UNDERTAKING J6.1

Undertaking

To produce the business case summaries for the nuclear capital projects listed in Exhibit D2, Tab 1, Schedule 2, Table 1, and the Nuclear OM&A Projects that have total costs greater than $10 M.

Response

Table 1 below provides a list of the nuclear capital projects greater than $10M as listed in Ex. D2-T1-S2, table 1, and the nuclear OM&A projects greater than $10 M as listed at Ex. F2-T3-S3 page 3. Approved business case summaries (BCSs) for the projects listed in Table 1 are attached.

The projects in Table 1 are subdivided into four groups. Tab A lists the six large capital projects that come into service during the test period for which Mr. Rupert requested additional information (Transcript Volume 6, June 2, 2008, page 93, lines 4-26). Tab B lists the remainder of the capital projects greater than $10M that come into service during the test period. Tab C lists the capital projects greater than $10M that are expected to be in-service beyond the test period and therefore do not impact revenue requirement. Tab D lists the OM&A projects that are over $10M and that have expenditures during the test period.

Please note the following exceptions and constraints with regard to the attached approved BCSs:

- To be consistent with the information provided in Undertaking J6.5, the list in Table 1 below includes a copy of the approved business case summary for Project 31718 – Darlington New Change Room Facility, which is now forecast to exceed $10M.

- For Project 38296 – Darlington Boiler Primary Side Cleaning, listed in Table 1 below, a BCS is not included. The planned test period expenditures for this OM&A project have not yet been released and a BCS for this work has yet to be completed.

- The attached BCSs contain redactions of commercially sensitive information. Specifically, project resource cost estimates (particularly costs for materials and external purchased contract services) and project contingencies are considered commercially sensitive. Their disclosure may unfavourably impact the vendor quotes OPG receives in the future. In addition, commercial information related to OPG non-energy customers and OPG margins on external business (e.g., Project 31555 – Darlington D2O Storage Facility) has also been selectively redacted due to its competitive commercial nature.

- OPG is required to restrict access to certain nuclear facility information by Regulations under the Nuclear Safety Control Act. As a result of these requirements, business case summaries for security projects are not attached. The following information applies to approval of security projects:

- For security-related and other regulatory projects, net present value or other cost/benefit analyses are generally not performed in preparation of the business case summary since the projects are required for continued station operation. Instead, the objective is delivering the required regulatory results at the lowest life cycle cost.

- In order to ensure greatest value/lowest viable cost for security projects, OPG therefore:

  - works closely with CNSC staff (directly, or via participation in industry associations) to clearly understand the intent of specific regulations, and constructively influence the resulting requirements to minimize cost of implementation;

  - generates alternatives to meet the resulting regulatory requirements;

  - seeks information as to how and at what cost other utilities have met these requirements; and,

  - competitively bids material and service contracts wherever possible.

This approach was followed for the security projects listed in the attached Table 1.

