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 regulated hydroelectric facilities during the test period. These capital expenditures form part of the capital budget for the regulated hydroelectric facilities presented in Ex. D1-T1-S1.

2.0 OVERVIEW OF CAPITAL PROJECT DESCRIPTIONS AND LISTINGS

OPG has used a tiered structure for reporting on all capital projects. Information is presented for projects which have budgeted expenditures during the 2011 and 2012 test period or in-service amounts between 2010 and 2012 as set out below:

- Tier 1 - Projects with a total cost of $10M or greater:
  - Project descriptions are provided in section 3.1.
  - Summary level information is further provided in Ex. D1-T1-S2 Table 1.
  - Business Case Summaries are provided as attachments to this schedule.

- Tier 2 - Projects with a total cost between $5M and $10M:
  - A description of this category of projects is provided in section 3.2.
  - Project descriptions and summary level information is provided in Ex. D1-T1-S2 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-T1-S2 Table 3.

Section 4.0 below presents information on OPG's regulated hydroelectric capital expenditures that: (a) have gone into service in the historical years, or (b) are expected to go into service, either during the 2010 bridge year or during the 2011 and 2012 test period. In-service information is further summarized in Ex. D1-T1-S2 Table 4. These in-service additions are included in the regulated hydroelectric rate base as presented in Ex. B2-T3-S1 Tables 1 and 2.

Section 5.0 below presents information on OPG's regulated hydroelectric capital expenditures that were identified in OPG's last payment amounts proceeding, but which were subsequently deferred to beyond the 2011 - 2012 test period.

3.0 CAPITAL PROJECT DESCRIPTIONS AND LISTINGS

3.1 Tier 1 Capital Projects

As noted, Tier 1 projects are those with total costs of $10M or more. There are a total of six regulated hydroelectric Tier 1 projects that have planned expenditures during the test period. These are described below. Further summary information on these projects is provided in Ex. D1-T1-S2 Table 1.

3.1.1 Niagara Tunnel Project (EXEC0007)

The total cost of the Niagara Tunnel Project is estimated to be $1.6B. This project commenced in 2005 and is projected to come into service by December 2013. Planned test period expenditures are $288M in 2011 and $199M in 2012. The Niagara Tunnel Project Business Case Summary is provided as Attachment 1 to this schedule.

The total flow of water available to the Sir Adam Beck generating stations pursuant to treaties between Canada and the United States exceeds the combined capacities of OPG's existing water diversion facilities (i.e., the Sir Adam Beck power canal and two tunnels) about 65 per cent of the time. The Niagara Tunnel project will create a third tunnel to divert additional water from the Niagara River to the Sir Adam Beck generating stations. Once the new tunnel is in-service, the amount of time that the available water will exceed the capacity of OPG's diversion facilities will be reduced to approximately 15 per cent. The additional water provided by the Niagara Tunnel project will increase the efficient utilization of the existing generation capacity at the Sir Adam Beck complex, thereby increasing energy production by an average of 1.6 TWh per year.

The Niagara Tunnel project was originally approved by OPG's Board of Directors ("the OPG Board") in July 2005 at an estimated cost of $985M and a June 2010 in-service date. However, the tunnel boring machine's progress was slower than expected under the original contractor schedule primarily due to excess rock overbreak in the tunnel crown. In June 2009, following the recommendations of the Dispute Review Board, OPG and the contractor signed an amended design-build contract with a revised target cost and schedule. The target cost and schedule took into account the difficult rock conditions encountered, restoration of the circular cross section in the rock overbreak, and the concurrent tunnel excavation and liner installation work required to expedite completion of the tunnel. The amended contract includes incentives and disincentives related to achieving the target cost and schedule. OPG's Board of Directors approved a revised project cost estimate of $1.6B and a revised scheduled completion date of December 2013. Some uncertainty with respect to the cost and schedule for both the tunnel excavation and liner installation will continue.

As of December 31, 2009, the tunnel boring machine ("TBM") has progressed 5,481 metres, which is 54 per cent of the tunnel length. The advancement of the TBM was temporarily interrupted from September 11, 2009 to December 8, 2009 to repair a short section of the temporary tunnel liner that failed about 1,800 metres behind the TBM location at that time, and to complete a planned overhaul of the TBM cutterhead, conveyor systems and other tunnel construction equipment. Installation of the lower one-third of the permanent tunnel concrete lining was ahead of schedule. Restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining began in September 2009. Installation of the upper two-thirds of the concrete lining is scheduled to begin in the spring of 2010.

3.1.2 DeCew Falls I Generating Station - Penstock and Saddle Replacement (DCW10019)

The DeCew Falls I Generating Station - Penstock and Saddle Replacement project was approved in October 2009 with an estimated cost of $10.3M and a final unit expected in-service in July 2011. Planned test period expenditures are $1.1M in 2011. The project Business Case Summary is provided as Attachment 1 to this schedule.

The four generating units at DeCew Falls I have a combined capacity of 23MW, and have been out-of-service since December 2008. The penstocks were installed when the station was expanded between 1906 and 1912. Numerous leaks have been experienced and addressed over the past 30 years, In 2008, an engineering investigation by an external consultant concluded that the penstocks could no longer be operated safely. The expected penstock replacement project was advanced and OPG is currently in the process of demolishing and replacing the penstocks. This project is a sustaining investment required to preserve the capacity of DeCew Falls I. The Life Cycle Plan for this facility confirmed that this was the preferred option.

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 $29.5M. This project will commence in 2012 and is projected to come into service by December 2014. Planned test period expenditures are $2.4M in 2012. As the Sir Adam Beck I GS - Unit G10 Upgrade project has not yet completed the definition phase of the hydroelectric project management process, a Business Case Summary has not yet been prepared for this project.

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, and the rehabilitation of Unit G9, which is currently underway. From experience in the OPG fleet, units with the history of G10 may not require a complete generator replacement. This will be confirmed in a complete water-to-wire condition assessment of the unit to be carried out by the Hydro Engineering Division and Niagara Plant Group staff as part of the project definition phase. The expected scope includes: new 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 efficient runner and a turbine upgrade.

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

If the above issues are not addressed, further deterioration and eventual failure of this unit is expected. Allowing Unit G10 to fail from service does not permit maximum utilization of Niagara River flows when additional water becomes available to the Sir Adam Beck generating stations through the new Niagara tunnel.

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. A new higher rated transformer will be required to handle this additional unit rating.

3.1.4 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 $29.4M. This project will commence in 2011 and is projected to come into service by December 2012. Planned test period expenditures are $12.5M in 2011 and $15.0M in 2012. As the Sir Adam Beck I Generating Station - Unit G3 Upgrade project has not yet completed the definition phase of the hydroelectric project management process, a Business Case Summary has not yet been prepared for this project.

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, and the upgrade of Unit G9, which is currently underway. From experience in the OPG fleet, units with the history of G3 may not require a complete generator replacement. This will be confirmed in a complete water-to-wire condition assessment of the unit to be carried out by the Hydro Engineering Division and Niagara Plant Group staff as part of the project definition phase. The expected scope includes: new 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 efficient runner and a turbine upgrade.

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. Unit G3 is in fair condition, but by 2011 it will no longer be counted on to provide reliable long-term operation; as there are issues with major components of both the generator and the turbine. Although frequent maintenance and continual attention have enabled continued operation, the equipment issues are substantial enough that they should be resolved through unit rehabilitation.

If the above issues are not addressed, further deterioration and eventual failure of this unit is expected. Allowing Unit G3 to fail from service does not permit maximum utilization of Niagara River flows when additional water becomes available to the Sir Adam Beck generating stations through the new Niagara tunnel.

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. A new higher rated transformer will be required to handle this additional unit rating.

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

The total cost of the Generator Protection Replacement and Control Upgrades project is estimated to be $21.1M. This project was approved in June 2009 and is expected to be completed by March 2012. Planned test period expenditures are $8.1M in 2011 and $0.5M in 2012. The Generator Protection Replacement and Control Upgrades project Business Case Summary is provided as Attachment 1 to this exhibit. The project is currently on schedule and on budget

The existing protections and controls at R.H. Saunders were installed when the station was first built and they are at their end of life. This project will ensure continued reliability from this facility and that the generator and transformer protections meet current protection standards and requirements for control systems, including meeting new North American Electric Reliability Corporation ("NERC") cyber security standards.

3.1.6 R.H. Saunders Generating Station – Station Service Replacement (SAUN0080)

The total cost of the Saunders Generating Station - Station Service Replacement project is estimated to be $10.7M. This project will commence in 2011 and is projected to come into service by December 2017. Planned test period expenditures are $0.2M in 2011 and $0.9M in 2012. As the Saunders GS - Station Service Replacement project has not yet completed the definition phase of the hydroelectric project management process a Business Case Summary has not yet been prepared for this project.

This project includes the replacement of the existing 600V station service circuit breakers and related distribution panels with new reliable circuit breakers. The advantages of new breakers include microprocessor based unit trip, multi-function metering, communication capabilities, conformance to applicable ANSI/IEEE Standards, life expectancy of 40 years, improved reliability and safer breaker maintenance.

R.H Saunders is equipped with four 600V switchgear load centres which were placed in service in 1956 and manufactured by CEMCO Electrical Manufacturing. CEMCO no longer exists and replacement parts are not available. Each load centre has a main breaker, tie breaker and feeder breakers. There are safety concerns with the switchgear and breaker arrangement for both electrical contact and arc flash hazards. The circuit breakers have been well maintained but they are approximately 55 years old and have some identified problems. These include operational and performance failures of the feeder and tie breakers. R.H Saunders is a registered black-start station and high circuit breaker reliability is a priority as they are required for operation during a black-start emergency.

The 600 volt station service originates from four load centres. To further distribute the station service supply to smaller loads, approximately 36 distribution panels are located throughout the facility. The original panels are equipped with non-visible, non-lockable moulded case circuit breakers. Due to their age and type, these circuit breakers may not reliably trip under faults or open all contacts when opened manually. Only two of these panels are new and come equipped with recommended lockable visi-break type circuit breakers. Replacement of the 600V station service equipment will improve reliability and enhance asset protection.

3.2 Tier 2 Capital Projects

As noted, Tier 2 projects are those with total costs between $5M and $10M. There are a total of five Tier 2 projects that have planned expenditures during the test period. The total cost of these five projects is estimated to be $29.4M. A description of these projects and further summary information on them is provided in Ex. D1-T1-S2 Table 2.

3.3 Tier 3 Capital Projects

As noted, Tier 3 projects are those with total costs less than $5M. There are a total of 28 Tier 3 projects that have planned expenditures during the test period. The total cost of these Tier 3 projects is estimated to be $40.3M. The average cost of a Tier 3 project is $1.4M. Further summary information on these projects is provided in Ex. D1-T1-S2 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, or (b) are expected to go into service, either during the 2010 bridge year or during the 2011 - 2012 test period. This information is presented using a tiered reporting structure that is consistent with previous sections of this schedule. In-service information is further summarized in Ex. D1-T1-S2 Tables 4 and 5.

4.1 In-Service Additions in Historical Years (2008 and 2009)

For 2008 and 2009, the actual capital in-service amounts were significantly lower ($31.1M in 2008, and $14.7M in 2009) than the planned additions forecast in EB-2007-0905. These variances primarily resulted from a simplified process for estimating in-service additions that was used in the 2008 - 2012 Business Plan which formed the basis for EB-2007-0905. This simplified process is no longer used. Up to and including the 2008 - 2012 Business Plan, the Hydroelectric Business Support group did not directly collect data for in-service additions from plant groups. Instead, an estimate based on project cash flows was used. Based on past experience, this method was deemed to provide a sufficiently accurate aggregated business unit estimate for planning purposes. However, in the early years of individual multi-year projects there are often significant cash flows without a corresponding in-service addition. In other words, in-service additions lag cash flows especially for large, multi-year projects such as the unit upgrades at Sir Adam Beck I Generating Station. In order to improve the accuracy of its future estimates, the Hydroelectric Business Unit has, as part of its present planning process, collected in-service information on an individual project basis for its regulated hydroelectric stations.

The other significant contributors to the in-service amount variances were the $7.6M in savings described below for the Sir Adam Beck I Generating Station. Unit G7 Frequency Conversion, and the cancellation of the $6.1M Elevator Rehabilitation project at the Sir Adam Beck I Generating Station.

The following two projects, which had costs greater than $10M and were identified in OPG’s previous payment amounts application (EB-2007-0905), were completed and went into service in 2008 and 2009. These projects were therefore added to OPG’s approved rate base in EB-2007-0905.

4.1.1 Sir Adam Beck I Generating Station – Unit G7 Frequency Conversion (SAB10032)

The project to convert Unit G7 from 25 Hz to 60 Hz and rehabilitate the unit was completed on schedule and officially placed in service three months later on June 30, 2009, in order to implement design changes to correct vibration problems discovered during unit commissioning. The final project cost was $7.6M less than the approved project estimate of $35.2M. The project was delivered significantly under budget due to lower than expected costs for Hydro One to reconfigure the 25 cycle bus work, reduced generator procurement costs, reduced costs due to the reuse of some existing 60 cycle equipment, and unused contingency. The additional capacity and energy from this project will be 62 MW and 100 GWh/year, respectively.

4.1.2 R.H. Saunders Generating Station – Replace HVAC System (H-97-1864)

The project was completed under budget and on schedule in May 2008 at a cost of $11.5M. This project included the replacement of the heating, ventilating, and air conditioning system in the administration building, including the removal of asbestos insulation on the associated piping and air handler units.

