Actual ($M)	2013 Budget ($M)	2014 Plan ($M)	2015 Plan ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Project summaries for the following projects are included in this section of the application															
	Niagara Plant Group and Saunders GS:															
	Niagara Plant Group															
1	Niagara Tunnel Project	EXEC0007	Value Enhancing	Ongoing	2005	Mar-13	1,500.0	1,474.2	2.0	0.0	231.8	265.5	231.2	122.9	2.0	0.0
2	Sir Adam Beck Pump GS - Reservoir Refurbishment	HDEV0028	Sustaining	New	2011	Dec-17	362.0	0.0	0.0	0.0	0.0	2.6	1.2	2.6	0.0	0.0
3	Sir Adam Beck I GS - Unit G9 Upgrade	SAB10047	Value Enhancing	Completed	2008	Jan-11	29.8	0.0	0.0	0.0	14.0	1.3	0.0	0.0	0.0	0.0
4	Sir Adam Beck I GS - Unit G10 Upgrade	SAB10050	Sustaining	Deferred	2013	Jun-15	25.6	0.0	0.0	25.4	0.0	0.0	0.0	0.5	10.6	14.5
5	Sir Adam Beck I GS - Unit G3 Upgrade	SAB10064	Sustaining	Ongoing	2011	Aug-13	23.0	22.7	0.0	0.0	0.3	1.7	16.6	4.3	0.0	0.0
6	Sir Adam Beck I GS - Rehabilitate Canal Lining	SAB10056	Sustaining	Deferred	2017	Dec-20	126.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Sir Adam Beck I GS - Unit G7 Frequency Conversion	SAB10032	Value Enhancing	Completed	2007	Apr-12	32.0	0.0	0.0	0.0	0.6	3.7	0.2	0.0	0.0	0.0
8	Sir Adam Beck Pump GS - Dyke Foundation Grouting	SABP0022	Sustaining	Cancelled			21.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Sir Adam Beck 1 GS - Unit G5 Upgrade	SAB10072	Sustaining	New	2014	Oct-16	24.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.0
10	Sir Adam Beck 1 GS - Unit G4 Upgrade	SAB10086	Sustaining	New	2015	Oct-17	24.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
	Saunders GS															
11	No projects in this category						0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Subtotal - Niagara PG and Saunders GS**						2,168.4	1,496.9	2.0	25.4	246.6	274.8	249.2	130.3	12.9	16.8
	Newly Regulated Hydroelectric:															
	Ottawa-St.Lawrence Plant Group[3]															
13	Des Joachims GS - Replace Main Output Transformers	DESJ0031	Sustaining	N/A	2006	Dec-13	26.3	4.3	0.0	0.0	6.4	7.0	4.6	3.9	0.0	0.0
14	Des Joachims GS - Turbine Runner Replacement	DESJ0016	Sustaining	N/A	2004	Dec-15	22.3	2.8	2.8	2.8	1.9	2.8	2.1	3.0	2.4	0.3
15	Otto Holden GS - Replace Sluicegates & Rehabilitate Sluicegates System	OTTO0021	Sustaining	N/A	2006	Dec-15	20.6	2.5	2.5	2.5	3.4	1.9	3.8	1.8	2.8	2.9
16	Otto Holden GS - Replace Headgates and Rehabilitate Gains	OTTO0039	Sustaining	N/A	2012	Dec-21	24.6	3.0	0.0	2.0	0.0	0.0	0.0	1.0	2.5	2.9
	Central Hydro Plant Group															
17	Ranney Falls Expansion Project	HDEV0024	Value Enhancing	N/A	2012	Mar-16	42.4	0.0	0.0	0.0	0.0	0.0	0.6	2.6	18.7	19.2
	Northeast Plant Group															
18	No projects in this category						0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Northwest Plant Group															
19	No projects in this category						0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	**Subtotal - Newly Regulated Hydroelectric**						136.2	12.5	5.3	7.3	11.6	11.6	11.0	12.4	26.4	25.3
21	**Total**						2,304.6	1,509.5	7.3	32.7	258.3	286.4	260.2	142.7	39.2	42.1

Notes:
1 Projects with expenditures during Test Period or in-service amounts during the Bridge Year.
2 Project costs shown include removal costs expensed to OM&A, whereas in-service amounts exclude these costs.
3 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Table 2
Capital Project Listing - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric
Projects $5M - $20M Total Project Cost[1,2]

Line No.	Project Name	Category	Changes from EB-2010-0008	Project Description	Final In-Service Date	Total Project Cost ($M)	In-Service 2013 ($M)	In-Service 2014 ($M)	In-Service 2015 ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:								
	Niagara Plant Group								
1	DeCew Falls I GS - Station Upgrade (DCW10024)	Sustaining	Deferred	General Station Upgrade of Electrical and Mechanical Equipment	Nov-15	12.0	0.0	7.3	4.5
2	Sir Adam Beck Pump GS - Transformer Replacements (SABP0025)	Sustaining	Completed	PGS Transformer Replacements	Dec-11	7.6	0.0	0.0	0.0
3	Sir Adam Beck Pump GS - Governor Replacement (SABP0033)	Sustaining	Cancelled	Governor Replacement - scope added to project SABP0041 included on Line 7		0.0	0.0	0.0	0.0
4	DeCew Falls I GS - Penstock and Saddle Replacement (DCW10019)	Sustaining	Completed	Penstock and Saddle Replacement	Oct-11	10.5	0.0	0.0	0.0
5	Sir Adam Beck Pump GS - Control Systems & Equipment Protections Upgrade (SABP0041)	Sustaining	New	Control Systems & Equipment Protections Upgrade	Nov-20	8.8	0.0	0.8	2.4
6	Sir Adam Beck 2 - Excitation System Upgrade (SAB20051)	Sustaining	New	Excitation System Upgrade	Nov-17	10.6	0.0	1.5	3.0
7	Sir Adam Beck 2 - Station Service Upgrade - Phase 2 (SAB20054)	Sustaining	New	SAB 2 Station Service Upgrade - Phase 2	Dec-14	5.8	2.7	2.7	0.0
	Saunders GS								
8	R.H. Saunders GS - Station Service Replacement (SAUN0080)	Sustaining	Ongoing	Replace main tie and feed breakers, 600V lockable visi-break distribution distribution panels	Dec-17	11.4	0.0	0.0	3.5
9	R.H Saunders GS - Replace Powerhouse Crane (SAUN0067)	Sustaining	New	Replace original 300 ton crane	Dec-15	11.1	0.0	0.0	8.8
10	R.H. Saunders GS - Replace Generator Protection & Control Upgrades (SAUN0047)	Sustaining	Completed	Replace protections and controls for generators, transformers, and transmission lines, including meeting NERC cyber security standards and coordinating protections with Hydro One.	Dec-11	19.9	0.0	0.0	0.0
11	**Subtotal - Niagara Plant Group and Saunders GS**					97.5	2.7	12.2	22.1
	Newly Regulated Hydroelectric:								
	Ottawa-St.Lawrence Plant Group[3]								
12	Barrett Chute GS - Replace Protections and Controls (BARC0020)	Sustaining	N/A	Replace Protections & Controls for Generator, Transformers, LV/HV buses and Common Plant Equipment	Dec-17	5.9	0.0	0.0	0.0
13	Chenaux GS - Protection Upgrades (CHEN0009)	Sustaining	N/A	Replace Generator, Transformer, Station Service Bus Protections and DC Segregation	Dec-16	12.3	0.0	0.0	0.0
14	Des Joachims GS - Upgrade 13.8kV Breakers and Switchgear (DESJ0023)	Sustaining	N/A	Replace Generator Breakers and Station Service Breakers - replace unit breakers and upgrade arc proofing	Dec-15	9.3	0.0	0.0	9.3
15	Des Joachims GS - Replace Generator, TF and Bus Protection (DESJ0024)	Sustaining	N/A	Replace generator protections/SS & LV Buses	Dec-18	10.0	0.0	0.0	0.0
16	Des Joachims GS - Rewind Generators G1, G3, G5 (DESJ0038)	Sustaining	N/A	Rewind Generators (G1,G3,G5) - Rewind G1, G3 and G5 Stators	Dec-14	8.9	1.6	1.6	0.0
17	Des Joachims GS - AC Station Service Replacement (H97-0197)	Sustaining	N/A	Replace AC station service transformers, switchgear and distribution panels	Dec-14	5.6	0.0	5.6	0.0
18	New Plant Group Headquarters Building (HOSL0009)	Sustaining	N/A	New Plant Group Headquarters Building	Dec-15	12.1	0.0	0.0	12.1
19	Des Joachims - Replace Generator Controls (DESJ0049)	Sustaining	N/A	Controls - replace generator controls	Dec-18	8.6	0.0	0.0	0.0
20	Stewartville GS - Protections and Control Upgrade (STEW0004)	Sustaining	N/A	Replace Protections & Controls for Generator, Transformers, LV/HV buses and	Dec-15	9.1	0.0	0.0	9.1
21	Stewartville GS - Rewind Generators G1-G3 (STEW0009)	Sustaining	N/A	Rewind Generators [G1-3]	Dec-18	5.2	0.0	0.0	0.0
	Central Hydro Plant Group								
22	Coniston GS - Penstock Replacement (CONI0011)	Sustaining	N/A	Penstock Replacement	Oct-17	6.1	0.0	0.0	0.0
23	Nipissing GS - Penstock Replacement (NIPI0002)	Sustaining	N/A	Penstock Replacement	Oct-15	8.0	0.0	0.0	8.0
24	South Falls GS - G2 Turbine Replacement (STHF0005)	Sustaining	N/A	G2 turbine and generator replacement	Oct-15	5.2	0.0	0.0	5.2
	Northeast Plant Group								
25	Lower Notch GS - G1 Capital Upgrade (LNCH0007)	Sustaining	N/A	G1 Capital Upgrade	Dec-14	14.3	0.0	14.3	0.0
26	Lower Notch GS - G2 Capital Upgrade (LNCH0013)	Sustaining	N/A	G2 Capital Upgrade	Dec-15	14.2	0.0	0.0	14.2
27	Otter Rapids GS - Replace T1 Transformer (OTTR0035)	Sustaining	N/A	T1 Transformer Replacement	Dec-17	6.7	0.0	0.0	0.0
	Northwest Plant Group								
28	No projects in this category								
29	**Subtotal - Newly Regulated Hydroelectric**					141.2	1.6	21.5	57.8
30	**Total**					238.7	4.3	33.7	79.9

Notes:
1 Projects with expenditures during Test Period or in-service amounts during the Bridge Year.
2 Project costs shown include removal costs expensed to OM&A, whereas in-service amounts exclude these costs.
3 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 3
Capital Project Listing - Previously Regulated Hydroelectric and Newly 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)	In-Service 2013 ($M)	In-Service 2014 ($M)	In-Service 2015 ($M)
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
	Niagara Plant Group						
1	**Aggregate Total All Projects < $5M**	28	42.6	1.5	17.7	6.6	7.8
	Saunders GS						
2	**Aggregate Total All Projects < $5M**	4	7.1	1.8	1.2	2.5	0.4
3	**Subtotal - Niagara Plant Group and Saunders GS**	32	49.7	1.6	18.9	9.1	8.2
	Newly Regulated Hydroelectric:						
	Ottawa-St.Lawrence Plant Group[2]						
4	**Aggregate Total All Projects < $5M**	47	65.7	1.4	10.4	8.6	8.8
	Central Hydro Plant Group						
5	**Aggregate Total All Projects < $5M**	22	32.0	1.5	6.3	2.5	4.6
	Northeast Plant Group						
6	**Aggregate Total All Projects < $5M**	35	40.2	1.1	12.4	7.0	6.7
	Northwest Plant Group						
7	**Aggregate Total All Projects < $5M**	26	40.2	1.5	8.1	18.0	10.6
8	**Newly Regulated - In Asset Service Fee**	1	1.0	1.0	0.0	0.0	0.0
9	**Subtotal - Newly Regulated Hydroelectric**	131	179.0	1.4	37.2	36.0	30.7
10	**Total**	163	228.7	1.4	56.1	45.1	38.9

Notes:
1 Projects with expenditures during Test Period or in-service amounts during the Bridge Year.
2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 4
Capital Project Listing - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric
In-Service Summary - All Capital Projects

Line No.	Project Description	Reference	In-Service 2013 ($M)	In-Service 2014 ($M)	In-Service 2015 ($M)
			(a)	(b)	(c)
	Niagara Plant Group and Saunders GS:				
1	**Projects ≥ $20 M**	D1-1-2 Table 1	1,496.9	2.0	25.4
2	**Projects $5M - $20M**	D1-1-2 Table 2	2.7	12.2	22.1
3	**Projects < $5M**	D1-1-2 Table 3	18.9	9.1	8.2
4	**Subtotal**		1,518.5	23.3	55.8
	Newly Regulated Hydroelectric:				
5	**Projects ≥ $20 M**	D1-1-2 Table 1	12.5	5.3	7.3
6	**Projects $5M - $20M**	D1-1-2 Table 2	1.6	21.5	57.8
7	**Projects < $5M**	D1-1-2 Table 3	37.2	36.0	30.7
8	**Subtotal**		51.3	62.8	95.8
9	**Total Capital Project In-Service Amounts**		1,569.8	86.1	151.5

Numbers may not add due to rounding.

Table 5

Comparison of In-Service Capital Additions - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric Operations ($M)

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	**Niagara Plant Group**	44.8	(38.0)	6.8	38.4	21.6	23.6	45.2	(30.1)	15.1
2	**Niagara Tunnel Project**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Saunders GS**	15.9	(2.9)	13.0	5.1	20.1	(2.0)	18.1	(18.1)	0.0
4	**Subtotal Facility Projects**	60.7	(40.9)	19.8	43.5	41.7	21.7	63.3	(48.2)	15.1
5	**Minor Fixed Assets**	0.2	(0.0)	0.2	(0.0)	1.2	(1.0)	0.2	0.2	0.4
6	**Total - Niagara and Saunders**	60.9	(40.9)	20.0	43.5	42.9	20.6	63.5	(48.0)	15.5
	Newly Regulated Hydroelectric:									
7	**Ottawa-St.Lawrence PG**[1]	N/A		60.6	(19.8)	N/A		40.8	(17.0)	23.8
8	**Central Hydro Plant Group**	N/A		3.6	4.4	N/A		8.0	(0.1)	7.9
9	**Northeast Plant Group**	N/A		8.9	(8.1)	N/A		0.8	2.4	3.2
10	**Northwest Plant Group**	N/A		9.4	6.4	N/A		15.8	(6.6)	9.2
11	**Subtotal Facility Projects**			82.4	(17.0)			65.5	(21.3)	44.1
12	**Minor Fixed Assets**	N/A		0.5	0.2	N/A		0.7	(0.3)	0.5
13	**Total - Other Plant Groups**	N/A		82.9	(16.7)	N/A		66.2	(21.6)	44.6
14	**Total Hydroelectric Operations**	60.9	(40.9)	102.9	26.8	42.9	20.6	129.7	(69.6)	60.1

Line No.	Prescribed Facility	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
15	**Niagara Plant Group**	44.7	(29.6)	15.1	27.2	42.3	(24.3)	18.0	24.8	42.8
16	**Niagara Tunnel Project**	0.0	0.0	0.0	1,474.2	1,474.2	(1,472.2)	2.0	(2.0)	0.0
17	**Saunders GS**	6.5	(6.5)	0.0	1.1	1.2	1.4	2.5	10.2	12.7
18	**Subtotal Facility Projects**	51.2	(36.1)	15.1	1,502.6	1,517.7	(1,495.2)	22.5	33.0	55.5
19	**Minor Fixed Assets**	0.3	0.1	0.4	0.4	0.8	0.0	0.8	(0.5)	0.3
20	**Total - Niagara and Saunders**	51.5	(36.0)	15.5	1,503.0	1,518.5	(1,495.2)	23.3	32.5	55.8
	Newly Regulated Hydroelectric:									
21	**Ottawa-St.Lawrence Plant Group**[1]	N/A		23.8	0.7	24.5	(3.5)	21.0	25.5	46.5
22	**Central Hydro Plant Group**	N/A		7.9	(1.6)	6.3	(3.8)	2.5	15.2	17.7
23	**Northeast Plant Group**	N/A		3.2	9.1	12.3	8.9	21.2	(0.4)	20.8
24	**Northwest Plant Group**	N/A		9.2	(1.4)	7.8	10.0	17.8	(7.4)	10.4
25	**Subtotal Facility Projects**	N/A		44.1	6.9	51.0	11.5	62.5	33.0	95.5
26	**Minor Fixed Assets**	N/A		0.5	(0.1)	0.3	(0.0)	0.3	0.0	0.3
27	**Total - Other Plant Groups**	N/A		44.6	6.7	51.3	11.5	62.8	33.0	95.8
28	**Total Hydroelectric Operations**	51.5	(36.0)	60.1	1,509.7	1,569.8	(1,483.7)	86.1	65.5	151.5

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Table 6
Capital Projects - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric Operations
Listing of Business Case Summaries Filed

Line No.	Project Number	Business Case Summary (BCS) Title	BCS Approval Date	Project Stage	BCS Status	BCS Status in EB-2010-0008
	(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:					
		Niagara Plant Group				
1	HDEV0028	Sir Adam Beck Pump GS - Reservoir Refurbishment	Sep-11	Definition	Developmental	N/A
2	SAB10064	Sir Adam Beck I GS - Unit G3 Upgrade	Feb-11	Execution	Full	Full
3	SAB10047	Sir Adam Beck I GS - Unit G9 Upgrade	Aug-08	Completed	Full	Full
4	SAB10032	Sir Adam Beck I GS - Unit G7 Frequency Conversion	Aug-07	Completed	Full	Full
5	SAB10050	Sir Adam Beck I GS - Unit G10 Upgrade	N/A	Definition	Developmental	N/A
6	SAB10072	Sir Adam Beck I GS - Unit G5 Upgrade	N/A	Initiation	N/A	N/A
7	SAB10086	Sir Adam Beck I GS - Unit G4 Upgrade	N/A	Initiation	N/A	N/A
		Saunders GS				
8		No projects in this category				
	Newly Regulated Hydroelectric:					
		Ottawa-St.Lawrence Plant Group[1]				
9	DESJ0031	Des Joachims GS - Replace Main Output Transformers	Feb-08	Execution	Full	N/A
10	DESJ0016	Des Joachims GS - Turbine Runner Replacement	May-06	Execution	Full	N/A
11	OTTO0021	Otto Holden GS - Replace Sluicegates & Rehabilitate Sluicegates System	Dec-08	Execution	Full	N/A
12	OTTO0039	Otto Holden GS - Replace Headgates and Rehabilitate Gains	Aug-12	Definition	Definition / Partial	N/A
		Central Hydro Plant Group				
13	HDEV0024	Ranney Falls GS Expansion Project	Dec-11	Definition	Developmental	N/A
		Northeast Plant Group				
14		No projects in this category				
		Northwest Plant Group				
15		No projects in this category				

Notes:
1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Table 7
Capital Projects - Previously Regulated Hydroelectric Operations
Status of Projects $5M and Greater with 2011 and 2012 In-Service Dates in EB-2010-0008

Line No.	Project Number	Project Name	In-Service Date at Time of EB-2010-0008 Application	Project Stage at Time of EB-2010-0008 Application	Current Project Status	
					Project Status	Projected/Actual In-Service Date
	(a)	(b)	(c)	(d)	(e)	(f)
		Niagara Plant Group				
1	DCW10019	DeCew Falls I GS - Penstock and Saddle Replacement	Apr-11	Execution	Completed	Oct-11
2	SAB10064	Sir Adam Beck I GS - Unit G3 Upgrade	Dec-12	Definition	Execution	Mar-13
3	DCW10024	DeCew Falls I GS - Station Upgrade	Dec-12	Initiation	Definition	Nov-15
4	SABP0025	Sir Adam Beck Pump GS - Transformer Replacements	Dec-11	Execution	Completed	Dec-11
5	SABP0033	Sir Adam Beck Pump GS - Governor Replacement	Dec-13	Definition	Cancelled - Scope merged with SABP0041 to start in 2013	N/A
6	SABP0034	Sir Adam Beck Pump GS - 13.8 kV Breaker Replacements	Mar-13	Initiation	Deferred - to start in 2016	Jun-18
		Saunders GS				
7	SAUN0047	R.H. Saunders GS - Replace Generator Protection & Control Upgrades	Mar-12	Execution	Completed	Dec-11
8	SAUN0079	R.H. Saunders GS - Replace Excitation System	Dec-13	Initiation	Deferred - to start in 2016	Dec-18

CAPITAL EXPENDITURES - NIAGARA TUNNEL PROJECT

1.0 PURPOSE

This Exhibit describes the Niagara Tunnel Project ("NTP") from its origin in studies and assessments performed by Ontario Hydro during the 1980s to its completion in 2013. The material that follows establishes that the NTP was an extremely large, complex and challenging construction project that OPG completed safely and cost effectively given the conditions encountered. The emissions free electricity produced from the water flowing through the NTP will benefit the people of Ontario into the next century.

Photo 1 - Looking out the Tunnel at the Outlet Site

The sections that follow demonstrate that the costs of the project as presented in the original Business Case Summary ("BCS") approved by the OPG Board of Directors ("OPG Board") in 2005 were a realistic estimate of the project's cost based on the information available. The evidence explains how the rock conditions encountered during tunneling proved to be extremely difficult necessitating the revised cost forecast and project schedule contained in the 2009 Superseding BCS approved by OPG Board. OPG ultimately completed the project some $100M below the approved funding with commercial service beginning nine months sooner than provided for in the Superseding BCS. In the detailed evidence that follows, OPG demonstrates that the entire $1,500M spent on this project represent prudently incurred costs that should be approved for inclusion in OPG's rate base.[1]

1.1 Introduction

The NTP is a 10.2 kilometre tunnel with an interior diameter of 12.7 metres, which will allow OPG to make better use of the available water flow in the Niagara River to produce on average an additional 1.5 TWh per year from the Sir Adam Beck ("SAB") Generating Stations 1 and 2.[2] As the project came into service in March 2013, this proceeding is the appropriate opportunity to review the prudence of the $514.8M in NTP expenditures beyond the original budget of $985.2M that was approved by OPG Board prior to the OEB's first order with respect to payment amounts for OPG's prescribed facilities under Section 78.1 of the *Ontario Energy Board Act*.[3]

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[1] This figure represents the projected cost to completion as of June 30, 2013. While these amounts are subject to change due to finalization of contract costs and ongoing project closeout activities, OPG does not expect material differences between these estimates and the final figures. OPG will provide final cost figures when they become available.

[2] A discussion of how this estimate changed from the 1.6 TWh figure in the original NTP Business Case is provided in Ex. E1-1-1, section 3.6.

[3] O. Reg. 53/05, section 6(2)4 requires the OEB to ensure that OPG recovers the capital and non-capital costs of the NTP approved by OPG Board of Directors prior to the first payment amounts order and to determine the prudence of any expenditures beyond the OPG Board approved amount.

1.2 OPG's Request and Ratemaking Treatment

OPG currently estimates that the costs of the NTP will be $1,500M. Table 1 below presents, as of June 30, 2013, OPG's estimated spending at completion for each major cost category of the NTP.

Table 1 - NTP Major Cost Categories[4]

Project Cost Flow Estimate	$M
OPG Project Management	4.6
Owner's Representative	36.2
Other Consultants	6.5
Environmental / Compensation	8.7
Tunnel Contract (including Incentives)	1,140.8
Other Contracts / Costs	68.7
Interest	234.5
Total Project Capital	1,500.0

Capital costs totalling $1,424.9M were placed in-service in March 2013. An additional $49.3M of capital costs are forecast to be incurred and placed in-service by the end of November 2013. OPG requests that the gross plant and depreciation impacts of these amounts be included in rate base. As discussed in Ex. B1-1-1, the previously regulated hydroelectric rate base values for 2013 reflect these in-service amounts subject to weightings of 9.5/12 and 1/12, respectively, in order to recognize that they were or are expected to be placed in-service part-way through March 2013 or by the end of November 2013, respectively. This is shown in Ex. B2-3-1 Table 2, note 2. The rate base values for 2014 and 2015 reflect the full-year impact of the net book value of the above in-service additions as well as an additional $2M forecast to be expended on project monitoring and closeout activities in 2014.

[4] In this table and in the tables elsewhere in the document, OPG presents the full project capital costs. As detailed in this section, relatively small amounts of these costs will be incurred after June 30, 2013; have entered rate base previously; or have been or will be expensed rather than capitalized.

The rate base values also reflect $19.2M of capital cost for the Accelerator Wall (see Section 6.5.3) that closed to rate base as an in-service addition in 2007 prior to OEB regulation of OPG's payment amounts.[5]

The details of the rate base values for the NTP gross plant are shown in Ex. B2-3-1 (see Table 2, lines 2, 12 and 22). Accumulated depreciation details are presented in Ex. B2-4-1 (see Table 2, lines 2, 12 and 22). OPG also requests that the test period revenue requirement include a total depreciation expense of $31.7M for the NTP ($15.85M per year in 2014 and 2015) (see Ex. F4-1-1 Table 1, line 2).

The NTP total project cost also includes $4.6M of non-capital removal costs, which were charged to OM&A. Of this amount, $3M was associated with the Accelerator Wall and was expensed prior to OEB regulation of OPG's payment amounts. The remaining $1.6M was incurred in 2011 - 2012 to remove a dewatering structure on the Pump Generating Station canal that would have adversely impacted NTP performance had it remained. The $1.6M was captured in the Capacity Refurbishment Variance Account discussed below.

This project is covered by the Capacity Refurbishment Variance Account established, effective April 1, 2008, under Section 6(2)4 of O. Reg. 53/05. As a result, the cost impacts associated with the project prior to the effective date of the payment amounts that include the NTP are recorded in the Capacity Refurbishment Variance Account. OPG requests that the audited year-end 2013 hydroelectric balance in the Capacity Refurbishment Variance Account, which will include amounts related to the NTP, be disposed of in this proceeding, as is discussed in Ex. H1-2-1.

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[5] As explained in EB-2008-0010, Ex. L-1-20(b) (Response to Board Staff IR #20 (b)):

> The accelerator wall is part of the existing International Control Dam (required primarily for ice management on the river) and is considered part of the Niagara Tunnel project because the tunnel's intake configuration required replacement of the accelerator wall. The in-service addition in 2007 was $19.2M, … and was included in the asset values that the OEB was required to accept under section 6(2)5 of O. Reg. 53/05 in setting OPG's initial payment amounts.

Amounts recorded in the Capacity Refurbishment Variance Account for the NTP are discussed in Ex. H1-1-1. As shown in Ex. H1-1-1 Table 7, these include OM&A costs of $1.6M incurred during 2011 - 2012 (that were not reflected in the EB-2010-0008 payment amounts) and depreciation expense, cost of capital and associated income tax impact for amounts placed or forecast to be placed in-service during 2013. Income tax impacts include variances between actual and forecast Capital Cost Allowance deductions.[6] The derivation of the capital cost components of the 2013 account additions is shown in Ex. H1-1-1 Table 7. The year-end 2013 balance for recovery in relation to the NTP (including interest on the account balance at the OEB-prescribed rate) is projected to be $116.8M.

1.3 Expert Report

OPG's counsel retained Roger C. Ilsley, a geotechnical and tunnel consultant as an expert to provide an independent review and assessment, based on industry standards, of the extent and quality of the geotechnical investigations conducted, the geotechnical reports issued and the relevant project specifications and drawings prepared for the NTP. Mr. Ilsley was also asked to review OPG's conduct in its dispute with the contractor over differing subsurface conditions (discussed below in Section 7.0). Mr. Ilsley prepared an independent expert report which is filed in Ex. F5-6-1.

1.4 Organization of the Evidence

The evidence is organized in three major sections. The first is the narrative contained in this Exhibit, which provides a detailed description of the project, its origins, development, and costs. Photographs and figures are included to illustrate various aspects of the project.

[6] As previously noted in EB-2010-0008, Ex. L-1-020 b, OPG elected to claim early Capital Cost Allowance ("CCA") related to the NTP. Therefore, since April 1, 2008, the approved payment amounts have reflected a forecast tax benefit to ratepayers associated with this election. For the test period, the CCA deduction with respect to the NTP is forecast at $41.3M in 2014 and $39.7M in 2015.

The second component is the three Appendices at the end of this Exhibit:

- Appendix A – timeline of the major project milestones
- Appendix B – review of the geotechnical work that preceded the project
- Appendix C – list of acronyms associated with the project

The third component is an accompanying volume of the key project documents:

- URS Corporation Qualitative Risk Report
- Project Execution Plans – 4 Major Revisions (0-3)
- URS Corporation Quantitative Risk Assessment
- OPG's Risk Assessment Update
- Full Board Approval Package for the original Business Case Summary ("BCS")
- Original Design Build Agreement ("DBA")
- Dispute Review Board Report and Recommendations
- Full Board Approval Package for the Superseding BCS
- Amended DBA ("ADBA")

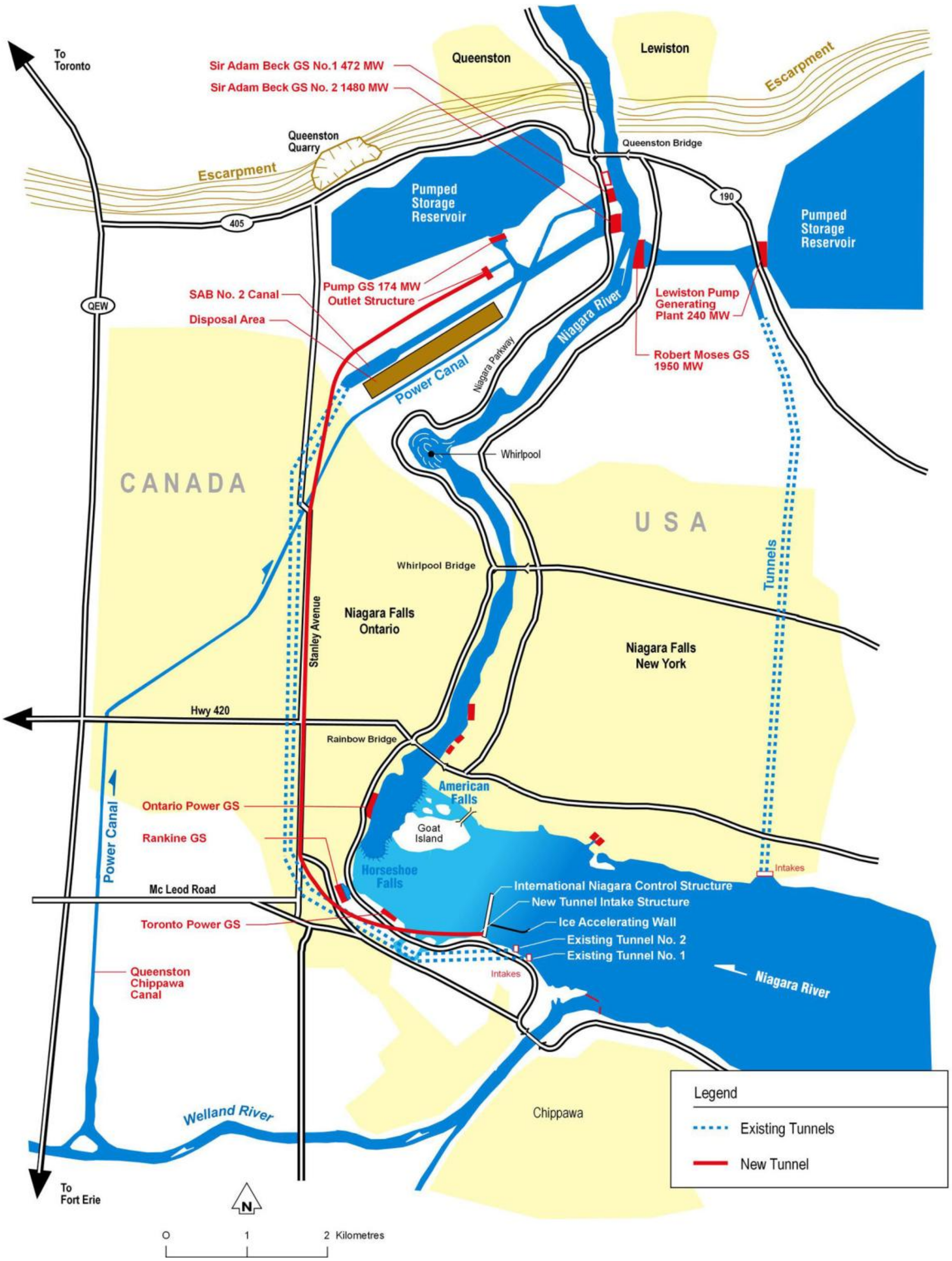
As some of these documents are quite large and contain complex graphics, these documents are included in the accompanying CD of "NTP Key Documents."

2.0 PROJECT BACKGROUND

2.1 Description

The scope of the NTP includes the design, construction and commissioning of a diversion tunnel that is 10.2 kilometres long with a 12.7 metre nominal internal diameter (14.4 metre excavated diameter) from a new intake under the existing International Niagara Control Works structure in the upper Niagara River above Niagara Falls to a new outlet canal feeding into the existing Pump Generating Station ("PGS") canal. The project also includes all required ancillary and enabling works.

Figure 1 - Project Map



This third tunnel will supplement the diversion capacity of the two tunnels and one open channel that currently bring water from the Niagara River to the SAB generating stations. The purpose of the third tunnel is to increase the flow of water available to the existing SAB stations, thereby enabling those generating facilities to produce on average an additional 1.5 TWh of electricity per year. As of March 2013, the third tunnel constructed through the NTP began bringing water to the SAB generation stations.