Table 1 – Projects > $10 Million with Expenditures in the Test Period

Tab A: Capital Projects Coming In-service During the Test Period (Board Panel Identified Projects)		
25609[1]	Nuclear Programs and Training	Security Fence Project
25905[1]	Nuclear Programs and Training	Security Monitoring Room
28452	Darlington	Second Darlington Full Scope Simulator Project
33925[2]	Darlington	Used Fuel Dry Storage Facility Project
34000	Darlington	Auxiliary Heating System – Phase 1 & 2
46537	Pickering A	Calandria Vault Inspection
Tab B: Capital Projects Coming In-service During the Test Period (Balance of Projects)		
25901[1]	Nuclear Programs and Training	Security Hardening Project
25902[1]	Nuclear Programs and Training	Controlled Area Improvements
25908[1]	Nuclear Programs and Training	Security Doors Upgrade
31718	Darlington	Construction Change Room
33293	Darlington	Main Control Room HVAC
33631	Darlington	Chiller Replacement to Reduce CFC Emissions
33815	Darlington	FH Computer Replacement
33977	Darlington	DCC Replacement
34008	Darlington	Feeder Replacement ‘ALARA’ Optimization
40543	Pickering B	CFC Chillers Replacement Project
49104	Pickering B	Auxiliary Power System for PB
49109	Pickering B	Standby Generator Governor Upgrades
62558[1]	Nuclear Programs and Training	Security Optimization
62567	Engineering & Modifications	Additional Feeder Cut and Weld Tooling
79016	Darlington	Fire Protection Upgrade Program Phase 2
79147	Pickering B	Chemistry Standards (CH-002) at PB
79148	Darlington	Fire Protection Upgrade Program Phase 3
Tab C: Capital Projects Coming In-service Beyond the Test Period		
31555	Darlington	D20 Storage and Drum Handling Project
31717	Darlington	Maintenance Facility
33955	Darlington	SDS Aging Management
33973	Darlington	Standby Generator Controls Retrofit
49251	Pickering A	$D_2$0 Storage and Drum Cleaning Facility
49266	Pickering A	Switchyard Relay Building Replacement
Tab D: OM&A Projects (Expenditures During Test Period)		
38296[3]	Darlington	Boiler Primary Side Cleaning
38457	Darlington	Environmentally Qualified Component Replacements
49201	Pickering A	Unit 4 Boiler Chemical Clean
49204	Pickering A	Unit 4 Boiler Flushing
49248	Pickering A	Units 1&4 -Replace Boiler Divider Plate Locking Tabs
40641	Pickering B	P7 and P8 Tab and Divider Plate Repair
40645	Pickering B	Boiler Water Lancing
62553	Engineering & Modifications	Digital Control Computer Aging Management

Note 1: Business Case Summaries for Security projects have not been provided.
Note 2: Full Release BCS (December 2007) is provided – covering both capital expenditures, and those funded by ONFA funds. Partial Release BCS (July 06) is also included for additional background information.
Note 3: Test period work will be approved under a new project number. A BCS for the test period work is under development, but not yet completed.

ONTARIOPOWER GENERATION

Second Darlington Full Scope Simulator Project 16 - 28452 Capital 16 - 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Routing	Location	Action	Signature	Date
Alyssa Hall Assistant Technical Engineer/Officer 701-3561	P72-2	Prepare BCS	Alyssa Hall	13-JUL-2007
Peter Moore Project Leader I 701-3567	P72-3	Review BCS	P. Moore	13 JUL 2007.
Tony Saliba Project Leader II 701-3047	P72-2	Review BCS	A. Saliba	13 July 2007
Gary Kotwa Section Manager PMO 701-3755	P72-1	Review BCS	Gary Kotwa	13 July 2007
Vince Tzambazis Project Manager - Design Projects 701-2520	P72-2	Review BCS	A. Saliba For	13 July 2007
Dianne Gaine Manager - Design Projects 701-4181	P72-1	Review BCS	D. Gaine	13 July/07
Sean Granville Operations Manager, Darlington [illegible]3-7715	D01 - OSB2A	Review BCS	[illegible]	2007/7/13.
Greg Hall Manager, Simulators and CBT Technology 701-5811	P0603	Review BCS	G. Hall	16-Jul-07
Silviu Idita Manager, DNGS Authorization Training 701-3090	P06	Review BCS	SILVIU A. IDITA Manager, Authorization Training	2007/07/13
Dwight Zerkee Manager, Nuclear Finance - Investment Management 702-5058	P8203	Review BCS	[illegible]	16 JUL 07
Mark Arnone Director Projects and Modifications 701-6063	P72-1	Review BCS	[illegible]	16 July 2007
[illegible] Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Second Darlington Full Scope Simulator Project 16 - 28452 Capital 16 - 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Routing	Location	Action	Signature	Date
Randy Leavitt Nuclear Finance 702-5085	P823	Review BCS	R Leavitt	July 17 2007
W. Robbins S.V. P. Darlington	D8-ES3	Submit BCS	[illegible]	July 18/07
J. Beech V.P. Nuclear Finance	H7-E19	Review BCS	[illegible]	July 18 2007
T. Mitchell Chief Nuclear Officer	P82-6	Review BCS	T Mitchell	20 July 2007
D. Power V.P. Corporate Investment Planning	H7-D06	Approve BCS	[illegible] / D Power	Aug 07 / Aug 22/07
P. Charlebois EVP & Chief Operating Officer	H19-A21	Review BCS	[illegible]	Aug 22/07
J. Hankinson President & Chief Operating Officer	H19-A21	Approve BCS	J Hankinson	Aug 23/07
		Choose One		
		Choose One		
		Choose One		
		Choose One		
		Choose One		
		Choose One		
		Choose One		
		Choose One		
R. Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Second Darlington Full Scope Simulator Project 16 - 28452 Capital 16 - 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