4.2 In-Service Additions in 2010 Bridge Year and 2011-2012 Test Period

Summary information for capital in-service additions is provided in Ex. D1-T1-S2 Tables 4 and 5. For the bridge and test years, additional detail by project is provided on Ex. D1-T1-S2 Tables 1, 2 and 3. The largest test period in-service additions are the unit upgrades at Sir Adam Beck I, and the replacement of generator protection and controls at R.H. Saunders. These projects are described above in section 3.1. In addition, the rehabilitation of Unit G9 at Sir Adam Beck I and the construction of the new St. Lawrence Power Development Visitor Centre at R.H. Saunders are expected to come into service in 2010 and are described below.

4.2.1 Sir Adam Beck I Generating Station - Unit G9 Rehabilitation (SAB10047)

The total cost of the Sir Adam Beck I Generating Station - Unit G9 Rehabilitation project is expected to be $32.1M. This project commenced in 2008 and is projected to come into service by December 2010. The Business Case Summary is provided as Attachment 1 to this schedule. The project is currently on schedule and on budget.

This project includes the replacement of the generator, the rehabilitation of and upgrade of the turbine including installation of a new efficient turbine runner, a new liner in the Johnson valve, and a new transformer with the upgrade of associated electrical equipment. The project is expected to increase the capacity of Unit G9 by approximately 10MW.

Unit G9 was last rehabilitated in 1974 and had substantially degraded in the last five years of its operation. Very high vibration levels and unit balance issues resulted in restricting the generator to 70 per cent output. Further deterioration and eventual failure was expected. Allowing Unit G9 to fail from service would not have permitted maximum utilization of Niagara River flows when additional water will become available to the Sir Adam Beck generating stations through the new Niagara Tunnel.

4.2.2 St. Lawrence Power Development Visitor Centre (HOSL0005)

This project is for the construction of a new Visitor Centre adjacent to R.H. Saunders Generating Station. The project was approved with a budget of $12.6M in March 2009 and is expected to be completed by September 2010. The Business Case Summary is provided as Attachment 1 to this schedule. The project is currently on schedule and on budget.

This facility will replace the original visitor centre on the sixth floor observation deck of the administration building that was closed in 1992 and cannot be reopened due to post-9/11 security concerns. In 2006, OPG committed to Cornwall area community leaders to consider reopening a visitors' centre. In 2008, OPG initiated community consultations but did not include this project in its plans until the final scope had been determined and agreed to by both OPG and external stakeholders. The Centre will provide a venue for both OPG and local stakeholders to deliver information regarding their areas of interest, including the significant impact on the local community related to the construction of R.H. Saunders. The project will allow OPG to more effectively deliver its hydroelectric communications (e.g., water safety) while improving community support for continued operation of OPG's second largest hydroelectric generating station.

5.0 DEFERRED PROJECTS

The following two projects, which had costs greater than $10M and were identified in OPG's previous payment amounts application (EB-2007-0905), have been deferred. As these projects will not commence until after the completion of the Niagara Tunnel Project, no expenditures will be made during the test period.

5.1 Sir Adam Beck I Generating Station – Rehabilitate Canal Lining (SAB10056, formerly H-98-0056)

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 costs were updated to reflect the repair work specified in the more comprehensive condition assessment. The project is programmed to be completed after the in service of the Niagara Tunnel project in order to minimize economic losses of reduced diversion flows to the Sir Adam Beck complex.

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

This project was deferred to coincide with the canal liner rehabilitation after the Niagara Tunnel project has been completed. The geological conditions under the pump generating station dyke foundation are prone to sinkhole formation. Sinkholes in turn may lead to “piping”, a phenomenon where water leaking through a dam begins to remove material from the dam. The clay liner and sinkholes are being closely monitored using advanced inspection technology to locate areas where the dyke may be compromised. In parallel, an investigation into the dyke protection measures is currently underway that will help to identify the scope of this project. This project may include a range of technical solutions, including: grout injection, a cut-off wall, and repairs to the upstream clay blanket.

LIST OF ATTACHMENTS

Attachment 1: Business Case Summaries

ATTACHMENT 1

Business Case Summaries

Provided below is a list of projects with total project cost of $10M or greater, and their associated business case summaries. Paper copies of the business case summaries are provided in a separate binder (EB-2010-0008 Volume 4).

Tab	Business Case Summaries	Project No.
1	Niagara Tunnel Project	EXEC0007
2	DeCew Falls I Generating Station – Penstock and Saddle Replacement	DCW10019
3	R.H. Saunders Generating Station – Replacement of Protections and Controls	SAUN0047
4	Sir Adam Beck I Generating Station – Unit G9 Rehabilitation	SAB10047
5	R.H. Saunders Generating Station – St. Lawrence Power Development Visitor Centre	HOSL0005

Note: Attachment 1 Tab 1 is marked “Confidential” because the original document contains confidential information. The redacted version provided as pre-filed evidence is not confidential.

ATTACHMENT 1

Business Case Summaries

Provided below is a list of projects with total project cost of $10M or greater, and their associated business case summaries. Paper copies of the business case summaries are provided in a separate binder (EB-2010-0008 Volume 4).

Tab	Business Case Summaries	Project No.
1	Niagara Tunnel Project	EXEC0007
2	DeCew Falls I Generating Station – Penstock and Saddle Replacement	DCW10019
3	R.H. Saunders Generating Station – Replacement of Protections and Controls	SAUN0047
4	Sir Adam Beck I Generating Station – Unit G9 Rehabilitation	SAB10047
5	R.H. Saunders Generating Station – St. Lawrence Power Development Visitor Centre	HOSL0005

Note: Attachment 1 Tab 1 is marked “Confidential” because the original document contains confidential information. The redacted version provided as pre-filed evidence is not confidential.

SUPERSEDING RELEASE FOR NIAGARA TUNNEL PROJECT (EXEC0007)

1. RECOMMENDATION:

Approve the release of $615 M additional funding for design and construction of the Niagara Tunnel Project (the "Project"), bringing the total Project cost estimate to $1,600 M including $985 M previously approved. Based on the amended design / build agreement, the tunnel will be in-service by December 2013, will increase the diversion capacity of the Sir Adam Beck Niagara GS complex by 500 m^3/s and facilitate a 1.6 TWh increase in average annual energy output from the Sir Adam Beck generating stations.

The Niagara Tunnel Project has been delayed due primarily to difficulties encountered by the contractor, Strabag Inc. (Strabag) in excavating the tunnel through the Queenston shale formation. Following an unsuccessful attempt to resolve Strabag's claim for cost and schedule relief, the parties submitted the dispute to the Dispute Review Board (DRB), as provided in the Design Build Agreement between OPG and Strabag. Following receipt of the DRB's recommendations OPG and Strabag have negotiated a settlement to ensure the tunnel is completed both safely and expeditiously.

Total Investment Cost: $1,600 M (including $985 M previously approved)

Year	To 2008	2009	2010	2011	2012	2013	2014	Totals
Project Capital	435	200	275	274	206	216	(6)	1,600
2009 Business Plan	432	173	235	143	2	-	-	985
Variance	3	27	40	131	204	216	(6)	615

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

Release Type: Superseding

Funding: The financing for the project is arranged through the Ontario Electricity Financial Corporation (OEFC). The amended agreement increasing the facility limit of $1B to $1.6B will be executed following the OEFC's third quarter Board meeting in September 2009.

Investment Financial Measures: The increased energy output resulting from the Project will receive a regulated rate as part of OPG's regulated hydroelectric assets. With a Levelized Unit Energy Cost of under 7 ¢/kWh and an equivalent Power Purchase Agreement price of less than 10 ¢/kWh, the Niagara Tunnel Project continues to remain attractive and economic relative to other generation alternatives. Other project financial metrics and sensitivities are presented in the Financial Analysis section of this BCS.

2. SIGNATURES

Submitted by:

Carlo Crozzoli
Carlo Crozzoli
Vice President
Hydro Development

Recommended By:

John Murphy
Exec. VP
Hydro

Approved By:

Donn Hanbidge
Chief Financial Officer

Approved By:

Tom Mitchell
President and CEO

3. BACKGROUND & ISSUES

Background

- On July 28, 2005, OPG's Board of Directors approved the Execution Phase of the Niagara Tunnel Project. The approved budget and in service date were $985 M and June 2010, respectively. This new water diversion tunnel will increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara Falls. This tunnel will allow the Sir Adam Beck generating facilities to utilize available water more effectively and is expected to increase annual generation on average by about 1.6 TWh (14%).

- The decision to proceed with the Execution Phase was taken after comprehensive geological studies, engaging an international tunnelling/mining consulting expert (Hatch Mott MacDonald) as OPG's Owner's Representative (OR), engaging Torys to provide legal oversight and advice, and conducting an international competition to select a Design Build contractor (Strabag).

- Preparation for the new Niagara Tunnel commenced more than 25 years ago, in 1982, when Ontario Hydro (predecessor 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 environmental assessment (EA) submitted in 1991 for the then planned project (two 500 m^3/s water diversion tunnels, a three-unit 900-MW underground generating station and transmission improvements between Niagara Falls and Hamilton). Among the commitments made through the EA process, was to utilize a tunnel boring machine (TBM) to excavate the tunnels from the outlet end, under the buried St. Davids gorge and following the route of the existing SAB2 tunnels ~~through the City of Niagara Falls. The EA received approval from Ontario's Minister of the Environment~~ in 1998, including provisions to begin with construction of one tunnel, the Niagara Tunnel Project.

- Through an international proposal competition, a fixed price Design Build Agreement (DBA) was awarded to Strabag AG on August 18, 2005 and construction commenced in September 2005. The TBM was acquired and assembled within 12 months and it commenced excavation of the tunnel on September 1, 2006.

- Significant challenges excavating and supporting the Queenston shale formation, due to overstressing and insufficient, unsupported stand-up time, resulted in excessive overbreak of rock from the tunnel crown, impeded TBM advance and required significant modifications to the initial support area immediately behind the TBM cutterhead.

- Upon entering the Queenston shale formation in April 2007, Strabag encountered subsurface conditions that resulted in significantly slower than planned progress. Strabag alleged large block failures, insufficient stand-up time and excessive overbreak encountered were not consistent with the conditions described in the DBA. Strabag alleged these claims constituted a Differing Subsurface Condition (DSC), and as a result, it should be entitled to cost and schedule relief.

- Following unsuccessful attempts to resolve the issue, Strabag submitted the claim to the Dispute Review Board (DRB). The DRB is part of the dispute resolution process set out in the DBA and consists of three tunnelling experts who were regularly updated on project progress and issues. The claim was heard over four days in June 2008.

- The DRB issued its non-binding recommendations in August 2008. The DRB ruled that the excessive overbreak encountered during the tunnel drive constituted a Differing Subsurface Condition and recommended that:

  "There is a DSC with respect to excessive overbreak" (and) "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."

- To settle the dispute concerning the alleged differing subsurface conditions in the Queenston shale formation and all other outstanding claims prior to November 30, 2008, OPG and Strabag agreed to convert the fixed price DBA into a target cost DBA with cost and schedule incentives and disincentives, and incorporate changes in the tunnel route to minimize further excavation with the crown in the challenging Queenston shale formation. Negotiated changes to the DBA include a target in-service date of [redacted] target cost of [redacted] and a significant shift in the risk profile for completion of the tunnel construction.

Financing

- In 2005, financing for the project was arranged through the OEFC with a facility limit of $1B. Preliminary discussions have taken place with the OEFC regarding an increase in the facility, to $1.6B, as well as a timing extension. However, staff have indicated that given their current priorities it would be difficult to expedite the required "Minister Directive" because OPG's Niagara Tunnel Project spend is currently well below the $1B facility limit. OEFC currently plans to have the final amendment executed after its third quarter Board meeting in September 2009.

Project Execution Strategy

- During October and November 2008, the parties negotiated a non-binding Principles of Agreement that would settle all claims up to November 30, 2008 and move to a Target Cost Contract for the remainder of the project with schedule and cost incentives and disincentives. The key tenets of the Principles of Agreement were as follows:

    - ~~Strabag claimed that it had incurred a loss of $90M up to November 30, 2008. Under the Principles~~ of Agreement, OPG would pay Strabag $40M to settle all claims up to November 30, 2008, leaving Strabag with a loss of approximately $50M.

    - Should the $90M loss not be substantiated, the agreement allows OPG to claw back the $40M on a prorated basis.

    - From December 1, 2008 onwards, Strabag could earn a $20M completion fee plus maximum cost and schedule incentives of $40M. If both Target Cost and Schedule are met, Strabag's loss will be reduced from $50M to $30M. Maximum incentives for early completion and lower cost will result in Strabag making a profit of $10M. If the project is late or cost is exceeded, Strabag will incur a $50M loss.

    - The incentive (bonus / liquidated damages) associated with the Guaranteed Flow Amount[1] (tunnel flow capacity more or less than 500 m^3/s) remains unchanged.

- On November 19, 2008, OPG's Major Projects Committee reviewed the Principles of Agreement and endorsed management's plan to proceed to build upon the Principles of Agreement by negotiating a Term Sheet followed by an Amended Design Build Agreement with Strabag. On February 9, 2009, OPG and Strabag executed a non-binding Term Sheet that further elaborates on the Principles of Agreement.

- Since then, the parties negotiated a Target Schedule of [redacted] and a Target Cost of [redacted] Both of these targets were developed on an open book basis with the OR and OPG auditors having access required to verify the reasonableness of key inputs. The Target Schedule is premised on a horizontal realignment that reduces the tunnel length by approximately 200 m, and a vertical realignment to exit the Queenston shale and move to the overlying rock formations where tunnelling conditions are expected to improve.