The new diversion tunnel and related works were delivered under a Design-Build Agreement ("DBA") with Strabag AG of Austria and its wholly owned subsidiary Strabag Inc. ("Strabag"). Strabag was the successful pre-qualified proponent in an international competitive request for proposal ("RFP") process. The tunnel has been excavated using a tunnel boring machine ("TBM") as required by the approvals given under the Environmental Assessment ("EA") process discussed below.

Strabag used a two-pass tunneling system as specified in its successful proposal. The term "two-pass" means that in the first pass the tunnel is bored and an initial lining installed; in the second pass, the permanent concrete lining is installed. The initial lining uses steel supports in the tunnel roof and a full circumference layer of shotcrete (sprayed concrete) installed after mining. The permanent lining is comprised of an impermeable membrane generally surrounding 600 mm of un-reinforced concrete locked in place by cement grout. The project was constructed to meet a minimum design life of 90 years.

2.2 Project History

2.2.1 <u>Early Project Background</u>

Preparation for a new Niagara Tunnel commenced over 30 years ago, in 1982, when Ontario Hydro (the predecessor company of OPG) began to study the possible expansion of its hydroelectric facilities on the Niagara River. Detailed engineering, environmental and socioeconomic studies were conducted from 1988 through 1994 with an EA submitted in 1991 for the then planned project consisting of two additional water diversion tunnels, each one capable of conveying 500 m^3/s, a three-unit underground generating station with a total capacity of 900 MW, and transmission improvements between Niagara Falls and Hamilton, Ontario. This project was referred to as the Niagara River Hydroelectric Development ("NRHD").

Among the commitments made through the EA process was to utilize a TBM to excavate the tunnels starting from the outlet end, proceeding under the buried St. Davids Gorge and following the route of the existing SAB 2 tunnels through the City of Niagara Falls. A TBM was required in light of the development that had occurred in Niagara Falls since the original two diversion tunnels were constructed using the drill and blast method in the 1950s, and to minimize the amount of excavated materials from the project requiring disposal. Other commitments included re-use of excavated materials where feasible and an agreement to compensate the host municipalities, the Regional Municipality of Niagara, City of Niagara Falls and Town of Niagara-on-the-Lake, for forecasted project impacts on tourism, roads and municipal services.

2.2.2 1998 Decision to Pursue Third Tunnel

Early in February 1998, in anticipation of receiving EA approval, Ontario Hydro initiated a review of the viability of proceeding with the first phase of the NRHD (i.e., the construction of one additional 500 m^3/s tunnel). This review included the solicitation and evaluation of bids for the construction of the tunnel during the summer and fall of 1998 using a design-build approach.

In October 1998, the Minister of Environment provided approval under the *Environmental Assessment Act* for the complete NRHD as outlined above. The EA approval stipulated that it would "terminate if construction has not commenced within ten years from the date of this approval." This stipulation could be extended a further five years "based on the review and approval of an environmental review assessment status report." It provided Ontario Hydro with the flexibility to undertake the development in phases (i.e., initial construction of one tunnel); but did require that no construction extend "beyond twenty years following the commencement of construction."

In the fall of 1998, the bids were reviewed and a recommended bidder was identified, but the contract was never awarded. In December 1998, Ontario Hydro informed the bidders that, given the imminent reorganization of the corporation, the final decision regarding the tunnel would be deferred until the reorganization was complete. The final decision on the project was scheduled to be made in July 1999, once the new OPG Board was in place and had an opportunity to consider the matter.

In late June 1999, OPG announced that it had decided to defer construction of the tunnel indefinitely. This decision was based on OPG's limited funding capacity and the desire to proceed with the Pickering A Unit 1 Return to Service before committing to construct the new tunnel. The recommended bidder was informed that if OPG decided to resume the project within two years, it would be prepared to enter into negotiations for an updated tender offer. The recommended bidder confirmed its acceptance of this arrangement.

The cost of the definition phase activities described above was written off by Ontario Hydro prior to the formation of OPG and is not included in the NTP costs covered by this Exhibit. OPG's expenditures on engineering studies for the 1998/99 tender developed information that was subsequently used in the preparation and conduct of the 2004/05 RFP process. As such, these expenditures should have properly been included as project costs, but because they were expensed prior to the NTP, they too are not included in this Application.

2.2.3 Government Direction

In November 2002, the Province announced that it had instructed OPG to proceed with the new tunnel at Niagara to expand the production of green energy. It also introduced related tax incentives that improved the project's economics as discussed below. The Minister of Finance issued a directive to the Ontario Electricity Financing Corporation ("OEFC") to finance the project once the successful proponent had been selected and a proposed contract negotiated.

2.3 Water Rights and Flows

2.3.1 Applicable Legislation

The Niagara River is an international waterway forming part of the boundary between Canada and the United States. It is the natural and principal channel for outflow from Lake Erie to Lake Ontario. The river is about 53 kilometres in length and carries about 96 per cent of the Lake Erie discharge, on average. The Welland Ship Canal provides a secondary discharge channel between these two lakes and carries the remaining 4 per cent.

The *Boundary Waters Treaty* of 1909 between Canada and the United States governs all boundary waters between the two countries, including Lake Erie/Niagara River. The *Niagara Diversion Treaty* of 1950 between Canada and the United States, among other things, provides for the construction of the International Niagara Control Works ("INCW"), determines the priority of use for the waters of the Niagara River and Welland Canal, and sets minimum flow requirements over Niagara Falls.[7]

Each of the *Boundary Waters Treaty* of 1909 and the *Niagara Diversion Treaty* of 1950 continue in perpetuity, but are terminable by either party on 12 months written notice. Given the significance of these treaties to both countries, OPG does not expect either country to exercise its termination rights in the foreseeable future. The *Boundary Waters Treaty* of 1909

[7] Canada and the U.S. have created certain international entities to implement and monitor the *Boundary Waters Treaty* of 1909 and the *Niagara Diversion Treaty* of 1950. The *Boundary Waters Treaty* of 1909 created an international commission called the International Joint Commission ("IJC") to help prevent and resolve disputes over the use of boundary waters between Canada and the United States. The IJC established the International Niagara Board of Control in 1953. The International Niagara Board of Control provides advice on matters related to the IJC's responsibilities for water levels and flows in the Niagara River. The International Niagara Board of Control's main duties are to oversee water level regulation in the Chippawa-Grass Island Pool and the installation of the Lake Erie-Niagara River ice boom. The International Niagara Board of Control also collaborates with the International Niagara Committee, a body created by the *Niagara Diversion Treaty* of 1950 to determine the amount of water available for Niagara Falls and power generation.

and the *Niagara Diversion Treaty* of 1950 grant Canada and the United States equal rights to use Niagara River waters available for power generation.[8]

Through a series of agreements between the Government of Canada and the Province of Ontario, and federal and provincial legislation, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance and operation of generating facilities under the *Boundary Waters Treaty* of 1909 and the *Niagara Diversion Treaty* of 1950.

2.3.2 Available Flows

The natural regulation ability of the Great Lakes results in a relatively stable pattern of discharge from Lake Erie. Based on the historical flow record for the Niagara River at Queenston, with adjustments for diversions to and from the Great Lakes, the average Lake Erie outflow is about 6,000 m^3/s. This total outflow is comprised of an adjusted average Niagara River flow of about 5,800 m^3/s and an adjusted average Welland Canal flow of about 200 m^3/s. Lake Erie discharge is normally highest during May and June and lowest during February.

The available flows in the Niagara River for electricity generation vary depending on hydrologic conditions and the seasonal scenic requirements for Niagara Falls. The *Niagara Diversion Treaty* of 1950 states that 100,000 cfs (2,832 m^3/s) must be allowed to flow over the Falls from 8:00 am to 10:00 pm April 1 to September 15 and from 8:00 am to 8:00 pm September 16 to October 31. At all other times 50,000 cfs (1,416 m^3/s) must be allowed to flow over the Falls. Any flow in excess of these amounts is divided equally between Canada and the United States for hydroelectric production. OPG has the exclusive right to use the Canadian share of the available flow.

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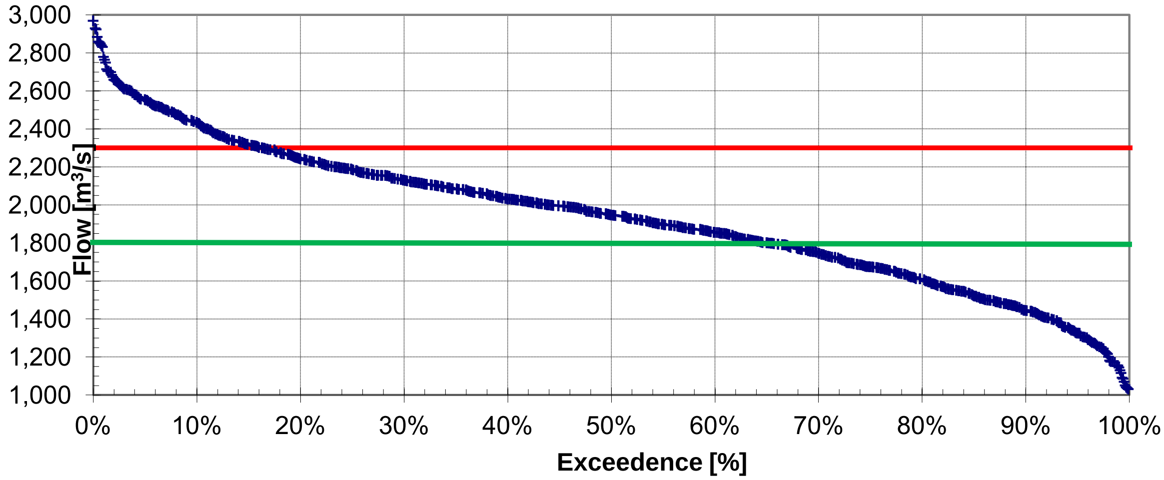
[8] The *Niagara Diversion Treaty* of 1950 recognizes certain diversion waters (5,000 cubic feet per second or approximately 142 cubic metres per second) which are diverted by Canada into the Great Lakes Basin as not being included in the allotment of waters under the provisions of the treaty. This water is diverted from the James Bay watershed by the Ogoki and Long Lac Diversions in northern Ontario to the Niagara system via the upper Great Lakes. This amount is therefore available solely to Canada and is used at OPG's Niagara hydroelectric facilities.

In Figure 2 below, the thick blue line shows the monthly Niagara River flows available to OPG based on historical data from 1926 through 2003. OPG's share of the Niagara River flow ranges from about 600 to 3,000 m^3/s, and averages about 2,000 m^3/s. The diversion capacity for the existing SAB diversion facilities prior to completing the new tunnel (canal and two tunnels) was about 1,800 m^3/s and is shown by the green line in Figure 2. Available flow exceeds the existing capacity about 65 per cent of the time. Completion of the NTP will increase the available diversion capacity to about 2,300 m^3/s, as shown by the red line in Figure 2. With the completion of the NTP, available flow is expected to exceed OPG's diversion capacity only about 15 per cent of the time.

Figure 2 - Niagara River - OPG Entitlement - Monthly Flow Duration Curve (1926-2003)



2.3.3 <u>Niagara Exchange Agreement</u>

The *Niagara Parks Act* (Ontario) assigns the Niagara Parks Commission ("NPC") the authority to grant certain rights to use the waters of the Niagara River for purposes of power generation. In 1892, the NPC granted a franchise agreement to the Canadian Niagara Power Company Limited ("CNP") for the construction and operation of the Rankine Generating Station ("Rankine GS") and for the taking of water from the Niagara River. The current owner of CNP is Fortis Ontario Inc. ("Fortis"). The franchise granted Fortis the right to generate

74.6 MW by taking approximately 283 m^3/s of water from the Niagara River for power production until April 30, 2009. The NPC also granted two other franchise agreements in 1900 and 1903 respectively for Toronto Power Generating Station ("Toronto Power GS") and Ontario Power Generating Station ("Ontario Power GS"). These two stations and their respective franchise agreements came to be owned by OPG.

When the Province approved the construction of SAB 1 and SAB 2, it gave the predecessor of Ontario Hydro the rights and authorities to build, operate and use the waters of the Niagara River under specific legislation passed in 1916, 1917 and 1951. As a result, two parallel systems now exist for the granting of rights to use water from the Niagara and Welland Rivers. The rights granted under NPC's authority are treated as having priority over the SAB rights because these rights were granted first.

Based on the two streams of water power granting authority, there existed ambiguities with regard to water rights at Niagara and the ability of third parties to gain rights to generate power at Niagara.

The negotiations regarding the Niagara Exchange Agreement ("NEA") were initiated by Ontario Hydro in 1998 with NPC and Fortis. In 2003, several agreements were reached between the NPC, Fortis, and OPG in order to secure and protect OPG's water rights on the Niagara and Welland Rivers through 2056. As part of these agreements, OPG was required to transfer ownership of the Toronto Power GS and the Ontario Power GS to NPC to develop the structures for purposes other than hydroelectric generation, including as a visitor attraction. As conditions of the transfer, OPG was required to conduct environmental assessments, perform required environmental remediation and make specific structural improvements to the buildings including removal of equipment, filling of the inner forebay at Toronto Power GS and sealing of the conduits at the Ontario Power GS gatehouse. In accordance with the agreements, Fortis' Rankine station reverted to the NPC at the expiration of the franchise agreement on April 30, 2009.

In consideration of Fortis relinquishing its rights and future claims to water from the Niagara River, Fortis was given access to 74.6 MW of production from OPG, which is equivalent to the permitted output of the Rankine GS, through April 30, 2009 and was to be allowed to purchase three OPG hydroelectric stations on the Trent River: Sills Island GS (2 MW), Frankford GS (3.2 MW) and Sidney GS (4.5 MW).

In order to facilitate this arrangement, on May 1, 2003, the Province issued an Order in Council ("OIC") approving a policy directive for NPC to participate in the above agreements. The policy directive required NPC to:

- not grant or permit any person other than OPG the right to take water from the Niagara River and Welland River for the period beginning on April 22, 2003 and ending in 2056;
- grant OPG rights or interests in lands as are necessary for the construction of the SAB Tunnel on terms and conditions having regard to the Commission and its programs;
- consent to the transfer of Fortis' right to take water from the Niagara River to OPG; and
- accept the transfer of Toronto Power GS and Ontario Power GS in the condition specified in the OIC.

The Province also issued another OIC under which the Lieutenant Governor-in-Council expressly waived its option to extend the Fortis water franchise beyond April 30, 2009.

The parties converted the policy directives into contractual agreements, but these contracts failed to win governmental approval prior to the provincial election in October 2003. Following the election, provincial policy no longer supported the sale or lease of generating assets.

With the option of a sale or lease no longer on the table, the Province and Fortis entered into a series of negotiations, which resulted in a Ministry of Energy direction to OPG to negotiate fair compensation with Fortis for its participation in the NEA. These negotiations resulted in OPG paying $10M as fair compensation on February 18, 2005.

OPG issued an RFP for the environmental, remediation and structural work necessary for the transfer of Toronto Power GS and Ontario Power GS to NPC. While the original budget for the work was estimated at about $10.4M plus a contingency of $2M based on engineering estimates provided by an external consultant, responses to the RFPs came in higher than the estimate due to construction market conditions at that time and the respondents' pricing of the risk allocation in the RFP. Nine companies initially indicated they had a desire to participate in the RFP process and to receive RFP packages, but only two companies submitted proposals. OPG determined that the lack of response from the other contractors was a reflection of the strength of the marketplace, the unique nature of the work, and the perceived risk profile associated with the work.

Following negotiations, OPG ultimately selected Peter Kiewit Sons Co. as the contractor and approved a contract cost of up to $20M. Klohn Crippen Berger Ltd. was selected as the Owner's Representative. Work on the two sites was completed in July 2007 and they were turned over to NPC on August 1, 2007. At $17.8M, the final cost of the work completed by Peter Kiewit Sons Co. was below the approved budget.

The total cost of the NEA was estimated in the original business case summary ("BCS") for the NTP at approximately $32.4M. This amount included all assessment work, the remediation work on the Toronto Power GS and Ontario Power GS and the settlement payment to Fortis, as well as interest and contingency. Table 2 below shows the original budgeted amounts for the NEA work and the amounts ultimately spent.

As shown in Table 2, the ultimate cost of the NEA work was $43.9M. The higher than anticipated costs are found in three areas:

- engineering and project management due to the increased scope and duration of the project;
- construction and remediation because of higher than anticipated bids from contractors due to market conditions at the time of the RFP and allocation of risk to contractor; and

- interest as a result of the additional costs and longer duration of this component and the entire NTP.

Table 2 - Niagara Exchange Agreement Costs

Niagara Tunnel Project Niagara Exchange Agreement Analysis					
	Orginal BCS	Act'l June 30/13	Delta	% Diff	Variance Explanation
NPG Support	202,129.53	162,466.99	(39,662.54)	-20%	Reduced requirement for NPG Contract Monitor
Enviro Consultant	225,000.00	198,508.38	(26,491.62)	-12%	Reduced scope (i.e. eliminated filing Record of Site Condition)
OR/Eng	726,000.00	1,178,116.95	452,116.95	62%	Additional scope and extended duration for the OR/Eng Services
Construction	10,394,858.00	17,826,058.50	7,431,200.50	71%	Market conditions at the time the RFP was issued resulted in higher than estimated proposals.
Remediation	1,000,000.00	500,627.49	(499,372.51)	-50%	Reduced requirement for remediation
Fortis	10,000,000.00	10,000,000.00	0	0%	
Interest	7,777,135.62	14,001,260.42	6,224,124.80	80%	Increased costs associated with Niagara Exchange Agreement work and longer duration for NTP.
Contingency	2,040,304.28	0	(2,040,304.28)	-100%	All contingency spent. Additional variance was funded from other elements of the NTP.
Total	**32,365,427.43**	**43,867,038.73**	**11,501,611.30**	**36%**	

OPG entered into the NEA to assure its exclusive right to use the water from the Niagara River and Welland Canal for power generation through 2056. This assurance contributes to the economic viability of the NTP. As such, all costs associated with the NEA are project development costs because they were incurred to ensure water availability for the NTP. These costs have been capitalized as part of the overall costs of the NTP and are included in the overall amount sought for recovery in this application.

2.4 Geology

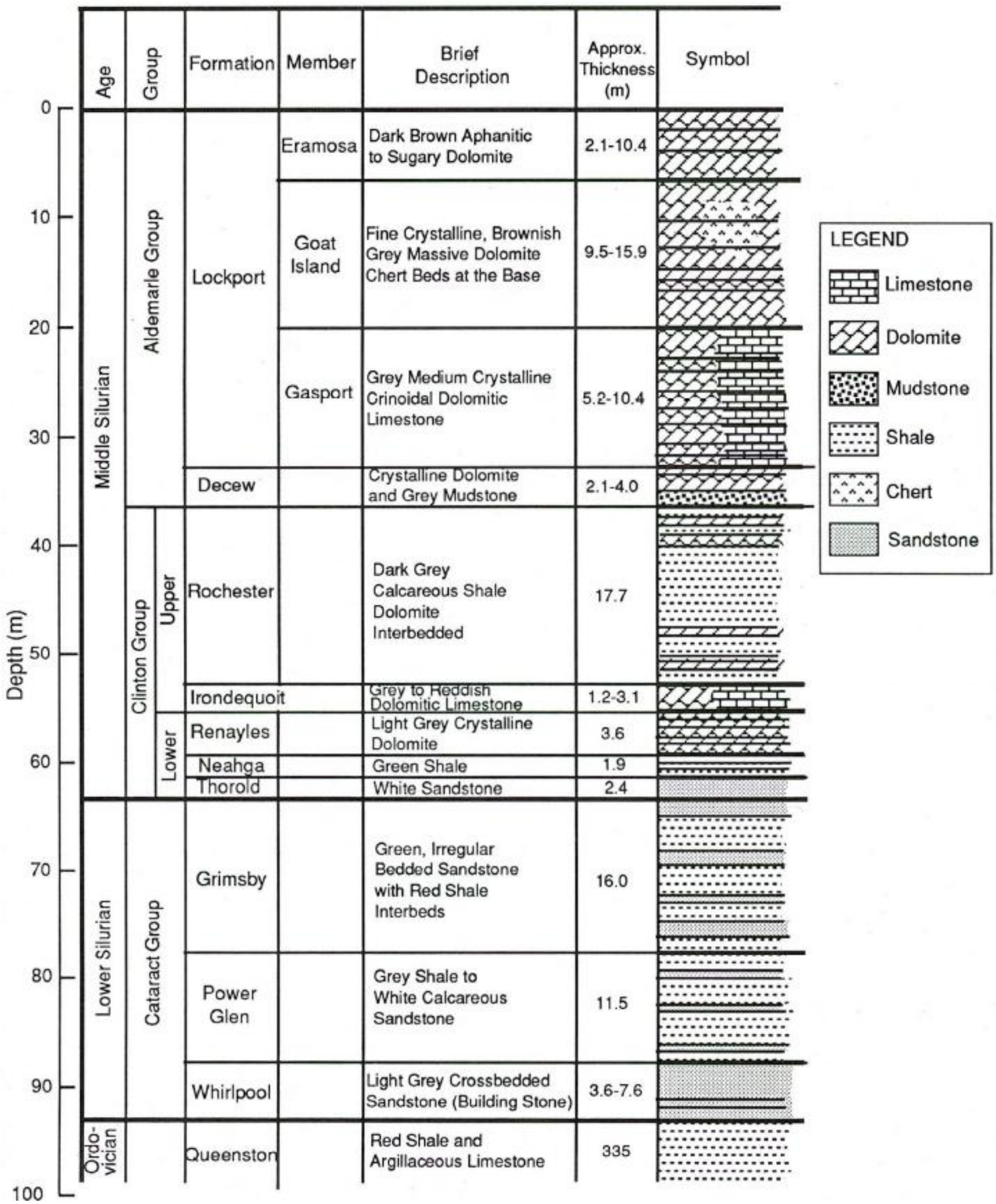
The Niagara Gorge, the largest existing river gorge in southern Ontario, is the dominant geologic feature in the area of the NTP. The gorge is 11 kilometres long stretching from Niagara Falls to Queenston. On average, the gorge is more than 80 metres deep and 150 metres wide. An ancient river ancestral to the present Niagara River cut a gorge similar to that of the current Niagara Gorge. This ancient gorge diverges from the current gorge near the Whirlpool area and cuts through the escarpment considerably to the west of the current gorge, near St. Davids. This part of the ancient gorge, known as the buried St. Davids Gorge (or “St. Davids Gorge”), is estimated to have been 350 to 600 metres wide and up to 200 metres deep. The subsequent glacial period resulted in the plugging of the gorge with sediments and glacial till, leaving little evidence of its presence on the surface. The need to successfully traverse the St. Davids Gorge was a primary determinant of the planned depth of the NTP.

The bedrock underlying the project area and exposed in the Niagara Gorge is a succession of sedimentary rocks of Middle and Lower Silurian and Upper Ordovician age (approximately 400 million years old). The Silurian beds typically have a thickness of about 90 metres, whereas the Ordovician beds are much thicker. The bedrock strata are largely undeformed and dip slightly in a southerly direction. The rocks include dolostones, limestones, sandstones and shales. A typical bedrock sequence as exposed in the Niagara Gorge is shown in Figure 3 below.

The Lower Silurian rocks are of the Cataract Group. The Grimsby formation consists of sandstone interbedded with shale. The Power Glen consists of shale interbedded with sandstone. The Whirlpool formation consists of sandstone with occasional thin shale partings. The lowest strata involved in the NTP are the Upper Ordovician rocks belonging to the Queenston formation.

The Queenston formation, commonly called “shale”, but actually a muddy siltstone, consists of bedded clay with a few argillaceous limestone and sandstone layers. It is characterized by alternating layers of stronger and weaker rock. This red shale layer can reach a thickness of over 300 metres. It weathers readily upon exposure to atmospheric conditions, is prone to slaking and is easily eroded. Queenston shale is commonly used for brick manufacturing in Ontario. The Queenston shale is subject to swelling when exposed to fresh water and contains groundwater that is highly corrosive and aggressive to concrete, containing both chloride and sulphate.

Figure 3 - Simplified Rock Strata Information from Figure 5.4 of the Environmental Assessment



2.5 Environment

As noted earlier, the EA conducted was for the entire NRHD project as conceived by Ontario Hydro in the early 1990s, which included two new tunnels, an underground generating station and new transmission facilities between Niagara Falls and Hamilton. Thus, many of the environmental impacts considered in the EA and the mitigation measures proposed have little relevance to the current NTP. This section discusses the environmental impacts that are related to the tunnel and the mitigation measures adopted for those impacts.

Disposition of excavated materials from the tunnel, particularly non-inert materials containing potentially significant levels of BTEX (Benzene, Toluene, Ethylbenzene and Xylene) was a significant environmental concern. Due to the planned depth of the proposed tunnels and underground powerhouses contemplated at the time of the EA, Ontario Hydro estimated that some 60 per cent of the rock brought to the surface would be Queenston shale that could be reused for brick manufacture. Of the remaining rock, a portion was composed of limestone and dolostone that could be used as aggregate and the rest was to be disposed of in a nearby quarry. The EA approval required Ontario Hydro to develop plans for the management of excavated materials and for the management of any contaminants (i.e., BTEX) prior to commencing the project.

Ontario Hydro also was required to monitor groundwater flows along the tunnel route as a condition of EA approval. Other approval conditions included:

- a study of potential impact on the Welland River and suggested mitigation;
- a study of run-off and sedimentation impacts on the Niagara River;
- a study of impacts on fisheries and aquatic habitat and mitigation as necessary; and
- a requirement to control the noise emitted from the project.

All of these studies and any resulting mitigation measures found necessary had to be accepted or approved by the responsible agencies before construction could commence.

2.6 Community Impact Agreement

In December of 1993, Ontario Hydro reached a Community Impact Agreement with the Regional Municipality of Niagara ("Regional Municipality"), the Town of Niagara-On-The-Lake ("NOTL") and the City of Niagara Falls (collectively, "the municipalities") to mitigate the predicted impacts of the construction of the NRHD on tourism, roads, domestic water supply, and sewage treatment. This agreement was negotiated pursuant to Ontario Hydro's commitment to mitigate the impacts identified in the EA.

The agreement provided that the municipalities would grant all local permits necessary for construction of the NRHD. In exchange, Ontario Hydro was required to:

- consider local planning requirements in developing the NRHD;
- consult with the municipalities on an ongoing basis;
- address complaints from residents impacted by the project;
- fund improvements and maintenance for roads impacted by construction traffic;
- provide funds to mitigate impacts on sewage treatment facilities;
- procure emergency services from the municipalities where practical and cost effective; and
- seek opportunities to enhance local economic benefits including provisions for engagement of local contractors, suppliers and labour.

The agreement also required Ontario Hydro to compensate the municipalities for the costs of monitoring the agreement.

In August 2005, OPG negotiated certain amendments to the agreement. These amendments confirmed that OPG was the successor to Ontario Hydro and modified the parties' obligations in recognition of the fact that the project would be constructed in phases, with Phase One consisting of the NTP. OPG's compensation payments related to sewage services were cut in half to reflect the reduced scope of Phase One. Pursuant to the original agreement, OPG applied escalation at the Ontario Consumer Price Index to the original compensation amount less the negotiated reductions. The resulting payments totaling $7.87M were made in October 2005 after the project received final approval.[9]

On June 19, 2013, OPG and the municipalities agreed to a further amendment to the agreement to allow the Regional Municipality to apply the remaining funds toward the rehabilitation of Stanley Avenue from Thorold Stone Road north to Whirlpool Road. No additional money was paid by OPG as a consequence of this amendment.

3.0 CONTRACTING PROCESS

3.1 Design Build

Undertaking the NTP required OPG to obtain specialized external expertise in tunnel design and construction because such activities are not part of OPG's normal business activities. The two major approaches for contracting large complex projects, such as the NTP, are Design-Build and Design-Bid-Build. In basic terms, under Design-Build, the project owner hires a single firm to design and construct a project that meets the owner's pre-established requirements. Under Design-Bid-Build, the owner, using internal or external design expertise, prepares detailed design and construction specifications and then hires a firm to construct the project according to the approved design and specifications.

OPG selected the Design-Build approach for the NTP as the preferred risk management strategy to:

- minimize project duration;
- capture tunnel contractor experience and innovations;
- fully integrate construction methods and constructability into the design;
- appropriately allocate project risks; and
- obtain as much upfront price certainty as possible.

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[9] Some earlier payments had been made by Ontario Hydro in the mid-1990s, but these were written off prior to the formation of OPG and do not form part of the project costs sought for recovery.

The Design-Build approach also provided OPG with single-point accountability for project execution because the Design-Build team provides all required services including coordination, design, permitting, procurement and construction. OPG had previously selected the Design-Build approach in the 1998 - 1999 RFP process for design and construction of the Niagara Tunnel.

In contrast, under the Design-Bid-Build approach, OPG would have first needed to engage a firm to design the NTP. By hiring separate contractors, initially for design and subsequently for construction, OPG would have foregone the schedule and communication interface benefits of having an integrated team execute both the design and construction. Bidding and award of the construction contract would have been delayed while OPG first held a competitive process to engage a design contractor and then had that contractor prepare the design, drawings and specifications necessary to put the project out to construction bids. In addition, under this approach, the ability of the construction contractor to innovate with respect to construction methods would have been constrained by the need to adhere to the independently prepared design.

Not only would the Design-Bid-Build approach have been slower due to the sequential procurement and execution of the design followed by a second procurement and execution of the construction, but engaging in two separate procurement processes likely would have increased overall cost. Under Design-Bid-Build, OPG also would have retained the risks associated with ongoing management of the interface between the design contractor and the construction contractor.

3.2 Pre-qualification

On June 24, 2004, OPG Board approved the recommendation to proceed with the NTP including a preliminary release of $10M to conduct a RFP process and to carry out such pre-construction activities as OPG deemed necessary. On June 25, 2004, the Province of Ontario endorsed the decision by OPG Board to proceed with the NTP. Based on OPG Board's approval, OPG commenced a RFP process in July 2004 by inviting submission of expressions of interest for pre-qualification, which were due in September 2004. Seven submissions were received, evaluated and ranked, following which OPG invited the five highest ranked firms to meet. The invited proponents were:

- Niagara Tunnel Constructors
- Peter Kiewit Sons
- Niagara Tunnelers
- Strabag AG
- Ed. Zublin AG

These five proponents were provided with the following documents:

- a summary of work on the project;
- Instructions to Proponents;
- Draft Contract Terms & Conditions; and
- Geotechnical Baseline Report.

They were then invited to present their views on these documents, their proposed project team, qualifications and their risk management approach to an OPG evaluation team. Members of the OPG evaluation team included the Major Projects Committee (“MPC”) of the OPG Board, OPG management and a member of Hatch Mott MacDonald (“Hatch”), the firm that OPG retained to act as its Owner’s Representative (“OR”). Both the Chairman of OPG Board and the President of OPG were present at each meeting. Proponents were encouraged to give candid feedback on various aspects of OPG’s proposed approach.

The five proponents met with OPG in Toronto in late fall 2004. Each proponent was allowed 3 hours to present its team and to provide initial comments on the documents previously provided to them by OPG. These documents were selected to describe the project, the proposed contracting approach and OPG’s proposed allocation of risk.

All proponents generally accepted the contracting approach proposed by OPG including risk allocation, although they qualified this acceptance because they had not seen the specific form of contract (i.e., Terms & Conditions). All proponents believed, based on what they had seen to-date, that sufficient geotechnical investigation had been undertaken by OPG and requested that all related documentation be provided to them at the proposal stage. All proponents generally endorsed the proposed three-part Geotechnical Baseline Report ("GBR") approach for establishing a contractual baseline for sub-surface hydro-geological conditions. Under this approach, the RFP would include OPG's GBR ("GBR A"); the respondents would include their proposed modifications to the GBR as part of their proposals ("GBR B"); and the final GBR ("GBR C") would be negotiated as part of the contract.

Four of the proponents endorsed the general configuration of the project and stated that a tunnel of the size contemplated (about 12.5 metres internal diameter), although at the upper end of then current technology, was achievable. The remaining proponent (Ed. Zublin AG) was of the opinion that, considering other site factors, building such a large tunnel would be a significant challenge. In a subsequent memo, all proponents were invited to identify items that they wish to see addressed or clarified in the contract documentation.

Following the presentations, OPG reviewed the strengths and weaknesses of the various proponents. Consensus was reached that four proponents should be invited to submit proposals. The OPG Evaluation Team recommended, and the OPG Board approved, inviting all of the respondents except Ed. Zublin AG to submit proposals. Based on its qualifications and responses at the proponents' meeting, OPG concluded that Ed. Zublin AG had insufficient experience compared to the other proponents in the areas of tunnel design and construction.