1/ RECOMMENDATION:

We recommend approval of a Full Release of $28.0 M Capital (including contingency) to complete the remaining phases of the Second Darlington Full Scope Simulator and the Darlington Learning Center Modifications Projects, with the objective of having a second full scope simulator available for training in Q3 2009. This includes U2 and U0 panels and the modification of the existing DLC to accommodate the simulator and supporting training facilities including upgrades/installation of HVAC, Fire Protection, electrical, LAN, telephone, PA, structural, training classrooms, conference/maintenance rooms, restroom facilities etc. The existing training simulator for Darlington Nuclear Generating Station cannot support Operations simulator needs. Simulator needs have increased beyond the hours available from a single simulator. There are 4 primary business objectives for this project:

1) The business objective is to address the high attrition rates for current DNGS certified staff. It is forecasted that 18 Authorized Nuclear Operators (ANOs) are eligible for retirement in the current business planning period and it is a requirement to assume 100% attrition as per the commitment to the CNSC (Attachment E: Correspondence from T. N. Mitchell, CNO, to G. R. Schwarz and T. E. Schaubel, CNSC. N-CORR-00531-03850.) Based on the staffing plans and current assumptions, without the second simulator, the sustainable ANO staffing levels of 56 required to run the business will not be accomplished within the current Business Planning Cycle.

2) The business objective is to support increased planned and minimum complements on each shift crew. DNGD has an more stringent licensing requirement to ensure only certified staff are on the MCR panel at all times, which means that the use of Supervised Control Panel Operators (uncertified staff) will no longer be allowed. Originally the license requirement was a minimum complement of 4 ANOs, and in 2005 the license minimum complement increased to 5 ANOs. By July 2009 the license minimum complement will increase to 6 ANOs. This factor will increase the demand on simulator hands-on hours. The REG-C N-CORR-00531-03217 compliance date is July 31, 2009. In order to ensure that there are 6 ANOs on duty at all times, 40 ANOs need to be assigned to the 5 operating crews and an additional 16 ANOs for other supporting roles is required to be self sustaining (See Attachment D).

3) The business objective is to ensure the safe and effective operation of the station to support not only the licensed positions on shift but also the supporting roles in areas of: outage planning, integrated planning, continuing and initial training, fix it now teams etc. To not staff and support these roles will result in a significant and adverse affect on the Stations Operating and Outage performance as well as challenge the safe operation of the station.

4) The business objective is to increase continuing training hands-on hours per year for certified staff to the recommended industry minimum standard and, thereby, meet CNSC expectations for authorized personnel training and eventually reach top industry standards. The CNSC references governing documents issued by INPO as their guideline to improve performance at Canadian Nuclear Plants. The Academy Document produced by the National Academy for Nuclear Training (NANT) under the support of INPO, "Guidelines for Continuing Training and Recertification of Licensed Personnel, January 2007, ACAD 07-001", states that the minimum number of technical content contact hours per year is 160 (200 on average), which includes 60 hours of hands-on simulator training. OPG has committed to the CNSC to follow this requirement and meet 200 hours of simulator focused continuing training hours per year (Attachment F: Correspondence from G. Preston, Executive VP & CNO to G. Schwarz, Dr. Personal Qualification Assessment Division CNSC, N-CORR-00531-00948, Sept. 29, 2000). DNGS is currently at 200 hours for simulator focused continuing training per year for certified staff, with only 30-35 hours being simulator hands-on time. 60 hours of hands-on time is considered a minimum (ACAD Standard) and in fact the majority of other utilities are training on average approximately 95 hours per year (See graph C in the Background and Issues Section).