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

Project Management

- A strong team remains in place for management and execution of the Niagara Tunnel Project and includes:

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

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

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

4. ALTERNATIVES AND ECONOMIC ANALYSIS

Key Project and Financial Assumptions:

- The Project is estimated to cost $1,600 M, including the previously released funding.
- The sunk cost on the Project to date (to the end of April 2009) is $463 M.
- The Project will receive a 10-year "holiday" for Gross Revenue Charge (GRC) payments.
- The Project will be funded through financing arranged with the OEFC.
- Other Assumptions are listed in Appendix B.

Status Quo – Proceed Under the Existing DBA (Not Recommended)

- Considering the significant schedule delay, contractor claims regarding differing subsurface conditions (primarily in the Queenston shale formation), recommendations of the Dispute Review Board in August 2008 that OPG and Strabag should equitably share the cost and schedule impacts, difficulties experienced in excavating and supporting the Queenston shale, and significant liquidated damages included in the existing DBA, there is a high risk that the contractor would abandon the project, requiring completion of the tunnel by another contractor with higher costs and a significant delay (see Alternative 2), and causing OPG to expend considerable resources on legal proceedings. This alternative is not recommended.

Alternative 1 – Proceed Under a Target Cost Amended DBA (Preferred Alternative)

- Complete design, construction and commissioning of the Niagara Tunnel under an amended DBA that features a target cost / target schedule with cost and schedule incentives and disincentives and incorporates changes in the tunnel alignment to minimize further excavation with the tunnel crown in the Queenston shale formation. This approach settles all of Strabag's outstanding claims to November 30, 2008, establishes a sharing of incremental costs and provides incentives for Strabag to complete the tunnel in a timely manner. The remaining cost for this alternative is $1,137 M and the total cost is $1,600 M. This is considered to be the least cost alternative for completion of the Project and is the recommended alternative. Appendix A provides a more detailed breakdown of the Project costs.

Alternative 2 – Engage another Contractor to Complete the Project (Not Recommended)

- Complete design, construction and commissioning of the Niagara Tunnel by terminating the existing DBA with Strabag and engaging another contractor. This approach would result in a further delay of 18 to 24 months to engage another contractor, unknown higher costs (actual plus mark-up), loss of experience gained to date and key personnel (contractor, designers and subcontractors) and require OPG to expend considerable resources on legal proceedings to recover damages from Strabag. This alternative is not recommended.

Alternative 3 – Cancel the Project (Not Recommended)

- Abandon design, construction and commissioning of the Niagara Tunnel, incurring additional costs in the order of $100 M to secure the site in a safe and environmentally acceptable state, and forego the opportunity to generate additional clean, renewable hydroelectric energy averaging 1.6 TWh per year for at least 90 years at the Sir Adam Beck generating stations. With this alternative, there is a low likelihood of recovering any of the $563 M incurred costs through the regulated rates. This alternative is not recommended.

Financial Analysis

- While the Niagara Tunnel is expected to be part of OPG's regulated hydroelectric assets and receive a regulated rate reflecting cost recovery and a return on capital, it is appropriate to consider several financial metrics, as follows, to ensure that this is an economic investment relative to other generation options:
    - Levelized Unit Energy Cost (LUEC) represents the price required to cover all forecast costs, including a return on capital over the service life, escalates over time at the rate of inflation, and it permits a consistent cost comparison between generation options with different service lives and cost flow characteristics.
    - Equivalent Power Purchase Agreement (PPA) represents the price required if one were to bid the project into the renewable RFP. It is similar to LUEC except only 20% of the PPA escalates at the Consumer Price Index.
    - Revenue Requirement is a measure that represents the annual accounting cost of this project including an allowed return on capital employed. Revenue Requirement generally declines over time as the rate base is depreciated.
    - These metrics are equivalent in present value terms over the life of the asset and reflect full recovery of costs including a return on the investment.

Financial 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

- The proposed Green Energy Act includes a "Feed-In-Tariff" (FIT) for 10 – 50 MW hydroelectric projects of 12.2 ¢/kWh (2009$). This proposed program is comparable to the PPA measure noted in the table above except that the FIT contract is for 40 years instead of 50 years assumed in the PPA calculation.

Financial Analysis – Alt 1	¢/kWh
Revenue Requirement (2014$)	8.7
Revenue Requirement for OPG Baseload Hydroelectric without the Tunnel (2014$)	4.0
Revenue Requirement for OPG Baseload Hydroelectric including the Tunnel (2014$)	4.4

- Completion of the Project will result in a significant increase in average annual energy output from the Sir Adam Beck GS complex with an increase of 0.4 ¢/kWh, from 4.0 to 4.4 ¢/kWh (2014$), in the estimated regulated rate for OPG's hydroelectric assets.

Financial Sensitivity Analysis

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

Sensitivity Analysis [Dec-2013 In-Service Date]	Project Costs ($B)	Incremental Energy TWh	LUEC ¢/kWh in 2009$	Equivalent PPA Price ¢/kWh in 2014$	Revenue Requirement ¢/kWh in 2014$
Preferred Alternative (total costs)	1.6	1.6	6.8	9.5	8.7
Preferred Alternative – Going Forward Costs[3] only	1.1	1.6	4.3	6.2	n/a
Incremental Impact					
Water Availability					
Lower quartile flow for first 5 years of service[1]		(0.9)	0.7	1.3	n/a
Upper quartile flow for first 5 years of service[1]		0.8	(0.5)	(0.9)	n/a
Overall reduction of 5% in Niagara River Flow[2]		(0.4)	1.1	1.7	n/a
Project Costs					
Higher Capital Costs (+10% going forward costs)	0.1		0.4	0.6	0.5
Project Costs $100 M Higher	0.1		0.4	0.5	0.5
Project Delayed 6 Months	0.09		0.4	0.5	0.5
Interest During Construction Rate +50 Basis Points	0.02		0.0	0.0	0.1
Shorter Service Life (30 year Life)			0.9	0.7	2.2
Elimination of 10 year Holiday on Gross Revenue Charge			0.6	1.5	1.5

(1) Calculated for the first 5 years of service only
(2) Annual flows assumed to be reduced by 5% each year, compared to historical flows for the life of the tunnel
(3) Project costs today of $0.5B are sunk and not included in LUEC or PPA calculation

- Based on the above economic analysis, it is concluded that completing the tunnel as outlined in Alternative 1 is economic when compared with alternative supply options and that the recommended alternative is the lowest cost option for completing the Niagara Tunnel. The sensitivity analysis confirms that this conclusion is robust over a broad range of scenarios.

5. THE PROPOSAL

- Enter into an amended Design / Build Agreement with Strabag Inc to design, construct and commission a new diversion tunnel to convey approximately 500 m^3/s of water from the upper Niagara River to the Sir Adam Beck GS complex at Queenston. The concrete-lined tunnel will be approximately 10 km long and have an average internal diameter of 12.7 m. Flow will exceed the increased diversion capacity only about 15% of the time compared to the current 65%, and resultant incremental average annual energy output from the Sir Adam Beck generating stations is estimated at 1.6 TWh (14%). The project includes a new intake and associated modifications to the existing International Niagara Control Works, an outlet incorporating the emergency closure gate near the existing PGS reservoir, and removal of the PGS canal dewatering structure. The new tunnel will be in-service by December 2013.

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

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

- The estimated project cost of $1,600 M includes a negotiated target price for completion of the Niagara Tunnel by Strabag, agreed payments under the Community Impact Agreement, agreed compensation paid for Welland River issues, actual costs incurred with respect to the Niagara Exchange Agreement (OP, TP and future water rights), Owner's Representative costs, and OPG direct costs, [redacted] of remaining pre-contingency costs) to address remaining project risks.

- The target Substantial Completion (In-Service) Date negotiated with Strabag is [redacted] however a schedule [redacted] is added to address potential schedule extension due to residual OPG risks. This contingency brings the expected completion date to December 2013.

- The target cost approach recommended for completion of the Niagara Tunnel changes the project risk profile from that included in the current release. OPG has retained risks associated with specific remaining tunnel construction risks (TBM main bearing failure, significant damage to the tunnel conveyor, unexpected subsurface geological conditions, etc) and with specific baselined target cost parameters (extent of overbreak in the tunnel crown, escalation, diesel fuel prices, etc). Accordingly, cost and schedule contingencies have been included in this superseding release, as described above.

- The estimated project cost flow is as follows.

Project Cost Flow Estimate ($M) (including Contingency)	To 2008	2009	2010	2011	2012	2013	2014	Totals
OPG Project Management	2.5	0.6	0.7	0.7	0.7	0.4	0.4	6.0
Owner's Representative	[redacted]							
Other Consultants								
Environmental / Compensation								
Tunnel Contract								
Other Contracts / Costs	57.6	1.1	8.5	2.5	0.1	0.0	0.0	69.8
Interest	37.6	28.2	42.7	58.3	72.9	47.1	0.0	286.6
Total Project Capital	434.5	199.8	275.3	274.5	206.4	215.9	(6.4)	1,600.0

Note: Cost flow in 2014 includes [redacted] maximum cost and schedule disincentive triggered by exceedence of Target Cost and/or Target Schedule.

Explanation of Schedule Variances

Project Schedule (including Contingency)	Current Approval	Revised Estimate	Variance
Start Project Execution	September 2005	September 2005	-
In-Service Date	June 2010	December 2013	42 months
Project Duration	57 months	99 months	42 months

- The primary activities to complete the project, along with their planned duration and daily progress rates are as follows.

Activity	Start Date	End Date	Duration (days)	Avg Rate (m/day)
Award DBA	18-Aug-05	18-Aug-05	0	n/a
TBM Supply & Assembly	01-Sep-05	01-Sep-06	365	n/a
TBM to 3,619m	01-Sep-06	02-Mar-09	913	4.0
TBM - 3,619m to Intake	03-Mar-09	28-Apr-11	786	8.4
Invert Concrete	15-Dec-08	20-Jan-12	1,131	9.0
Overbreak Infill	01-Sep-09	08-Apr-12	950	10.7
Arch Concrete	11-Mar-10	11-Oct-12	945	10.8
Liner Contact Grouting	11-May-11	12-Dec-12	581	17.6
Liner Pre-Stress Grouting	01-Feb-12	24-Mar-13	417	24.5
Complete Intake Structure	28-Dec-09	28-Dec-10	365	n/a
Complete Outlet Structure	01-Jan-11	30-Jul-11	210	n/a
Install Intake Gates	23-Feb-13	28-Feb-13	5	n/a
Install Outlet Gates	01-Jul-12	19-Sep-12	80	n/a
[redacted]				n/a
[redacted]				n/a
[redacted]				n/a
[redacted]				n/a

Note: The Target Schedule was based on actual progress to March 2, 2009 (3,619 m).

- Based on Strabag's baseline schedule, the average TBM advance rate was expected to be 14.55 m per day over 715 days with TBM hole-through expected in August 2008. The TBM commenced boring the tunnel as planned on September 1, 2006, but the actual TBM progress rate to date has averaged only 4.07 m per day (27% of the planned rate). The primary reasons for the slower than planned TBM progress to date include:
  - delays associated with worker training, high groundwater inflow, cementitious ground-up rock clogging and damaging the TBM cutters, and difficulties installing full-ring rock support through the initial decline from the tunnel portal (contractor subsequently eliminated further full-ring rock support).
  - challenges experienced in safely excavating and supporting the overstressed Queenston shale (Sta 0+800 m to Sta 3+900 m, including the buried St. Davids gorge area), resulted in excessive crown overbreak and required several TBM outages for modifications to the initial support area immediately behind the cutterhead, and facilities to remove excess rock from the tunnel invert.

- Permanent tunnel lining operations have been delayed by the slow TBM advance to date, such that invert concrete placement, planned to start in October 2007, did not begin until December 2008.

- Rerouting of the tunnel between Sta 2+974 m and Sta 9+000 m to minimize remaining excavation with the tunnel crown in the Queenston shale formation shortens the tunnel length by about 200 m to 10.2 km and is expected to facilitate TBM advance rates averaging 8.4 m per day for the remainder of the tunnel drive due to tunnelling in rock with higher strength and lower in-situ stress resulting in reduced crown overbreak and reduced initial rock support requirements. Slower TBM advance rates than originally planned are expected due to:

  - Worse than expected conditions in the Queenston shale beyond the St. Davids gorge resulting in continuing excessive overbreak requiring spiling and additional rock support throughout the Queenston shale. These conditions caused Strabag to begin the vertical realignment to the upper formations in December 2008 at Sta 3+300 m.

  - Spending a longer duration in the upper formations results in more mixed face mining. Some of these rock formations are harder and more abrasive, causing greater cutter wear and requiring more frequent replacement. The mixed face conditions also result in "eccentric loading" on the cutterhead that will be managed by reducing the penetration rate to less than 1.5 m/hr in order to avoid damaging the TBM main bearing.

  - The higher alignment will bring the tunnel to within about 85 m of the existing SAB diversion tunnels with a potential for increased water ingress resulting in reduced productivity.

- Returning the tunnel to a circular profile prior to installing the concrete lining has necessitated an overbreak restoration operation. Adding this fourth, concurrent operation adds significant complication and risk to the project logistics.

- Strabag revised its estimate for a two-stage completion of the work at the Intake (allowing for delay of completion of the structure in order to remove equipment from the tunnel) and removal of tunnel equipment.

Explanation of Cost Variances

Project Cost Flow Estimate ($M) (including Contingency)	Current Approval	Revised Estimate	Variance	Variance (%)
OPG Project Management	4.4	6.0	1.6	36
Owner's Representative	[redacted]			
Other Consultants				
Environmental / Compensation				
Tunnel Contract (including Incentives)				
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

- The estimated increase in the cost for OPG Project Management is directly related to the extended duration of the Project.

- The estimated increase in the cost for the Owner's Representative is directly related to the extended duration of the Project.

- The estimated increase in the cost for Other Consultants is attributable to surveys for subsurface property rights acquisition for tunnel realignment and to the extended duration of the Project.