OPG determined that having at least four proponents in the next phase was desirable because of the likelihood that not all of them would submit a proposal. At least two, and preferably three, proposals would be necessary to ensure sufficient competitiveness and to enable an effective negotiation phase. OPG also approved payment of a $600k honorarium to each unsuccessful firm submitting a conforming proposal. Such honorariums are frequently used on large complex projects such as the NTP to partially defray the cost of preparing proposals. Proposal preparation for a project of this size and complexity requires a significant investment of time to properly complete the necessary design drawings and engineering specifications. OPG concluded that offering an honorarium to the unsuccessful firms would likely result in receiving more and better quality responses to the RFP.[10]

3.3 Risk Assessment

In November of 2004, OPG retained URS Corporation ("URS") to perform both qualitative and quantitative risk assessments of the NTP. The scope of the URS work included identification, assessment and presentation of NTP risks in a way that provided the groundwork for the risk management methods used as the NTP proceeded. URS analyzed the NTP within an overall risk management framework provided by the Code of Practice for Risk Management of Tunnel Works.[11]

The initial URS report covered qualitative risk assessment, and included identification and assessment of project risks. This work was undertaken jointly with OPG and Hatch subject matter experts drawn from the NTP project team. A three-day workshop was conducted to validate the list of identified risks and assess their likelihood and consequences.

URS assembled the resulting information into an initial high-level risk register, which collected and organized the risks identified. The risk register also indicated the party responsible for control and management of each risk, as well as contingency plans and measures for risk mitigation that had been identified, but not yet implemented. The risks and consequences are first presented as "inherent risks" without mitigation and then shown as "residual risks" remaining after mitigation. The risk register was designed and implemented

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[10] The Ontario contractors industry, including the Ontario Association of Architects, the Ontario General Contractors Association and the Canadian Design Build Institute, have strongly endorsed the practice of honorariums when procurement of complex projects are done through the Design Build process. The Government of Ontario's Infrastructure Ontario has included this process in its project tenders.

[11] This code was issued by The International Tunnelling Insurance Group "to promote and secure best practice for the minimisation and management of risks associated with the design and construction of tunnels." It can be found at http://www.imia.com/downloads/external_papers/EP24_2006.pdf.

as a living document that would be frequently updated as the project moved from conceptualization to completion.

Following the completion of the qualitative risk assessment, URS undertook the quantitative assessment. The quantitative assessment was performed using a Monte Carlo simulation based analysis. The methodology consisted of identifying the conceivable hazards that could occur during the project, and assessing a probability of occurrence for each hazard as well as their potential cost and schedule impacts. The probabilities and consequences were then combined to identify potential outcomes in 5,000 scenarios for the project and to obtain probability distributions of possible outcomes. Based on these distributions, the probability, cost and schedule values were established by members of an expert panel, which included NTP team members from OPG and Hatch. The expert panel's efforts were facilitated by URS. The analysis only addressed the costs and risks impacts for the project (i.e., to the time of commissioning) and did not include risks associated with post-project operation.

As both the qualitative and quantitative risk evaluations undertaken by URS were done prior to completing the solicitation for a design-build contractor, OPG recognized the need to update the quantitative risk evaluation once the final proposals were received from the design-build proponents. This update was undertaken by an expert panel of NTP team members consisting of personnel from OPG, Hatch and Torys LLP ("Torys"), OPG's external legal counsel. It was completed on July 27, 2005, the day before the selection of the successful proponent was approved by the OPG Board. OPG used the model that had been developed by URS and updated it to:

- confirm analytical assumptions and numerical inputs;
- add any additional hazards identified and remove any that were no longer relevant; and
- reflect any differences among the proposals submitted.

In the OPG update, the top two contributors to potential cost increases were: 1) "Dispute Review Board interpretation of Agreement unfavourable" and 2) "DSC [Differing Subsurface Conditions] claim due to rock strength." These same two factors, in reverse order, were also identified as the top two contributors to potential schedule delay for which OPG, rather than the contractor, would be responsible. Based on the results of the updated quantitative risk assessment model, OPG estimated that for the tunnel construction portion of Strabag's proposal, a \$96M cost contingency and a 36 week schedule contingency were required to achieve a 90 per cent probability that the project would remain within its budget and schedule.[12] OPG then determined the overall cost contingency to be \$112M for the project as a whole.

3.4 Invitation to Submit Design-Build Proposals

In late December 2004 invitations to respond to the RFP were sent to the four firms identified in the preceding section with the proposals due on April 15, 2005. The RFP consisted of three volumes: the first contained the invitation letter, instructions, the draft DBA and various appendices; the second volume contained concept drawings; and the third contained construction labour agreements from the Electrical Power Systems Construction Association ("EPSCA"). The RFP requested that the proponents return a form indicating whether they would be submitting a proposal.

Three of the four invitees, namely Niagara Tunnel Constructors, Niagara Tunnelers and Strabag AG, indicated that they would submit a proposal. In January 2005, these three proponents participated in a mandatory site visit. In association with the visit, the proponents also reviewed background documents in a data room that had been established by OPG near the project site.

Amendments to the invitation documents were distributed starting February 2005. In total, five amendments were issued reflecting changes made in response to questions or issues raised by the proponents. Based on a request from all three proponents, the deadline for

[12] As noted in the OPG risk update (page 2): "The schedule contingency only took into consideration OPG-accountable schedule risks, as the DBA compensated OPG for contractor-accountable delays through the payment of Liquidated Damages. Moreover, the schedule contingency assumed that the project schedule, which was set by the contractor, included some contingency as determined by the contractor."

submitting proposals was extended from April 15 to May 13, 2005 on the understanding that no further extensions would be authorized.

3.5 Proposal Evaluation and Negotiation

OPG prepared a detailed evaluation process as described in the first sub-section below. The second sub-section discusses the actual evaluation of the proposals received and the negotiations with the various proponents to refine the proposals prior to selecting the successful firm.

3.5.1 Evaluation/Negotiation Process Overview

OPG used a structured evaluation process developed jointly with the OR to evaluate the three proposals submitted. The Evaluation Team consisted of experienced personnel from OPG, Hatch and Torys. The team used evaluation criteria and scoring that were established for this project based on input from the both OPG and external members of the project team and documented before the proposals were received. A summary of the evaluation categories and their relative scoring is shown in

Table **3** below.

Table 3 - Evaluation Categories and Scoring

Summary Evaluation Categories	**Score (#)**	**Percent (%)**
Compliance with Owner's Mandatory Requirements	Yes/ No	Yes/ No
Design & Construction Approach	80	16%
Response to GBR	45	9%
Price/Schedule/Flow Guarantee	150	30%
Adherence to Invitation and Agreement	45	9%
Risk Management Approach/Impact on OPG Risk Profile	65	13%
Project Team & Key Personnel	45	9%
Preliminary Project-Specific Safety/Security/Emergency Plans	35	7%
Environmental Compliance Plan and QA/QC Program	35	7%
Total	**500**	**100%**

The technical aspects of the proposal were scored by the Technical Evaluation team whose members were experienced in areas such as construction, hydraulics, tunneling and geotechnical analysis. The proposals' commercial aspects were scored by the Commercial Evaluation team whose expertise included procurement, risk analysis, legal and financial analysis. Each team had a lead responsible for coordinating activities and ensuring adherence to the evaluation process. Each team worked independently so that the technical and commercial issues were evaluated on their own merits. The two teams together comprised the Evaluation Team.

The evaluation process was designed to ensure that all proposals received a complete, fair and unbiased review. During the initial evaluations, the proposals were given code names [Fox (Niagara Tunnel Constructors), Bear (Niagara Tunnelers) and Moose (Strabag)] so that the evaluators did not know which company's proposal they were reviewing.[13] Legal advice regarding the evaluation process was obtained from both OPG internal counsel and Torys on an ongoing basis.

A Steering Committee was established to provide oversight of the Evaluation Team. The Steering Committee consisted of the Project Sponsor (OPG Senior Vice President), the Project Director (OPG Vice President) and the OR Project Manager. The Steering Committee's role was to oversee the evaluation process by reviewing Evaluation Team activities and discussing the evaluations with the team. This process served as an additional check that the evaluations were comprehensive and conducted in a fair and unbiased manner. The Steering Committee worked in parallel with the Evaluation Team and reviewed key areas of the proposals identified by the Evaluation Team. The Steering Committee was responsible for recommending the successful proponent to the MPC, which, after reviewing

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[13] The proponents were as follows:

- <u>Niagara Tunnel Constructors</u> made up of Hochtief (50%), Aecon (20%) and Vinci (30%) with engineering by Hochtief & Klohn Crippen
- <u>Niagara Tunnelers</u> made up of Obayashi (80%) and Kenaidan (20%) with engineering by Jacobs, Black & Veatch and Golder Associates
- <u>Strabag AG</u> made up of Strabag (100%) with Dufferin as subcontractor and engineering by ILF and Morrison Hershfield

and confirming the selection, sought approval of the recommendation from the full OPG Board.

During the evaluation process OPG met with the various proponents in order to clarify the proposals. Once the initial evaluations were complete, OPG negotiated separately with each of the proponents in order refine the proposals so as to obtain the 'best value' proposal from each proponent. Additional information and proposal modifications produced during the negotiations were used to re-tabulate the evaluation scores. The evaluation criteria used during the negotiation phase were those used in the evaluation phase. A Negotiating Team comprised of OPG staff from the Evaluation Team and the Steering Committee, the OR Project Manager and legal counsel represented OPG in the negotiations.

3.5.2 Proposal Evaluation/Negotiation

A chronology of the evaluation/negotiation process is presented in Table 4 below.

Table 4 - Evaluation / Negotiation Process Chronology

Activity	Date
Proposals received by OPG	May 13, 2005
Proposals received by evaluation team	May15, 2005
Clarification meetings with Proponents	May 24 to 26, 2005
Decision to negotiate with three Proponents	May 29, 2005
Negotiation meetings with all Proponents	June 15 to July 9, 2005
Negotiation meetings with two leading Proponents	July 14 to 15, 2005
Final scoring of two leading proposals	July 17, 2005
Recommendation for Award (to MPC)	July 28, 2005
Recommendation for Award (to OPG Board)	July 28, 2005

In the initial stages of the evaluation, each member of the Technical and Commercial Evaluation teams performed his or her evaluations independently without consulting with other team members. The OR Project Manager ensured that the same Evaluation Team member evaluated the same areas in each proposal. The OR Project Manager also obtained additional information from each proponent as required by the Evaluation Team and Steering Committee and distributed this additional information to all members of the Evaluation Team.

After completion of independent evaluations, the OR Project Manager convened separate meetings of the Technical and Commercial Evaluation teams to discuss scoring of the proposals. The OR Project Manager reviewed the scoring criteria and then asked attendees to present and discuss their scoring in the key areas of concern in an attempt to reach a consensus score. The OR Project Manager recorded the consensus score for each of the evaluation criteria on a consolidated evaluation form.

The Steering Committee reviewed the evaluation results and requested justification from members of the Evaluation Team as appropriate. Once the Steering Committee was satisfied that the evaluation procedure was followed, well documented and that each proposal was evaluated fairly and without prejudice, the Steering Committee recommended proceeding to negotiations with all three parties. The Steering Committee also kept the MPC apprised of the negotiations through verbal updates.

Between May 29 and July 17, 2005, the evaluation scores were tabulated several times as additional information became available in the course of the negotiations. The scoring at the end of the July 12th tabulation had Strabag and Niagara Tunnel Constructors within 2 per cent of each other (with Niagara Tunnel Constructors in the lead) and Niagara Tunnelers about 8 per cent behind. Based on these standings, the Evaluation Team agreed to restrict the final round of negotiations to Strabag and Niagara Tunnel Constructors, the two highest scoring proponents.

Final negotiation meetings were held on July 14 and 15, 2005 with Niagara Tunnel Constructors and Strabag, respectively. At these meetings the two proponents were required to respond to a number of questions on details of their proposals and also to ensure attendance of the key individuals who would work on the project. Each of these key people was interviewed by the Negotiating Team. Following these meetings, the Evaluation Team met to re-tabulate scores. The results of the re-tabulation had Strabag and Niagara Tunnel Constructors with virtually the same score. The two were separated by less than 0.4 per cent, with Strabag leading.

To break this virtual tie, the Evaluation Team agreed that each of the eight core team members who were present at the final scoring meeting would be polled on which proponent should be awarded the contract. The eight members were asked to write their recommendations on a slip of paper that was provided to the OR Project Manager. The OR Project Manager then randomly selected the slips of paper representing each member's selection at which point each in turn was asked to explain his or her choice of proponent. The results of the polling yielded a 5 to 3 margin in favour of Strabag. After the polling was complete, members of the Evaluation Team were asked individually if they had any significant reservations about recommending Strabag. None of the members, including the three who voted for Niagara Tunnel Constructors, expressed any concerns about selecting Strabag.

On this basis, the Evaluation Team recommended that Strabag be awarded the contract for the NTP. The Steering Committee concurred with this recommendation and presented it to the MPC on July 28, 2005. The MPC discussed this recommendation with the Steering Committee before deciding to endorse it to the entire OPG Board. The OPG Board approved the award of the contract to Strabag subject to OPG arranging satisfactory financing. OPG then proceeded to enter into contract negotiations with Strabag.[14]

3.6 Contract Approval

Between late July and mid-August 2005, OPG and Strabag undertook an intensive period of negotiation to finalize contract details. During this period, OPG and Strabag agreed on all contract provisions including the final details of the GBR, financial security and contract pricing. Once the negotiations were concluded, OPG waited for final confirmation of project financing from the Ontario Government before the agreement was signed. On August 18,

[14] Per the terms of the RFP, the two unsuccessful bidders were each paid $600k in October 2005.

2005, the Minister of Finance issued a Directive to the OEFC to lend OPG up to $1B for construction of the NTP. The DBA was signed that same day.

4.0 PROJECT BUSINESS CASE AND BUDGET

As part of its approval process for the project, OPG prepared a Full Release Business Case that was reviewed and approved by OPG Senior Management and OPG Board in August 2005. The Business Case package presented to the OPG Board contained:

- a recommendation and executive summary;
- a Business Case Summary (“BCS”), which discussed the project history, issues, risks execution and management, alternatives, and financial analysis; and
- Appendices including a Release Quality Estimate (“RQE”) showing a detailed project budget from inception to conclusion; financial modelling assumptions and a tabular risk profile including consequences and mitigation measures.

These documents are all included in the CD of NTP Key Documents accompanying this Exhibit.

Prior to presenting this material to the full OPG Board, the MPC had undertaken a more detailed review of the financial analysis underlying the project. This review involved several presentations on:

- financial assessment of the project including the impact of rate regulation;
- the model used to analyze the project including the assumptions underlying the model and its operation;
- the modeling used to develop the estimate of incremental energy production from the project;
- the risk matrix developed for the project including risks, consequences and mitigation; and
- the Project Definition Rating Index (“PDRI”) developed by the Construction Industry Institute.

To confirm the results of the financial analysis, management obtained an independent third-party assessment. This assessment, done by Access Capital, was presented to the MPC prior to recommending approval of the project to OPG Board. The assessment concluded that OPG's financial analysis team was proficient, and that the financial model produced accurate, verifiable results and correct calculations of various costs. The Access Capital report noted that the 90-year life of the project was longer than would be typically used for evaluating power projects, but that it was consistent with the project's design life, and, in any event, OPG's model allowed for analyzing shorter lives. The report also noted that the potential variability in available water would make private financing of this project difficult without mitigation or a significant reserve, but noted that the existence of rate regulation with a variance account to recognize the impacts of both favourable and adverse water conditions would mitigate this risk.

The BCS also included the results of the sensitivity analyses, which were undertaken to test the impacts of alternative assumptions. Among the assumptions tested were:

- periods of high and low water availability (based on the upper and lower quartiles of historical water availability, respectively) during the project's first five years of operation;
- an overall five per cent decline in available water from historical levels throughout the 90-year life of the NTP;
- ten percent higher cost;
- a service life of 30 years; and
- elimination of the 10-year Gross Revenue Charge ("GRC") payment holiday.

Under most of these scenarios, the project remained competitive with the 8 cents/kWh price, then used as a proxy for the price of renewable energy alternatives.

5.0 DESIGN-BUILD AGREEMENT

The DBA between OPG and Strabag was signed on August 18, 2005. An electronic copy of the DBA is included in the CD of NTP Key Documents accompanying this Exhibit. It remained in effect until December 1, 2008, the effective date of the Amended Design Build

Agreement ("ADBA") as discussed below. The DBA consisted of a main agreement and numerous appendices, which together set out the terms that governed Strabag's construction of the project and OPG's requirements and payment for this work. This section summarizes the major provisions of the DBA.

The main body of the DBA specified that the intake canal and structure, tunnel, outlet canal and structure, and associated facilities comprise the project. It provided that Strabag will construct these facilities in accordance with the DBA (including the Owner's Mandatory Requirements, the Contractor's Proposal Documents, Final Submittals, Applicable Law and other terms of the agreement) and good industry practices. It contained a date for Substantial Completion of the project, which is defined as the date the tunnel is ready for its intended use with water flowing through it. GBR C formed part of the DBA and is the basis on which any claims for differing subsurface conditions ("DSC") were to be assessed. The DBA explicitly allocated risk between OPG and Strabag in a manner that both parties accepted on an informed basis. It also specified that OPG would not supervise or direct Strabag's means and methods of completing the project.

The DBA (Section 11.1) provided for the establishment of a Dispute Review Board ("DRB") to assist OPG and Strabag in resolving any performance disputes that were not resolved by good faith negotiation. Once a dispute was referred to the DRB, it was charged with preparing fully reasoned written recommendations on an appropriate resolution. The parties could either accept the recommendations or either party could indicate its rejection by giving the other party notice of its intent to take the matter to arbitration under the Rule of Arbitration of the International Chamber of Commerce.[15] Recommendations not rejected by notice within 30 days were to be deemed accepted by both parties.

In the DBA, Strabag warranted that it had the requisite experience and qualifications to successfully complete the project and that it would only engage competent and qualified sub-

[15] The DBA originally provided that a dissatisfied party could seek judicial review rather than arbitration, but this was changed in Amendment 1 made on March 15, 2006. Amendment 1 also substantially modified the operation of the DRB.

contractors. Strabag also represented that it prepared its proposal documents with the same care and skill that would be applied by leading professional engineers in Canada and the United States for a similar type of project. The DBA named certain key project personnel that could not be changed without OPG's approval. Furthermore, the DBA identified that worker and public safety are primary goals of the project. It also required Strabag to protect the environment and to meet all of the conditions of approval in the project's EA.

In terms of financial security, the DBA required that Strabag provide one or more letter(s) of credit in a total amount of not less than $70M. Strabag was also required to provide parental indemnities guaranteeing its performance and indemnifying OPG for any damages resulting from a breach by Strabag. Prior to Final Completion of the project as determined under the DBA, Strabag was required to deliver a maintenance bond of 10 per cent of the contract price. This bond remains in force until the end of the warranty period, which is one year following the date of Substantial Completion, but may be extended if any defects require correction during the warranty period.

The DBA additionally required Strabag to procure and maintain the following insurance: worker's compensation coverage, motor vehicle liability ($5M), errors and omissions ($10M), and, as required, marine watercraft hull and liability ($25M). Strabag was required to self-insure for construction equipment. OPG was required to procure and maintain builders' all risk insurance ($80M), wrap-up liability insurance ($25M) and, as required, marine cargo insurance.

Finally, the DBA contained certain bonus and liquidated damages clauses that recognized the benefits of early completion and the costs of delay, respectively, and the possibility that the tunnel would deliver greater or lesser flow than the contract required. The DBA provided Strabag an incentive of $125,000 during the period November to March inclusive and $90,000 during the period April to October inclusive for each complete day that actual Substantial Completion occurred before the contracted date. For each complete day that actual Substantial Completion occurred after the contracted date Strabag was obligated to pay OPG liquidated damages of $250,000, from November to March inclusive, and $180,000, from April to October inclusive. If flow testing revealed that the tunnel delivered more than the contracted flow (500 m^3/s $\pm$2 per cent for measurement error), OPG was to pay a bonus based on a sliding scale established in the contract. Similarly, if the tunnel delivered less than the contracted flow, Strabag was obligated to pay graduated liquidated damages. The liquidated damages amounts are twice the bonus amounts. In any event, the total liquidated damages or bonus from all provisions could not exceed 20 per cent of the contract price.

The DBA contained numerous appendices that form part of the agreement. Among the most significant were:

- Appendix 1.1 (j), which established the contract price of $622.6M by major components, the major items being a) the diversion tunnel at $406.9M, b) the TBM at $78.2M, and c) the Intake Channel, Accelerating Wall and Approach Wall at $54.9M;
- Appendix 1.1(t), which contained the specifications for the TBM;
- Appendix 1.1 (vv), which set out the Owner's mandatory requirements, including that the primary elements of the Niagara Tunnel Facility Project were required to be designed and constructed for a service life of 90 years with no tunnel outages during that time, and that Strabag was required to install, test and commission a new high-powered TBM suitable for safely excavating in the ground conditions as described in the GBR;
- Appendix 1.1 (sss), which summarized all of the work that the contractor is expected to perform;
- Appendix 2.2(a), which presented an organization chart of the contractor's personnel showing the key personnel that require OPG approval for changes;
- Appendix 2.4(d), which presented the safety and security plans;
- Appendix 2.12(c2), which showed an outline of Strabag's Quality Assurance/Quality Control programs;
- Appendix 5.4, which was the GBR underlying the contract; and
- Appendix 11.1(a), which was the Dispute Review Board Agreement.

6.0 CONSTRUCTION UNDER THE DESIGN-BUILD AGREEMENT

6.1 Project Documentation

6.1.1 Project Charter

The Project Charter sets out at a high level the need and justification for the project, as well as its objectives, deliverables, budget, management approach and the authority of the OPG Project Director. It is included as Appendix A to the Project Execution Plan, which is found in the CD of NTP Key Documents accompanying this Exhibit. The Project Charter was signed by the Project Sponsor, the OPG Project Director and the Manager of the Niagara Plant Group ("NPG") as the ultimate customer for the project.

6.1.2 Project Execution Plan

The Project Execution Plan ("PEP") is OPG's guiding document for the NTP. Its purpose is to identify, define and categorize the issues that are key to project success as early as possible, and to provide the project team members, end users and line authority with a common understanding of the project and how it will be executed. The PEP was developed in consultation with the project team members. It identifies project objectives, scope, responsibilities, strategies, constraints, processes and mechanisms to be employed in management of the project.

The PEP has been regularly reviewed and updated as necessary during the execution of the NTP. Version 0 was prepared and signed during Phase One of the NTP, the planning and procurement phase, which covered the development and release of the RFP, the evaluation of proposals, negotiation with proponents, the negotiation of the DBA with Strabag and the approval of the project by OPG Board. Phase One commenced in June 2004 and was completed in August 2005 when the contract with Strabag was signed.

PEP Revision 1 incorporates the activities in Phase Two of the NTP, the construction and commissioning phase, which covers detailed design, the construction of all elements of the NTP under the DBA, and the work necessary to place the facility into service. PEP Revision 2 covers construction of the NTP under the Amended Design Build Agreement, discussed below, which was negotiated with Strabag following release of the Dispute Review Board recommendations. Revision 3 addresses the strategies and procedures that will be employed for the completion, closeout and turnover of the project. It also incorporates changes as a result of the revised OPG Risk Management Plan (discussed below) and the execution of the first amendment under the ADBA. Organizational changes at OPG are also reflected in the third revision of the PEP. Included in the CD of NTP Key Documents accompanying this Exhibit are the four full revisions of the PEP.

The OR, as Project Manager, is responsible for developing and maintaining the PEP in consultation with the project participants. Each section of the PEP has an owner (listed in PEP Appendix B) who is responsible for recommending updates to that section for submission to the OR. Project execution is periodically audited against the PEP by the Project Director to ensure that the plan is being followed and updated as necessary.

The PEP establishes the following objectives for the project:

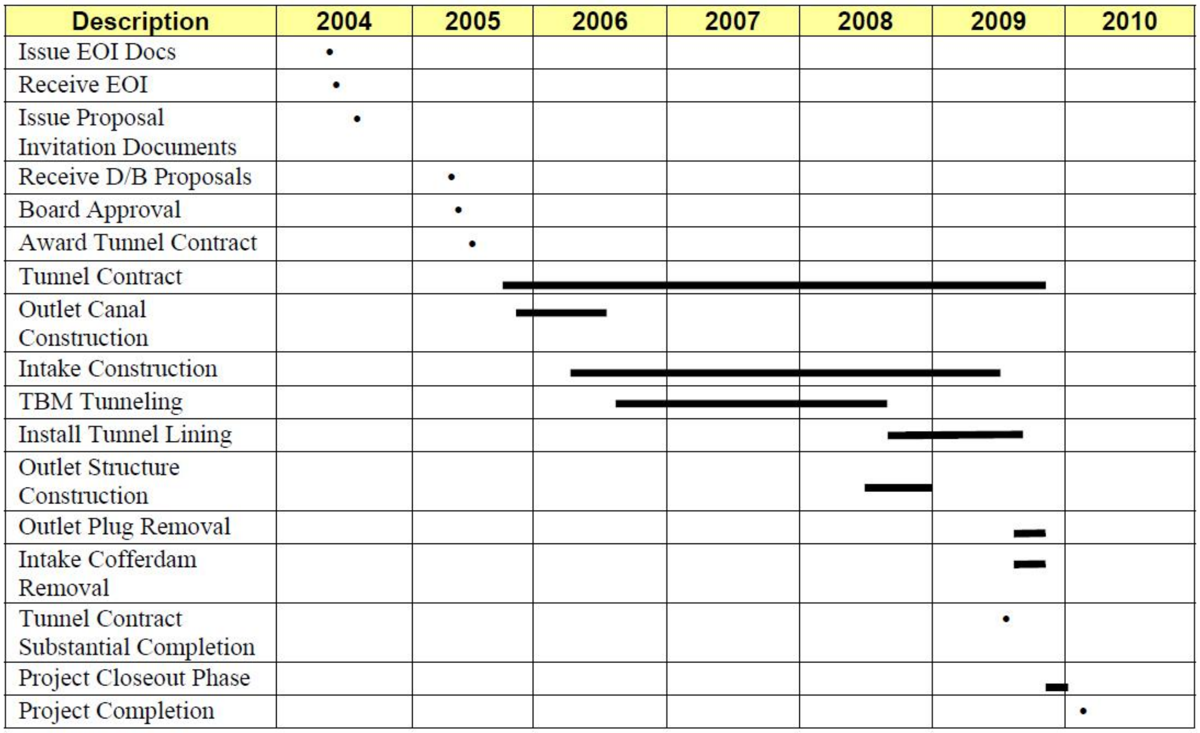
- Safety – The project's primary objective is safety, with the goal being to complete the Project without fatalities, critical injuries and lost time injuries, and to maintain public safety.
- Environmental Protection – The NTP must meet the commitments contained in the EA, the conditions of the EA approval, and all legislated environmental and mitigation requirements.
- Quality – The design and construction must meet all specified performance requirements, including a 90-year service life without any outages for key elements of the facility including the tunnel, intake structure and outlet structure. The project must also deliver the Guaranteed Flow (500 m^3/s) or the contractor will have to pay liquidated damages.
- Cost and Schedule – the project is to be maintained within the approved schedule and budget.

The PEP contains a project scope (shown in Section 3 of the PEP) that organizes all the activities of the project. The major breakdown is:

- Third Party Requirements, which includes work on environmental commitments, permits and community impact agreement elements;
- Tunnel Contract, which refers to the selection of the design-build contractor and negotiation of the contract;
- Tunnel Construction, which encompasses the construction of the intake structure and channel, the tunnel and the outlet structure and canal;
- Enabling Activities and Miscellaneous Construction, which covers work on sub-surface rights, rights of way, road improvements and associated survey activities; and
- Project Management, which relates to plans, schedules, approvals and other project management activities performed by the OPG Project Director or the OR Project Manager.

The PEP also contains a summary schedule which presents a breakdown of the project milestones and major construction activities. Figure 4 below shows the schedule from the PEP Revision 1, as of March 27, 2006.

Figure 4 - Schedule from PEP Revision 1 (March 27, 2006)

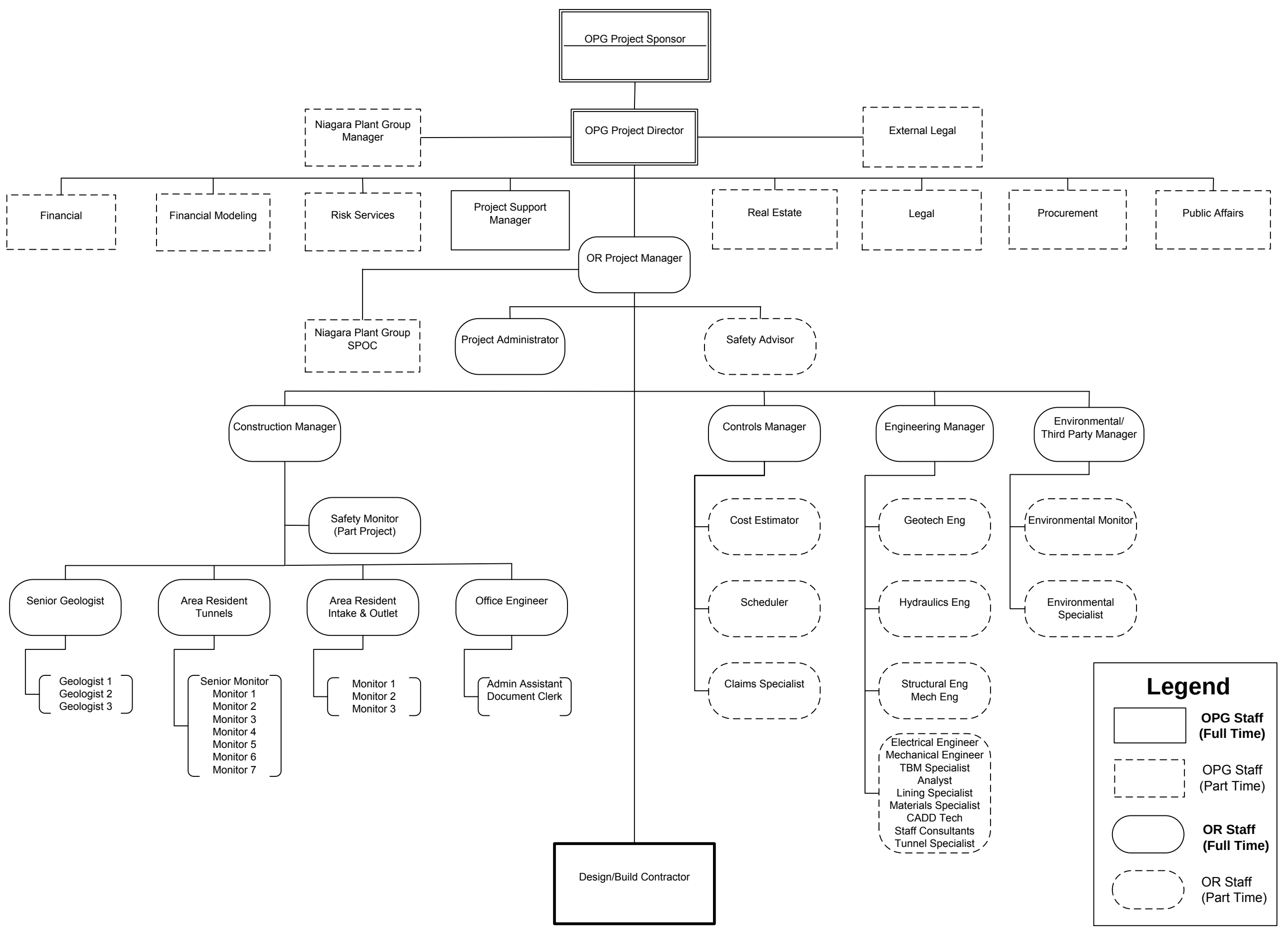


6.2 Project Management

This section discusses the management of the project under the DBA. The Organization Chart in Figure 5 below summarizes the project management structure during construction (Phase 2).

Figure 5 - Niagara Tunnel Project – Phase 2 (Construction)

Summary Organization Chart



6.2.1 OPG Project Sponsor

The Project Sponsor is the OPG senior executive directly responsible for the project and provides senior management oversight. The Project Sponsor reports to the Senior Vice President, Hydro-Thermal Operations. The Project Sponsor is the chief liaison between the project team and OPG Board and other OPG senior executives including the Risk Oversight Committee ("ROC") and Enterprise Leadership Team ("ELT"). Among the Project Sponsor's other responsibilities are to issue the Project Charter, review the project Risk Management Plan for adequacy, and review and endorse the Project Execution Plan and Project

Communication Plan. The Project Sponsor also reviews the weekly and monthly progress reports prepared by the OR and facilitates necessary funding approvals for the project.

6.2.2 Project Director

The Project Director is the OPG employee directly responsible for the overall execution of the NTP and is accountable for meeting the safety, environmental, cost, schedule, and quality objectives of the project. He directs the OR, supervises the internal OPG groups working on the project, liaises with the NPG and keeps the Project Sponsor informed about the project's progress and any issues with respect to it.

The Project Director integrates OPG's work activities with those of all other project participants. He is responsible for reviewing and facilitating approval of project cost estimates, budgets and timelines. The original negotiation of the DBA, renegotiation of the ADBA and any subsequent amendments were all overseen by the Project Director. He is the key point of contact between OPG and Strabag.

One of the Project Director's main activities is to oversee the working relationship between OPG and the OR. The Project Director manages the OR contract and is the primary contact between OPG and the OR. He approves the OR's project delivery team, ensures that the project reporting from the OR, including weekly progress and construction reports, meets OPG's needs and that necessary OPG resources are available to the OR. Working with the OR, the Project Director also approves contractor invoices for payment.

In terms of project documentation, the Project Director oversees preparation and updates of key project documents such as the Project Charter, Business Cases and the PEP. He ensures that information about the project is communicated to OPG senior management and within OPG on a regular basis. The Project Director reviews all external communications about the project and is the liaison with external parties about the project.