- The estimated decrease in the cost for Environmental / Compensation is due to reduction in the compensation for sewage handling and treatment under the Community Impact Agreement.

- The estimated increase in the Tunnel Contract cost is due to the conversion from a fixed-price to target cost plus mark-up [redacted] for head office overhead recovery, due to the extended duration of the tunnel construction and due to the contingency included to address additional construction risks assumed by OPG.

- The estimated decrease in Other Contracts / Costs includes additional insurance premiums associated with the extended duration of the tunnel construction offset by the reduction in agreed compensation for Welland River water level fluctuations.

- The estimated increase in Interest is due to the increased direct costs of the work and the extended duration of the Project.

6. QUALITATIVE FACTORS

- Sustainable Energy Development
  - The new tunnel will enable increased generation at the Sir Adam Beck GS complex utilizing Niagara River flow available to Canada for power generation that exceeds the capability of the existing diversion system (canal and two tunnels), and reducing spill over Niagara Falls from approximately 65% to approximately 15% of the time.
  - ~~Rehabilitation of Sir Adam Beck GS No.2, completed in April 2005, including overhaul or~~ replacement of primary mechanical / electrical equipment, improving conversion efficiency, increasing discharge capacity by 11% and adding 194 MW (15%) of capacity increases the gap between the existing diversion capacity and generating station discharge capacity.
  - There is potential to upgrade units at Sir Adam Beck GS No.1 by 100 to 150 MW, including conversion of the 25 Hz units, and further optimize conversion efficiency of the additional water to be supplied by the Niagara Tunnel Project.
  - Completion of the Niagara Tunnel Project in advance of an 8 to 12 month outage planned for 2017 for rehabilitation of the Sir Adam Beck GS No.1 diversion canal will significantly reduce associated energy losses (2.7 to 4.0 TWh) and financial losses.

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

- Regulatory Approvals & Third Party Agreements
  - Conditions of the EA Approval have been addressed.
  - The Community Impact Agreement, signed with host communities on December 23, 1993 addresses predicted impacts on tourism, roads, domestic water supply and sewage treatment during construction of the Project, and includes provisions for engagement of local contractors, suppliers and labour and for local road improvements. Agreed compensation payments were made to the host municipalities. [redacted]
  - The Project incorporates work and associated costs required under terms of the agreement between the Niagara Parks Commission (NPC) and OPG. This work has been completed and the Ontario Power GS and Toronto Power GS properties were returned to NPC on August 1, 2007.
  - Issues with Welland River water level fluctuations raised by the Niagara Peninsula Conservation Authority were addressed and agreed compensation was paid.

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

- Health & Safety
  - Safety program / performance was a significant factor in contractor pre-qualification.
  - The Design / Build Contractor has implemented comprehensive project site specific plans for construction safety and for public safety and security.
  - Strabag and its subcontractors have achieved commendable Health and Safety performance to date with a Lost Time Injury Frequency of 0.8 per 200,000 hours worked, less than half of the average for Ontario's heavy civil construction industry.

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

7. RISKS

- Prior to project execution, OPG, with the assistance of URS (a specialist consultant), conducted a comprehensive risk assessment (qualitative and quantitative) for design and construction of the Niagara Tunnel. Major project risks were identified through a series of workshops involving the project team and key stakeholders. During project execution, a Risk Register and associated Risk Management Plan have been maintained to manage residual risks.

- As required by the underwriters of the builder's all risk insurance policy, OPG (represented by OR) and the Contractor developed and maintain a Combined Risk Register for management of the tunnel construction risks.

- OPG's Risk Services Group facilitated the updating of the original risk registers. The input data was gathered through five separate facilitated workshops involving OPG project team and OR representatives who were asked to provide individual estimates of both the likelihood and the impact of 13 key risks that they had previously identified. Further details on the key risks are summarized in Appendix C.

- In addition, six schedule uncertainty risks (TBM mining, invert concreting, infill shotcreting, arch concreting, contact grouting and pre-stress grouting) were similarly assessed.

- These cost and schedule uncertainties were combined using Monte Carlo simulations to generate estimates of possible cost and schedule outcomes at various levels of confidence. The results indicated that a cost contingency of [redacted] would likely be sufficient to cover the cost uncertainties at a 90% confidence level for the 13 identified risks and six schedule uncertainty risks.

- The estimated in-service date is December 31, 2013, [redacted]

- The financial analysis completed for the recommended alternative is based on spending the entire cost and schedule contingency and is therefore considered to be conservative and robust.

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

Type of PIR	Target Project In Service Date	Target PIR Completion Date
Comprehensive	June 2013	December 2013

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Tunnel Capacity	500 m^3/s	500 m^3/s	Flow test using tracer transit time method.	Independent Testing Contractor
In-Service Date Including Contingency	December 2013	[redacted]	Compared with contracted Substantial Completion Date and approved changes.	
Actual Cost	$1,600 M	Less than $1,600 M	Compared to the approved release.	

Responsibilities

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

Project Execution Monitoring

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

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

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

Remedial Work at Ontario Power GS and Toronto Power GS

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

Tunnel Flow Capacity Verification

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

Project Financial Analysis

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

Lessons Learned

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

APPENDIX A

ONTARIOPOWER GENERATION	**PROJECT** **Summary of Estimate**	Date	24-Apr-2009
		Project #	**EXEC0007**

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

Estimated Cost in Million $

Year	**To 2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**Totals**	**%**
OPG Project Management	2.5	0.6	0.7	0.7	0.7	0.4	0.4	6.0	0.4
Consultants	[redacted]								
Design & Construction									
Other Contracts / Costs	65.8	2.1	8.4	2.5	0.1	0.0	0.0	79.0	4.9
Interest	37.6	28.2	42.7	58.3	72.9	47.1	0.0	286.6	17.9
Contingency	[redacted]								
Totals	434.5	199.8	275.3	274.5	206.4	215.9	(6.4)	1,600.0	100.0

Notes:

1. Schedule — Start Date: Jun-2004; In-Service Date: Dec-2013
2. Interest and Escalation rates are based on current allocation rates provided by Corporate Finance
3. Includes Removal Costs of: **n/a**
4. Includes Definition Phase Costs of: **n/a**
5. Percentages above relate to the total cost.
6. Cost flow in 2014 includes ($20 M) maximum cost and schedule disincentive triggered by exceedence of Target Cost and/or Target Schedule.

Prepared by:	**Approved by:**
Rick Everdell Project Director – Niagara Tunnel	Carlo Crozzoli Vice President – Hydro Development

Appendix B:
Niagara Tunnel Financial Model – Assumptions

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

Project Cost Assumptions:

1. Design/Build contract costs of [redacted] which include [redacted] for tunnel contract and [redacted] for recovery of overheads, completion fee bonuses, performance disincentive, GFA (Guaranteed Flow Amount) bonus allowance and [redacted] contingency
2. Other cost of [redacted] which include [redacted] for contingency
3. Interest during Construction (IDC) of [redacted]
4. Total project costs of $1600M

Financial Assumptions:

1. Debt Rate of 6%
2. Return on Equity (ROE) of 8.65%
3. Debt Ratio of 53%

Project Life Assumptions:

1. Substantial Completion Date provided by the proposed Design/Build contractor of [redacted]
2. [redacted] of contingency has been added to arrive at the in-service date of December 2013
3. The tunnel life is 90 years

Energy Production Assumptions:

1. The tunnel will contribute an additional ~1.6 TWh/yr to the production at the SAB facilities
2. The tunnel will "re-capture" ~1.1 TWh during the SAB1 canal outage in 2017

Operating Cost Assumptions:

1. When energy production begins OPG will realize a 10 year holiday on Gross Revenue Charge (GRC)
2. GRC based on $40/MWh escalated at CPI after 2013
3. Annual incremental OM&A costs of ~$.1M
4. 27% tax rate

Appendix C - Niagara Tunnel Project Major Risks Table

Risk #	Risk	Objectives	Cause of Risk	Mitigation	Remediation/Plan B	Assumptions	Milestones	Comments
1	TBM Main Bearing Failure delays project completion and increases project costs	On time and on budget	Main bearing failure, damaged seals dirt in hydraulics rock conditions and poor maintenance	1 L10 life with sufficient safety factor, 2 Selection of a TBM with a proven design, 3 Contingency planning, 4 Bi-weekly oil sampling, 5 Careful adjustment of thrust with mixed face, 6 Regular inspections by remote camera, and 7 Secure bearing and bring bearing closer to site (Ohio possibly)	Replace TBM main bearing	Spare bearing exists [redacted]	Risk expires at the end of tunnel mining April 2011(i e TBM @ CH 10,170 m)	If bearing is not available, then the delay is 18 months to manufacture the bearing Consider shipping delays due to winter weather P5 is best case scenario where lining work has not started yet and so less delay Cost of bearing is [redacted] L10 (15,000 hours) based on operating/drilling time, so even though the project duration lengthened 6,000 hours actual expected drilling time Financial impact does not include labour costs Labour included in schedule delay costs
2	Main Conveyor Failure delays project completion and increases project costs (10 km belt failure)	On time and on budget	Rock conditions steel or rock slicing the belt, poor maintenance and poor operating practices/ monitoring	1 Metal detection, 2 Contingency planning, 3 Keep critical spare parts and belts on site, 4 Video monitoring cameras on conveyor belt, 5 Increased visual monitoring, 6 Conveyor structural (rollers) inspection	Replace the conveyor belt	10 km conveyor belt failure (5 km of tunnel) Belt readily available to install is P5 scenario [redacted]	Risk expires at the end of tunnel mining April 2011 (i e TBM @ CH 10,170 m)	Financial impact does not include labour costs Labour included in schedule delay costs
3	Inundation or flooding of tunnel from intake	On time, on budget and safety	Cofferdam breach	1 Cofferdam height designed for 50 year return 2 Design checks by contractor 3 Review by OR 4 Close contact and cooperation with INCW operators 5 Monitoring system to check phreatic surfaces within cofferdam cells 6 Leakage monitoring of cofferdam 7 Seasonal inspection, as well as translational and tilting movements of the cells throughout the entire period when the cofferdam is dewatered and reviewed by cofferdam designer ((sherwood) 8 Ensure valve is locked out and cannot be operated 9 Maintenance plan for extended life.	Dewater, restore all equipment, repair/replace cofferdam cells	Worst case everything floods Flood TBM, invert carrier, and arch carrier 8 weeks to repair cofferdam, 4 months to dewater (need to procure pumps and deliver) P5 - everything survived P95 - replace concrete, repair damaged carrier Assume no loss of life [redacted] Financial Impact does not include labour Assume minimal cost to repair cofferdam P5 - Insurance covers equipment and materials repair	Starts upon completion of tunnel mining (i e April 2011) until gates at intake are in place (i e March 2013)	Original contractual removal date is September 2009
4	Critical work impeded by winter restrictions	On time on budget and safety	Ice conditions preventing marine activity	Plan the work to minimize the amount of marine activity required		Worst case cofferdam removal occurs during winter months Cofferdam removal is currently scheduled during winter 2013 [redacted]	Starts December 2012 and ends mid-April 2013 (end of winter conditions)	
5	Tunnel collapse	On time, on budget, safety and quality	Liner overstress, support failure, engineering error/omission, rock conditions and water ingress	1 Independent design reviews by Contractor and OR 2 Geotechnical presence on site (full time) 3 Regular interfacing with designer 4 Design/adjustments as required during construction 5 Tunnel instrumentation and monitoring of rock support 6 Clearly defined support for the whole range of expected ground conditions 7 Material testing (rock dowels, shotcrete) 8 Monitoring, Convergence monitoring for cracks 9 Regular review of convergence measurements by designer/ Experienced supervision/ Design of TBM minimizes unsupported length of tunnel/ On-site presence of tunnel designer (ILF) from June 2009 onwards	Repair and restore tunnel	Localized collapse of tunnel (of 10 - 20 m) that damages major equipment (i e TBM, invert forms, conveyor, ventilation etc) Insurable event with $1,000,000 deductible Worst case collapse of temporary liner, since permanent liner collapse would lead to more localized collapse P5 is minor localized damage etc [redacted] Insurance deductible for P5	Risk expires October 2012 (i e arch lining completion)	Emergency evacuation plan in place