6.2.3 Owners Representative

The Owner's Representative ("OR"), Hatch Mott MacDonald in association with Hatch Acres ("Hatch"), provides independent monitoring, review, auditing, testing, and reporting of the contractor's designs, activities and products. Hatch administers the contract, performs continuous review of contract performance and coordinates project meetings and documents. Hatch has a full-time onsite organization whose main objective is to ensure the contractor's compliance with the DBA/ADBA and to facilitate achievement by OPG of the project's safety, cost, schedule and quality objectives.

OPG chose Hatch to be the OR for the following reasons:

- Hatch Mott MacDonald is one of the top tunneling firms worldwide.
- Hatch, working with Acres Bechtel, acted as the Owner's Representatives when this project was tendered in 1998 and OPG was very positive about Hatch's performance.
- Acres had provided engineering support on Beck 3 and the tunnel design since 1991. Hatch purchased Acres in June 2004.
- The sub-surface risks of this project were investigated and analyzed by Acres and Hatch. As a result, Hatch has considerable knowledge about the project, including geological risks, permitting and costs. To transfer this information to another firm would have required substantial time and effort.
- Hatch is Canadian owned and headquartered in Mississauga. As a result, OPG has excellent access to senior personnel at Hatch.

Hatch has acted as the OR through both phases of the NTP. In Phase One, the planning and procurement phase, the OR was active in all aspects of the solicitation including pre-qualification of bidders and the RFP process. At the pre-qualification stage, the OR developed the evaluation criteria, reviewed submissions and made recommendations to OPG as to which entities should be pre-qualified. In collaboration with OPG and external legal counsel, the OR prepared the RFP documents provided to prospective bidders, including the proposed contract and the GBR, and administered the bidding process.

Hatch worked with OPG's procurement function to evaluate the bids received, including the design drawings and the proposed means and methods, for consistency with the RFP requirements. Hatch organized the RFP evaluation process. The OR Project Manager served on the Evaluation Steering Committee. Other Hatch staff members served on the Technical and Commercial Evaluation teams.

The OR and OPG staff negotiated with the bidders to obtain their best proposals. Once Strabag was selected as the successful firm, the OR continued to participate in the negotiations to finalize the terms of the DBA.

In Phase Two, detailed design, construction and commissioning, the OR provided oversight and monitoring to facilitate achievement of OPG's safety, cost, schedule and quality objectives. OR monitoring staff provided full-time coverage on construction shifts during tunneling and final lining production shifts. The OR performed on-site quality oversight of tunnel construction and reviewed actual construction against project drawings and specifications to ensure compliance with the Contractors Construction Quality Plan, Contract Drawings, Method Statements and Specifications. The OR recorded daily work activities, performed quality audits of Strabag's operations and maintained detailed records showing the progress of work activities.

In instances where construction deviated from the provisions of the contract, the OR took steps to remedy the matter. Where additional engineering studies and investigations were required, the OR either conducted them or arranged for them to be performed. The OR also reviewed notices, drawings and other documentation from Strabag and responded appropriately after consulting with OPG. The OR maintained the administrative systems that it established and prepared budget and weekly and monthly progress reports on design and construction and facilitated and recorded various project meetings. Finally, the OR reviewed third party invoices and Strabag's applications for progress payments prior to submitting them to OPG for payment.

With respect to safety, where Strabag is the "constructor" (as that term is defined under the *Occupational Health and Safety Act*, Ontario), the OR monitored and audited Strabag's safety performance. At the intake area, when OPG is the constructor (explained more fully in Section 6.5.3), the OR was responsible for managing project site safety on OPG's behalf in accordance with OPG's policies and procedures.

6.3 Project Risk Management

In addition to the PEP, OPG periodically updated the OPG Risk Management Plan ("RMP"). The RMP was prepared at the onset of the project by building on and extending the risk assessment work initially developed by URS prior to contract award as discussed above in Section 3.3. It documented how risk management is performed for the NTP, as well as the roles and responsibilities of the project team members, the methodology and tools to be used, and the schedule for risk management activities. The RMP summarized the NTP risk management process as consisting of the following activities: risk identification, risk assessment, risk response planning, risk monitoring and control, and risk reporting.

Strabag independently conducted risk assessments as part of its proposal preparation and submitted a summary risk register with its proposal. Both OPG and Strabag continued independent risk management initiatives during the design/construction phase of the NTP so as to protect their proprietary information. However, OPG and Strabag were required to adopt significant portions of the "Code of Practice for Risk Management of Tunnel Works" (referenced above in Section 3.3 as a condition of obtaining insurance coverage for the project). These provisions required OPG and Strabag to share details of their respective risk assessments and to systematically coordinate construction phase risk management efforts to identify risks and mitigate them to the extent possible.

As a result of these requirements, two risk registers are discussed in the OPG Risk Management Plan: the OPG Qualitative Risk Register ("OPG Risk Register"), which later evolved into the NTP Key Risk Register as discussed below, and the Construction Phase Qualitative Risk Register ("Combined Risk Register").

Until June 2009, the OPG Risk Register was reviewed by OPG and the OR periodically and was maintained by the OR on OPG's behalf. The OPG Risk Register listed and managed overall risk from an OPG perspective. It included the hazards giving rise to each risk, the causes of these hazards and their potential consequences. A tracking number and priority level was provided for each hazard. The OPG Risk Register also addressed mitigation measures, and evaluated the residual risks remaining after mitigation. For each risk, a responsible individual, known as the risk champion, was identified.

OPG took over maintenance of the OPG Risk Register in June 2009, when the ADBA was signed. The OPG Risk Register was renamed the NTP Key Risk Register to reflect the new project risk management approach adopted in the context of the Superseding Business Case Summary contingency assessment whereby top priority risks from the Combined Risk Register and the OPG Risk Register were grouped into key project risks.

Under the new process, OPG and the OR assessed each key project risk using selected attributes such as probability and financial impact. Based on the assessment, they developed risk response actions. If an identified project risk was to be mitigated, the mitigation activities reducing the probability and/or impact were documented and mitigation plans were revisited, as required, to align with any updates identified in the Combined Risk Register. A remediation plan was developed for each key risk to identify the actions that would be taken if the risk occurred. Actions taken to monitor the risk were also identified and updated as necessary.

OPG and the OR reviewed the NTP Key Risk Register Summary on a monthly basis. In addition, under the revised risk management approach, OPG's Project Risk Management ("PRM") group held schedule and cost risk workshops to estimate the worst, most likely and best case durations for the remaining key construction activities.

The OR, on OPG's behalf, and Strabag jointly prepared the Combined Risk Register based on input from both parties' standalone risk registers. It followed the same format as the OPG Risk Register, but identified only those risks specific to the design and construction of the

NTP. OPG and Strabag met approximately every 6 weeks to review the Combined Risk Register. At these meetings, the parties identified new risks, tracked mitigation measures and evaluated the impact of such measures on existing risks. Items that were viewed as no longer representing a hazard were marked as closed, but were kept in the register for reference.

6.4 Oversight

6.4.1 OPG Management

Given the size and scope of the NTP and the importance that OPG places on its successful completion, the project has received significant management attention since its inception. The OPG executives directly responsible for managing the NTP, the Project Sponsor and Project Director, have been discussed above. This section discusses the additional oversight provided by OPG's senior executives.

The senior executive for hydroelectric matters, historically the Executive Vice President, Hydro ("EVP Hydro") and now the Senior Vice President Hydro-Thermal Operations ("SVP Hydro-Thermal"), is responsible for all of OPG's regulated and unregulated hydroelectric activities.[16] He oversees the execution of all hydroelectric development projects including the NTP. The NTP Project Sponsor reports to him. Since 2005, the EVP Hydro was directly involved in all significant decisions with respect to the NTP.[17] The SVP Hydro-Thermal sits on the Steering Committee established under the ADBA to resolve any disputes between OPG and Strabag that arise during the construction of the NTP.

Since the beginning of NTP construction, the status of the project and issues associated with it have been discussed at the standing OPG senior management meetings that address matters significant to the overall operation of the company.

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[16] In January 2012, these responsibilities were incorporated into the newly created position of Senior Vice President Hydro-Thermal.

[17] Prior to December 2005, the Senior Vice President, Energy Markets was responsible for the NTP.

The EVP Hydro (now the SVP Hydro-Thermal) was the primary liaison between the NTP team and the MPC, which provided OPG Board oversight of the project throughout most of its history.[18] In addition, SVP Hydro-Thermal develops materials and recommends items for the CEO to submit to the OPG Board in relation to the major approvals necessary for the NTP.

During the period of the dispute with Strabag over differing sub-surface conditions, discussed below, OPG also created a Contract Litigation Oversight Committee ("CLOC") to provide independent oversight of OPG's strategy for contract dispute resolution and negotiations and to advise the CEO on the conduct of the dispute. The CLOC was chaired by OPG's Chief Financial Officer and included external members Norman Inkster, former head of the RCMP, and Barry Leon, a lawyer then at Torys who specialized in international litigation and arbitration. Both men have significant experience in investigating and resolving complex disputes.

The CLOC also obtained independent technical advice from John Hester, an expert on tunnel construction and the tunneling industry. In the period leading to presentation of the dispute between OPG and Strabag to the DRB, the CLOC provided independent review of the strategy OPG employed and the presentations OPG made. After the DRB rendered its decision, the CLOC continued to advise the company on negotiations with Strabag until an agreement was reached.

[18] In mid-2010, the Risk Oversight Committee (ROC) assumed responsibility for OPG Board oversight of major projects and the MPC was disbanded.

6.4.2 OPG Board

OPG's Board of Directors is actively engaged in overseeing management's actions with respect to the NTP and has been since the beginning of the project. As discussed below, review and direction of the project has been undertaken by a committee of the OPG Board. Currently, it is the Risk Oversight Committee ("ROC"); previously, it was the Major Projects Committee ("MPC"). For major decisions, the entire OPG Board was involved in approving the actions previously reviewed and recommended by the ROC or the MPC.

The MPC and full OPG Board were involved in reviewing and approving the pre-qualification and RFP processes discussed above, which led to the selection of Strabag. In fact, MPC members participated in the meetings used to determine which of the pre-qualified firms would be invited to submit proposals. The MPC also reviewed and recommended the final list of invited firms to the full OPG Board, which approved it.

Following receipt of proposals, the MPC was kept apprised of the evaluations and negotiations with proponents. The MPC reviewed and accepted management's selection of Strabag and endorsed management's recommendation that the project be approved to the full OPG Board.

Once construction began, the MPC was regularly informed of its progress and visited the site. When it appeared that the project would be delayed beyond the contracted completion date, the MPC requested and received weekly progress reports. Throughout OPG's DSC dispute with Strabag, the MPC was actively involved in reviewing OPG's positions and assessing the impact of alternative resolutions.

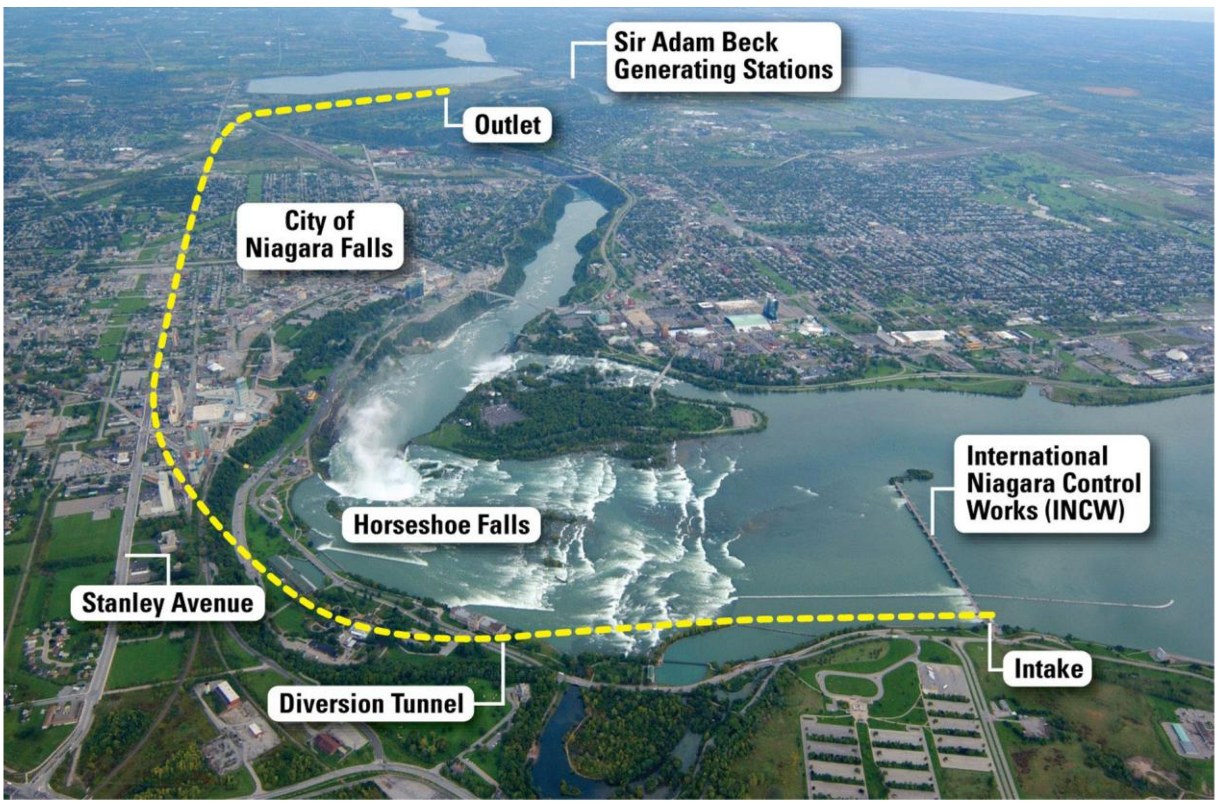
Once the DRB rendered its decision, the MPC reviewed the available alternatives with management and endorsed the approach of negotiating a revised contract with Strabag. The MPC monitored the negotiations and upon their successful completion, recommended the Amended Design Build Agreement ("ADBA") to the full OPG Board for approval along with the Superseding Business Case supporting the new project budget.

6.5 Construction Progress

6.5.1 Introduction

Mobilization of the workers and equipment needed to begin the project started soon after the contract was signed in August 2005. Construction began with site preparation activities, which commenced in September 2005. Site preparation covered three primary areas: the outlet site, the intake site and the site offices. This work consisted of clearing, grading, road construction and the erection of fences and gates.

Photo 2 - Aerial View of Project



The project construction offices were located off of Stanley Avenue in close proximity to the outlet. Temporary trailers were used until the project site offices were installed and occupied in January 2006. Both the OR ("Hatch") and Strabag occupied offices on the site.

The three major activities associated with the project were:

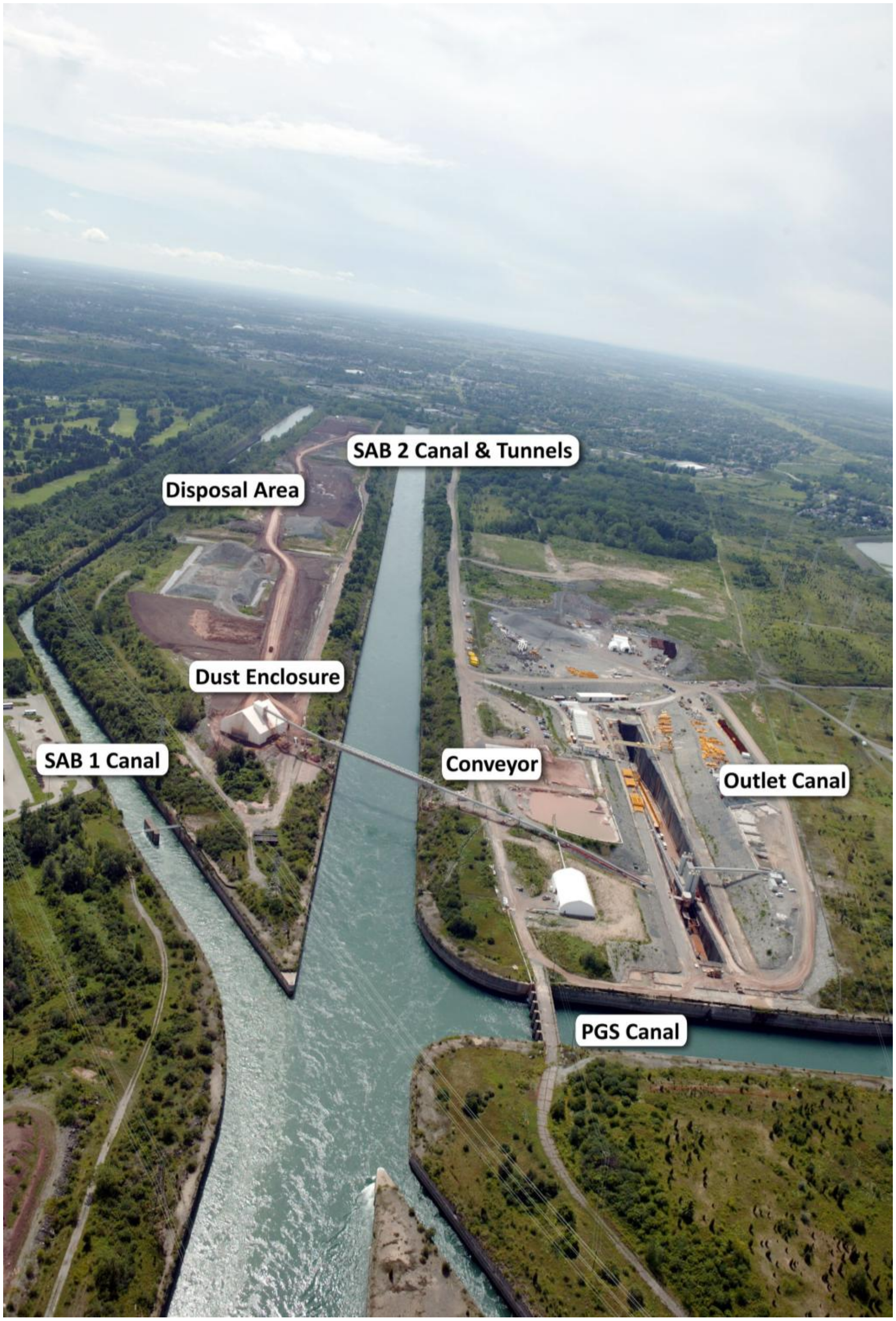
- outlet construction, which included the canal that connects the project to the PGS canal as well as the outlet structure;
- intake construction, which included the intake channel in the Niagara River, the intake structure, building a new accelerating wall and demolishing the old one, and building an approach wall along the shore of the Niagara River; and
- tunnel construction, which included the TBM, the tunnel drive, invert concrete, profile restoration, arch concrete and grouting operations.

These activities are discussed in detail in the following sections.

6.5.2 Outlet

NTP construction began at the outlet. The project offices, materials and equipment storage area and concrete batch plant were all located close to the outlet. The rock excavated from the NTP was transported by a series of conveyors from the TBM through the outlet to the storage area between the SAB 1 and the SAB 2 canals. Queenston shale was segregated from other rock types for re-use by Ontario brick manufacturers as required by the EA Conditions of Approval.

Photo 3 - Aerial View of Outlet Site



Outlet work was carried out in two stages. The first stage involved the construction of the outlet canal and tunnel opening for the commencement of TBM operation. Site preparation, overburden removal and excavation started at the outlet in September 2005. This was followed by drilling, blasting, and excavation to create the outlet canal. A ramp was built to enable workers and equipment to access the outlet. To protect the exposed Rochester shale, Strabag applied shotcrete within the outlet canal excavation. Strabag also installed geotextile mesh on the canal walls to control loose falling rocks. The resulting outlet canal is 350 metres long, 23 metres wide and between 30 and 40 metres deep. During the construction of the tunnel, the outlet canal served as the entry point for the TBM and as the staging site for the transfer of materials to and from the TBM. With the NTP in operation, this canal delivers water from the tunnel into the current PGS canal connecting the PGS reservoir to the crossover where the existing tunnels and canal meet.

Photo 4 - Outlet Site "Crossover"

The second stage of the outlet work was undertaken after the TBM finished boring the tunnel, and consisted of the construction of the reinforced concrete outlet structure, installation of the control gate and removal of the rock plug to complete the connection to the existing PGS canal. The outlet structure was completed in March 2012. It incorporates the transition between the round tunnel and the rectangular steel gate. Guides for the permanent gate and for a sectional service gate (stop logs) are embedded in the concrete of the outlet structure. A surge shaft designed to contain any surge that occurs during gate closure and to provide future access into the tunnel was also incorporated into the structure.

The articulated outlet gate was completed in December 2012, and the dry-testing and commissioning of the outlet gate was completed by February 2013. Outlet gate testing was also carried out in March 2013 after the tunnel was watered to ensure the gate functioned properly under wet conditions.

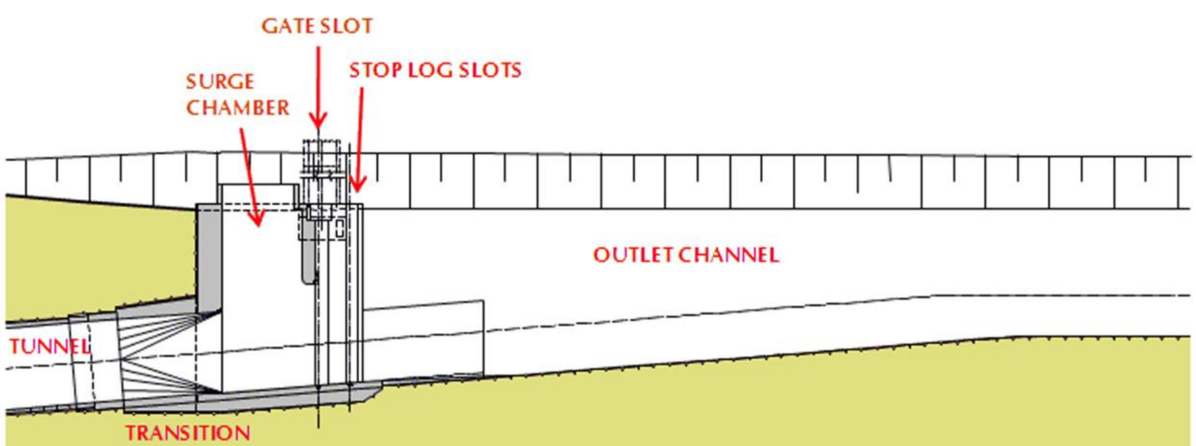
Both the intake and outlet gates were originally expected to be installed and commissioned on a fixed price basis. Due to the delay in the project, installation of the gates did not begin until late 2012, some four years later than originally anticipated. By that time, the estimated cost for the installation and commissioning of the gates had increased. To recognize this increase, the original fixed price contract was restructured as a time and materials contract.

Photo 5 - Outlet Gate

Rock plug removal work began in November 2012. Stage 1 of the work, line drilling along the sides of the plug, was completed at the end of November 2012. Stage 2, blasting to thin the plug from 44 metres to 12 metres, began in early December 2012 and was completed by the end of the month. The vehicle ramp, which was built to enable workers and equipment to access the outlet, was excavated during Stage 3. The fourth and final stage consisted of removing the remaining 12 metres thickness of the rock plug by in-water blasting. This work was conducted after the outlet gate had been closed and the outlet canal had been flooded with water from the PGS canal. A five week outage of the PGS was required to complete Stage 4 of the rock plug removal. This outage took place from February 6 to March 8, 2013. The final rock plug blast was successfully conducted on February 12, 2013.

The extension of the project schedule also impacted the rock plug removal schedule, resulting in additional costs being incurred by Strabag's subcontractor, Dufferin Construction Company ("DCC"), because the removal work was performed during the winter rather than the summer as initially contemplated. Consequently, the parties agreed to modify the original fixed price contract and proceed with this work on a time and materials basis. DCC work records were submitted daily to Strabag and the OR, and costs were tracked to determine the actual cost of the work.

Figure 6 - Outlet Diagram



Between March 3 and 4, 2013, controlled water inflow was used to fill the tunnel. As the water level is higher at the intake, valves at the intake gate were used to complete the initial filling process. Once the tunnel was full of water and the wet testing of the gates had been completed, the intake gate sections were removed, the outlet gate was raised and water started flowing through the tunnel.

6.5.3 Intake

Work on the intake proceeded in three phases. The first phase began with marine work. This consisted of in-river replacement of the ice accelerating wall, which is used to control the flow of water and ice,[19] and the construction of the cofferdam erected to keep the intake area dry. This work was completed in October 2007. The second phase was the work on the intake structure carried out within the cofferdam, as explained more fully below. The third phase was removal of the cofferdam and ice groyne.[20]

The initial plan was that OPG would maintain an “owner-only” status for the entire project with Strabag being responsible for all “constructor” obligations under *Occupational Health and Safety* (Ontario) legislation. However, as OPG operates the water diversion structure and control gates pursuant to the *Niagara Diversion Treaty* of 1950, a significant aspect of maintaining marine safety rested with OPG. Furthermore, it was not until the second phase, when Strabag operated within the area isolated by the cofferdam, was Strabag practically able to operate free from the influence of OPG’s use of the control gates and any ongoing OPG operations. As a result, in June 2005, OPG applied to the Ministry of Labour (“MOL”) and received approval to designate a discrete portion of the NTP as a separate part project (“INCW Part Project”). For the first and third phases of intake site work, OPG was designated as the constructor. Separating out the discrete INCW Part Project was an important part of

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[19] This structure is also sometimes referred to as the Accelerator or Acceleration Wall.

[20] The ice groyne was constructed upstream of the INCW structure to enhance ice flow in the intake channel and to provide ice protection for the cofferdam during the NTP’s construction phase. It consisted of a large rock base with build-up of granular material. Once the sectional gates for the intake were put in place and the cofferdam was removed, the ice groyne had fulfilled its purpose and was removed.

maximizing safety and was necessary due to the physical and legal constraints involved with these portions of the work.

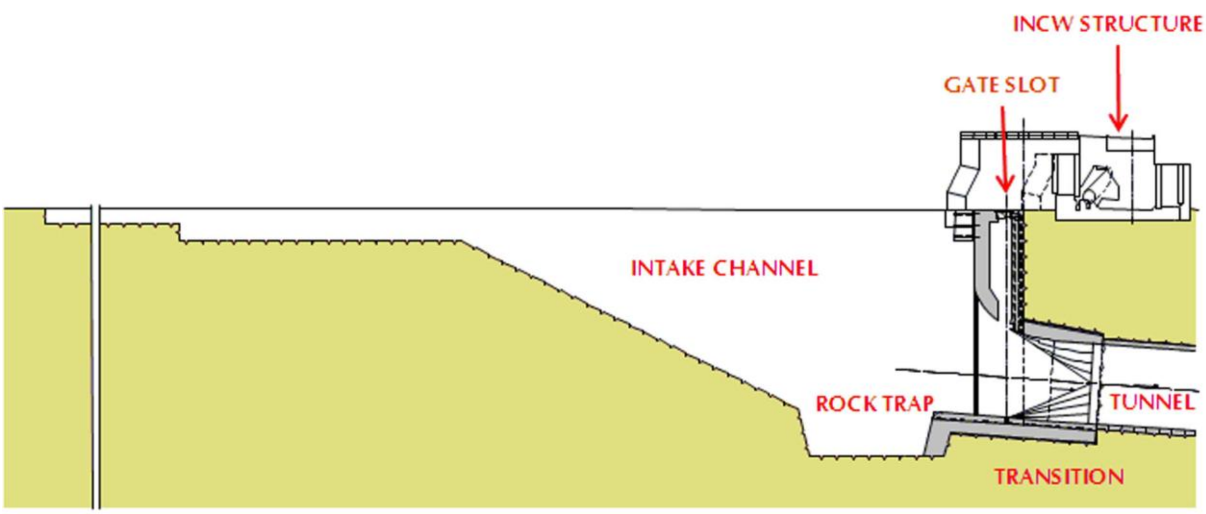
6.5.3.1 Facilities

The intake portion of the work consisted of the following elements:

- excavation of a 140 metre long underwater approach channel in the riverbed;
- construction of a submerged bell-mouth intake structure in the Niagara River beneath Bay 1 of the existing INCW;
- construction of a new accelerating wall and the demolition of the existing one; and
- construction of a new approach wall.

Each of these elements is discussed below.

Figure 7 - Intake Diagram



The underwater channel was constructed in two stages. Underwater blasting was used to initially shape the channel in the river bottom. Then a 61 metre by 122 metre area upriver from and surrounding gate #1 was enclosed by a cofferdam consisting of steel sheet piles used to frame the cells, with a concrete seal at the riverbed and gravel fill. Pattern grouting through the cells was used to fill in any voids in the underlying limestone rock.

Upon completion of the cofferdam, the water was removed by pumps to create a dry area where the channel could be completed using the drill and blast method. This area contains the tunnel intake where water is drawn into the tunnel and served as the exit and disassembly point for the TBM, Backup Unit ("BU") and other tunnel equipment.

Photo 6 - Aerial of Intake Site Surrounded by Cofferdam

The intake structure is designed to allow water to access the tunnel at a flow rate that is sufficiently slow to prevent a surface vortex and air entrainment, and to allow surface water and ice to continue to flow through the INCW Bay 1. It includes guides for sectional service gate, a removable guide structure, ten 13.3 metre wide gate sections, handled by mobile crane, and a square to round transition from gate slot to tunnel. The sectional gate allows for closure of the tunnel to enable dewatering when and if required. The intake also includes a rock trap along the bottom of the channel to capture rocks and other debris moving along the river bottom before they enter the tunnel. The intake structure was constructed within the cofferdam.

To connect the intake with the main tunnel, a pilot grout tunnel about 300 metres long was excavated and surrounding rock was grouted to reduce the groundwater inflow impact on the TBM drive through the final section of the tunnel under the Niagara River. The grout tunnel consisted of a 7 metre by 8 metre excavation accomplished by drilling and blasting. The grout tunnel was constructed to allow high pressure grout injection into all the rock cracks and crevices surrounding the tunnel to form a 26 metre diameter watertight envelope to prevent flooding from the river above as the TBM surfaced. As the TBM moved toward the surface it ascended by boring along the grout tunnel.

The 530 metre accelerating wall in the Niagara River begins at Pier 5 of the INCW. The accelerating wall is used to control the flow of water and ice. It was built of large precast concrete boxes with a newly developed locking system to withstand the forces of ice, water and debris in the Niagara River. In-water blasting as well as tremie concrete (concrete placed directly in water) pads were used to form the level bed on which the precast boxes sit. They are anchored with concrete and filled with gravel. A cast in place concrete slab caps the wall.

Photo 7 - Aerial View of New Accelerating Wall

The pre-existing accelerating wall was located about 30 metres closer to shore than the new wall. It was constructed of creosoted timber cribs filled with rocks, which were demolished and removed during the course of constructing the new wall.

The 360 metre intake approach wall is located upstream of the INCW structure and runs along the south shore of the Niagara River. The approach wall is a combination of a training and a retaining wall replacing the previously sloped river bank. It extends from the INCW to the SAB Tunnel No. 2 intake. It was constructed using the same method as described above for the accelerating wall. The intake approach wall and the accelerating wall work together to optimize the water flow and ice-flushing capability of the INCW structure inside the accelerating channel.[21]

6.5.3.2 Scheduling

Mobilization of marine equipment (barges, tugs, cranes, etc.) started in April 2006. In-water blasting for the new intake channel started in May 2006. Replacement of the accelerating wall started in June 2006 along with construction of the cofferdam. Accelerating wall replacement was essentially completed in December 2006. Cofferdam foundation grouting and dewatering were completed in July 2007.

6.5.3.3 Intake DSC Dispute

Starting in May 2006 a series of project change notices were filed by Strabag on behalf of its sub-contractors based on claims of DSC and other changes to the work required at the intake. The intake DSC disputes alleged various differences between the actual conditions experienced during construction of the intake channel, accelerating wall and approach wall and those presented in the GBR. Specific DSC claims included the discovery of a greater amount of overburden on the riverbed, a difference in the riverbed elevation and the presence of boulders within the riverbed.

Disputes also arose with respect to other aspects of the work at the intake site. These included the identification of "fractured rock seams" found in the intake channel, inefficiencies claimed to have resulted from the schedule acceleration requested by Strabag, the re-alignment and lengthening of the new acceleration wall, and obstructions encountered while installing the grout curtain for the cofferdam.

[21] In addition to freezing water from the Niagara River itself, masses of ice can form in Lake Erie and float down the river. This situation may create blockages, ice damage, or reduction of flow into the power plant intakes. Chunks of ice may even enter intake tunnels causing potentially serious damage, unless ice-flushing measures are taken.

OPG and Strabag could not agree on the scope of the changes in work that resulted from these differences or on the appropriate change in contract price to reflect the additional work. OPG requested documentation supporting the claimed amount of about $19.3M in extra costs. After reviewing the documentation, OPG estimated the cost of these changes at roughly $5M and provided a change directive increasing the value of the contract by this amount. Eventually, one of the sub-contractors, McNally Construction, filed a lien and commenced a lien action against OPG and others.

OPG and the parties negotiated a compromise in settlement of all issues, claims and actions relating to the disputes over work at the intake, and any other potential claims related to intake work performed prior to July 25, 2007. Under this settlement, OPG agreed to change the contract price by a total of $7.5M, which represented an additional $2.5M above the $5M contract change already agreed to by OPG. A settlement agreement and a full and final release to this effect were signed on September 20, 2007. A court order was subsequently registered to vacate the lien and the lien action.