Appendix C - Niagara Tunnel Project Major Risks Table

Risk #	Risk	Objectives	Cause of Risk	Mitigation	Remediation/Plan B	Assumptions	Milestones	Comments
6	Community Impact Agreement renegotiation	On budget and corporate reputation	Increased project duration leads to additional impact on Niagara community infrastructure	1 Effective negotiation strategy and communication with stakeholders 2 Ensure continued compliance with terms of Community Impact Agreement (CIA)		Project end date of June 2013	[redacted]	Existing money in the CIA fund and can be used instead of additional funds This item should be moved to base estimate
7	Unanticipated problems removing equipment	On time and on budget	Access and spatial constraints logistics, etc	Proper planning (including staging of equipment (e g cranes, cutting equipment)		Craning and spatial constraints for TBM and arch carrier are the biggest/most complex pieces of equipment to remove from tunnel therefore more prone to unanticipated problems Assume arch lining operation and grouting operation Interference Critical path if arch carrier catches up with TBM [redacted] Does not adjust the target cost or target schedule, but does affect actual schedule	Risk commences May 2011 and expires March 2013 (i e scheduled removal of all equipment from tunnel)	Is there a crane big enough with the reach needed to remove the main bearing?
8	Delays in providing outage for rock plug removal	On time and on budget	Inability to provide outage when contractor requires it	1 Early engagement of Independent Electricity System Operator (IESO) to understand consequence of rock plug outage and improve chance of getting outage when it is needed Communicate request for flexibility to IESO 2 Communicate outage changes to IESO as soon as possible		Source of outage delay comes from IESO Note IESO needs 18 months notice and NTP can only provide approximately 6 months notice of when they think rock plug removal would be required Spring or fall might be easier to get an outage from IESO since there could be less demand, however system status could be a factor (e g nuclear station vacuum building outages) [redacted] Assume bonus for 200,000/day for Contractor	[redacted]	Dewatering structure in canal to be removed because it reduces flow Outage only applies to Sir Adam Beck Pump Generating Station (SAB PGS)
9	Delayed tunnel mining due to health and safety hazards	Safety, on time and on budget	Falling rock conditions, silica methane, hydrogen sulphide, carbon monoxide and oxygen concentration	1 Design ventilation and dust abatement systems 2 Implementation of ventilation and dust abatement systems (e g foam in cutterhead, water mist sprays) 3 Regular operation of ventilation system and optimization/maintenance of dust abatement system 4 Wearing of personal protective equipment (PPE)	Respirators (full face masks) Worker training	High Silica concentration is worst case Assume hazard is identified before major event through monitoring of conditions Use of full faced respirator due to high silica in Whirlpool Sandstone is not included in scheduled labour progress [redacted]	According to schedule April 2009 to January 2010 TBM mining in Whirlpool formation to Power Glen 2 formation)	
10	Prototype overbreak infill operation prolongs schedule	On time, on budget, safety and quality	Prototype operation for arch infill and initial setup delays (i e procurement & delivery of equipment)	1 3 months of planned float in the schedule 2 Planned learning curve via slow initial progress rate 3 Properly designed system	Timely modifications to improve the efficiency of the infill operation	Critical path Scheduled advance rate is based on expected average shotcrete delivery and discharge rate (i e site shotcrete limitations) 3 month float in schedule, 3 km length for infill operation [redacted] Based on 24/7 operation, 2 production shifts		Some flavour of concurrent activities, could cause double counting 7 months until it becomes critical path 3 months float at the end (i e conditioning work, not infill activities) In worst case, then 2 months impact on critical path Delivery & procurement could be 2 months delay Delay in critical path due to late delivery of carrier (delays start date) Financial impact is slower progress in Queenston Shale

Risk #	Risk	Objectives	Cause of Risk	Mitigation	Remediation/Plan B	Assumptions	Milestones	Comments
11	Concurrent activities delay progress	On time, on budget	Logistics of concurrent activities	1 Proper planning of logistics in the tunnel 2 Adequate passing bays in the tunnel 3 Traffic control system 4 Ensure TBM mining is on schedule 5 Ensure arch infill carrier is launched on schedule		Worst case shutdown arch lining activities because of too many concurrent activities Assume that it does not occur at the end [redacted]	Risk expires in April 2011 (i e when TBM mining complete)	Short window where TBM and arch infill activities occur concurrently Impact of TBM mining rate affects this risk
12	Nonconformance and/or noncompliance is identified and requires rework	Quality on time and on budget	Contractor performance leads to inadequate design and construction quality inadequate quality control and assurance	1 OPG full-time presence during construction 2 Structured submittal and stringent design review process by Hatch and Strabag 3 Monitoring of construction works against plan (Hatch and Strabag) 4 Review formal non-compliance process of Contractor QC reports regularly 5 Full time quality assurance manager built into contract		Worst case re-pouring of concrete, tearing out localized areas f liner and membrane (i e aggregate of 25 m) because of substandard concrete/thickness, etc Concrete placement at [redacted] and removal at [redacted] Assumes all nonconformances/noncompliances are detected Quality concerns discovered during operation are outside the scope of this analysis Assume no schedule delay so no burn rate	March 2010 (i e arch lining commences) to October 2012 (i e arch lining completion)	Adjust target if structure is removed and no problem is found
13	Contract management problems increases project costs	On budget, on time, quality aspects	Unanticipated claims inadequate Design Build Agreement contract, successful subcontractor claims, inadequate owner involvement during contract execution frivolous claims	1 Revision and use of project execution plan (PEP) and detailed project procedures 2 Periodic review and update of PEP 3 OPG conducting intermittent audits 4 Well defined contract language around disallowed costs Adequate contract language to clearly define contractor's obligations 5 Adequate and proactive Owner oversight		Worst Case unexpected ground conditions (e g sidewalls spalling effecting gripper efficiency) Frequency and magnitude of occurrence captured in P95 Assume no schedule delay so no burn rate	Risk expires one year after project completion (i e 1 year limitation on claims)	Target date extended due to claims
14	Lower than planned TBM progress in each rock strata due to overbreak above baseline	On time and on budget	Rock conditions	1 Reviewed historical TBM progress in different strata and incorporated into schedule 2 Set target rates for anticipated overbreak 3 Engagement of field engineer to optimize solutions for dealing with rock conditions		No contingency in TBM mining schedule Schedule includes planned maintenance and historical unplanned outages Estimates includes slower than anticipated progress due to rock conditions, unanticipated cutter destruction and unanticipated machine issues [redacted] Assume exceeding overbreak calculations already built into schedule	Risk expires afterTBM mining (i e scheduled April 2011)	
15	Adverse Impact to existing structures	Impact to OPG, on budget, on time	Effects of tunneling near existing tunnels and structures			Worst case is damaging the tunnel [redacted] to repair tunnel Lost revenue for one tunnel [redacted] Dewatering time is 365 days		
16	OPG Abandons Project	Reputation, Costs, Impact to OPG	Shareholder does not approve financing, OPG chooses not to proceed with project					The quantitative analysis is based on the expectation that the Niagara Tunnel Project is completed under a new Design Build Agreement with Strabag It is recommended that this risk and its financial impact be considered as an alternative in the superseding business case
17	Cost Recovery Uncertainty	Impact to OPG	Non prudent costs associated with the project are incurred					This is not an execution phase project risk. It is recommended that the financial impact of this risk be included in the operating revenue of the superseding business case NPV calculations
18	Tunnel does not meet 90 year life or does not meet substantial performance requirements	Quality, on time and on budget	Contractor performance leads to inadequate design and construction quality, inadequate QC and assurance					This is not an execution phase project risk. It is recommended that the financial impact of this risk be included in the operating revenue of the superseding business case NPV calculations
19	Contractor defaults on its obligations	On time, on budget, impact on OPG	Potential of significant loss					The quantitative analysis is based on the expectation that the Niagara Tunnel Project is completed under a new Design Build Agreement with Strabag The approach taken by the project team is to consider the consequences of this risk should it occur through another superseding business case

DECEW FALLS NO.1 GS (ND1)
PENSTOCK AND SADDLE REPLACEMENT (DCW10019)

1. RECOMMENDATION:

Approval is recommended for release of $10.455M for the replacement of four ND1 penstocks and related saddles.

A recent inspection and subsequent engineering investigation concluded that the penstocks could no longer be operated safely. The 4 operational units were subsequently shut down. The continued operation of ND1 as a 4 unit station was found to be the preferred alternative in the approved DeCew Life Cycle Plan. This alternative was found to be the most economic option, providing the highest NPV and lowest risk.

The demolition of the existing penstocks is presently underway and will be complete in 2009. Expediting the replacement project will minimize production losses.

$000's	Funding	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	Choose								-
Requested Now	Full		3,180	6,225	1,050				**10,455**
Future Funding Req'd	Choose								-
Total Project Costs		-	3,180	6,225	1,050	-	-	-	10,455
Ongoing Costs									-
Grand Total		-	3,180	6,225	1,050	-	-	-	10,455
Investment Type Sustaining		**Class** Capital		**NPV or IEV** 19,383		**IRR** 14.5%		**Discounted Payback** 14 years	

LUEC = 76 $/MWh

Funding for this project was included in the 2009 Niagara Plant Group (NPG) Capital budget. It has been included in the 2010-2014 Business Plan with revised estimates.

2. SIGNATURES

Submitted By:

Dave Heath Sept 25, 2009
David Heath Date
Plant Group Manager, NPG

Recommended By:

John Murphy Oct 19/09
John Murphy Date
Executive Vice-President, Hydro

Finance Approval :

D Hanbidge Oct 13/09
Donn Hanbidge Date
EVP & CFO

Line Approval :

J Mitchell Oct 19/09
Tom Mitchell Date
President and CEO

3. BACKGROUND & ISSUES

The DeCew Falls ND1 generating station is located in St. Catharines, Ontario. The station has been in service since 1898 and contains four operational generating units (G5, G6, G7 and G8), with an average capacity of 5.7 MW, each supplied by individual penstocks. Unit 9 has been dewatered and mothballed since 1989, but its penstock has remained in place. Unit 4 was also retired in 1989, and its penstock has been plugged at the headworks but remains in place. Construction of G5 through G8 occurred between 1906 and 1912.

The ND1 penstocks are the oldest in the NPG system and have experienced numerous leaks over the last 30 years. These have ranged from "pin-hole" leaks to cracks several inches in length. In 1995, a failure occurred on penstock No. 7. The length of the overall penstock damage was approximately 190 feet, located upstream and downstream of the headblock. It is suspected that during the cold weather, an ice blockage developed in the penstock resulting in a vacuum.

An investigation carried out in 2008 by Structural Integrity Associates inspected sections of the penstocks G5-G8 between the inlet and the headblock. This study focused on the extent of internal wall loss that has occurred adjacent to the riveted lap seams.

Based on the analysis, the predicted failure Factor of Safety was deemed to be unacceptable by NPG and the four operational units were immediately shut down in December 2008.

Status of Penstocks

The demolition of the penstocks is presently underway and will be complete by the end of September, 2009. Since the existing penstocks could not be reused and would eventually need to be removed, a separate demolition project was released ahead of the replacement project in order to expedite the overall schedule of getting the units back in-service.

Life Cycle Plan

Maintaining ND1 as a 4 unit station is the preferred alternative in the approved DeCew Life Cycle Plan. It was found that this alternative was the most economic option, providing the highest NPV and lowest risk.

The DeCew life cycle plan assessments included alternatives significantly increasing the existing generating capacity at the site. Water is discharged from the site to Lake Ontario via Twelve Mile Creek. As Twelve Mile Creek discharge capacity is limited, these options are not feasible based on environmental and approval considerations, and were not recommended.

The remaining options involved either the status quo or shutting down the smaller ND1 station and utilizing the water at the larger NF23 and Beck complex. Shutting down the ND1 station theoretically would marginally increase the energy production from Niagara. However, it would reduce the ability to produce peak energy while increasing off peak energy production. This would result in less revenue generated from these assets. It would also increase costs, as production transfer to other Niagara stations would attract the 26.5% marginal rate for the Gross Revenue Charge property component versus a 4.5% marginal rate at the smaller ND1 station.

Shutting down ND1 would also have negative production impacts on the City of St. Catharines at their existing downstream Heywood GS, their proposed Schickluna GS, and OPG's proposed Lake Gibson GS project.

Business Need

Replacement of the ND1 Penstocks and Saddles will provide for sustained and safe station operation of the station.

4. ALTERNATIVES AND ECONOMIC ANALYSIS

Choose One	Do Nothing	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost				
Project Cost	3,806	10,455					
NPV (after tax)	(2,470)	19,383					
Impact on Economic Value		21,853					
IRR%		14.5%					
Discounted Payback (Yrs)		14					

Base Case: (Status Quo) – Do Not Replace Penstocks (Not Recommended)

- The Status Quo alternative would result in retiring the DeCew ND1 units. This would result in the loss of hydroelectric generation. Shutting down ND1 would also have negative production impacts on the City of St. Catharines at their existing downstream Heywood GS, their proposed Schickluna GS and OPG's proposed Lake Gibson GS.
- This alternative is not recommended.

Alternative 1: Replacement of penstocks and saddles on Units 5, 6, 7 and 8 (Recommended)

- This alternative involves replacement of the 4 in-service units penstocks and saddles. Operating DeCew ND1 as a 4 unit station is the preferred alternative in the approved DeCew lifecycle plan. This was found to be the most economic option, providing the highest NPV and lowest risk.
- The NPV for the recommended Alternative 1 is $19,383k and the IRR is 14.5%. A sensitivity analysis has been completed and the tornado diagram on page 6 shows the variability from the base NPV.
- This is the recommended alternative.

5. THE PROPOSAL

Results to be delivered

Replace the 4 penstocks and associated saddles and valves, so that ND1 returns to full operation by 2011.

Scope of Work

- Install new penstocks for units 5, 6, and 8. These penstocks are to extend from the intake structure down to the upstream side of the turbine inlet valve.
- Install new penstock for unit 7. This is to extend from the intake structure down to the upstream

side of the turbine inlet valve, excluding two existing welded sections of penstock located on either side of the headblock. The new penstock is to be joined to these existing sections that were installed in 1996.

- Installation of new saddles already removed under the demolition project and modifications to the tops of saddles not previously removed. The profiles of the penstocks are to be raised to accommodate saddle modifications and to ensure accurate alignment and support of the new penstocks.
- New headblocks are to be installed on units 5, 6, 7 and 8.
- Install new steel walkways joining the tops of the headblocks.
- Insert new steel liners within the existing encased portion of the intake structure and upstream wall of the powerhouse.
- Replacement of the 4 intake valves and actuators
- Replace/rebuilt the 4 existing relief valves.
- Relocate 13.8 KV overhead line.

Exclusions from Scope

- Demolition of the penstocks, saddles and headblocks. The demolition project is presently underway and will be completed in September 2009. Since the existing penstocks could not be reused and would eventually need to be removed, a separate demolition project was released ahead of the replacement project in order to expedite the overall schedule of getting the units back in-service.

Schedule

BCS Approval	September 25, 2009
Project Award	September 30, 2009
Contractor Mobilization	October, 2009
G7 In-Service	July 2010
G8 In-Service	August 2010
G6 In-Service	March 2011
G5 In-service	April 2011

6. QUALITATIVE FACTORS

Qualitative Factors

- Niagara Escarpment Commission permit is not required, as penstock replacement was deemed to be a maintenance item
- Trades work was assigned to the Building Trades Union (BTU) in accordance with the Chestnut Park Accord Addendum.
- Labour resources will be coordinated between BTU contract and OPG staff.
- Project activities will be conducted in accordance with Niagara Plant Group Environment, Health and Safety (EH&S) Management System.
- This project will improve efficiency in the Niagara Plant Group by ensuring operational integrity, improved reliability of the penstock and reduced maintenance costs.

Project Management

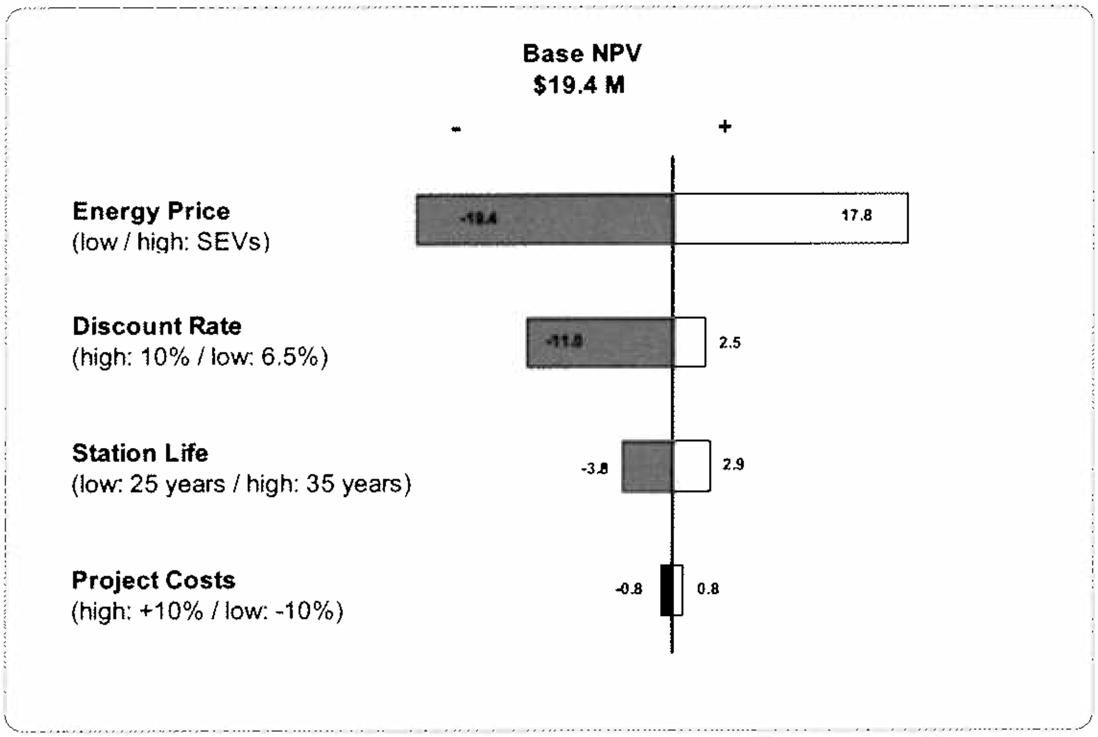
- The project will be executed by the Niagara Plant Group Project Management Department.
- Cost projections are release quality based on proposals received from pre-qualified Tier 1 contractors. Appendix A provides a Summary of Estimate for the project.

- The project will be executed by the Niagara Plant Group Project Management Department. A draft Project Execution Plan identifying scope, schedule and cost has been developed for this project. A final Project Execution Plan will be in place prior to the contractor mobilization in October 2009.

7. RISKS

Risk Category	Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost	Final project cost higher then estimated	Release funding insufficient to complete project	Medium	Detailed design and firm quotation received from Contractor for supply and installation. A contingency allowance is included in the project estimate to address any discovery work.	Low
Scope	Poor Definition of Scope of Work	Increased Cost	Medium	Detailed site survey and assessment by consultant. Detailed design engineering by consultant with review by NPG and Hydro Engineering.	Low
Schedule	Delay in completion of the project will result in lost generation revenue	Reduced revenue	High	Penstock demolition project almost complete. Scope of work well defined. Contractor is ready to mobilize.	Low
Environment	Spill	Reportable Spill	Low	NPG Environmental policies will be followed	Very Low
Regulatory	Delays in obtaining necessary permits	Delay in start of project	High	Discussion was held with the Escarpment Commission and a permit is NOT required as work was deemed maintenance	Very Low
Health & Safety	Risk of Injury to workers	Worker Injury	Low	NPG Safety policies will be followed	Very Low

Sensitivity Analysis – Tornado Diagram



8. POST IMPLEMENTATION REVIEW (PIR) PLAN

- A Project Closure Report will be submitted within two months of the date of the completion of project execution. It will include the results of the Project Department review of the project. This review will compare the planned cost and schedule milestones as outlined in the Project Execution Plan, to the actual cost and schedule milestones.

Type of PIR	Target Project In Service date	Target PIR Completion date
Simplified	April 2011	Six months after project PCR

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
1. Correct Installation/ construction	N/A	As per drawings and technical specifications	Inspections as per specified contractor Q/C and OPG Q/A programs	OPG Site Monitor, Design consultant, Asset Management Engineering
2. Leakage	Penstocks are leaking	Water tight penstock	Inspection	Asset Management Engineering , Design Consultant

- The penstock replacement project will be monitored for quality as per the technical specifications throughout the construction phase. Any deficiencies will be corrected during the course of the project.

- Prior to commencing the commissioning of the penstock and associated civil works, a complete review/audit of all Q/C and Q/A documents will be conducted by the commissioning team of stakeholders.

- A detailed "Commissioning Plan" for placing the new penstock into service is being prepared.

APPENDIX A:

ONTARIO POWER GENERATION	PROJECT Summary of Estimate	Date	August 2009
		Project #	**DCW10019**

Facility Name:	**DeCew Falls No.1 GS (ND1)**
Project Title:	**Replacement of Penstocks**

Estimated Cost in Million $

Year	2009	2010	2011	2012	2013	Totals	%
Engineer & Project Mgmt.	47	205	50			302	2.9
Consultant	[redacted]					[redacted]	
Construction/Installation							
- Hydro	12	6	6			24	.2
- Others	[redacted]					[redacted]	
Interest	111	375	30			516	4.9
Contingency	[redacted]					[redacted]	
TOTAL	**3180**	**6225**	**1050**			**10455**	**100**

Notes:

1. Schedule — Start Date: Sept. 2009; In-Service Date: April 2011
2. Interest and Escalation rates are based on current allocation rates provided by NPG Finance
3. Includes Removal Costs of: $0k
4. Includes Definition Phase Costs of: N/A
5. Percentages above relate to the total cost. N/A

Prepared by:	**Approved by:**
Tony Palma Sr. Project Management Engineer	Gord Allan Project Manager

1. RECOMMENDATION:

Approval is recommended for the full release of $21.7M (Capital) to upgrade the protection and controls at the R.H. Saunders Generating Station. The existing protections and controls are original and at end of life. This upgrade will ensure continued reliability from this facility and that generator and transformer protections will meet current protection standards, meet the DC separation requirement for control systems, and meet the NERC cyber security requirements.

This investment is required now to meet the NERC cyber security requirements by the end of 2009 and to ensure that the assets at Saunders are appropriately protected from electrical and mechanical faults.

Project cost flow:

$000's	Funding	LTD 2008	2009	2010	2011	2012	Total
Previously Released	None						
Requested Now	Full Release	0	5,070	8,545	7,802	283	21,700
Total Project Cost		**0**	**5,070**	**8,545**	**7,802**	**283**	**21,700**

This is a sustaining project with a NPV of ($16.6 M).

2. SIGNATURES

Submitted by:

01 June 2009

Executive VP Hydro Date

Recommend by:

EVP & Chief Operating Officer Date

Finance Approval :

June 4/09

SVP & CFO Date

Line Approval :

President & CEO Date

3. BACKGROUND & ISSUES

R.H. Saunders GS is a sixteen unit hydroelectric station spanning half the width of the St. Lawrence River to the international boundary at Cornwall, Ontario. All sixteen units were placed in service between July 1958 and December 1959. The station is classified as a "Flagship" in Hydroelectric's portfolio management system and is controlled locally. The station capacity (MCR) and 2008 annual energy production are 1,045 MW and 6,978 GWh respectively. Priced at the current regulated rate of 36.66 $/MWh, the 2008 production represents gross revenues of $256M. Identical in layout, the sixteen unit Franklin D. Roosevelt Power Project, a NYPA facility, extends from the international boundary to the U.S. shoreline.

The electrical protections are used to protect and minimize the severity of an electrical fault to the generators, transformers and lines. The mechanical protections protect or minimize the severity of mechanical related failures to the generator. Examples of electrical failures are stator ground faults, line faults and split phase generator winding faults. Examples of mechanical failures are high bearing temperature, loss of governor oil and generator overspeed. Replacement of the protections would provide protections that meet the current industry and OPG standards. The generator controls allow the hydroelectric operator to not only dispatch the generators but provide the operator with the status of the equipment to allow them to make informed operating decisions. The protections and controls are original and at end of life and the replacement would ensure continued reliable operation at this facility.

Current deficiencies that have been identified in the plant condition assessment (2006) and through plant staff interviews include: the protections do not meet the current protection standard; lack of DC separation between generator controls and generator/transformer protection; and the existence of a single point of failure for multiple generator alarms.

The line protection at the Saunders GS is owned by OPG and is at end of life. Changing the line protection would require coordination with Hydro One since they have identical equipment at their facility protecting the line. Hydro One has requested that the line protection between Saunders GS and St. Lawrence TS be upgraded to a differential protection to ensure complete protection of the lines. To accomplish a differential protection, the telecommunication media between the two facilities needs to be upgraded from metallic cables to fibre optic communication and primary relays at both facilities changed.

In June 2006, the North American Electric Reliability Corporation (NERC) made effective the Cyber Security Standards CIP-002-1 through CIP-009-1. The implementation plan requires that Critical Assets, which includes Saunders GS, comply with the standards by Dec 31, 2009. It has been verified with the IESO that the use of "air-gapping" meets the requirement of the standard for Saunders. This sanctioned technique removes routable protocols, which introduces a barrier and therefore reduces the security risk and meets the regulatory needs. "Air-gapping" ensures that the use of an external data connection to the facility such as the internet will not create a security risk to the facility.

This project is consistent with the Hydroelectric portfolio management strategy and follows the completion of two similar projects in the plant group. The portfolio management strategy states that experiments or shortcuts in capital work are generally not acceptable for flagship assets in order to minimize risk with these facilities. The successful completion of two similar projects at Chat Falls and Otto Holden has proven that the solution is viable, and the lessons learned from the previous projects have been applied to the technical specification for Saunders.

For projects where the scope includes protection or controls, consideration is usually given to the replacement of protection, controls and governors simultaneously due to installation synergies and to ensure the final product is tightly integrated. The original project scope only consisted of protections replacement, but it was subsequently determined that it would be more cost effective to replace the controls during the same project. This did not prove to be the case for governor controls. The project also provides an opportunity to incorporate cyber security modifications in order to meet NERC requirements.

4. ALTERNATIVES AND ECONOMIC ANALYSIS

Base Case: (Status Quo)

- This alternative is not recommended since it would not meet the NERC cyber security requirements, does not address the deficiencies in the current protections and does not address the lack of DC separation.

Alternative 1: Upgrade Protection and Controls (Recommended)

- This alternative would replace the generator protection and controls, main output and station service transformer protections, line protection and operator interface for alarms and controls, and includes an "air-gapping" solution to meet requirements for cyber security.

Alternative 2: Upgrade Protections - Delay Controls Replacement

- This alternative would replace the generator, main output and station service transformer and line protections, and would also ensure compliance with cyber security. However, this alternative assumes replacement of the generator controls in 2019-20 as a separate project.

Alternative 3: Upgrade Protections, Controls and Replace Governor Pilot Stage

- This alternative is similar to the previous alternative with the addition of governor pilot stage replacement. This alternative would provide the station with enhanced governor controls but is not recommended since the current governor can meet regulatory requirements and suitable spare parts are available.

Choose One	Choose One	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3
Project Cost		21,700		* 14,164	28,810
NPV (after tax)		(16,595)		(19,513)	(20,823)
Impact on Economic Value		(16,595)	-	(19,513)	(20,823)

* does not include cost of generator controls

5. THE PROPOSAL

- Replace generator protections, transformer (main output and station service) protections and replace line protections with a differential protection to sustain reliable generation.
- Implement an "air-gapping" solution for all external communication to the control network to meet the requirements (minimize the impact) of the NERC Critical Infrastructure Protection by December 31, 2009.
- Replace generator controls so that controls are unitized and DC supplies are segregated to support worker isolation and asset protection.
- Co-ordinate line protection upgrade to a differential protection with Hydro One. Arrange

appropriate terms of use, payment and easements for Hydro One fibre optic cables that are required to support the protections.

- Project strategy is to award the work to a single experienced contractor who has done similar work at our stations to minimize risk to OPG.
- A Draft Project Execution Plan (PEP) has been prepared for this project.

Schedule

- Project approval June 1, 2009
- Award of Contract June 1, 2009
- Implement "air-gapping" at Saunders by Sept 30, 2009
- G1, G2, G3, G4, T1 Bank, G5 in-service Q4 2010
- G6, G7, G8, T2 Bank, G9, G10 and G11 in-service Q1 2011
- G12, T3 Bank, G13, G14, G15, G16 and T4 Bank Q2 2011
- Project Closeout March 2012

6. QUALITATIVE FACTORS

- New protection and control panels will be CSA certified and DC supplies to the panels will be unitized to enhance worker safety in addition to asset protection.