6.5.3.4 Intake Completion

Following the removal and disassembly of the TBM and BU from October 2011 to March 2012, work at the intake focused on the completion of the concrete pour for the intake structure. This was achieved by the end of April 2012.

Once the intake structure was completed, the work associated with the installation of the intake gate commenced. The intake gate consists of a sectional steel service gate and guide tower. However, unlike the outlet gate which is a permanent structure, the intake gate sections and guide tower are installed only when the tunnel is to be dewatered, and will be stored at a nearby location when not in use. The intake gate underwent dry fit testing, and installation and removal of the guide tower to ensure it functioned as designed.

While the intake gate was installed and commissioned during much of 2012, tunnel equipment (i.e., invert bridge system) continued to be disassembled and removed using a

550 tonne crane. The scrap steel leftover from the equipment removed was sold for approximately $800k.

The last intake gate section was installed on November 13, 2012. MOL was on site the same day to discuss the transfer of control from Strabag to OPG for the purposes of completing the third phase of intake work: the removal of the cofferdam and ice groyne, and the placement of approach wall blocks. On November 15, 2012, OPG resumed the role of constructor at the intake and the intake channel (area within the cofferdam) was flooded.

Cofferdam removal work commenced on November 19, 2012 and was completed on February 3, 2013. The ice groyne was then removed by excavation in still water commencing February 23, 2013 and was completed on March 3. As of March 8, the third phase of intake site work was complete and OPG was no longer the constructor at the intake site. The MOL was then informed on March 11 that Strabag was the constructor until the end of the project.

6.5.4 Tunnel Construction

6.5.4.1 Tunnel Boring Machine

When the Tunnel Boring Machine ("TBM") used for the NTP was put into service, it was the largest open gripper main beam TBM in the world with a diameter of 14.44 metres.[22] The TBM and back-up was 150 metres long and weighed about 4,000 tonnes. It was named "Big Becky," the winning entry from a naming contest among local schools. The name reflects the contributions of Sir Adam Beck in hydroelectric development and the size of the TBM.

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[22] There are two main types of TBMs: open (unshielded) and closed (shielded). Open TBMs require systematic rock-support behind the cutter head because the final lining is installed later. They use a gripper system that pushes against the tunnel side walls to advance. Where a concrete liner is required, it is installed by means of second pass operation after the TBM has completed mining. Closed TBMs are equipped with a shielded body under which supporting operations, including installation of a precast concrete lining system, are carried out. They advance via thrust cylinders that push off against the tunnel lining segments installed behind the machine. The entire tunnel is excavated and lined in one-pass.

Use of an open TBM was designed to allow for the installation of Strabag's proposed pre-stressed cast in place concrete liner with an impermeable waterproof membrane.[23] With an open TBM, the initial lining consists of rock bolts, friction anchors, wire mesh, steel channels, and shotcrete, which are used in various combinations depending on the conditions encountered.[24] This initial lining is intended to support the rock until the waterproof membrane is placed and the final concrete lining is cast. The TBM was configured to permit initial support adjustments as required during construction based on the rock conditions encountered.

Strabag's construction methodology was scored higher by the Evaluation Team because Strabag was the only contractor that proposed a cast-in-place liner with an impermeable membrane to protect it from water egress or ingress. This was an important feature not only because it enhanced the life expectancy of the tunnel liner, but also because geological tests indicated that the Queenston shale has the potential to swell if exposed to fresh water. The waterproof membrane proposed by Strabag increased the Evaluation Team's confidence that Strabag's tunnel design would be able to meet the required 90-year lifespan. The cast-in-place liner also reduced the potential for voids to develop between the liner and the surrounding rock as could have occurred with a closed (shielded) TBM and a precast liner. Finally, with fewer construction joints, a cast-in-place concrete liner is smoother than a precast concrete liner, which leads to increased water flow because of reduced friction.

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[23] During the 1998 bidding process, all of the qualified contractors had proposed a closed TBM with a precast concrete segmental lining. For this reason, the 2005 Invitation to Submit Design/Build Proposal anticipated a closed TBM with a one-pass concrete liner. Unlike the other respondents, however, Strabag considered both open and closed TBMs before arriving at their proposed approach of using an open TBM with a cast-in-place concrete lining as the most effective method of meeting the requirements of the project including the 90 year life, impermeability and target flow.

[24] The initial lining was installed in two stages using the two primary areas for installing rock support behind the TBM cutterhead, which were known as L1 and L2. Initial support in the tunnel crown was installed immediately behind the TBM cutterhead in the L1 position, and shotcrete was placed about 40 metres behind the face at the L2 position. Initial support was generally comprised of 4 metre-long Swellex friction anchors, 150 mm C-channels, and welded wire mesh. As the TBM progressed and overbreak increased, shotcrete was placed between approximately the 10 o'clock and 2 o'clock locations in the tunnel crown from additional portable sprayers at the L1 position. A shotcrete layer was sprayed in a full circle at the L2 position.

Strabag considered three TBM manufacturers in its proposal. Ultimately, it selected The Robbins Company ("Robbins") of Solon, Ohio, which is one of the preeminent TBM manufacturers in the world. The design of the NTP TBM involved experienced tunnelers and an experienced TBM manufacturer working together to develop a machine suitable for the project. Extensive geotechnical information was made available to designers. Strabag and Robbins jointly developed the schedule for manufacturing, assembling, testing and commissioning the TBM to meet the rock conditions anticipated during NTP construction. Ancillary equipment for use with the TBM was ordered from specialized firms selected by Strabag including Rowa Tunnelling Logistics of Switzerland, which supplied the back-up unit, and H&E Systems of Germany, which manufactured the conveyor belt system used to remove the excavated material.[25]

To reduce the overall duration of the project, and thereby its cost, TBM components were manufactured in North America and Europe and shipped to the site for assembly and testing. This approach eliminated the time and cost required to have the TBM components shipped to the Robbins factory in Ohio, assembled and tested, disassembled for shipment to the site and then reassembled and re-tested on site, as was initially envisioned in the DBA.

[25] The back-up unit is a 125 metre long series of trailers that moves along behind the TBM. It contains the computerized controls for the TBM and supports ancillary functions such as dust suppression, drilling, shotcrete application and removal of rock.

Photo 8 – "Big Becky" Assembled in the Tunnel Outlet Site Prior to Tunneling

Prior to agreeing to on-site TBM assembly and commissioning, OPG assessed the risks associated with Strabag's proposal against the potential schedule advantages. To mitigate these risks, representatives of Robbins, Rowa Tunnelling Logistics and other firms supplying ancillary TBM equipment were on site during assembly and commissioning. Based on this mitigation, the residual risk was considered to be low. Moreover, since the DBA contained a fixed price for the TBM and allocated all TBM related risks to Strabag, OPG accepted the TBM delivery and commissioning schedule created by Strabag and Robbins.

TBM assembly began in April 2006 within the outlet canal excavation. Assembly of the TBM and ancillary equipment was completed in August and the TBM began mining in September 2006.

During the course of the tunnel excavation, Strabag performed numerous modifications to the TBM to allow it to operate more effectively and to safely address the rock conditions being encountered. Many of these modifications occurred in the L1 area of the TBM, where rock support is first installed. These changes included removing the ring erector, modifying existing rock drills to provide more articulation, installing a new forward drill for advance rock support, replacing fixed work platforms with manlifts to improve worker access, implementing various actions to improve cutterhead reliability, and adding a conveyor for muck removal from the tunnel invert.

Ultimately, while challenging rock conditions delayed the progress of the TBM, it successfully bored one of the largest diameter hard rock tunnels ever undertaken and it did so safely.

6.5.4.2 The Tunnel Drive

Based on Strabag's baseline schedule, boring of the tunnel or the tunnel drive, was expected to begin on September 1, 2006 and conclude on August 15, 2008. This schedule anticipated average progress of 14.55 metres per day over 715 days of tunneling. The tunnel drive began as scheduled on September 1, 2006, but it did not conclude until March 30, 2011. The average daily progress achieved was 6.06 metres per day and the tunnel drive lasted 1,671 days. This delay and the costs associated with it account for the majority of the NTP's increased cost above the original project budget. This section discusses the progress of the tunnel drive and the conditions and issues that Strabag faced and ultimately overcame. The related matter of the dispute between OPG and Strabag over differing subsurface conditions ("DSC") is discussed below in Section 7.0.

Start-up issues related to TBM crew training, ancillary equipment commissioning (e.g., ring erector and rock drills, shotcrete applicators), groundwater incursion and issues with cutterhead performance caused tunnel boring progress to be slower than projected from the very beginning of TBM operation. Strabag initially indicated that these were "start-up" issues and it could make up the lost time once these matters were resolved, but after a few months of slower than expected progress that position could no longer be sustained.

By the end of 2006, after four months of tunneling, Strabag indicated that it intended to begin installing the permanent tunnel lining (impermeable membrane and concrete) for the tunnel arch before the completion of TBM excavation rather than waiting until the end of the tunnel drive. This change was aimed at reducing the impact of the tunnel drive on the project's overall critical path and increasing the likelihood of completing the project on schedule.

In March 2007, Strabag produced a revised schedule showing the anticipated completion date for tunnel boring as March 12, 2009, some seven months later than the original schedule. The scheduled completion date for the project as a whole, however, remained unchanged because of the decision to undertake the tunnel lining concurrently with TBM boring.

TBM progress improved for a time in spring 2007 as start-up issues were resolved and the machine moved through less challenging rock layers above the Queenston shale. In May 2007, however, as Strabag was mining in the top layer of the Queenston shale immediately below the interface with the Whirlpool sandstone, a large rock block (approximately 30 tonnes) fell and damaged the TBM. TBM progress was stopped for more than three weeks, while the rock was removed and the damage repaired. Strabag filed its first claim for DSC based on this incident.[26] Strabag also used the stoppage to make other modifications to the TBM, including installation of a forward drilling rock drill, which were necessary to enable the installation of the new rock support measures.

In summer 2007, with the TBM now completely in the Queenston shale, the overbreak above the TBM cutterhead increased substantially and progress was slow.[27] Strabag began installing forward raking pipe spiles ("spiles") in an umbrella formation above the areas to be mined in an effort to limit the magnitude of the overbreak and to safely advance the TBM (see Photo 9 below).[28] Rock support measures behind the cutterhead including shotcrete, wire mesh, steel channels and rock bolts continued to be installed. As a result of the slow progress, Strabag submitted a revised schedule in June 2007 showing that completion of the NTP project would be delayed about five months beyond its original schedule. Given the contingency approved by OPG Board, however, the revised completion date remained within the OPG-approved schedule.

[26] This claim, contained in Project Change Notice ("PCN") 17, was eventually included in the matters that went to the DRB. The details of this notice and related dispute notices are all discussed below in Section 7.0, "Differing Subsurface Conditions Dispute."

[27] Overbreak is the cracking and loosening of rocks above the TBM cutterhead. It has the effect of distorting the circular profile created by the TBM.

[28] The spiles used in the NTP are pipes up to 9 metres long that are drilled nearly horizontally into the rock over the cutterhead in an umbrella pattern to help keep the rock in place as the TBM advanced.

Photo 9 - Installation of Spiles in an Umbrella Formation

In autumn 2007, the TBM continued mining within the Queenston shale and progress remained slow. The TBM's advance rate increased somewhat in late September as rock conditions slightly improved, allowing Strabag to cease installing spiles. During this time, Strabag first indicated that it was considering a realignment of the tunnel to allow the TBM to exit the Queenston shale sooner and thereby increase the boring rate. Strabag requested that OPG evaluate whether realignment was possible and what issues it would raise. OPG agreed to consider the implications of realignment including the need to acquire new subsurface rights and to seek an EA amendment.

In mid-October 2007, Strabag issued a progress schedule which showed a further delay in final completion to almost nine months beyond the contracted date. This was the first schedule revision that put project completion outside the date approved by OPG Board. On OPG's behalf, the OR requested Strabag to provide a Recovery Plan to mitigate the anticipated schedule overrun. Strabag's response was that the schedule delays were entirely attributable to the DSCs previously raised in various Project Change Notices ("PCN"s). Strabag also stated that it had taken whatever actions possible, so far uncompensated, in an attempt to keep the project on schedule. Strabag closed its response by indicating that the path forward required a resolution of its outstanding DSC claims.

At the end of November 2007, senior executives from OPG and Strabag met and agreed that the two parties would try to resolve their differences based on realigning the tunnel. They further agreed that if the issues pertaining to the new alignment and the DSC claims raised in the PCNs were not resolved within three months, the matter would go to the DRB for resolution as soon thereafter as possible.

By the end of November 2007, the tunnel drive reached the beginning of the area under the buried St. Davids Gorge.[29] Over the next few months, while tunneling under the gorge, overbreak increased and Strabag resumed installing spiles. Progress slowed.

At the end of December 2007, the OR received a letter from Strabag with a new realignment proposal that superseded the realignment options previously discussed. This proposal involved both a horizontal realignment, that placed the tunnel mainly underneath Stanley Avenue and reduced its distance by approximately 200 metres, and a vertical realignment to a considerably higher elevation in order to reduce boring in the Queenston shale. The proposal envisioned the completion of tunnel boring on August 27, 2010, more than two

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[29] The DBA (section 5.5 (e)) defined an 800 metre area under the buried St. Davids Gorge (from approximately 1,400 to 2,200 metres) where Strabag could not claim differing subsurface conditions. This provision was included because Strabag's RFP response proposed raising the low point of the tunnel some 50 metres higher than shown in the RFP's conceptual design. Strabag made this proposal in order to reduce the tunnel's slope, which shortened the tunnel, improved its water flow characteristics and allowed Strabag to use rubber tired vehicles rather than rack and pinion rail transports.

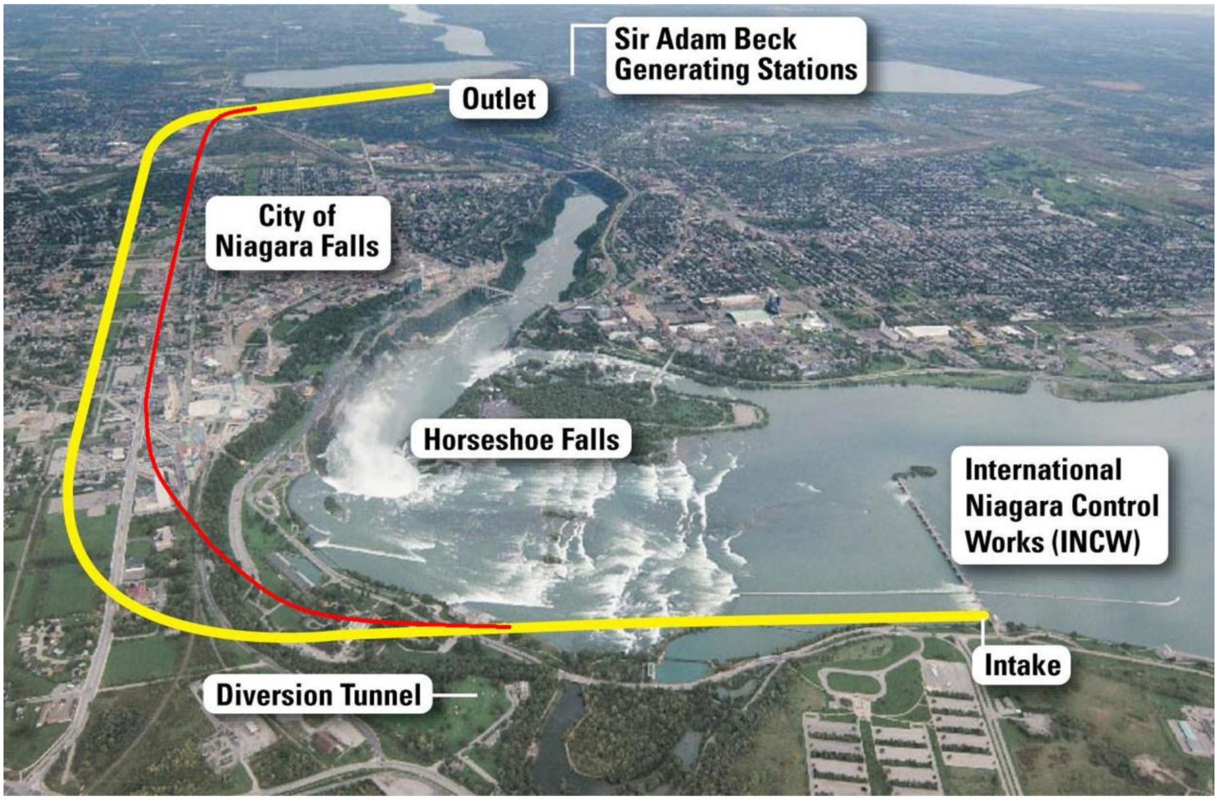
years later than the contracted schedule. The forecasted substantial completion date was June 18, 2011, some 20 months later than contracted.

OPG began exploring the issues associated with the proposed realignment. These issues included the additional subsurface property rights expropriation that would be required, the potential impacts on groundwater and BTEX rock quantities, and the potential impact on the existing tunnels. OPG submitted an application for the minor EA amendment required by the realignment, which was approved on March 31, 2008.

Throughout the early months of 2008, slow progress continued as the TBM worked under the buried St. Davids Gorge. Strabag continued to install measures to reduce overbreak and used spiles where the amount of overbreak warranted. Talks between OPG and Strabag continued in an effort to reach an agreement on a new alignment and to resolve ongoing disputes over the rock conditions and the resulting slow progress of the project. In early February, Strabag submitted a proposal for recovery of the additional costs it claimed due to DSC. By mid-February 2008, the parties agreed that they had reached an impasse and determined to take their dispute to the DRB.

During the spring of 2008, TBM progress continued to be slow, although advance rates improved as the TBM emerged from the zone of influence of the buried St. Davids Gorge. In May, OPG and Strabag agreed on horizontal realignment; vertical realignment was put on hold pending resolution of the dispute by the DRB.

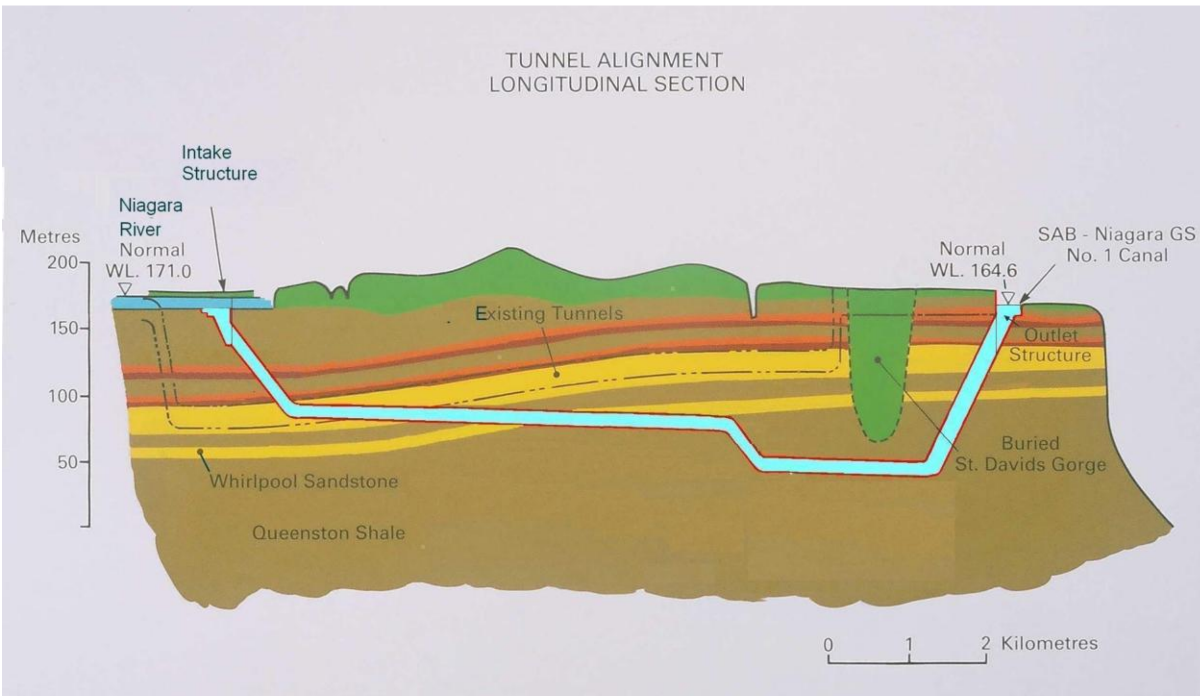
Photo 10 - Aerial View of Horizontal Realignment



Although the TBM made relatively steady progress in the summer of 2008, averaging more than 250 metres per month from June through September, advance rates remained below plan and the schedule continued to slip. While Strabag began tunneling along the realigned horizontal route in early September, it maintained its position that vertical realignment would be addressed only in the context of an overall resolution of outstanding issues. Discussion of this overall resolution began after the DRB issued its decision in late August as discussed in Section 7.0, below.

While OPG and Strabag renegotiated the contract, tunnelling proceeded. In the fall of 2008, Strabag resumed spiling to address the substantial overbreak (greater than three metres) being experienced. In light of these conditions, Strabag determined, with OR concurrence, to begin the vertical realignment to exit the Queenston shale as soon as the horizontal realignment moved the tunnel route out from below the existing tunnels. In late October, Strabag took a planned outage lasting almost five weeks to improve and modify TBM equipment and extend and improve the conveyor system. When Strabag resumed mining in late November, it continued advancing along the horizontally realigned route, which permitted vertical realignment to begin in late December 2008.

Figure 8 – Vertical Tunnel Realignment



Throughout the first part of 2009, TBM boring sloped up through the Queenston shale and continued along the new horizontal alignment. The TBM reached the Whirlpool formation in July and by the end of that month was one day ahead of the ADBA target schedule (discussed later in Section 9.2). In August, the arch of the tunnel reached the Power Glen shale formation and overbreak increased. Nevertheless, the TBM continued to progress ahead of the ADBA schedule.

On September 11, 2009, about 100m^3 of Queenston shale and temporary tunnel lining (shotcrete, wire mesh and steel channels) fell from the right side of the tunnel between 3,605 metres and 3,625 metres, about two kilometres behind where the TBM was then located.[30] Work was stopped immediately. There were no injuries and all workers were safely evacuated from the tunnel. The Ministry of Labour ("MOL") subsequently issued a Stop-Work Order stopping all tunnel work beyond 3,500 metres pending an investigation, remedial work and verification of the adequacy of the tunnel crown support.

Photo 11 - Fall of Ground 2009

[30] Measurements used to describe locations in the tunnel represent the distance from the outlet where tunnel boring began. This fall of ground occurred approximately 3.6 kilometres from the outlet. These measurements are often referred to as "chainage" or "station" measurements.

Remedial work involved installing a rock-fill ramp to gain access to the fall area and scaling and installation of new rock support measures in the area of the fall. In accordance with the remediation plan reviewed and accepted by the MOL, Strabag began clean up and repair of the primary rock support and lining on September 20, and continued to install wire mesh, steel channel ribs, rockbolts and shotcrete until October 12. The MOL lifted the Stop-Work Order on October 16 and the contractor proceeded to scale loose shotcrete from the tunnel crown (from 3,700 metres to the TBM) and began applying a precautionary layer of wire mesh to prevent falling shotcrete and enhance worker safety.

A full investigation of the fall of ground was conducted by Strabag and the OR. The investigations concluded that a loosening of the rock support dowels put more pressure on the face plates for the dowels than they could hold, which led to the fall. The investigations also concluded that Boreholes NF-4 and NF-4A contributed to the loosening of the dowels by allowing relatively fresh water to penetrate and degrade the rock surrounding the dowels. These boreholes were drilled in 1984 and 1990, respectively as part of the geotechnical investigation for the NRHD. Owing to the horizontal realignment, the tunnel excavation had intersected with the borehole on February 27, 2009. The boreholes were a source of groundwater inflow before being plugged with grout in March 2009.

The investigation also revealed that Strabag needed to improve monitoring procedures, protocols and frequency, as there were indications that excessive movement was detected on September 10, 2009 at a monitoring point just five metres from where the fall occurred, and that no alert was sounded and no action was taken to check on the stability of the area. Following the fall of ground incident, Strabag reported to the OR that it implemented new monitoring software, installed additional measuring stations and tunnel support enhancements, established tighter trigger levels and adopted more rigorous procedures to monitor and respond to ground movements. Strabag also noted that some of these measures either had been planned or were initiated prior to the fall of ground incident.

Due to the fall of ground and associated remedial work, tunnel boring was suspended for a total of 46 days, from September 11 to October 26, 2009. Once the remedial work was completed, Strabag undertook a planned TBM maintenance shutdown, primarily to overhaul the cutterhead, which lasted until December 8, 2009.

While the TBM was stopped due to the fall of ground, remedial work and planned maintenance shutdown, work continued on other aspects of the tunnel. This work included lining and profile restoration in the area before 3,500 metres, construction at the intake and outlet, equipment modifications, and work on the conveyor and dust enclosure.

Ultimately the fall of ground in 2009 only set back the schedule for overall NTP completion by approximately 17 days because the parties agreed under Appendix 5.3C of the ADBA that a one day delay to TBM mining translated into 0.375 days delay to the critical path.

At the time of this event, a decision was made to forego a claim under the Builder's All Risk ("BAR") insurance because Strabag's estimate to execute the remedial work was comparable to the $2M insurance deductible. Strabag's subsequent request for a Target Cost increase of $4.5M could not be substantiated by the OR records that valued the actual costs for the remedial work at $2.1M. Based on the decision to forego a BAR insurance claim, OPG offered, and Strabag accepted, a Target Cost increase by $2M. Altogether, the final impact of the 2009 fall of ground was an increase to the target schedule by 17 days and an increase to the Target Cost by $2M.

In the first part of 2010, tunnelling progress improved, but the advance rate remained below the target established in the ADBA. Strabag took measures to remove loose shotcrete and install protective wire mesh. Overbreak amounts varied, but were generally less than what had been experienced while tunnelling in the Queenston shale.

By spring 2010, the TBM was making good progress and the gap between targeted and actual performance began to significantly decrease. Progress improved further in the summer of 2010 such that by the end of August, mining was ahead of the ADBA schedule by 15 days. Mining during this period was in the Power Glen and Grimsby formations.

At the end of 2010, tunnel boring was on track with the ADBA schedule. Progress in the later part of 2010 had continued to exceed anticipated rates, but repairs to fix the cracked TBM main beam in December required a shutdown of more than three weeks. In the beginning of 2011, excellent progress resumed such that by the end of January 2011, boring was 21 days ahead of schedule. No overbreak was experienced during this month. By the end of March 2011, tunnel boring was essentially complete. For purposes of the ADBA, TBM mining was certified as substantially complete as of March 30, 2011.

6.5.5 Tunnel Lining

6.5.5.1 Invert Lining

The invert is the bottom portion of the tunnel covering roughly the lower one-third of its circumference. As with the rest of the tunnel, the invert was initially lined with shotcrete. In early December 2008, once the TBM advanced sufficiently far into the tunnel, Strabag began installing the permanent waterproof membrane and concrete lining in the invert.

The permanent lining consists of multiple layers. A protective fleece is laid over the initial shotcrete lining.[31] Then a two-layer, impermeable waterproof membrane (a total of 3.5 mm of flexible polyolefin) is laid over the fleece.[32] The integrity of the dual-layer membrane is verified by withdrawing trapped air and creating a vacuum between the layers to ensure the membrane is impermeable. The welds which form the seams between each sheet of membrane are also tested by inflation with air to ensure their integrity. Once testing is

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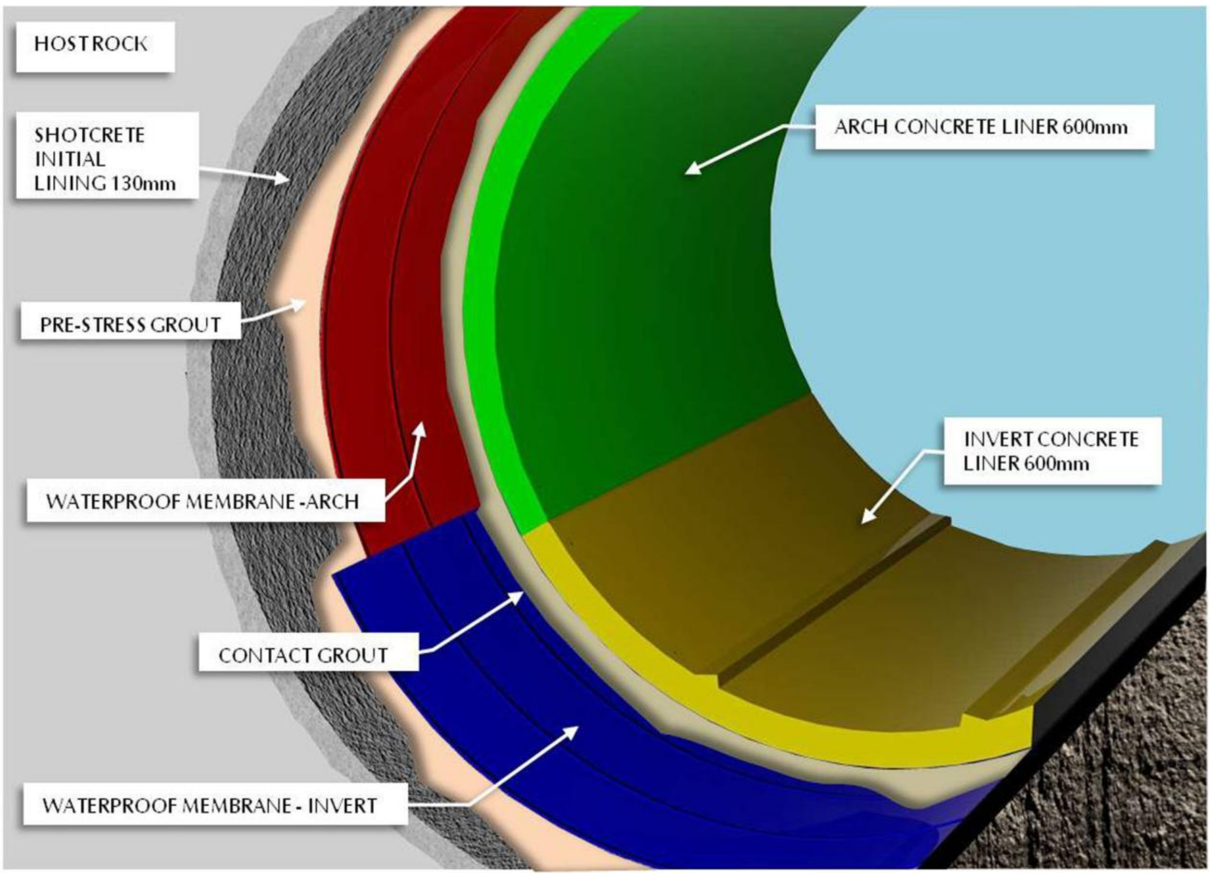
[31] The geotextile protective fleece consists of woven fabric material which is compatible with the waterproofing membrane material. It is backed by a thin plastic membrane on the surface facing the initial lining shotcrete, which facilitates the flow of interface grout. The geotextile fleece material and Velcro disks are attached to the shotcrete with nails. In the invert, gravity holds the membrane in place prior to pouring the concrete. In the arch, the Velcro disks hold the polyolefin membrane in place to facilitate seam welding, testing and concrete placement.

[32] The waterproof membrane is a durable and dense synthetic material. The membrane material is designed to meet high standards regarding the resistance to chloride ion diffusion.

complete and the membrane and seams are approved, a concrete liner approximately 600mm thick is poured over it and allowed to cure. The lining is illustrated in Figure 9 below.

Figure 9 - Tunnel Lining Details



The concrete lining was installed in 12.5 metre sections. Two 12.5 metre forms permitted daily advance of up to 25 metres. A purpose-built self-propelled bridge structure enabled the installation and testing of the membrane, and the pouring and curing of the invert concrete sections with minimal disruption to vehicle access through the tunnel. Invert concrete lining was completed on July 30, 2012.

Photo 12 - Testing of the Invert Lining

6.5.5.2 <u>Profile Restoration</u>

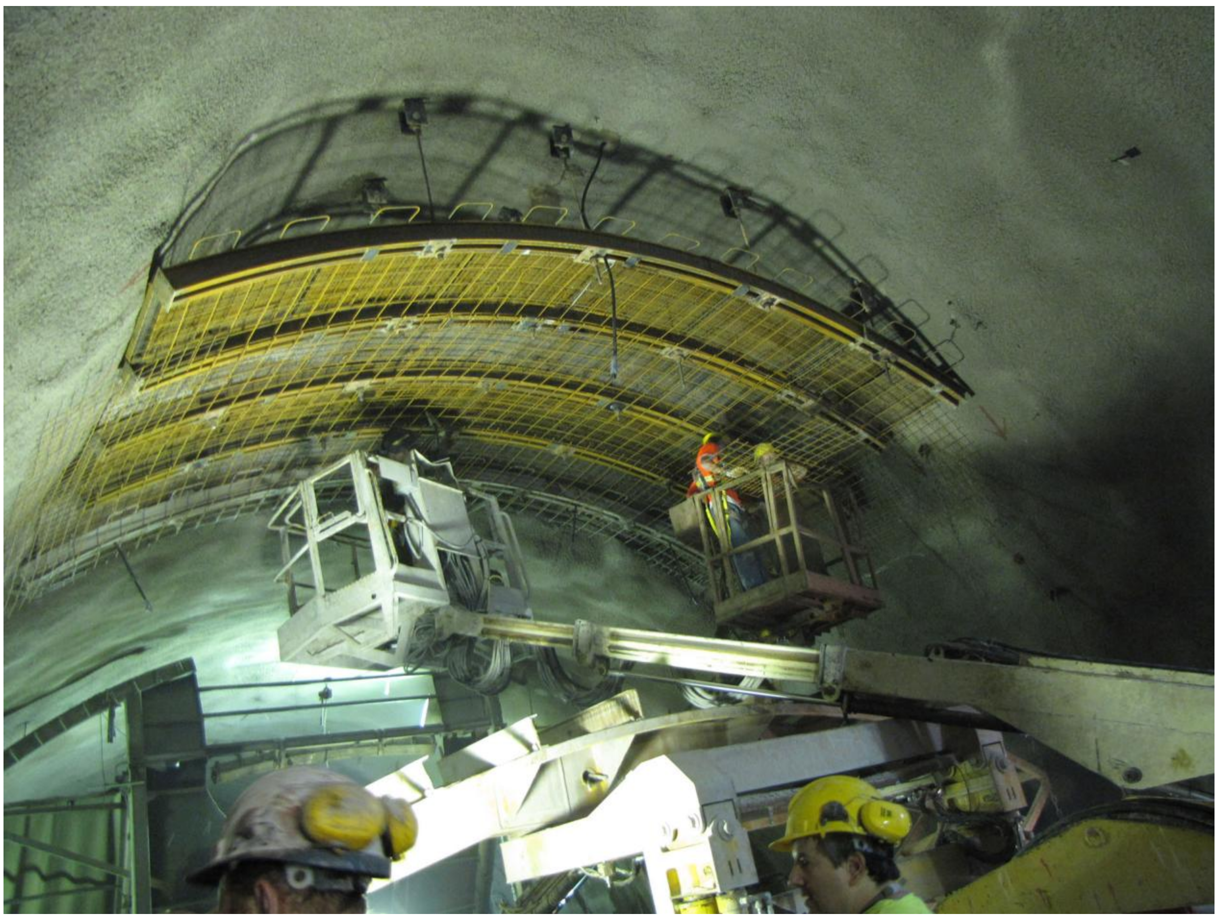
Profile restoration is the process of recreating the tunnel's circular shape. In some parts of the tunnel, considerable overbreak in the arch along the tunnel's top significantly altered the circular shape produced by the TBM. Profile restoration on the scale required for the NTP is not typical in tunnel construction, but was required because of the amount of overbreak experienced. As neither party anticipated this scale of restoration work, it was not included in the DBA. The amount of restoration work required the development of specialized equipment during the execution of the project.

Overbreak in the invert along the tunnel bottom was much less significant than in the crown. Where necessary, shotcrete also was used to restore the invert profile. Crown profile restoration work began in September 2009.

Photo 13 – Overbreak of more than 4 metres

In areas of overbreak, profile restoration is accomplished through the application of wire mesh, shotcrete, rock dowels, sacrificial steel forms and concrete with the particular approach selected depending on the extent and shape of the overbreak. As discussed above, the amount of overbreak varied significantly in different rock formations, reaching a maximum of over four metres in some areas. In areas with little or no overbreak, profile restoration only involved grinding to remove excess shotcrete applied as part of the initial lining. This was necessary to prevent reduction in the arch concrete thickness or radius, and to remove sharp surfaces that could damage the impermeable membrane. The circular shape and uniform concrete liner thickness are essential to facilitate specified compression of the concrete lining when injecting the pre-stress grout.

Photo 14 - Profile Restoration (Type 2)

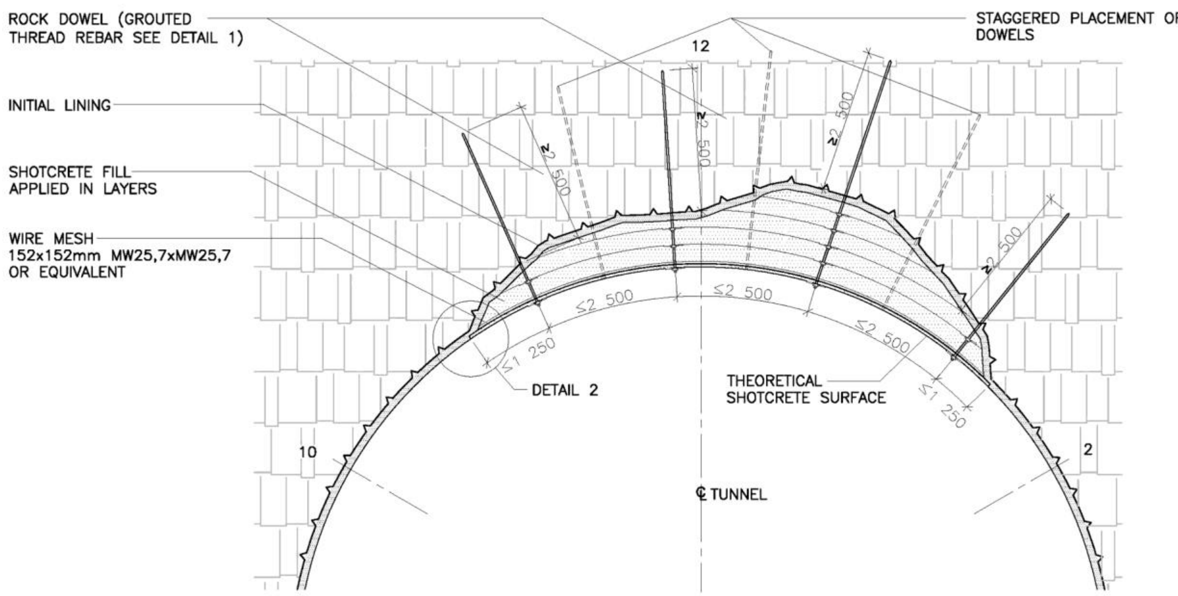


The following categories of profile restoration were employed:

- Type 1 for overbreak infill up to 1.5 metres, which requires drilling and installation of grouted anchors into the overlying rock, hanging threaded rods and wire mesh from the anchors, applying shotcrete to the required profile, and grouting to fill any voids; and

- Types 2a and 2b for overbreak infill over 1.5 metres, which requires drilling and installation of anchors into the overlying rock, hanging adjustable rods from the anchors, hanging prefabricated structural steel arches incorporating wire mesh and expanded metal, applying shotcrete to embed the steel arches, creating a form at the required profile, infilling the overbreak zone above the sacrificial form with shotcrete (Type 2a) or with concrete (Type 2b), and grouting to fill any voids.

Figure 10 - Restoration of Overbreak of Limited Depth/Volume (Type 1)



To accomplish profile restoration, Strabag initially used three different elevated work platforms:

- Carrier 1, for shotcrete grinding and installation of rock anchors, wire mesh and structural steel arch forms;
- Carrier 2, for applying shotcrete to infill Type 1 overbreak areas up to 1.5 metres, to coat structural steel arch forms used where overbreak exceeds 1.5 metre, and to infill above the arch forms; and
- Carrier 3, for cavity grouting to fill voids in the overlying rock and the interface between the initial shotcrete and the infill material.

To augment the capability of Carrier 1 and increase the pace of profile restoration, a fourth carrier (Carrier 0) was added in the summer of 2010 and began operation later that year. To further expedite profile restoration, the operation described above was augmented with additional mobile equipment including unique long boom drills and shotcrete robots.

In areas where inspection identified loose or cracked shotcrete in the tunnel arch, Strabag scaled the initial lining to remove the loose or cracked material and then repaired these areas with wire mesh, rock bolts and shotcrete. Convergence monitoring surveys and periodic visual inspections of the initial lining were used to detect rock movements in order to identify areas requiring remedial action including enhancement of the rock support where needed.

Profile restoration was completed on September 19, 2012.

6.5.5.3 Arch Lining

Arch lining is the process of installing the impermeable waterproof membrane and pre-stressed concrete liner in the upper two-thirds of the tunnel (the “arch”). The arch lining is similar to that used in the invert with the major difference being that the arch is lined with a single layer electrically testable membrane rather than the dual layer membrane used in most of the invert. This membrane is tested by passing an electric current through it. The test equipment measures the conductivity of each section. Damaged membrane results in “hot spots”, which are located visually or with the help of an infrared camera and repaired. The membrane is then retested to ensure no holes remain before concrete placement.

The membrane was installed using an Arch Membrane Carrier which positioned the membrane panels so that they could be attached by a Velcro system to the geotextile nailed to the initial shotcrete lining. After testing, the polyolefin panels were heat welded together and the seams tested. This process ensured that there were no leaks in the membrane before the arch forms were set and filled with concrete.

Photo 15 - Installation of Arch Membrane

The Arch Concrete Carrier has two moveable forms that are each 12.5 metres long. They are positioned and then the concrete is pumped above them and allowed to cure. The concrete is installed in alternating sections. Arch concrete was completed on November 6, 2012.

Photo 16 - Arch Concrete Carrier

6.5.5.4 Grouting

To ensure a uniform connection between the membrane and the concrete lining and fill any voids in the exterior curve of the concrete lining, low pressure contact grout is used. Contact grouting started in April 2011 and was completed on November 10, 2012.

The final concrete liner is then pre-stressed through the use of high pressure interface grouting injected between the initial shotcrete lining and the membrane through the use of pre-installed hoses. While the pre-stress grouting is being applied sensitive instrumentation is used to ensure that compression of the concrete liner is uniform around the tunnel. Pre-stress grouting started in August 2011 and was stopped for approximately a month starting on December 7, 2012 to facilitate the removal of the grouting and arch concrete carriers in the tunnel. Pre-stress grouting was completed on February 4, 2013, almost two months ahead of the ADBA target schedule.

6.5.5.5 July 2011 Fall of Ground

On July 2, 2011, a portion of the tunnel roof partially collapsed between 6,033 metres and 6,080 metres, resulting in about 1,200 m^3 of fallen rock and initial lining and rock support materials. No one was injured. The tunnel was initially shutdown from 5,933 metres to 6,130 metres to prevent access to the area. Strabag's consulting engineer and the MOL inspected the site along with the OR and Strabag staff. Following the MOL inspection, a Stop-Work Order was issued for the area between 5,983 metres and 6,130 metres, pending Strabag's submission of its engineering assessment and plans for safe remediation of the area. The Stop-Work Order for this area of the tunnel was in effect from July 5 to September 27, 2011.

The upper limit of the failure occurred in the Grimsby formation between 6,050 metres and 6,060 meters to a depth of approximately seven metres above the tunnel crown. Most of the failure was within a thinning wedge of the Power Glen shale/sandstone layer, which is comparatively stiffer than the overlying Grimsby shale rock mass and the underlying Power Glen shale. Horizontal stresses concentrate in this formation because the surrounding rock does not have the stiffness to withstand such stresses. Strabag's consulting engineer cited the overload of the initial support systems caused by these rock conditions as the primary cause of this fall of ground.

Photo 17 - Fall of Ground 2011

During the original excavation of the area in March 2010, stress-induced deformation occurred in the form of a small notch at about the 11:30 position. Rock support installed at the time consisted of the following elements:

- 4 metre friction anchors;
- steel channels in crown (“C-channels”);
- welded wire mesh;
- shotcrete, with a “slot” left in the shotcrete arch to allow deformation to occur without causing spalling, as had been a problem in other areas of the tunnel; and
- additional 4 metre field bolts.

3D monitoring arrays were also installed through this portion of the tunnel in March 2010. In association with these arrays, the following three threshold "trigger" levels were established to assess the stability of the excavation:

- at the "design" level, deformations were within the expected level and no action was required.
- at the "review" level, Strabag was to evaluate the specific situation and assess if any further action was required.
- at the "action" level, the stability of the tunnel excavation was jeopardized and immediate action was required to install additional support.

In November 2010, analysis of the survey monitoring data indicated that deformations in the fall of ground area were at the "review" trigger level. As a result, Strabag reviewed the situation and installed additional Swellex anchor bolts and mesh as a remedial measure. In December 2010, Strabag's routine inspection revealed that there was more convergence in the tunnel roof and monitoring data indicated accelerating movement. In addition, shotcrete cracking was observed on the crown. As a result of this deformation, additional review and geotechnical assessment of the rock reinforcement requirements was undertaken. Following this review, Strabag developed a supplemental construction drawing for the installation of additional support between 5,690 and 5,710 metres and between 6,000 and 6,160 metres. The drawing indicated that six metre long grouted "hollow bar dowels" on a two metre staggered pattern with an additional 130mm shotcrete layer and wire mesh were to be installed.

Areas approaching the "action" trigger level and areas showing acceleration were given priority for the installation of additional support. Before the fall of ground occurred, the additional support shown in the supplemental drawings was installed between 5,690 metres and 5,710 metres. By January 2011, monitoring data revealed movement between 6,000 metres and 6,160 metres, the area where the fall ultimately occurred, had decreased. This data was interpreted as indicating stabilization. Consequently, Strabag determined that, unless new movement occurred, installation of additional support in this area was not immediately required. The additional support work was scheduled for a planned shutdown starting on July 4, 2011.

Monitoring frequency for this area changed according to the rate of deformations recorded. Before the fall occurred, monitoring frequency had increased to twice a week and the area was kept under frequent visual observation. The last few readings at some arrays did indicate some acceleration of movement, but the established “action” trigger level was never reached before the fall occurred.

Bolts removed from the fall of ground area were tested in December 2011, and results indicated that the breakage was not an installation or manufacturing issue. Based on the information available, Strabag concluded that the most probable cause of the July 2, 2011 fall was the unique geological conditions at the local boundary between the Grimsby and Power Glen formations, in particular, the thickness, relative stiffness and redistribution of high horizontal stresses in the rock immediately above the tunnel excavation. This conclusion is supported by the fact that the bolts broke close to the Grimsby shale and Power Glen shale/sandstone interface. However, inadequate rock support measures and response to visual and survey monitoring signs of instability may have also contributed to the incident.

Strabag divided the required remediation into phases. Phase 1 involved stabilization of the tunnel on both sides of the fall between 5,900 metres and 6,170 metres. Phase 2 was rehabilitation and replacement of the tunnel rock support where it was damaged by the fall. Work on the two phases overlapped with the remediation being completed at the end of December 2011.

An insurance claim was submitted under the Builder’s All Risk policy to recover the cost of remedial work associated with the July 2011 fall of ground. The claim was subject to a $2M deductible.

In May 2012, the OR submitted a summary of the costs associated with the fall of ground work to the adjuster. The costs totalled approximately $17.6M, and included work done outside of the MOL mandated area, where reinforcement of the rock support was considered necessary to ensure the safety of the workers and equipment before entering and repairing the MOL mandated and fall of ground areas.

OPG received a letter from the insurance adjuster on August 13, 2012, which noted that, on the basis that the fall of ground itself did not exceed 100 metres, there is a $10M limit to the loss at hand. The adjuster's evaluation report attached to the letter found that substantiated costs based on the documentation received by the OR were only about $7.5M. In June 2013, after several information exchanges with the adjusters, the OR submitted a final revised cost summary, which reduced the claim amount to approximately $12.1M. Regarding the $10M limit, the OR pointed out that although the fall of ground may have been less than 100 metres, the area of damage associated with this loss significantly exceeded 100 metres. Ultimately, however, the insurers rejected this position, invoked the $10M limit and are expected to pay this amount by October 2013. This amount is relatively close (within $400k) to the amount by which the Target Cost in the ADBA was increased due to the July 2, 2011 fall of ground.

6.5.5.6 Swelling at Low Point

In the fall of 2009, it was noted that water from construction activities and surface water from the outlet portal was migrating under the invert concrete at the low point in the tunnel. The ingress of water had caused the invert liner to float, and created a concern for the potential swelling of the rock, a phenomenon that occurs when rocks of the Queenston formation come into contact with fresh water. A Notice of Defective Project and a Disallowed Cost Notice[33] were consequently issued to Strabag in November 2009 by OPG. As a temporary measure, Strabag installed sumps at the low point to remove the water.

[33] Under s. 1.1(O)(1)(ii) of the ADBA, any cost arising from or incurred as a result of repair or remediation of the Work to be carried out prior to Substantial Completion and due to the previous or ongoing presence of fresh water outside the impermeable membrane liner in any part of the tunnel contained in the Queenston, is a Disallowed Cost, and is not payable by OPG.

A program of testing and analyses was implemented to assess the extent of fresh water infiltration into the Queenston shale, the effects of swelling, the capacity of the liner to resist swelling loads and the effectiveness of the grouting process to seal any potentially damaged membrane. Since it was impossible to see below the invert concrete, testing and analyses considered worst case scenarios as well. In 2010, OPG retained Dr. K. Y. Lo of the University of Western Ontario to investigate the situation. A year later, in 2011, Dr. Lo's tests concluded that fresh water was present and that swelling had occurred at the low point. Strabag's design consultant, ILF, then proceeded to assess the effect of swelling and the capacity of the concrete liner to resist the swelling loads over the design life of the structure. ILF models demonstrated that the unreinforced concrete liner had sufficient structural capacity to resist all short-term and long-term loading, including the swelling loads caused by chloride ion diffusion due to water already trapped in the rock and water that would infiltrate into the rock through a damaged membrane over the life of the tunnel. An independent analysis carried out by the OR also confirmed that the as-built concrete liner had sufficient structural capacity to resist all applied loads including the swelling loads under all loading conditions for the life time of the tunnel.

In 2012, MFPA Leipzig Lab in Germany was contracted through ILF to further conduct independent testing of membrane integrity to confirm the as-built liner system's capacity to meet the design requirements and assess the effectiveness of grouting to seal any potential damage and restore the watertight barrier. The first series of tests showed that the membrane prevented water passage when it was intact, but also revealed that aggregate debris could damage the membrane under the invert concrete. A second round of tests with improved grouting and using as-built invert concrete samples were successfully concluded in November 2012. The tests were repeated to confirm the results.

Ultimately, the tests concluded that the liner system with the membrane damaged by debris and loading during construction and then grouted with contact and interface grout as per the construction specifications would effectively prevent water penetration into the rock and, therefore, prevent chloride ion diffusion from the rock for all loading conditions for the design life of the tunnel.

The OR prepared an additional report in February 2013 summarizing all the investigations conducted with respect to the low point swelling issue. It concluded that although the Queenston shale below the invert at the low point of the tunnel was exposed to infiltration of fresh water during construction, efforts to extract the water, repair the cracks in the concrete liner, and the application of contact and interface grouting effectively sealed any damaged membrane and prevented further water penetration into the rock. The OR determined that the as-built tunnel liner complied with the Owner's Mandatory Requirements and applicable code requirements.

7.0 DIFFERING SUBSURFACE CONDITIONS DISPUTE

7.1 Overview

The contract between OPG and Strabag provided for the establishment of a Dispute Review Board ("DRB") to assist the parties in dispute resolution as discussed in Section 5.0 above. Pursuant to those provisions, a DRB chaired by Peter Douglass, with P.E. Sperry and Dennis McCarry as members, was created. The DRB established procedures on how it would interact with the owner and contractor, keep informed of project progress through periodic meetings and offer informal advice when requested by both parties. The DRB also set the framework for formally resolving any matters presented through Dispute Requests. This framework required written materials, presentations at a hearing and a decision rendered in the form of written recommendations.

In May 2007, after almost nine months of tunneling, Strabag issued a Notice of Differing Subsurface Conditions ("DSC") pursuant to section 5.5(a) of the DBA. Strabag followed up by issuing Project Change Notice ("PCN") 17, which claimed that the actual rock conditions encountered were significantly more adverse than those described in the GBR between 806.50 metres and 839.70 metres. This notice was triggered by the fall of a large rock onto the TBM on May 16, 2007, which stopped tunneling for more than three weeks. PCN 17 claimed an unspecified increase in contract costs, to be determined once technical solutions to address the new rock conditions were developed and implemented.

Over the next six months, while tunneling continued, Strabag and OPG (through the OR) exchanged letters and other documentation about the existence of DSC with little agreement. On November 7, 2007, Strabag issued Dispute Notice 001, which sought to resolve this outstanding issue using the claims procedure in section 5.7 of the DBA or through an immediate referral to the DRB. OPG replied, stating that the dispute must be held in abeyance until tunnel boring is complete because it is covered by DBA section 5.5(c), which addresses rock support changes stemming from DSC. Strabag disagreed with this interpretation of the contract and urged OPG to allow this matter to be put before the DRB forthwith.

As mentioned above, at the end of November 2007, senior management at OPG and Strabag agreed to spend a maximum of three months attempting to resolve the dispute informally and develop a new tunnel alignment. These efforts proved unsuccessful and in mid-February 2008, the parties agreed that they had reached an impasse and would refer the matter to the DRB for a hearing as soon as possible.

On February 27, 2008 Strabag issued Dispute Notice 002 reiterating the position it took previously regarding PCN 17. This second notice continued to assert that the conditions encountered constituted DSC and further asserted that the financial responsibility for them rested with OPG as the owner.[34] The notice requested that the dispute be resolved pursuant to Section 11 of the DBA, which covers the DRB.

In early March the parties met with the DRB to establish the procedures and timing of the hearing. Both Strabag and OPG submitted questions in advance to the DRB to guide the discussion. Strabag's questions were as follows:

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[34] Dispute Notice 002 actually states that financial responsibility rests with the OR, but this is best viewed as either a typo or a shorthand reference to the owner.

- Does the amount of overbreak encountered in the tunnel exceed the baseline conditions described in the GBR, Sections 1.7, 8.1.2.6 and 8.1.2.7, and thereby constitute a Differing Subsurface Condition?
- Does spiling as it is being employed by STRABAG improve the rock conditions and thus reduce the amount of overbreak that would otherwise occur?
- Based on the Rock Mass Rating (“RMR”) values described in the GBR Table 6.8 and the GBR referenced 1976 Proceedings by BIENIAWSKI, Z. T., STRABAG expected a stand-up time of the crown of at least one day for the Queenston Formation to be encountered in the tunnel. Was this expectation reasonable?

OPG proposed that the dispute first address the issue of whether Strabag’s decision to employ different means and methods than those described in the DBA precluded a claim for DSC. The second issue that OPG proposed to be addressed, if necessary, was whether the dispute could be properly characterized as a claim for differing rock support under DBA section 5.5 (c), in which case it would not be considered until tunneling was complete and the rock conditions along the entire tunnel were assessed.

Based on this view, OPG submitted the following questions to the DRB:

- Pursuant to Section 5.4 of the DBA, to what degree is the behaviour of the geotechnical subsurface conditions attributable to a change or deficiency in Strabag's designs, means, methods, sequences, timing and level of workmanship? For greater clarity, to what extent is Strabag's inability to achieve the agreed TBM advance rates and any "excessive" overbreak the result of Strabag’s own designs, means and methods of construction?
- To the extent that the behaviour of the geotechnical subsurface conditions is not attributable to a change or deficiency in Strabag's designs, means, methods etc. under Section 5.4, is Strabag's residual claim covered by the procedure agreed by the Parties as set out in Section 5.5(c) of the DBA?
- Are the Rock Conditions set out in Geotechnical Baseline Report (“GBR”) Section 8.1.3.7, (Rock Conditions 1,2,3,4, 4Q, and 5, with Rock Condition 6 expressly covering

"any other rock condition not covered") an exhaustive catalogue of the types of rock conditions agreed to by the Parties as their geotechnical baseline?

- Is Strabag precluded from requesting an adjustment in the contract price or contract schedule for any differing subsurface conditions in respect of its work under the St. Davids Gorge by the provisions of DBA Section 5.5(e)?
- Is Strabag precluded from requesting an adjustment in the contract price or contract schedule for rock overbreak in excess of the baseline 30,000 m^3 set out in Section 8.1.2.7 of the GBR, other than for amounts pre-agreed to be reimbursed for disposal of rock overbreak and for application of shotcrete at unit rates set out in DBA Appendix 1.10?

The DRB discussed the possibility of establishing whether Strabag's means and methods were the source of the overbreak as a threshold issue as OPG proposed, but ultimately decided to hear the issues of Strabag's means and methods and the existence of DSC concurrently. The DRB established the type and order of presentations for the hearing that was held in June 2008.

7.2 Dispute Positions

7.2.1 Strabag

Strabag's fundamental position was that OPG remained responsible for the consequences of the geologic conditions different from those enumerated in the GBR and that the conditions actually experienced in tunnelling were different. Strabag claimed that DSC were evidenced by large block failures, excessive overbreak and inadequate "stand-up" time (i.e., insufficient time to install rock support prior to rock failure). Strabag further claimed that the Table of Rock Conditions and Rock Characteristics in the GBR failed to adequately describe the rock conditions encountered and either represented a DSC on its own, or alternatively confirmed the presence of DSC. Strabag's position was that any changes that it made to the means and methods of rock support were the result of DSC, rather than the cause of DSC. Finally, Strabag claimed that it was entitled to relief from DSC anywhere they were encountered, including under the buried St. Davids Gorge.

7.2.2 OPG

OPG's position was that no DSC existed. Subsurface conditions were as described in the GBR and Strabag's proposed design reflected these conditions. During the course of construction, Strabag substantially modified its TBM design and rock support by abandoning the use of a ring erector and full perimeter steel sets in the Queenston formation. Strabag stopped using full perimeter steel sets, as shown in its design, not because of ground conditions, but because it could not make the ring erector work. OPG also claimed that, to the extent any DSC existed, the DBA required that these be addressed after the tunnel was completed and that Strabag was solely responsible for conditions under the buried St. Davids Gorge.

7.3 Hearing

The hearing was held from June 23 through 26 in Niagara Falls, Ontario. It opened with presentations by Strabag, its design consultant ILF, and its three external experts. The external experts included the President of Robbins, the TBM manufacturer. The DRB asked questions during and after these presentations. With questions, the presentations took the entire first day of the hearing.

OPG's presentations were made by the various personnel from Hatch, including the OR Project Manager. In addition, OPG had four external experts present on geotechnical and design issues. OPG's presentation and the DRB questions on them occupied the entire second day of the hearing.

The third and fourth hearing days were taken up with rebuttal presentations and DRB questions. The hearing was closed at the end of the fourth day.

7.4 DRB Decision

The DRB issued its Report and Recommendations on August 30, 2008, some two months after the hearing concluded. While OPG's position was adopted on most issues, the DRB did find that excessive overbreak constituted a DSC and that the Table of Rock Conditions and

Characteristics was defective. Table 5 below shows the specific issues identified by the DRB and its findings on each issue.

Table 5 - DRB Conclusions and Recommendations

Issue	Finding
Large Block Failures	There is no DSC. The actual conditions were adequately described in the GBR.
St. Davids Gorge	Given the provision of the DBA Section 5.5 (e), the Contractor has no claim for any DSC in this section of the tunnel.
Insufficient Stand-Up Time	There is no DSC based on insufficient stand-up time, as the Contractor's reliance on Rock Mass Rating values stated in the GBR was inappropriate.
Excessive Overbreak	"There is a DSC with respect to the excessive overbreak, provided the defective provisions of the GBR are overlooked, because the GBR contained potentially misleading statements that make the Contractor's position reasonable. Any substantial changes in the designs, means and methods of the support (i.e., Type 4S) were the result of DSCs encountered and not vice versa. Since the development of the GBR was the mutual responsibility of both Parties, we recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible." DRB Report, pages 18-19
Inadequate Table of Rock Conditions and Rock Characteristics	"The Table of Rock Conditions and Rock Characteristics is inadequate to define the subsurface conditions that were encountered. More importantly, the classification of support types based on the "closest match" to rock conditions and rock characteristics given in this Table, together with rock characteristics defined as "all other conditions", renders the concept of DSCs essentially meaningless and the GBR defective. The DRB recommends that the Parties jointly revise the Table of Rock Conditions and Rock Characteristics in such a manner that it describes the rock characteristics to be assumed in terms that are mappable (or otherwise quantifiable) so that it can serve as a clear basis for defining DSCs throughout the remainder of the tunnel excavation. The DRB also recommends that the terms 'closest match' and 'all other conditions' be removed from the GBR." DRB Report, page19

The DRB's conclusions were unanimous. At the end of the document the DRB added the following additional finding:

> The DRB members have rarely experienced such an excellent, cooperative atmosphere between the Parties on a tunnel project. This is especially impressive considering the pioneering nature of the Work and the problems and issues encountered. The Board is confident that the Parties can negotiate an amendment(s) to the DBA that, while not commercially optimum for either Party, will allow the Project to proceed to optimum completion. DRB Report, page 19.

8.0 RESPONSE TO DRB DECISION

8.1 Identification and Assessment of Options

In response to the DRB Report, OPG in consultation with the OR concluded that four options were available:

- Negotiate changes to the existing DBA based on cost sharing as recommended by the DRB including revising the Table of Rock Conditions and Rock Characteristics and GBR as required.
- Settle all outstanding disputes with Strabag and negotiate a new target cost contract for project completion including incentives and disincentives based on cost and schedule to completion.
- Reject the DRB recommendations and pursue arbitration under the Rules of Arbitration of the International Chamber of Commerce as provided in the DBA (Section 11.5, as amended).
- Seek to replace Strabag with a new contractor to complete the tunnel.

These options are discussed in more detail below in Section 10.0, "Superseding Business Case."

OPG quickly concluded that the fourth option should only be considered as a last resort because of the cost and schedule consequences of locating, hiring and mobilizing a replacement contractor. While OPG remained concerned about schedule delays and Strabag's claimed cost overruns, OPG was generally satisfied with the quality of work

Strabag was doing on the project and with Strabag's continuing commitment to operate safely in the face of challenging rock conditions.

OPG also rejected arbitration as an initial approach. OPG concluded that there was no advantage in pursuing arbitration unless attempts at negotiation failed. Arbitration was seen to entail greater risk, require additional time and provide a less certain outcome than negotiation.

Ultimately OPG concluded that negotiation with Strabag toward a resolution of outstanding disputes and a path forward to complete the tunnel on a target price basis with risk/reward incentives was the preferred option to explore, as it encouraged continuing efforts to achieve or exceed targets. Strabag continued to perform well despite the fact that during this period rock conditions were particularly challenging and Strabag had to resume installing spiles to contain the overbreak, as discussed above in Section 6.5.4.2, "The Tunnel Drive."

The fact that Strabag continued working safely in these challenging rock conditions and continued to cooperate with OPG to complete the tunnel further supported OPG's view that negotiation was the preferred approach. OPG assessed that keeping Strabag engaged in completing the project would likely lead to the best result in terms of cost and schedule. Both OPG's senior management and OPG Board supported continued negotiations with Strabag rather than exploring the option of replacing Strabag with a new contractor. OPG also asked the external experts on the CLOC for their views and they too supported continuing to negotiate a revised agreement with Strabag.

8.2 Discussions with Strabag

After receiving the DRB Report, both OPG and Strabag filed arbitration notices, but each confirmed that the notices were filed only to preserve their respective rights under the agreement.[35] Both parties agreed that their joint focus over the next few months would be on negotiating a mutually satisfactory resolution of their disagreements and a path forward to project completion. To this end, Strabag agreed to bring forward two proposals to resolve existing disputes and move the project forward.

In early October 2008, Strabag submitted two options to OPG for resolving the current dispute and moving forward. Option A involved continuing the fixed priced approach in the DBA with additional cost included to reflect the rock conditions encountered and anticipated going forward. The bulk of the cost increase came from the addition of two new rock support types (4R and 4S) to reflect areas of substantial overbreak. Option A included per metre costs and estimated quantities (in metres) for each of these new rock support types. In addition, Strabag included its claimed cost for modifications to the TBM and a contingency amount for future TBM risks. Finally, this option included compensation for the extension of the project schedule. Taken together these costs were estimated at approximately $190M.

Strabag also estimated that the cost of pending claims, profile restoration and other future modifications would total an additional $90M, but indicated that this figure was only a preliminary estimate. Strabag proposed the elimination or renegotiation of the liquidated damage and early completion bonus provisions. All told, Strabag estimated the revised fixed price of the tunnel at approximately $910M under Option A.

In Option B, Strabag proposed converting the contract to a target price and reducing the overhead fee from 19 per cent to 12 per cent. OPG and Strabag would agree on a target price and schedule under this approach with the benefits of any cost savings and early completion to be shared equally between Strabag and OPG. This option also included two disincentives: the overhead fee would decrease as contract cost increased reaching zero per

[35] The DBA provided that a party who was dissatisfied with one or more DRB recommendations had 30 days to notify the other party in writing of its intent to commence arbitration (DBA section 11.1 (f) as amended). In order to preserve its right to seek arbitration if necessary, OPG provided the required notice of intent to commence arbitration because it disagreed with the DRB recommendations concerning excessive overbreak and the need to revise the Table of Rock Conditions and Rock Characteristics. Strabag similarly notified OPG in writing that it rejected all 5 DRB recommendations and intended to pursue arbitration.

cent at $1B; and the overhead fee would also be reduced for late completion reaching zero per cent if the project was six months late. The target price under this option would be $856M, a figure derived by reducing the price estimated for Option A to account for the reduction in overhead fee from 19 per cent to 12 per cent.

Strabag saw the following benefits from adopting Option B:

- It eliminates ongoing concerns about deficiencies in the GBR.
- It includes sufficient incentives to encourage the contractor to complete the project as quickly and cost effectively as possible.
- It allows all available resources, including the expertise of the OR, to be fully dedicated to optimizing project execution and developing innovative solutions to emerging issues.