- Control system design will ensure a single failure of the control system will limit the loss of control to a single generator to ensure continued revenue from the remaining generators.

- IESO and Hydro One approvals/reviews will be obtained to maintain market registration and transmission connection agreement.

- Easement will be negotiated for Hydro One for their fibre optic cables.

- Replacing all the station protection and controls will ensure that this equipment throughout the facility is composed of the fewest number of unique parts while maintaining reliability. This will minimize the number of spare components and unique training required to support this system.

7. RISKS

Risk Category	Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost	Higher contractor costs.	Exceeding the release amount.	M	A fixed price contract has been negotiated for the replacement of the protection and controls. Discussion has occurred with Hydro One in negotiating a cost associated with the fibre optic cable.	L
Scope	Appropriate scope has not been properly identified in technical specification.	Exceeding release amount and extending the schedule.	M	The technical specification utilized has undergone numerous improvements and iterations for other protection and control projects. The specification was then customized for Saunders GS.	L
Schedule	Outage delay due to contractors.	Prolonged generator and/or transformer outages resulting in lost opportunities.	M	The outage proposed by the contractor appears reasonable based on OSPG experience. The contract will also include rewards and penalties to promote the proper behaviour.	L
Resources	Lack of sufficient contract monitors during outages.	Lengthen the generator and/or outage	M	A plan is currently being prepared to supplement the project crew with other station's personnel when required.	L

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

- A preliminary PIR will be conducted on the "air gapping" solution based on an assessment that will be conducted by Hydro Engineering Division (HED).
- Accountability: Ottawa/St. Lawrence Plant Group Asset Management & Technical Services
- Date to be completed: January 31, 2010

- A simplified PIR will be performed to confirm asset protection issues are resolved by proper DC distribution and electrical and mechanical protections. Controls will be assessed to ensure the hydroelectric operators are provided with correct information to make operating decisions. HED will conduct the assessment and measure against current standards.
- Accountability: Ottawa/St. Lawrence Plant Group Asset Management & Technical Services
- Date to be completed: 6 months after Project Closure Report has been submitted.

APPENDIX A:

ONTARIO POWER GENERATION	PROJECT Summary of Estimate	Date	May 12, 2009
		Project #	**SAUN0047**

Facility Name:	RH Saunders GS
Project Title:	**Protection and Control Upgrade**

Estimated Cost in Million $

Year	2009	2010	2011	2012	2013	2014	2015	Totals	%
OPG Project Management (012)	0.08	0.19	0.12	0.02				0.41	2
Engineering (310)	0.05	0.43	0.03	0				0.51	2
Hydroelectric (PWU Labour) (010)	0.05	0.24	0.18	0.01				0.48	2
P&C Contract ,Contractor /(BTU labour)/ EPSCA (310)	[redacted]							[redacted]	
Permanent Materials (200)	[redacted]							[redacted]	
Interest (700)	0.05	0.38	0.15	0.02				0.60	3
Contingency (988)	[redacted]							[redacted]	
Totals	5.07	8.55	7.80	0.28				21.70	100

Notes: 1. Schedule Start Date: June 1/09

In-Service Dates as follows:

G1, G2 Oct 2010 ($2.1); G3, G4, T1 Bank Nov 2010 ($2.1); G5 Dec 2010 ($2.1); G6, G7 Jan 2011 ($2.1); G8, T2 Bank, G9 Feb 2011 ($2.1); G10, G11 Mar 2011 ($2.1); G12, T3 Bank, G13 Apr 2011 ($2.1) , G14, G15 May 2011 ($2.1), G16 Jun 2011 ($2.1).

2. Interest and Escalation rates are based on current allocation rates provided by Corporate Finance
3. Includes Removal Costs of: **$0.8M**
4. Includes Definition Phase Costs of: **0**
5. Percentages above relate to the total cost.

Prepared by:	**Approved by:**
May 21/2009	May 21/09.
Project Engineer	Project Manager

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.

<u>Post Implementation Review (PIR)</u>

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. <u>QUALITATIVE BENEFITS</u>

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.

Graphical Representation of Risk using a Tornado Diagram:

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.

ONTARIOPOWER 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.

ONTARIO POWER GENERATION	Document Number: HOSL0005	Revision:	Page: 1 of 12
	BUSINESS CASE SUMMARY Cornwall Energy and Information Centre		

1. RECOMMENDATION

Recommend full release approval of $12.6M (which includes Definition Phase release of $526k spent to date) to construct a new Energy and Information Centre in the city of Cornwall adjacent to the R.H. Saunders Generating Station. The Centre will provide a venue for the delivery of information regarding OPG and its generating facilities and the history of the development and construction of the Seaway and how it affected the local communities. The Centre will also provide stakeholders with a venue to deliver information on their areas of interest. The Centre will also align with the Provincial Government's commitment to adopt a LEED (Leadership in Energy and Environmental Design) standard for all new government-owned buildings.

The sixth floor of R.H. Saunders originally housed an Energy and Information Centre. This has been closed since 1992 and has not been reopened to the public due to OPG and New York Power Authority post-9/11 security concerns.

Definition Phase approval was obtained in Q2, 2008 to conduct public stakeholder consultations, evaluate and select a Centre design and obtain proposals from pre-approved vendors. The start of construction of the Centre will be tied to the timing of the St. Lawrence Seaway and Power Project 50th anniversary celebrations in 2009 and will be completed in the summer of 2010.

Total Investment Cost: - $12,554k (Capital) which includes $526k spent to date

	LTD	2009	2010	Total
Definition Phase – Spent to Date	$526k			$526k
Execution Phase		$8,735k	$3,293k	$12,028k
Total Project	$526k	$8,735k	$3,293k	$12,554k

Expenditure Type: Capital
Investment Type: Sustaining
Release Type: OAR element 1.1

2. SIGNATURES

Submitted by:

12 March 2009

John Murphy
EVP Hydro
Date

Recommended by:

March 13/2009

Bruce Boland
SVP – Corporate Affairs
Date

Finance Approval:

Mar 13/09

Don Power
VP Corporate Investment Planning
Date

Line Approval:

Mar 16/09

Pierre Charlebois
EVP & COO
date

3. BACKGROUND & ISSUES

R.H. Saunders GS is a sixteen unit hydroelectric station spanning half the width of the St. Lawrence River to the international boundary at Cornwall, Ontario. All sixteen units were placed in service between July 1958 and December 1959. The station is classified as a "Flagship" in Hydroelectric's portfolio management system and is controlled locally. The station capacity (MCR) and average annual energy production are 1,045 MW and 6,869 GWh, respectively. Identical in layout, the sixteen unit Franklin D. Roosevelt Power Project, a New York Power Authority (NYPA) facility, extends from the international boundary to the U.S. shoreline.

The R.H. Saunders facility originally included an Energy and Information Centre on the sixth floor "Observation Deck" of the administration building of the powerhouse. This Centre was closed in 1992. OPG has held small scale station tours under strict control since the closure of the centre. However, reopening the original information centre is not an option due to OPG and NYPA post-9/11 security concerns.

In 2006, OPG made a commitment to local municipal leaders and provincial politicians/officials to consider reopening an off-site energy and information centre in Cornwall. An off-site information centre would not require stringent security measures and would be similar in concept to NYPA's new information centre. NYPA has also closed their information centre at the Franklin D. Roosevelt Power Project and have subsequently constructed a new off-site facility in view of their station.

Construction of the Centre will provide a venue near OPG's second largest hydroelectric generating station to tell the hydroelectric "story" and maintain/improve public acceptance of the station and its continued operation. It will also promote OPG's corporate brand and image with respect to all of OPG's generation types and would serve to educate students and the public about the operations and benefits of power generation, with the main focus on hydroelectric power.

An engineering consultant (Thompson Rosemount Group – TRG) was retained to perform Developmental Phase activities. These activities included stakeholder consultations and the development, evaluation and selection of a centre design, including detailed building specifications and the preparation of a Request for Proposal. TRG acquired the services of Holman Exhibits (interior/exhibit design consultant) to prepare the interior exhibits, models and displays. These displays were developed during the external stakeholder meeting process which provided the opportunity to seek input from the various stakeholder groups on the exhibits and associated documentation intended for the Energy and Information Centre.

A preliminary cost estimate of $10,127k was prepared by OPG's consultant in the summer of 2008 based upon a 10,000 square foot Energy and Information Centre and conventional building standards. However, it became apparent early in the stakeholder process that additional space would be required to accommodate OPG's and the stakeholders' requested exhibits. It was also decided that, if possible, that the information centre building design should align with the Provincial Government's commitment to adopt a LEED (Leadership in Energy and Environmental Design) standard for all new government-owned buildings. The LEED Building Rating System promotes a whole-building approach to sustainability in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality. The Cornwall Energy and Information Centre would be the second LEED certified building in Cornwall.

As part of the Definition Phase, estimates for four design proposals were developed, two of which included LEED certified buildings. After review of the four designs and stakeholder consultations, OPG's directed the engineering consultant to prepare detailed building specifications and a Request for Proposal for a 13,280 square foot building. The building specifications incorporate all the external stakeholders' and OPG's needs and would be constructed to meet a LEED Silver rating. These additional requirements result in a cost increase of $2,427k compared to the originally proposed 10,000 square foot non-LEED rated building (see Appendix D).

The final design and recommended alternative has been reviewed and unanimously agreed upon by both OPG and the external stakeholders including:

- the City of Cornwall;
- the United Counties of Stormont, Dundas and Glengarry;
- the Iroquois and South Dundas Chamber of Commerce;
- the Akwesasne First Nation;
- the Lost Villages Historical Society;
- the St. Lawrence Seaway Management Corporation;
- Cornwall and Seaway Valley Tourism;
- St. Lawrence College;
- the St. Lawrence River Institute of Environmental Sciences, and;
- the St Lawrence Parks Commission.

The construction start of the project is tied to the timing of the St. Lawrence Seaway and Power Project 50th anniversary celebrations.

4. ALTERNATIVES AND ECONOMIC ANALYSIS

An architectural/engineering firm and interior/exhibit design consultant were retained during the Definition Phase to prepare a Technical Specification and request proposals for the construction of the new Energy and Information Centre. The architectural/engineering firm participated in the development and evaluation of alternatives and recommended the preferred supplier.

Alternative 1: Construct a 10,000 square foot Non- LEED Rated Facility - Cost$10,127k, NPV ($14,815k)

- This alternative does not include additional square footage required to meet the project objectives for all internal and external stakeholders.
- No interactive features would be included thus limiting the effectiveness of selected exhibits.
- The building would not be as energy efficient as the LEED rated alternatives thus OPG would not be portrayed as a sustainable and environmental leader to the visiting public.

This alternative is not recommended due to the limited space provided to meet OPG and stakeholder exhibit requirements and would not be LEED rated.

Alternative 2: Construct a 13,280 sq. ft. LEED Rated Silver Facility – Cost $12,554k, NPV ($17,097k)

- The additional square footage required for this alternative, compared to Alternative 1 will accommodate all the stakeholder exhibits, as presented and affirmed during the external stakeholder consultation process.
- All proposed Hydro and other exhibits are included.
- Roadway and parking space including bus drop off area in close proximity of the facility for senior, school children etc. is included in this alternative (not in Alternative 1).
- The building would be more energy efficient than typical commercial standards and would demonstrate OPG's commitment to be a leader in energy conservation and the protection of the environment.
- Appendix D shows the details of additional costs for Alternative 2 compared to Alternative 1.

THIS IS THE RECOMMENDED ALTERNATIVE

Alternative 3: Construct a 13,280 sq. ft. LEED Rated Platinum Facility – Cost $17,457, NPV ($20,691k)

- Additional $5,000k in project cost compared to recommended alternative.
- The guidelines to achieve LEED Platinum certification are stringent. The Canadian Green Council conducts a post construction audit and there is a risk that the building may be ineligible for LEED certification if it does not comply with the guidelines.
- There would be minimal OM&A maintenance costs savings associated with sustaining a Platinum LEED designation for this facility as compared to the preferred alternative LEED Silver ratings.
- Even if the building initially does meet LEED Platinum guidelines, long term compliance may not be sustainable.

This alternative is unacceptable due to the significantly higher capital costs to achieve a LEED Platinum rating versus a Silver rating, and the additional risks associated with meeting and sustaining LEED Platinum standards.

Financial Analysis

	Alt. 1	Alt. 2	Alt. 3
Total Project Costs ($k)	$10,127	$12,554	$17,457
NPV (2009 PV ($k) 50 years	($14,815)	($17,097)	($20,691)

Other alternatives considered but rejected:

- **Do Nothing** - Inaction will result in the loss of an opportunity to enhance stakeholder relationships and provide an educational and public relations venue at OPG's second largest hydroelectric generating station.
- **Construct an 8000 square foot non-LEED rated building** – This building size would be too small to accommodate all required exhibits. As well, the educational models would need to be incorporated into other viewing areas and exhibit space, thus would greatly sacrifice the story lines to be portrayed. The building would be of conventional construction (ie, not LEED rated).

5. THE PROPOSAL

Results to be delivered

- Award of construction contract
- Construct a 13,280 square foot LEED Silver rated venue as per the technical specification and design alternate produced during the Definition Phase of the project.
- Fabricate and install all exhibits and displays as agreed upon during the stakeholder consultation process.
- See Appendix A for illustrations of building.