Strabag's proposals were thoroughly considered by OPG, the OPG Board and the CLOC. OPG, in consultation with the OR, noted that neither of Strabag's proposals adequately captured the notion of a "fair and equitable sharing of the cost and time impacts" as recommended by the DRB. However, OPG also noted that as Strabag continued to do a good job and work safely on the project despite the difficult rock conditions in the tunnel, it was in OPG's interest to attempt to settle with Strabag. To that end, OPG's management recommended adopting a three-part negotiation strategy and counter-proposal:

- a lump sum payment to be made by OPG to settle Strabag's costs and claims to November 30, 2008;
- a revised contract effective from December 1, 2008 forward with a negotiated target price and schedule (similar to Strabag's proposal B); and
- incentives and disincentives to ensure completion of work.

Strabag and OPG had a number of meetings throughout October and early November of 2008. At these meetings the various options tabled by Strabag and OPG were discussed. Ultimately, the parties agreed to the approach reflected in the Principals of Agreement that captured both the advantages of Strabag's proposal B as well as OPG's attempt to incorporate a fair cost-sharing approach. The Principles of Agreement and the process of negotiating the ADBA are discussed in the following sections.

9.0 CONTRACT RENEGOTIATION

9.1 Agreed Approach

9.1.1 Principles of Agreement

OPG and Strabag ultimately developed a Principles of Agreement ("Principles") document which was based on a hybrid approach that included resolution of Strabag's claim for DSC in the Queenston formation and renegotiation of the DBA going forward. Both parties committed to complete the project in a safe, environmentally sound and expeditious manner and to reflect the DRB recommendations as they worked toward a revised agreement.

OPG agreed to pay Strabag $40M to resolve all issues to November 30, 2008. This figure reflected an effort to share Strabag's claimed losses of $90M. As a good faith gesture, OPG committed to make the $40M payment within 15 days of the Principles signing, but Strabag was required to provide OPG with a $40M letter of credit to cover the possibility that a final agreement would not be reached. OPG also had the right to audit Strabag's losses and to the extent that the full $90M was not substantiated in the audit, the $40M payment could be reduced proportionately.

Going forward, the tunnel would incorporate revised horizontal and vertical alignments to minimize boring in the Queenston shale.[36] The renegotiated contract would be based on a target cost and schedule. The target cost would be developed on an "open book" basis to reflect the reasonably estimated cost to complete the project. It would not include any profit, but would include a negotiated 5 per cent overhead fee (a reduction from Strabag's 12 per cent proposal) on allowed project costs and also would provide incentives and disincentives, as discussed below in Section 9.2.

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[36] As noted above, the horizontal realignment had already begun in early September 2008, some two months before the Principles of Agreement were signed.

The Principles further provided for the development of project management processes that would facilitate greater OPG involvement in project decisions, recognizing that Strabag would continue to direct and be responsible for the design and construction of the tunnel. The document also required that the future design build agreement be supported by adequate financial security and that Strabag maintain the existing design and construction team throughout the duration of the project except where Strabag provides substitute personnel acceptable to OPG. Finally, the document made clear that it was not the parties' intent to have the Principles affect existing performance warranties and guarantees.

In term of next steps, the Principles required that the parties negotiate a Term Sheet further delineating the provisions above.

9.1.2 Term Sheet

The Term Sheet envisioned in the Principles was signed on February 9, 2009. It confirmed and elaborated on the approach outlined in the Principles by making clear that:

- The cost and revenues of all claims for work conducted prior to December 1, 2008 are Strabag's in exchange for OPG's payment of $40M.
- The cost and schedule impact from claims arising from work conducted after December 1, 2008, shall be dealt with under the provisions of the amended agreement, which is to be based on a target cost approach.
- The cost of claims that bridge December 1, 2008, are to be apportioned between the parties in accordance with the first two bullets.

The Term Sheet detailed that the DBA provisions would remain in effect until the amended agreement was signed and that the new agreement would be retroactive to December 1, 2008. For the period between the signing of the amended agreement and December 1, 2008 ("the interim period"), OPG would pay Strabag the amounts necessary to reflect the difference between payments made under the DBA and those due under the amended agreement plus interest at the rate set out in the DBA.

The Term Sheet required that Strabag provide OPG with detailed cost information starting from December 1, 2008 and that it unconditionally open its books to OPG. The Term Sheet also required that Strabag continue its fixed price arrangements with its current sub-contractors and that Strabag obtain OPG's approval for any new subcontracts above a threshold amount.

Under the Term Sheet, the DBA was to be the starting point for the amended agreement and its terms would only be changed to reflect the target cost approach contained in the Principles. The Term Sheet also embodied the parties' agreement to develop protocols on how they will work together to complete the project as well as develop a target cost and target schedule. An important principle agreed in the Term Sheet was that to the extent applicable, the cost and schedule for project activities other than tunnel boring, rock support and profile restoration would not exceed the cost and schedule in the DBA for these other project activities (e.g., work on the intake, outlet and tunnel lining).

Pursuant to the Term Sheet, the parties negotiated a Memorandum of Understanding ("MOU") on the target schedule, signed on February 24, 2009, which established a new Substantial Completion date for the project of June 15, 2013. Based on the target schedule, an MOU on target cost was also negotiated and signed on April 7, 2009, which established a target cost of $985M for Strabag's work.

While the Term Sheet was prepared to facilitate the creation of an amended agreement, it was not itself a complete agreement. Many significant issues remained to be negotiated, such as the target cost and schedule details, the operation of the Steering Committee created to resolve disputes, and whether the occurrence of DSC should lead to a change in the target cost and schedule. Ultimately, these matters were all addressed and resolved in the Amended Design Build Agreement.

9.2 Amended Agreement

The original DBA was used as the base for the Amended Design Build Agreement ("ADBA"). Most DBA provisions were retained unchanged except as necessary to convert the agreement to a target cost contract.[37] Under the ADBA, OPG and Strabag agreed on a Target Cost of $985M, a contract schedule with Substantial Completion by June 15, 2013 and changes to the allocation of risk. Strabag will be entitled to its costs to complete the project and incentives will apply if it completes the project for less than the Target Cost or before the agreed Substantial Completion date. Conversely, disincentives will apply if the costs exceed the Target Cost or the project is late.

The ADBA defines Actual Cost as the $302M paid to Strabag prior to December 1, 2008 plus the accumulated Allowed Costs (defined below) from December 1, 2008 onwards, minus any proceeds from the sale of assets and any insurance payments received by Strabag. Actual Cost will be used to calculate the applicable cost incentives and disincentives which apply to Strabag. Strabag will be reimbursed for all costs it incurs to complete the project ("Allowed Costs") that are not specified to be Disallowed Costs in the ADBA. Disallowed Costs include items such as costs arising from Strabag's negligence, wilful misconduct or breach of Applicable Law, head office costs, interest costs, certain insurance deductibles, costs for warranty work, costs to correct or remove a defective part of the project and third party liability. Strabag also will be entitled to apply an overhead recovery fee of 5 per cent to Allowed Costs from December 1, 2008 onwards to cover the costs of head office support. OPG is to make monthly payments under the contract based on anticipated Allowed Costs for the coming month and true up the prior month's payments.

The Target Cost will be adjusted to reflect changes in costs for certain items, as baseline assumptions were included in the calculation of the Target Cost with the expectation that the Target Cost would be adjusted up or down to reflect actual circumstances such as, for example, changes in the baseline inflation assumption or diesel fuel costs.

[37] Capitalized terms in this section are defined in the ADBA, which is included in the CD of NTP Key Documents accompanying this Exhibit.

The Contract Schedule is based on a Substantial Completion date of June 15, 2013 and will be adjusted for certain events set out in the ADBA. The schedule is premised on the horizontal realignment that reduced the tunnel length by approximately 200 metres, and a vertical realignment which allowed the tunnel to exit the Queenston shale and move to the overlying rock formations where tunnelling conditions were expected to, and did in fact, improve. Certain incentive and disincentive payments described below are based on the Target Cost and Substantial Completion date.

Under the ADBA, if OPG's actions impact cost or schedule, then Strabag will be entitled to an adjustment in the Target Cost and Contract Schedule. This is to address provisions in the ADBA that either require Strabag to obtain OPG's consent for certain matters or that impose obligations on OPG, which may impact the Target Cost or Contract Schedule.

In addition to the payments described above, Strabag received an Interim Completion Fee of $10M upon completion of TBM mining activities on March 30, 2011 and was also entitled to a Substantial Completion Fee of $10M on March 9, 2013 upon achieving Substantial Completion. A Cost Performance Incentive/Disincentive will be calculated as 50 per cent of the difference between Actual Cost and the Target Cost as adjusted. A Schedule Performance Incentive of $200,000 per day is due for each day that Substantial Completion occurred before the June 15, 2013 date for Substantial Completion set out in the contract, unless this date is adjusted through a contract amendment.[38] If the project had exceeded the contract schedule, Strabag would have been required to pay OPG a Schedule Performance Disincentive of $67,000 per day for each day that the project exceeded the contract's Substantial Completion date, as adjusted. The agreement limits the maximum aggregate cost and schedule incentives to $40M and the maximum cost and schedule disincentives to $20M.

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[38] The Substantial Completion date has been extended by ADBA amendments. ADBA amendments are discussed below in Section 11.3.

Consistent with the original DBA, an incentive or disincentive will be applied to the extent measured flow deviates from the Guaranteed Flow Amount ("GFA") of 500 cubic metres per second by an amount which exceeds the plus or minus two per cent dead band. Strabag also continues to provide the warranties and financial guarantees contained in the DBA, including a parental indemnity, a Letter of Credit and a Maintenance Bond.[39]

The ADBA provides for adjustment to the Target Cost and Contract Schedule should a Major Risk Event occur. The adjustment mechanism is set out in the Major Risk Table in Appendix 5.3C of the ADBA. The Major Risk Events are as follows:

- main TBM bearing failure, except due to negligence;
- conveyor belt damage greater than 1 kilometre, not due to negligence;
- gas concentration above Ontario *Occupational Health and Safety Act* limits;
- water ingress greater than 100 litres/second;
- BTEX levels greater than threshold accepted by Ministry of the Environment
- unexpected subsurface geotechnical conditions requiring a material change to means and methods or having a material impact on cost and schedule;
- measured crown overbreak depth and volume greater than baseline only if progress slower than planned;
- critical marine work at intake area affected by operational constraints at the International Niagara Control Works; and
- unknown subcontractor claims.

The ADBA provides that disputes not settled at the project level are to be brought to a Steering Committee consisting of a senior representative from each of OPG and Strabag. The Steering Committee may resolve the matter itself or seek advice or non-binding recommendations from experts. As was the case in the original DBA, all unresolved disputes go to arbitration under the Rules of Arbitration of the International Chamber of Commerce ("ICC"), with arbitration normally occurring only after Substantial Completion unless the

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[39] In the ADBA the amount of the Maintenance Bond is set at up to 10 per cent of the Target Cost. Strabag and OPG have agreed to a Maintenance Bond of $50M, or approximately 5 per cent of the Target Cost.

Steering Committee members mutually agree to submit a dispute to ICC arbitration at an earlier date.

10.0 SUPERSEDING BUSINESS CASE AND REVISED PROJECT BUDGET

While the ADBA was being finalized, OPG began preparing a Superseding Business Case Summary ("Superseding BCS") to seek approval from the OPG Board for the target cost and schedule.[40] OPG management had kept OPG Board apprised of the status of negotiations through updates to the OPG Board's Major Projects Committee ("MPC"). The MPC had reviewed the Principles of Agreement prior to their adoption and endorsed management's decision to negotiate a revised agreement with Strabag based on a target cost and schedule. The Superseding BCS was the vehicle to seek formal OPG Board approval of the new contracting approach and the resulting target cost and schedule.[41]

The Superseding BCS included a summary of progress on the project and the difficulties encountered in tunneling, leading to the DSC dispute before the DRB. It then summarized how the project will be executed under the ADBA.

Schedule and cost variance explanations were also provided in the Superseding BCS. Some of the primary drivers cited for the schedule variances are:

- Slower than planned TBM progress due to worse than expected conditions in the Queenston shale once the tunnel passed the St. Davids Gorge.
- Expectation of continuing challenges as the tunnel ascends to higher rock strata and undertakes more mixed-face mining.[42] Some of the rock types in the upper formations are harder and more abrasive, causing greater cutterhead wear and requiring more frequent cutter replacement. The mixed face conditions also produce "eccentric loading"

[40] The full OPG Board approval package for the Superseding BCS is contained in the accompanying CD of NTP Key Documents.

[41] The ADBA was signed in mid-June, after OPG Board had reviewed and approved the cost and schedule variances for the project based on the Superseding BCS.

[42] Mixed-face mining occurs when the TBM is boring different rock types at the same time. For example, as the tunnel elevation increased, the top of the TBM was mining Whirlpool Sandstone while the bottom was in Queenston shale. When these rock types differ in hardness, it causes uneven loading on the TBM cutterhead.

on the cutterhead that necessitated reducing the penetration rate to less than 1.5 m/hr in order to avoid damaging the TBM main bearing.

- Restoring the tunnel to a circular profile ("profile restoration") is an additional task that was not included in the original schedule. Profile restoration must be completed prior to installing the arch membrane and concrete lining. Undertaking this operation concurrent with the mining, invert lining and arch lining operations added significant complication and risk to project logistics.
- Additional time to allow for removal of tunneling equipment before removal of the cofferdam at the intake structure.

The forecast cost changes between the DBA and the ADBA are shown in Table 6 below. The bulk of the increase is attributable to the tunnel contract (including contingency), but the longer schedule also increases the cost of maintaining the OR on site and interest cost.

Table 6 - Cost Changes between the DBA and the ADBA

Project Cost Flow Estimate ($M) (including Contingency)	Original Approval (DBA)	Revised Estimate (ADBA)	Variance	Variance (%)
OPG Project Management	4.4	6.0	1.6	36
Owner's Representative	25.4	40.4	15.0	59
Other Consultants	4.0	5.9	1.9	48
Environmental / Compensation	12.0	9.6	(2.4)	-20
Tunnel Contract (including Incentives)	723.6	1,181.7	458.1	63
Other Contracts / Costs	78.9	69.8	(9.1)	-11
Interest	136.8	286.6	149.8	110
Total Project Capital	985.2	1,600.0	614.8	62

There were four alternatives presented in the Superseding BCS. In addition to the recommended alternative of proceeding under the target cost and schedule approach negotiated in the ADBA, the following three alternatives were considered and rejected:

- Continue under the DBA – This alternative was rejected because OPG concluded that it would lead to Strabag abandoning the project based on projected costs of over $300M more than the contract price under the DBA. Under this approach, Strabag would have been expected to continue tunneling under difficult conditions and to experience an ongoing revenue loss in the hope of receiving some unspecified additional compensation upon project completion. This approach would have also ignored the DRB recommendation that OPG and Strabag work toward finding an equitable solution to resolve the dispute between them. Were Strabag to have abandoned the project, the result would be an extensive delay to obtain a new contractor, additional cost and protracted litigation, as discussed in Alternative 2 below.

- Engage Another Contractor to Complete the Project – This alternative was not recommended. The market for contractors with suitable experience in two pass tunneling with waterproof membrane and pre-stress concrete lining technology and installation techniques is very limited. Thus, there was no guarantee that a suitable contractor would be found to take over the project using the existing methods and equipment. OPG estimated that if a suitable replacement contractor could be found, it would take 18 - 24 months to engage this new contractor and bring them up to speed. Engaging a new contractor would also result in higher costs because a new contractor would require actual cost plus markup to complete the project. Under this approach, OPG also would lose the benefit of the substantial knowledge gained by Strabag in constructing the tunnel. Finally, OPG would need to expend considerable legal resources in an attempt to recover damages from Strabag with no guarantee of success.
- Cancel the Project – This approach was not recommended because it would result in a total expenditure of $563M with nothing to show for it. This figure consisted of $463M that had already been expended plus an additional $100M to secure the site in a safe and environmentally acceptable state. Adopting this alternative would cause Ontarians to forego at least 90 years' worth of additional clean renewable energy at the Sir Adam Beck generating stations. OPG also recognized that there would be a low likelihood of recovering the $563M of project costs in rates if it were cancelled.

The Superseding BCS updated the financial analysis contained in the original BCS for the project's increased cost and new completion date. This is shown in Table 7 below.

Table 7 - Superseding BCS Financial Analysis

Financial Measure	Original Approval July 28, 2005 ($985M; June 2010 In-Service)		Superseding Release May 21, 2009 ($1.6B; Dec. 2013 In-Service)	
		in 2009 $		in 2009 $
LUEC (¢/kWh)	(2005$) 4.8	5.2	(2009$) 6.8	6.8
PPA (¢/kWh)	(2011$) 6.7	6.7	(2014$) 9.5	9.4
Revenue Requirements (¢/kWh)	(2011$) 5.8	5.6	(2014$) 8.7	7.9
Revenue Requirements Post GRC Holiday (¢/kWh)	(2021$) 9.4	7.4	(2025$) 13.0	9.5

Based on the information in Table 7, the Superseding BCS evaluated the cost of the NTP against various metrics including the price being paid for hydroelectric energy under the Feed-in-Tariff contracts and the projected impacts on the payment amounts for regulated hydroelectric production. Based on these comparisons, the Superseding BCS concluded that the project remains an attractive source of clean energy. The sensitivity analysis included in the Superseding BCS confirms that this conclusion remains valid across a broad range of scenarios.

Based on the Superseding BCS, OPG Board approved a revised maximum budget of $1,600M and an in-service date of no later than December 31, 2013 for the project and authorized management to execute the ADBA on behalf of the corporation. OPG Board also authorized the request for an increase of the credit facility with the OEFC to $1,600M to reflect the new project budget.

11.0 CHANGES UNDER THE ADBA

11.1 Cost and Schedule Tracking Under the ADBA

While many aspects of project management and controls that existed under the DBA were retained for the ADBA, certain changes were introduced to reflect the target cost and schedule approach in the ADBA. Changes were made in cost and schedule management procedures by OPG, the OR and Strabag to facilitate timely tracking of allowed expenditures relative to the Target Cost and progress against the target schedule. As there is significant interrelationship between cost and schedule, slippage in the schedule was seen to provide an early warning of potential cost increases. Thus, schedule control was viewed as key to controlling cost because significant deviations in project costs were most likely to result from schedule deviations.

To manage the schedule, the location of each principal tunnel construction activity (TBM mining, invert concrete, profile restoration, arch concrete, contact grouting, and pre-stress grouting) was tracked as it progressed through the tunnel. This tracking allowed for timely reporting of progress and variation from the target schedule.

Strabag developed and submitted a computerized version of the baseline target schedule that aided in the identification, tracking and monitoring of critical path activities. Strabag updated this schedule monthly to document progress against the baseline, to recalculate the critical path and to forecast Substantial and Final Completion dates. This schedule was reviewed by the OR and any necessary revisions were made before it was accepted. The Schedule Performance Incentive/Disincentive in the ADBA also worked to encourage timely completion of the project and helped ensure that the interests of OPG and Strabag were always aligned.

Cost for each of the key tunnel construction activities listed above (and later on for specific critical path activities such as cofferdam removal and rock plug removal) were also tracked by Strabag, the OR and OPG. Strabag agreed to upgrade its financial software package to a more robust system that facilitated enhanced reporting, analysis and audit. Key elements of ongoing cost management included:

- 24/7 on-site presence by the OR;
- ongoing monitoring for Disallowed Costs;
- a Request for Expenditure ("RFE") process covering any project expenditures over \$100k;
- an "Open Book" approach whereby Strabag's books and accounts were available for review on an ongoing basis;
- OR review of Strabag's books and records;
- monthly detailed review of invoiced amounts conducted by a third party accounting firm engaged by OPG; and
- a supplemental review of the monthly invoices by the OPG project management team and OPG Finance.

The following metrics were used to analyze schedule and cost progress:

- Budgeted Cost of Work Scheduled ("BCWS") based on the monthly breakdown for key tunnel construction activities from the agreed target schedule and Target Cost;
- Actual Cost of Work Performed ("ACWP") based on contractor invoices and actual month-end progress for the key activities; and
- Budgeted Cost of Work Performed ("BCWP") based on estimated cost to achieve the actual month-end progress for the key activities.

For each of the principal tunnel construction activities the following index ratios were used to indicate progress. The Schedule Performance Index ("SPI") is the ratio of the dollar value of the work performed to the dollar value of the work scheduled to be performed (SPI = BCWP/BCWS). These figures indicated, based on value, how much of the work schedule was actually accomplished. The Cost Performance Index ("CPI") is the ratio of budgeted cost to the actual cost for work performed (CPI = BCWP/ACWP). This indicated how the forecast cost of work performed compared to the actual cost of completing this work. These ratios were reported to OPG senior management on a monthly basis to enable them to track schedule and cost performance for each major activity on the project.

11.2 Audits Under the ADBA

11.2.1 <u>2009 Audit</u>

OPG's internal audit group conducted an audit of the 2009 project costs that Strabag invoiced OPG for the NTP. The purpose of this audit was to independently assess Strabag's compliance with the provisions of the ADBA relating to Allowed Costs. For the twelve month period, Strabag invoiced OPG approximately $144M related to project costs incurred in 2009. The audit examined approximately 30 per cent of the total costs billed including costs incurred for both suppliers and labour.

The audit found that with one exception, the 2009 project costs reviewed were in compliance. The one exception was some $5,000 in interest charges resulting from late payment of monthly utility bills that were incorrectly invoiced to OPG. These charges are a Disallowed Cost under the ADBA. Strabag typically reversed these charges from the next month's invoice, but in a few instances did not do so, which led to the Disallowed Costs remaining in the invoices to OPG. This was promptly corrected.

The audit also found that the roles and responsibilities of the various parties reviewing the project costs needed to be clarified. The OR, OPG's local accountants and OPG staff all needed to have a better understanding of their respective roles in reviewing Strabag's invoices so that this task could be accomplished in a comprehensive and efficient fashion. To accomplish this, the audit recommended that these parties document the oversight accountabilities and associated processes and controls that are in place. Based on this documentation, any identified gaps should be addressed. The audit also recommended that OPG's audit group not take part in the invoice verification process in a management capacity because of a conflict with the group's mandate to maintain independence from management processes.

OPG management accepted and implemented the audit recommendations.

11.2.2 <u>2010 Audit</u>

In 2010, OPG's audit group conducted a second audit to independently assess OPG's processes to manage the more significant execution phase risks of the NTP such as schedule, cost, scope and change control, reporting, quality and safety. Overall, the audit found the processes and controls to manage these risks to be generally adequate and it assessed the enterprise-level risk implications of the findings from the audit as moderate. The rating of "generally adequate" is defined by OPG's audit group to mean that sufficient controls are in place and generally operating effectively with some improvements required.

The areas identified for improvement were noted as:

- instances where OPG did not properly exercise project oversight because it did not review and comment on key documents, did not enforce the requirement that Strabag perform an environmental audit on its environmental construction activities, and did not audit the OR against the Project Execution Plan;
- reporting of permanent works deficiencies from the OR to OPG is inconsistent and insufficiently transparent; and
- the calculation of the overall project Schedule Performance Index ("SPI"), when initially reported, did not sufficiently reflect the importance of critical path activities.

The audit recommended that the OPG Project Director review and provide input to key documents and procedures on a timely basis and ensure that required audits of Strabag and the OR are performed. While noting that the OR had effective controls in place to monitor non-conformance and deficiencies for permanent construction work, the audit recommended that the OPG Project Director and the OR work together to establish a structured reporting format that identifies recurring problems, trends, corrective and preventative actions, and cost implications. The audit also recommended improvements to the SPI calculation, but noted that the recommended change had already been made before the audit was complete.

OPG management accepted the recommendations and undertook actions to address them.

11.2.3 2011 Audit

In 2011, another audit was undertaken to assess the effectiveness of contract management processes and controls established by OPG to monitor costs under the ADBA. This audit report began by acknowledging a number of actions that OPG had taken to mitigate the financial risk arising from the ADBA. These include:

- structuring the ADBA as a target price contract with incentives and disincentives related to cost and schedule performance;
- maintaining the OR on site to provide contract administration, design review and construction monitoring; and
- retaining a local accounting firm to verify that Strabag's invoiced amounts are supported by Strabag financial records for items such as payroll, subcontractor costs and materials.

The audit concluded that, while the above measures provide some assurance, controls over cost management and procurement, including supporting documentation, required improvement. The audit found that there was a lack of documentary evidence that the OR's monitoring and analysis of Strabag's performance and progress was being used to critically evaluate project costs. The audit confirmed that the OR's field monitoring reports demonstrate that the OR has detailed knowledge gained from daily presence on the job site. However, due to the lack of formality and documentation of the OR invoice review process, the audit was not able to confirm the control effectiveness of the OR's cost management oversight. The audit recommended that the OR's cost control procedure be formalized by providing documentation and that the OR retain evidence of its detailed review of the actual charges. The audit also recommended that OPG staff increase their on-site presence through participation in monthly invoice review meetings with the OR and Strabag.

OPG management accepted the recommendations and agreed that the OPG Project Director would work with the OR to improve the monthly invoice review process. The agreed-on improvements included documenting both the revised procedures for the OR and the actual monthly reviews conducted for each Strabag invoice. The monthly review process would also address the reasonableness of estimated amounts, and the reasonableness and accuracy of reconciled amounts relative to independent progress records maintained by the OR. Additionally, any variances would be explained, as necessary. OPG management also committed to having an OPG representative regularly participate in monthly invoice review meetings.

The audit also noted that procurement documentation maintained by Strabag for major project expenses required improvement. Under the Request for Expenditure ("RFE") provision of the ADBA, Strabag was required to seek pre-approval of all expenditures above $100k. While the audit acknowledged that the RFE process was designed to ensure sound procurement decisions, it found a lack of sufficient documentation to confirm that the process was consistently applied. It recommended that Strabag create and retain formal files to provide assurance that procurement activities were effective and supportive of OPG's cost management objectives.

OPG management accepted this recommendation and agreed that the OPG Project Director would work with the OR to ensure that documentation associated with past and future RFE procurement activities complies with the agreed documentation standard. OPG Management also committed to confirming that the previous RFE procurement decisions were valid. To this end, the OPG Project Director worked with the OR to implement a system to track and document all RFE expenditures relative to the approved amounts and vendors. Finally, the OPG Project Director also committed to confirming that all Strabag expenditures requiring RFE approval under the ADBA have been accepted by OPG and that no associated expenditures exceed the approved amount. All agreed actions were completed.

11.2.4 <u>2012 Audit</u>

The objective of the 2012 Audit was to independently assess OPG, the OR and Strabag project management processes and controls and to provide reasonable assurance about their effectiveness. The audit scope included a review of the management processes and controls for risk, cost, and schedule management as well as a review of organizational roles and responsibilities related to these processes. It also included an assessment of the 2011 Audit findings to ensure all recommendations had been effectively implemented.

OPG's audit group again rated the project management processes and controls to be "generally adequate" with an enterprise level impact of "moderate". The audit concluded that all action plans in the 2011 Audit had been successfully implemented, and that the project had made substantial progress in dealing with the overbreak and fall of ground conditions that had posed significant schedule challenges for the project in the past. Having made substantial progress to recover project schedule, the 2012 Audit recommended that the NTP team focus on planning its remaining commissioning and close-out activities, and capture these remaining tasks in detail within the project's schedule and forecasts to continue supporting the objectives of on-schedule and on-budget completion.

A number of work elements were identified by the 2012 Audit as requiring more detailed planning in order to demonstrate with high confidence that the project will meet its final cost and schedule objectives:

- Intake Gate
- Outlet Gate and Hoist
- Approach Wall Completion
- Tunnel Cleanout
- Cofferdam Removal
- Rock-Plug Removal
- Demobilization Efforts
- Site Restoration Work

In addition to the above, the audit noted that detailed planning must also be expanded to include all administrative project closeout activities, such as, for example, tracking of as-built drawings, test data sheets, operation manuals, maintenance manuals, and transfer to OPG of all records and submittals required to successfully close-out the project.

Furthermore, the audit found that the project lacked a formalized process for the recovery of costs associated with the disposal of surplus goods. The NTP has an asset listing detailing approximately $19.1M (book value) in major equipment (vehicles, cranes, heavy equipment, temporary buildings, etc.) and the ADBA required all proceeds from the sale of surplus goods be credited back to the project as cost recoveries.

OPG management accepted the recommendations of the 2012 Audit and developed and implemented an action plan to address them.

11.3 ADBA Amendments

11.3.1 Amendment No. 1

The first ADBA Amendment was executed on July 25, 2012. It incorporated most, but not all, of the Project Change Directives ("PCD"s) that have been issued since the contract was renegotiated. It also recognized changes to the Target Cost resulting from a number of PCD Deemed Amendments,[43] and transfers of funds between items within the Target Cost that do not change the overall scope of the work or the Target Cost.

ADBA Amendment No. 1 increased the Target Cost by approximately $9M and revised the cost allocation outlined in Appendix 1.1 (TTT) of the ADBA for the purposes of cost control, cost projection and cost performance indices. The revised Target Cost is about $994M. Moreover, Amendment No. 1 increased the Substantial Completion date by 17 days from June 15, 2013 to July 2, 2013. This change was a result of an adjustment for crown overbreak, determined in accordance with the Major Risk Table at Appendix 5.3C of the ADBA.

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[43] Section 5.1(d) of the ADBA states that any PCD that does not direct, or provide OPG's consent to, a material change to the Work, the Target Cost or the Contract Schedule, will be deemed to be an Amendment.

11.3.2 Amendment No. 2 (Pending)

ADBA Amendment No. 2 will formalize any PCDs issued subsequent to Amendment No. 1 and disposition Strabag's claims for adjustment of the Target Cost and target schedule due to:

- agreed scope changes,
- fall of ground impacts,
- escalation exceeding the baseline,
- diesel fuel costs exceeding the baseline, and
- incremental sub-contractor costs for gate installation, cofferdam removal and rock plug removal.

12.0 PROJECT COMPLETION

12.1 Disposal of Surplus Goods

Under the ADBA, OPG became the owner of all goods that were purchased by Strabag to construct the NTP, with the exception of the TBM and TBM accessories. Since the ADBA is a Target Cost contract, Strabag's and OPG's interests are aligned in maximizing the value of any recovery from the sale of surplus goods because any amounts recovered lower the final Actual Cost, which benefits both parties.

Strabag initially made an offer to purchase some surplus equipment for about $4.8M. After consideration, OPG and the OR decided to reject the offer because it was unclear that the offer captured fair market value for the equipment. Instead, OPG directed Strabag to submit a plan for disposing the surplus goods in the most cost effective, competitive and transparent manner. A number of options were considered:

- restocking or supplier buy-back;
- sell to specific buyer;
- auction;
- sell at scrap price; and
- disposal.

In order to ensure that the project received the best value for the surplus goods, Strabag employed different disposal strategies for different categories of goods. For each type of surplus good, the above disposal methods were ranked in order of their likelihood of providing the maximum credit to the project. The disposal method with the highest rank is to be employed first and if unsuccessful, a method with a lower rank would be employed. For example, stock items were to be restocked with the vendor/supplier if the restocking fee was determined to be reasonable and likely to produce the highest recovery. For standard construction equipment, structures, and items not restocked, it was determined that an unreserved auction would likely produce the best price. All items would be sold as scrap if they cannot be sold otherwise, and items would be disposed of as a last resort.

Strabag issued an RFP on March 26, 2013 for proposals seeking an auctioneer with an extensive network for buyers of construction equipment on the global market. On April 25, 2013, after having conducted site visits with multiple proponents, OPG accepted Strabag's recommendation to retain Ritchie Brothers Canada Ltd. ("Ritchie Brothers") to auction the surplus goods. Under the contract between Ritchie Brothers and Strabag, Ritchie Brothers received a straight commission rate of 10 per cent on the realized proceeds. All proceeds from the sale, less the commission, would be a credit to the project.

The auction was successfully completed on June 17 and June 18, 2013. The equipment was sold "as is" and "where is". The inventory was sold for a total of about $5.6M for a net return to the project of about $5M. A further auction will take place in September 2013 for the disposal of site offices.

12.2 Site Restoration

Under the ADBA, Strabag is obligated to restore all areas of the site it has disturbed to pre-project conditions, and to provide restoration plans to OPG for review.[44] Sites to be restored were the intake and outlet construction areas and locations where concrete drop shafts were installed (3,369 metres, 5,318 metres, and 8,002 metres). As the intake construction area is located on lands leased from the NPC, Strabag worked with the NPC to develop the intake restoration plan.

All site restoration activities are expected to be complete by the fall of 2013.

12.3 Flow Verification

Under section 8.3 of the ADBA, a flow verification test is to be conducted within two weeks of the Substantial Completion date to determine the as-constructed flow capacity rating for the tunnel and any variance to the Guaranteed Flow Amount (“GFA”) of 500 m^3/s. The flow test was conducted using an ultrasonic flow meter system that determined the flow rate by sending pulses between transducers located on the walls of the tunnel near the outlet structure.

The flow verification test was executed under the Chief of Test, Alden Labs, and witnessed by representatives from Strabag, the OR and OPG. The flow verification test was originally scheduled for March 2013, but was aborted due to unsuitable ice conditions at the intake site. The test was rescheduled for the week of July 22, 2013. On July 23 and July 24, the flow test was successfully completed. Alden Labs confirmed that the flow capacity for the tunnel was 495.1 m^3/s, which is within the $\pm$2 per cent allowed for measurement error under the ADBA. Consequently, no incentive or disincentive applied.