Project Schedule

- Full BCS Release: Q1 2009
- Construction Award: Q2 2009
- Facility construction: Q3 2009 – Q3 2010
- Exhibit installations: Q2 2010
- Completion of construction and opening: Q3 2010

6. QUALITATIVE FACTORS

- The stakeholder consultation process investigated and confirmed:
    - the possibilities for outdoor exhibits and signage

- the desirability of self-guided exhibits
- a simulation exhibit of the R.H. Saunders powerhouse construction
- the desirability of on-site internet-accessed information sources associated with the exhibits
- the story lines associated with exhibits on electricity generation in Ontario, related environmental impacts, and the loss of land areas due to the construction and opening of the Seaway

- The building will have a design that will include but not be limited to:
  - Geothermal heating and cooling – ground source heat pump
  - rainwater collection for fire fighting purposes
  - collection of grey water to supply facility sanitary services
- The building will be situated to minimize disturbance of the natural environment. Where necessary, trees and vegetation will be relocated to areas surrounding the Centre and bike path
- The existing public bike path will be relocated to traverse the Centre site

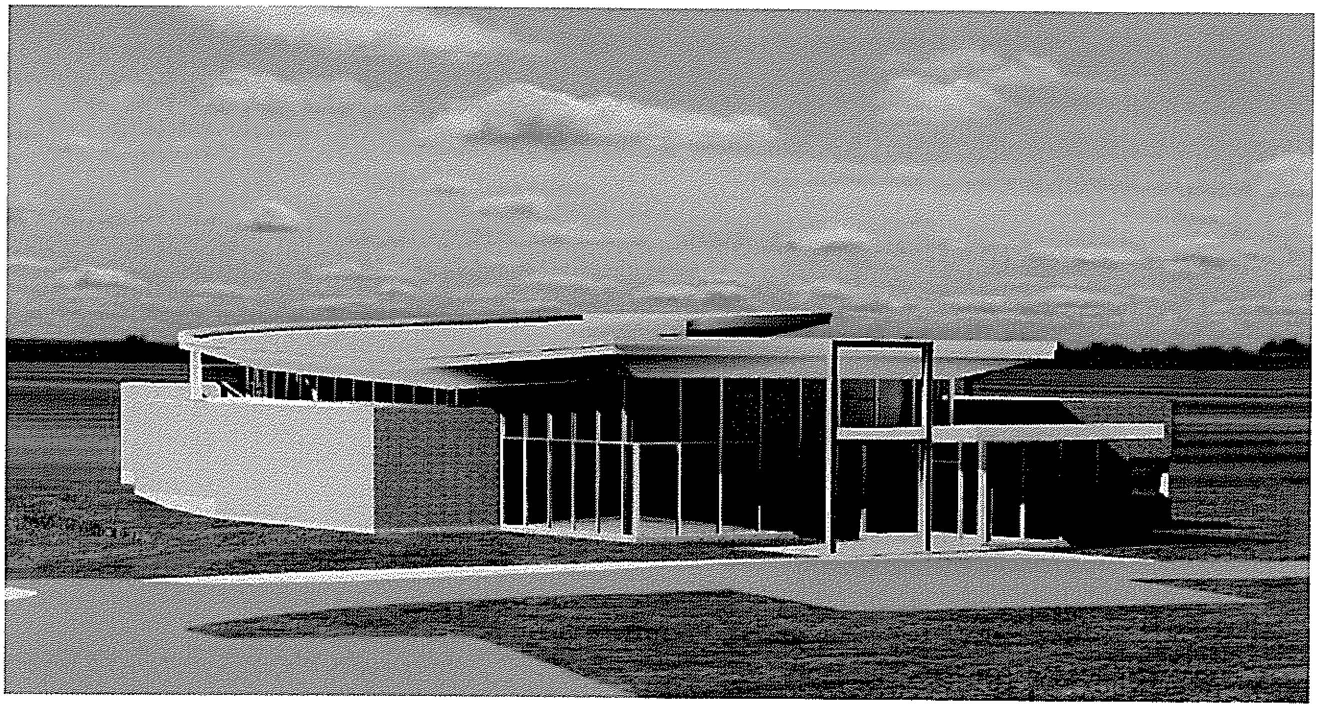
7. RISKS

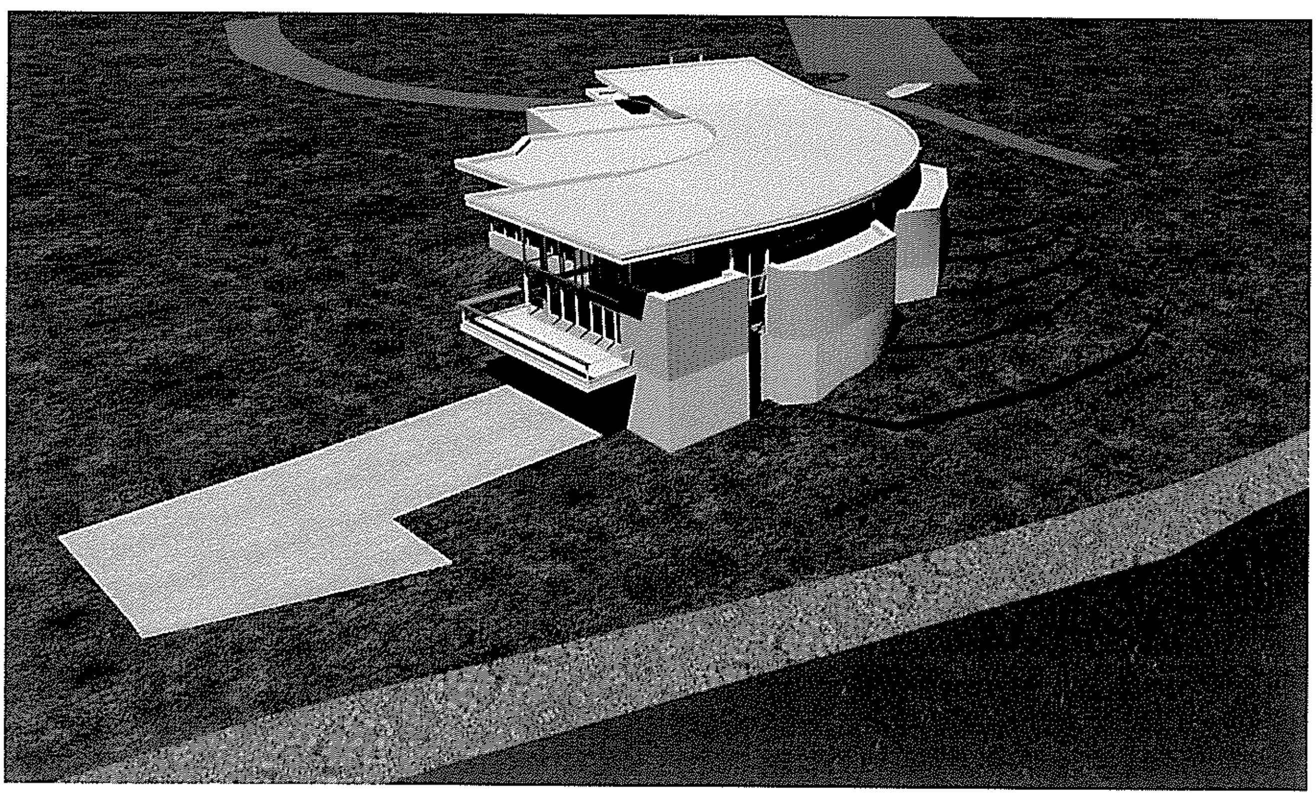
Risk Description	Impact	Initial Risk (before Mitigation) (H,M,L)	Mitigating Activity	Residual Risk (after Mitigation) (H,M,L)
Cost				
1. Cost overruns.	1. Cost exceeds release amount.	1. M	1. Costs associated with construction of the facility were obtained from four fixed price proposals. These proposals have been guaranteed until April 1, 2009.	1. L
2. Unknown exhibits costs.	2. Exceeding release amount.	2. L	2. Interior display costs provided by Holman Exhibits and were included in the construction fixed priced proposal.	2. L
Scope				
1. Preliminary design concepts rejected by advisory committee.	1. Increased project cost due to design changes.	1. L	1. The conceptual designs of both the building and exhibits were presented to OPG and external stakeholders. Both were accepted and the project scope was frozen prior to issuing the Request for Proposal. Superseding release will be required if additional scope items are included other than the deliverables listed in the Project Charter.	1. L
2. Building design change.	2. Technical specifications not complete resulting in cost overruns and construction extra costs. Exceeding release amount would require a Superseding BCS submitted for approval.	2. M	2. The Request for Proposal was based on a detailed technical spec and tendering documents. The project team will include an onsite Project Manager monitoring construction and reporting to OPG full time throughout the duration of the project.	2. L
Schedule				
1. Project delays due to time required to award construction contract.	1. Project delays and cash flows will be transferred to future years. Opening of the centre would be deferred missing the 2010 tourism season and visitor opportunities.	1. L	1. Detailed design and technical specification, including all drawings, were included in the Request for Proposal. Construction firms were pre-qualified prior to RFP issue.	1. L
Environmental				
1. Contaminated materials discovered during site excavation activities.	1. Exceeding release amount and project delays to remove and dispose of contaminated materials.	1. M	1. Geotechnical bore hole drilling and sub surface investigations determined the site is within acceptable Environmental Protection Act guidelines.	1. L
2. Facility would be located on an archeologically sensitive area.	2. Construction of the building would be deferred and an alternate site would be investigated.	2. L	2. Engineering consultant contacted Heritage of Ontario to review the project site. Studies confirmed the building site does not have any archaeological value. (The site resides on 40 feet of fill which was developed during the construction of the Seaway.)	2. L
Technical				
1. Insufficient scope of work for LEED certification.	1. LEED certification not approved.	1. M	1. Facility designed to LEED Silver standards. Design Engineer will be retained as OPG's Owners Representative to verify LEED requirements during construction.	1. L
2. Insufficient building size	2. Modifications to the exhibits areas. Stakeholder expectations not met.	2. L	1. Building size increased to accommodate all stakeholder requirements.	2. L

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

- The completion of Execution Phase deliverables will be confirmed in a report by the Ottawa/St. Lawrence Plant Group Asset Management Department.
- Commissioning Authority - Thompson Rosemount Group - to issue the LEED Report and final documentation from the Canadian Green Council that the facility achieved a LEED Silver Rating

APPENDIX A:






Cornwall Energy
Information Centre


CONSTRUCTION
Bringing together USA and Canada

APPENDIX B:

Project Title: **Cornwall Energy and Information Centre**

HYDROELECTRIC Summary of Estimate	Date	March 10, 2009
	Project #	HOSL0005

	LTD	2009	2010	TOTAL	%of TOTAL
Project Management/Engineering	$20k	$92k	$35k	$147k	1%
Consultant/Engineering	[redacted]				
Hydroelectric (PWU labour)		$88k	$52k	$140k	1%
Contractor (including EPSCA) and other Material Costs (Note 6)		[redacted]			
Interest	$4k	$285k	$322k	$611k	5%
Contingency		[redacted]			
TOTAL (GROSS)	$526k	$8,735k	$3,293k	$12,554k	100%

NOTES:

1 Schedule: Start Date: April 2009
In-service Date: Q3 2010

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

3 Removal Costs: not applicable

4 Estimate includes Definition Phase Costs of: $526k

5 Fixed priced contract cost and estimated EPSCA charges: [redacted]

6 Additional material costs not included in the fixed price contract: $800k (e.g. signage package, theatre and interactive equipment, office furniture, phone/fax/copier.

7 Contingency is based on [redacted] of estimated project management, consultant, labour, and contractor costs.

Prepared by:	**Approved by:**
Bruce Burwell mar 10/09	Mar 10/09
Bruce Burwell Project Engineer/Officer	Project/Production Manager

APPENDIX C:

Financial Model – Assumptions

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

Project Assumptions:

1. Cost estimate for the preferred alternative (Alt.2) was obtained using the RFP process. OPG received four fixed price proposals.
2. Design engineer provided Class "A" estimate, which includes escalation, for Alternatives 1&3
3. Alt. 1 - 10,000 square foot Non-LEED Rated Facility.
4. Alt. 2 - 13,280 square foot LEED Rated Silver Facility (preferred alternative)
5. Alt. 3 - 13,280 square foot LEED Rated Platinum Facility

Operating Cost Assumptions:

6. Estimated annual maintenance and operations costs for alternative 1 is $509K starting in 2011
7. Estimated annual maintenance and operations costs for alternative 2 is $532K starting in 2011
8. Estimated annual maintenance and operations costs for alternative 3 is $530K starting in 2011

APPENDIX D:

Additional Costs for Alternative 2 (Recommended) Compared to Alternative 1

Alternative 1 (10,000 sq.ft. Non-LEED rated facility) Total Costs:	$10,127k
Additional Sq. Footage	$900k
Exhibit Design Increase	$350k
Video Security System	$50k
Architectural and Engineering Increase	$120k
Additional Roadway, Parking and Bus area	$30k
LEED - Additional road work for site drainage and curb less shoulders	$50k
LEED – Additional LEED Management and engineering fees	$100k
LEED - LEED registration and application fees	$40k
LEED - LEED requirement for heat island reduction – White roof	$70k
LEED - Tree planning and relocation for LEED shading credit	$20k
LEED - Upgrade glass thermal panels	$20k
LEED - Geothermal – ground source heating and cooling	$100k
LEED - Material upgrades (e.g. Polished concrete floors)	$250k
LEED - Additional construction management fees	$100k
LEED - Water efficiency system (e.g. - Grey water re-use)	$50k
LEED - Exhibit sustainable materials	$10k
Additional Interest	$108k
Additional Contingency	$59k
Alternative 2 (13,280 sq.ft. LEED rated facility) Total Costs:	**$12,554k**

Note: The total additional cost associated with a LEED rated building is $810k.