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[44] Sources of the restoration obligations are: s. 2.2.5 of Appendix 1.1 (vv) – Owner’s Mandatory Requirements of the ADBA; s. 1.2.1(bbb) of Appendix (rrr) –Summary of Work of the ADBA; s. 1.3.1 of Appendix (rrr) –Summary of Work of the Draft Design/Build Agreement which refers to EA Approval Condition Number. 7.2(c); s. 12.3 of the Environmental Assessment.

12.4 Asset Turnover

The OPG Project Director developed an asset turnover summary to provide an overview of the physical assets and other materials to be transferred to the Niagara Plant Group ("NPG") in order to facilitate operation and maintenance activities. It also outlined the securities and warranties that are available to OPG during the warranty period.

On March 9, 2013, after Substantial Completion of the NTP was achieved, the NPG accepted transfer of operating control over the tunnel, including the intake and the outlet gate and hoist. OPG expects that the transfer of operating control to the NPG over the outlet and intake sites will occur prior to Final Completion. Documentation and records will be transferred to the NPG in accordance with the NTP Documentation Turnover Plan.

12.5 Schedule

The NTP's Substantial Completion occurred on March 9, 2013, well in advance of the revised target schedule date.

Strabag continues to be engaged in site restoration, disposal of surplus goods and preparation for documentation turnover. Final Completion, when Strabag's activities are done, is now expected to occur by October 31, 2013, at which point Strabag's contract will be complete. The OR's activities will then be complete by the end of 2013. A complete project close-out is projected for July 31, 2014 following the completion of groundwater monitoring obligations and the sealing of boreholes and wells.

12.6 Estimated Project Cost to Completion

Table 8 below presents the estimated costs to completion for the NTP as of June 30, 2013 and compares them to the costs in the Superseding BCS. As explained above, due to ongoing project close-out activities, these costs will change slightly. If the cost changes are material, OPG will update this estimate. In any event, cost changes will be captured in the Capacity Refurbishment Variance Account as discussed above in Section 1.2.

Table 8 - Total Project Capital

Item	Original Release	Superseding Release BCS	Actual Costs to June 30, 2013	Estimated Cost at Completion (as of June 2013 forecast)	Delta To Superseding	% Difference
OPG Project Management	4.4	6.0	4.4	4.6	-1.4	-23%
Owner's Representative	25.4	40.4	35.2	36.2	-4.2	-10%
Other Consultants	4.0	5.9	6.2	6.5	0.6	10%
Environmental / Compensation	12.0	9.6	8.7	8.7	-0.9	-9%
Tunnel Contract (including Incentives)	723.6	**1,181.7**	**1,095.4**	**1,140.8**	**-40.9**	**-3%**
Mobilize/Demobilize	*31.7*	*31.0*	*30.4*	*32.1*	*1.1*	*4%*
Maintenance Bond	*2.2*	*0.7*	*-*	*0.7*	*-*	*0%*
Performance LC	*1.0*	*5.4*	*6.8*	*7.2*	*1.7*	*32%*
Insurance Premium	*2.7*	*4.3*	*2.6*	*2.7*	*(1.6)*	*-37%*
Design	*5.9*	*9.7*	*11.7*	*11.6*	*1.9*	*20%*
Intake Channel and Walls	*54.9*	*64.8*	*67.4*	*67.4*	*2.6*	*4%*
Diversion Outlet Canal	*12.7*	*12.9*	*15.4*	*15.4*	*2.5*	*20%*
Dewatering Shafts	*3.8*	*3.6*	*3.8*	*3.8*	*0.1*	*4%*
Intake Structure	*5.3*	*8.6*	*6.1*	*6.1*	*(2.5)*	*-29%*
Intake Gates	*2.3*	*2.5*	*4.7*	*4.7*	*2.3*	*91%*
Outlet Structure	*7.2*	*12.8*	*11.7*	*11.7*	*(1.1)*	*-9%*
Outlet Gates and Hoist	*6.0*	*3.6*	*4.7*	*4.7*	*1.1*	*31%*
Diversion Tunnel	*406.9*	*689.4*	*687.3*	*687.3*	*(2.2)*	*0%*
Tunnel Boring Machine	*78.2*	*78.2*	*78.2*	*78.2*	*-*	*0%*
Flow Verification Test	*0.1*	*0.6*	*0.3*	*0.4*	*(0.2)*	*-34%*
Demolish Dewatering Structure	*1.5*	*1.5*	*0.1*	*0.1*	*(1.4)*	*-96%*
DRB Estimated Cost	*0.2*	*0.4*	*0.3*	*0.3*	*(0.0)*	*-9%*
Scope Changes		*0.7*	*0.7*	*0.7*	*0.0*	*0%*
Provisional Sum		*0.2*	*0.2*	*0.2*	*(0.0)*	*0%*
Changes in Applicable Law		*0.2*	*0.1*	*0.1*	*(0.1)*	*-50%*
Warranty Administration Fee		*0.1*	*-*	*-*	*(0.1)*	*-100%*
Office and General Cost		*54.1*	*72.5*	*77.7*	*23.6*	*44%*
Overhead Recovery		*35.3*	*36.0*	*36.4*	*1.1*	*3%*
Interim Completion fee		*10.0*	*10.0*	*10.0*	*-*	*0%*
Substantial Completion fee		*10.0*	*10.0*	*10.0*	*-*	*0%*
Cost Performance Disincentive		*(20.0)*			*20.0*	*-100%*
Schedule Incentive			*33.0*	*40.0*	*40.0*	*0%*
One Time Settlement Interest			*1.4*	*1.4*	*1.4*	*0%*
Allowance for Proposed ORST Rebate		*(7.9)*		*-*	*7.9*	*-100%*
Contingency	101.0	*169.0*		*29.8*	*(139.2)*	*-82%*
Other Contracts / Costs	78.9	69.8	70.6	68.7	(1.1)	-2%
Interest	136.9	286.6	234.5	234.5	(52.1)	-18%
TOTAL PROJECT CAPITAL	**985.2**	**1,600.0**	**1,455.1**	**1,500.0**	**(100.0)**	**-6%**

12.7 Incentive Payments Under the ADBA

Based on the project's Substantial Completion relative to the contract's Substantial Completion date as amended, OPG expects to pay Strabag the maximum incentive of $40M under Section 8.6 of the ADBA. As shown in Table 8 above, OPG has included this amount in its estimate of project costs at completion.

13.0 CONCLUSION

As the discussion above demonstrates, numerous challenges emerged during the course of constructing this extremely large and complex project. These challenges derived primarily from tunnelling conditions which were substantially more difficult than those reasonably anticipated. As discussed above and further elaborated in Appendix B, extensive studies and other investigation of geologic conditions were conducted by Ontario Hydro and others well in advance of the NTP. No amount of preparation however, can provide perfect knowledge of subsurface conditions more than 100 metres underground over the course of a tunnel route more than 10 kilometres long. When challenges to the project schedule and cost emerged, OPG addressed them in a reasonable manner and, working with Strabag and the OR, ultimately overcame every obstacle to deliver a project that will provide substantial value for the people of Ontario into the next century. On this basis, the entire amount of project costs detailed above was prudently incurred and should be recovered.

APPENDICES

13.1 Appendix A – Chronology of Major Milestones / Events

Date	Milestone / Event
1982-1987	**Comprehensive Conceptual Analysis** • Potential development alternatives analyzed • Geotechnical investigations conducted • Recommended the development of additional diversion and generation capacity at the Sir Adam Beck complex
08-Aug-1988	**Ontario Hydro Board Authorized Project Definition Activities** • Included preliminary engineering and an environmental assessment
Mar-1991	**Ontario Hydro Submitted Environmental Assessment (“EA”) for Niagara River Hydroelectric Development (“NRHD”)** • Proposed NRHD included two new tunnels, a three-unit 1050 MW underground generating station (referred to as Beck 3), and transmission improvements in the Niagara Peninsula • Allowed for staging of the project (i.e. the diversion facilities, one or both tunnels, could proceed in advance of the generation and transmission facilities)
22-Dec-1993	**Community Impact Agreement (“CIA”) Signed** • CIA signed between Regional Municipality of Niagara, Town of Niagara-on-the-Lake, City of Niagara Falls and Ontario Hydro for tourism, road upgrades and facility improvements that would be necessary if the NRHD were to proceed • CIA was based on the full NRHD with estimated construction duration of 7 years and estimated peak construction workforce of 800
Feb-1998	**Ontario Hydro Initiates Review of Phase 1 of NRHD** • Decision to initiate Phase 1 (construction of one new tunnel)
Apr-1998	**Ontario Hydro Retains the Beck Diversion Group (“BDG”) as the Owner’s Representative for Project** • Acres International Limited, Bechtel Canada and Hatch Mott MacDonald comprised BDG
Jun-1998	**Ontario Hydro Solicits Bids for Phase 1 of NRHD** • Solicited bids for detailed design and construction of one new tunnel • Bids received in Sept-1998 and analyzed in Oct-1998 resulting in a recommendation for award
14-Oct-1998	**Complete NRHD receives EA Approval** • EA approval provided Ontario Hydro with the flexibility to undertake the development in phases
Dec-1998	**Ontario Hydro Delays Award of Contract** • Ontario Hydro informs bidders that given the imminent reorganization of the Corporation, the final decision regarding the tunnel would be deferred until after April 1999
Jun-1999	**OPG Decides to “Defer Indefinitely” the Project** • OPG decided to focus on other major projects (e.g., return to service of Pickering A) before committing to construct the new tunnel

Nov-2002	**Province States It Will Direct OPG to Proceed with New Water Diversion Tunnel** • The Province subsequently indicated a strong desire to have the project completed in the shortest possible timeframe
24-Jun-2004	**OPG Board of Director's Approve Preliminary Release** • Preliminary release of $10M to conduct a Request for Proposal ("RFP") process and to carry out such other preconstruction activities as OPG deems necessary
Jul-2004	**OPG Engages Hatch Mott MacDonald ("HMM")** • HMM, an international tunnelling/mining expert consultant company, was engaged as OPG's Owner's Representative ("OR") for the Project • HMM to work in association with Hatch Acres
13-Aug-2004	**Request for Expressions of Interest ("EOI") Issued** • Request for EOIs for prequalification of potential proponents issued • Responses received by 09-Sep-2004 from seven (7) companies and consortiums
Dec-2004	**Invitation to Submit Design/Build Proposals Issued** • Invitations issued to four pre-qualified proponents • Final Amendment (#5) issued on 26-Apr-2005
18-Feb-2005	**Agreement Signed Between the Niagara Parks Commission ("NPC") and OPG** • 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 for 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 • Associated $10M settlement with Fortis Ontario, approved by the OPG Board on 08-Feb-2005, secured an irrevocable assignment of the water associated with Rankine generating station. These costs are included in the release estimate for the Project
13-May-2005	**Design/Build Proposals Received** • Three (3) proposals received • Proposals evaluated by separate commercial and technical teams
Jun-2005 to Jul-2005	**Proposal Evaluation and Negotiations with Proponents** • Based on evaluation scores, it was determined that negotiations should proceed initially with all three proponents to determine the "best value" proposal • When the proposals were re-scored after additional information was received and preliminary negotiations occurred, OPG began negotiating solely with the top two proponents • At the conclusion of the process, OPG chose Strabag AG as the successful proponent
28-Jul-2005	**OPG Board of Director's Approve NTP Execution Phase** • Niagara Tunnel Project approved with a budget of $985M and an in-service date of June-2010. • OPG Board approval subject to obtaining Provincial financing, through Ontario Electricity Financial Corporation, which was authorized on 18-Aug-2005

18-Aug-2005	**Design Build Agreement ("DBA") Signed with STRABAG AG**
Sept-2005	**STRABAG occupied site and started NTP construction**
17-May-2006 and 19-Jun-2006	**STRABAG Issues Claims for Differing Subsurface Conditions ("DSC") for Underwater Construction at the Intake Channel and Acceleration Wall** • Initiation of a dispute regarding a DSC for excessive overburden on the river bed encountered during construction of the intake channel that was claimed to differ materially from the subsurface conditions described in the Geotechnical Baseline Report ("GBR") • DSC claim related to work at the acceleration wall where conditions (i.e. bedrock elevation and the presence of large boulders) were claimed to differ materially from the GBR
01-Sep-2006	**TBM Excavation Commences** • TBM was acquired and assembled within 12 months according to the schedule proposed by STRABAG and incorporated into the DBA
23-May-2007	**STRABAG Claims DSC for Adverse Conditions in the Queenston Shale** • On or about 16-May-2007 near 840 m, immediately below the Whirlpool sandstone formation, a large block of Queenston shale dropped from the tunnel crown • STRABAG claimed DSC relative to the GBR
20-Sep-2007	**Settlement and Release Agreements Covering the Intake Channel DSC Signed** • Addressed DSC for the Intake Channel and Acceleration Wall underwater construction • Settlement Agreement signed by OPG and STRABAG • Release Agreement signed by OPG, STRABAG, Dufferin Construction and McNally Construction
24-Oct-2007	**STRABAG Initially Proposes a New Tunnel Alignment** • STRABAG suggested a number of benefits of realignment including an improved tunneling process
05-Nov-2007	**STRABAG Delivers Dispute Notice 001** • Dispute Notice 001 delivered to OPG concerning STRABAG's DSC claim associated with "Collapse in the Tunnel Crown," signaling their intent to refer this matter to the Dispute Review Board ("DRB") as a complex dispute triggered by a DSC, under the process contained in DBA s 5.5(a) • OPG countered on 12-Nov-2007 by requesting that Strabag agree to have the DRB first decide whether DBA s 5.5(c) applies. That section states settlement of DSC's concerning differing rock support requirements should be addressed only upon completion of the tunnel excavation
04-Feb-2008	**STRABAG Submits an Optimized Alignment & Revised Schedule Proposal** • Proposal also included information on alleged DSCs, efforts to mitigate DSCs, and implications to TBM drive and costs
14-Feb-2008	**OPG and STRABAG Senior Management Decide to Obtain a Determination from the Dispute Review Board ("DRB")** • Determination requested from DRB concerning the merits and materiality of DSCs alleged by STRABAG • DRB response would be considered by both OPG and STRABAG to pursue further negotiations including finalization of commercial terms of the realignment

31-Mar-2008	**Ministry of Environment ("MOE") Accepts the Proposed Tunnel Realignment** • MOE accepts OPG request for a minor amendment to the approved EA regarding the proposed tunnel realignment
04-Apr-2008	**STRABAG's DSC Position Summary Delivered to the DRB and OPG** • Initiated the DRB Hearing Process • OPG and STRABAG position papers, including expert reports, were subsequently exchanged and delivered to the DRB on 23-May-2008. • OPG and STRABAG rebuttal papers were exchanged and delivered to the DRB on 13-June-2008.
23-Jun-2008 to 26-Jun-2008	**DRB Hearing Held** • Due to the volume of materials to be considered and the complexity of the dispute, the DRB advised that their deliberations and written recommendations would likely require 60-90 days
30-Aug-2008	**DRB Report and Non-binding recommendations Received** • Report presents the DRB's unanimous conclusions and recommendations under five topics
09-Sep-2008	**STRABAG Commences Horizontal Realignment of Tunnel** • Started at approximately CH2+980
Oct-2008	**OPG Management Recommend Pursuing a Negotiated Settlement with STRABAG** • OPG evaluated options including engaging another Contractor to complete the Project and proceeding under the existing Design Build Agreement • Negotiated settlement was determined to provide the greatest likelihood of completing the project at the lowest cost in the shortest duration
11-Nov-2008	**Principles of Agreement Signed** • Negotiations were held from 15-Oct-2008 to 17-Oct-2008 and 03-Nov-2008 to 05-Nov-2008 • Outlined how the Parties would reach a final resolution of STRABAG's claim of Differing Subsurface Conditions in the Queenston Formation
31-Dec-2008	**STRABAG Starts Vertical Realignment of Tunnel** • Started at approximately CH3+300
09-Feb-2009	**Term Sheet Signed** • Negotiated Term Sheet required as part of the Principles of Agreement in order to further elaborate how the Parties would finalize the Revised Agreement to complete the Niagara Tunnel Project
24-Feb-2009	**Agreement on Revised Contract Schedule** • Substantial Completion date of 15-Jun-2013 with incentives and disincentives relative to target in-service date
07-Apr-2009	**Agreement on Target Cost** • Negotiations resulted in a Target Cost of CAD $985M with incentives and disincentives relative to the target cost
21-May-2009	**OPG Board Approval** • Board approves the revised schedule and cost, and the amendment and execution of the Amended Design Build Agreement with STRABAG
04-Jun-2009	**Amended Design Build Agreement ("ADBA") Signed** • Effective date of ADBA is December 1, 2008
11-Sep-2009	**Fall of Ground between 3,605m and 3,625m** • Approximately 100 m^3 of Queenston Shale and temporary tunnel lining

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	(shotcrete, wire mesh and steel channels) fell from the right side of the tunnel crown • Investigations concluded that a loosening of the rock support dowels put more pressure on the dowels' face plates than they could hold, which led to the fall. Boreholes NF-4 and NF-4A contributed to the loosening of the dowels by allowing relatively fresh water to penetrate and degrade the surrounding rock • Set back the schedule for NTP completion by approximately 17 days based on one day of delay to TBM mining translating into 0.375 days of delay to the critical path • Final cost impact of the 2009 fall of ground was estimated at $2 M, which is equal to insurance deductible, so no claim was made
30-Mar-2011	**TBM Mining Completed** • Boring of tunnel complete • TBM disassembly and removal follows
02-Jul-2011	**Fall of Ground between 6,033m to 6,080m** • Approximately 1,200 m^3 of shotcrete, steel ribs, wire mesh and loose rock fell from the tunnel crown • Remediation costs initially estimated $17.6 M, including work done outside of the MOL mandated area, but later revised to $12.1 M. Insurer took the position that since the actual fall of ground area was less than 100 metres, a $10M claim limit applied and will pay this amount • ADBA Target Cost will be increased by $10.4M

25-Jul-2012	**ADBA Amendment No. 1**
	• Incorporated a number of Project Change Directives ("PCD"s), and recognized a number of PCD Deemed Amendments
	• Recognized budget transfers that have occurred without change to the Target Cost or to the scope of the Work
	• Amended Appendix 1.1(TTT)—Target Cost:
	  ○ aggregate change of $9,0003,566.91 to the Target Price resulting from the incorporated and recognized PCDs
	  ○ the revised Target Cost is about $994 M
	  ○ revised allocation of the Target Cost for the purposes of cost control, cost projection and cost performances indices only.
	• Amended the Substantial Completion date to 02-July-2013
	• Amended Appendix 1.1(hhh)—Project Change Directive Form
	• Amended Appendix 2.2(a)—Organizational Chart

30-Jul-2012	**Invert Concrete Lining Completed** • Decommissioning of invert shutter was completed by 15-Aug-2012
19-Sep-2012	**Profile Restoration Completed** • Decommissioning of restoration carrier/bridges was completed by 05-Oct-12
06-Nov-2012	**Final Concrete Lining Completed** • Arch concrete carriers were moved to the outlet for disassembly and removal by 31-Dec-2012
04-Feb-2013	**Grouting Operations Completed** • Contact grouting was completed on 10-Nov-2012, and the contact grout carrier was moved to the outlet for disassembly and removal by 30-Dec-2012 • Pre-stress grouting was completed on 04-Feb-2013, and the mobile pre-stress grout carrier was removed from the tunnel by 22-Feb-2013
09-Mar-2013	**Substantial Completion**

	After 24 hours of uninterrupted flow, the Substantial Completion milestone was achieved on 09-Mar-2013
31-Oct-2013	**Forecast Final Completion Date** The date forecasted for the completion of site restoration, disposal of surplus goods and documentation turnover. At this point, STRABAG's contract and activities will be complete.
31-July-2014	**Forecast Complete Project Close-out Date** The date forecasted for complete project close-out, following the completion of groundwater monitoring obligations and sealing up of boreholes and wells. Final reports will be issued and internal documentation will be completed.

13.2 Appendix B – Summary of Geologic Investigations

Beginning in 1983, extensive geotechnical investigations were undertaken during concept and definition phases for the expansion of OPG's Niagara hydroelectric facilities, which at that time contemplated two additional tunnels and a new underground generating station ("Beck 3"). These investigations were heavily focused on the Queenston shale formation because drilling in this formation was required by the plans to excavate the new tunnels under the existing Sir Adam Beck No. 2 tunnels with sufficient separation to allow the use of the existing rights of way (i.e., tunnel at greater depth in the same corridor). Because the plan also involved tunneling under the buried St. Davids Gorge (to reduce excavated material disposal relative to an open canal) and constructing the planned underground powerhouse, the investigations also focused on the buried St. Davids Gorge area and the planned powerhouse area.

As indicated in Table 1 below, the geotechnical investigations were carried out in stages and included a total of 59 boreholes and a geotechnical test adit (small test tunnel). Rock cores were retrieved from the boreholes to determine physical and engineering properties (chemical composition, strength, in-situ stress, joints, swelling potential, etc.). This investigation work involved internal staff, experienced engineering consultants (i.e., Acres, Golder), geotechnical engineering faculty from the University of Western Ontario, University of Toronto, Laurentian University, University of Michigan, and other international geotechnical engineering and construction experts from universities in Florida and Germany who participated through technical review panels (see Table 2 below).

Twenty of the 59 boreholes were along the 10 kilometre tunnel route with the remainder in the area of the proposed powerhouses, along other potential tunnel alignments and around the Pump Generating Station reservoir. Besides core retrieval for testing, in-situ stress measurements were conducted in some boreholes to assess the magnitude and orientation of the horizontal stress regime. Piezometers were also installed in many of the boreholes to assess groundwater conditions.

The geotechnical adit was originally 580 metres long and three metres in diameter. It was subsequently enlarged on a trial basis to 12 metres in diameter over its last 30 metres. The adit was excavated at the Sir Adam Beck complex by Thyssen Mining Corporation of Canada Ltd (subcontractors to Acres Bechtel Canada). Excavation occurred between August 1992 and July 1993 (see Figure 1 below). The adit was tested and observed as part of the investigation program, and monitoring continued through March 1994.

Construction of a geotechnical adit is not typically done for tunnel projects because of the associated time and cost. The trial enlargement was specifically designed and constructed to simulate the excavation of the planned diversion tunnels in the Queenston shale formation using a full-face tunnel boring machine. In consultation with engaged experts on the Specialist Consulting Board, the adit helped OPG conclude that rapid, full-face tunnel excavation in the Queenston shale formation on the planned scale was technically feasible and cost-effective.

The relevant geotechnical parameters were summarized in the draft Geotechnical Baseline Report ("GBR") and included in OPG's Design Build Request for Proposal documents. The contractor, Strabag, refined the GBR to incorporate its interpretation of the data and rock behaviour expected relative to its planned means and methods of construction. The collaboratively negotiated 3-stage GBR was included in the Design Build Agreement as the agreed baseline for expected geotechnical conditions.

After contract award, Strabag drilled seven additional boreholes to verify the rock conditions in the vicinity of the buried St. Davids Gorge. These boreholes confirmed that the Queenston shale was intact and that Strabag's proposed alignment (which was higher than the concept alignment in the RFP) was feasible.

At 14.4 metres in diameter, the Niagara Tunnel is precedent setting for excavation by an open full-face tunnel boring machine in rock. Rock is not a uniform material and subsurface conditions can vary considerably over a short distance. Despite extensive investigations, rock behaviour during tunneling cannot be precisely predicted from boreholes and adits that provide representative data for only a small percentage of the rock to be excavated. Consequently, tunnel designs are based on experience and interpretation of the geotechnical parameters. Actual rock conditions and its behaviour during tunnel construction cannot be fully known before the excavation is complete. Sub-surface conditions always remain a significant risk to both design and construction of tunneling projects.

Table 1 - Work Completed During Various Stages of Geotechnical Investigations

Stage / Work Completed	Timeline
Concept Phase • Drilled 5 boreholes (SD-1 to SD-5) in buried St. Davids Gorge • Drilled 25 boreholes (NF-1 to NF-26, excluding NF-16 – was not drilled) along potential tunnel alignments, surface and underground powerhouse locations and around the PGS reservoir	1983 - 1989
Definition Engineering Phase 1 • Drilled 16 boreholes. Five in the Diversion Facilities area (NF-4A, NF-28, NF-30, NF-32 and NF-33), four in the St. Davids Gorge area (SD-6 to SD-9), and seven in the Generation Facilities area (NF-27, NF-29, NF-31, NF-34 to NF-37)	1990
Definition Engineering Phase 2 • Drilled 13 boreholes (NF-38 to NF-50) • Exploratory adit program	1992-1993

1 **Table 2 - Roles of Experts / Consultants**

Expert / Engineering Consultant	Role / Area of Expertise
Dr. K.Y. Lo – University of Western Ontario	Swelling Potential in Queenston Shale
Dr. E. Hoek – University of Toronto	Rock Mechanics
Dr. D. McCreath – Laurentian University	Rock Mechanics
Dr. B. Haimson - University of Wisconsin-Madison	In-situ Stress / Hydraulic Fracturing
Dr. Don U. Deere	Member of the Geotechnical Specialist Consulting Board
Dr. Walter Wittke – Beratende Ingenieure fur, Germany	Member of the Geotechnical Specialist Consulting Board
Acres Bechtel Canada (“ABC”)	Engineering Procurement Construction Management (“EPCM”) Consultant
Golder Associates	EPCM Consultant (worked in conjunction with ABC)
Clair. H Murdock Consultants Inc.	Estimating
MultiVIEW Geoservices Inc.	Seismic Survey of St. Davids Gorge

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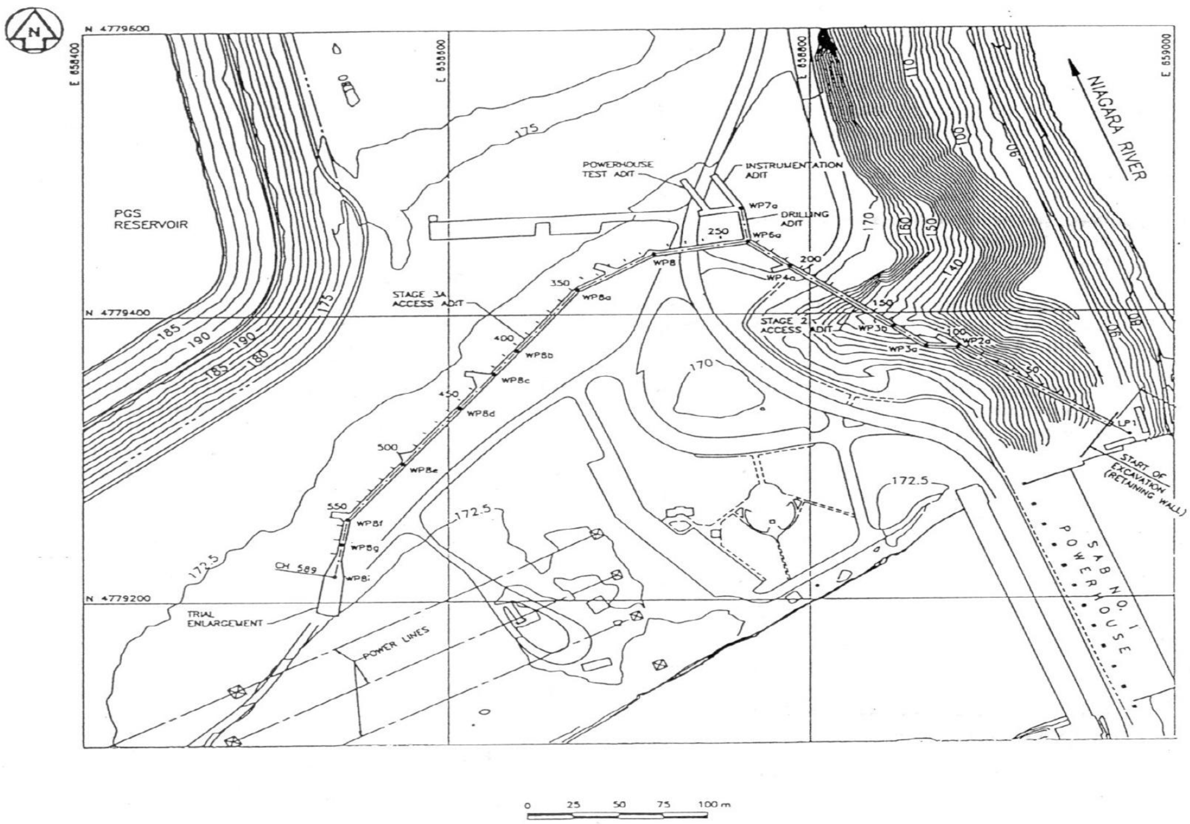
Figure 1 - Geotechnical Adit – Layout and Survey Control



Ontario Hydro
NRHD – Definition Engineering Phase 2
Additional Geotechnical Investigations
Exploratory Adit – Layout and Survey Control
ABC
Acres Bechtel Canada

13.3 Appendix C – Acronyms and Definitions

ACWP	Actual Cost of Work Performed
ADBA	Amended Design Build Agreement
BAR	Builder's All Risk Insurance
BCS	Business Case Summary
BCWP	Budgeted Cost of Work Performed
BCWS	Budgeted Cost of Work Scheduled
BDG	Beck Diversion Group
BTEX	Benzene, Toluene, Ethylbenzene and Xylene
BU	Backup Unit
CofA	Certificate of Approval
CBS	Cost Breakdown Structure
CCA	Capital Cost Allowance
CCB	Change Control Board
CI	Change Initiation
CIA	Community Impact Agreement
CLOC	Contract Litigation Oversight Committee
CNP	Canadian Niagara Power Company Limited
CPI	Cost Performance Index
CT	Contractor Transmittal (from OR)
DBA	Design Build Agreement
DCC	Dufferin Construction Company
DFO	Fisheries and Oceans Canada (Department of Fisheries and Oceans)
DRB	Disputes Review Board
DS	Document Submittal
DSC	Differing Subsurface Condition
DT	Document Transmittal (to OR)

EA	Environmental Assessment
ELT	Enterprise Leadership Team
EOI	Expression of Interest
EPSCA	Electrical Power Systems Construction Association (Union)
FIT	Feed-In-Tariff (Green Energy Act)
GBR	Geotechnical Baseline Report
GDR	Geotechnical Data Report
GFA	Guaranteed Flow Amount
GIP	Grass Island Pool
GRC	Gross Revenue Charge
H+E	H+E Logistics (subcontractor to Strabag)
H&S	Health and Safety
HDS	High Definition Survey
HMM	Hatch Mott MacDonald Ltd.
ICC	International Chamber of Commerce
IESO	Independent Electricity System Operator
ILF	ILF (Strabag's Tunnel Designer)
IJC	International Joint Commission
INBC	International Niagara Board of Control
INCW	International Niagara Control Works
INCW Part Project	Part of the Niagara Tunnel Project where OPG is the "constructor" (as defined in OH&SA) for a limited period
JSA	Job Safety Analysis
LRIA	Lakes and Rives Improvement Act
LTI	Lost Time Injuiry
LUEC	Levelized Unit Energy Cost
M&S	Monteith and Sutherland
MHL	Morrison Hershfield Limited (Surface Works Designer for Strabag)

MNR	Ministry of Natural Resources
MOE	Ministry of the Environment
MOL	Ministry of Labour
MOM	Minutes of Meeting
MOU	Memorandum of Understanding
MPC	Major Projects Committee
MRPH	Maximum Reasonable Potential for Harm
NCN	Nonconformance Notice
NCR	Nonconformance Report
NEA	Niagara Exchange Agreement
NOTL	Niagara on the Lake
NPC	Niagara Parks Commission
NPCA	Niagara Peninsula Conservation Authority
NPG	Niagara Plant Group
NRCC	Niagara River Control Centre
NRHD	Niagara River Hydroelectric Development
NRP	Niagara Region Police
NTP	Niagara Tunnel Project
OCIP	Owners Controlled Insurance Program
OEFC	Ontario Electricity Financing Corporation
OMR	Owner’s Mandatory Requirements
OH&SA	Occupational Health and Safety Act
OIC	Order-in-Council
OPG	Ontario Power Generation
OR	Owner’s Representative, Hatch Mott MacDonald Ltd. with Hatch Acres
ORST	Ontario Retail Sales Tax
PCD	Project Change Directive
PCN	Project Change Notice

PDRI	Project Definition Rating Index, developed by the Construction Industry Institute
PEP	Project Execution Plan
PFD	Personal Flotation Device
PIR	Post Implementation Review
PKS	Peter Kiewit Sons Ltd.
PGS	Pump Generating Station
PPE	Personal Protective Equipment
PRM	Project Risk Management
Project	Niagara Tunnel Project
PTTW	Permit to Take Water
RFE	Request for Expenditure
RFI	Request for Information
RFQ	Request for Quotation
RMP	Risk Management Plan
RMR	Rock Mass Rating
ROC	Risk Oversight Committee
ROWA	ROWA (TBM Backup System Manufacturer)
RFP	Request for Proposal
RQE	Release Quality Estimate
SAB	Sir Adam Beck
SBA	Self Breathing Apparatus
SCI	System Classification Index
SPI	Schedule Performance Index
SPOC	Single Point of Contact
TBM	Tunnel Boring Machine
TCP	Traffic Control Person
VFD	Variable Frequency Drive

WBS	Work Breakdown Structure
WSIB	Workplace Safety Insurance Board
WTP	Water Treatment Plant
WUL	Wrap-Up Liability Insurance