Training projections are outlined in a "Two Simulator Rationale" (Attachment G) document prepared by the Training Department that estimated Simulator loading based on approved 2005 - 2009 staffing plans and training program documentation as well as an estimated numbers of hours required to meet industry standards. The results were verified though an external third party review and the risks were assessed by performing a sensitivity analysis.

e objective will be achieved by the addition of a second full scope simulator and supporting facilities at the Darlington earning Centre (DLC). Initial training programs will continue at the existing simulator located in the Pickering Learning Centre PLC) with all continuing/re-certification training performed at the DLC. This strategy will ensure that adequate time is available to handle the increased demands for training, delivery and testing.

Anticipated licensed staffing requirements to support the upcoming REG-C N-CORR-00531-03217 compliance date of July

009, has been considered and included in the Future Business Planning Cycle. Related OM&A costs to maintain the new mulator and DLC facilities are described in Appendix C under Financial Model Other Assumptions.

$000's (incl contingency)	Class	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Capital	Developmental	69	864	-	-	-	-	-	933
Currently Released	OM&A		-	-	-	-	-	-	-	
Requested Now	Capital	Full	-	1,479	18,812	6,104	628			27,023
Requested Now	OM&A		-							
Future Funding Req'd	Capital	None								
Future Funding Req'd	OM&A									-
Total Project Costs			69	2,343	18,812	6,104	628	-	-	27,956
Other Costs										-
Ongoing Costs										-
Grand Total			69	2,343	18,812	6,104	628	-	-	27,956

Investment Type	Class	NPV	IRR	Discounted Payback
Sustaining	Capital & OM&A	44,948	16.0%	10.2

Submitted By:

July 18/2007

(for) Wayne Robbins — Date:

Sr. Vice President Darlington Nuclear

Finance Approval:

Aug 22/07

Don Power — Date:

VP Corporate Investment Planning

Line Approval (Per OAR Element 1.1 Project in Budget):

Aug 23/07

Jim Hankinson — Date:

CEO

BACKGROUND & ISSUES

The training of Authorized Staff including Shift Managers, Control Room Shift Supervisors and Unit Main Control Room Operators is a critical component of Plant Operations. The training and qualification of these staff is time and resource intensive. The standards and regulatory requirements surrounding this area are governed by the regulatory body governing the operation of the plant (CNSC) and best industry practices (INPO and WANO).

The training of the authorized staff can be broken down into three specific areas.

- Initial training (and testing) of personnel to be qualified for certified positions.
- Continuing training programs to maintain the skills and qualification to meet both DNGS and industry standards.
- Recertification testing of authorized staff. This facet of the program is to allow support continued licensing of the authorized individual by the CNSC.

In the late 1990s, an Integrated Improvement Plan (IIP) initiative was developed to consolidate and improve training at the site. Space for a future simulator was included in the construction of the DLC. A project that involved moving the existing Simulator from the PLC to the DLC was approved in 2003 and then subsequently cancelled in early 2004 by the Nuclear Executive Committee prior to the start of any field execution activities (ref. D-BCS-33813-10001). Although it had a number of benefits, this project did not address the cause of many of the training deficiencies – insufficient simulator time.

Later in 2004, a Darlington Authorization Training Focus Group was formed in response to a number of candidates withdrawing from the program (ref. SCR D-2004-05573). The purpose of the group was to evaluate training methods and to explore alternative strategies to achieve the Darlington staffing plan for Authorized Nuclear Operators (ANOs). A number of solutions were put forward (See A/R# 28055593) and have since been implemented to improve the program and increase the success of candidates. These included:

- improving the selection and preparation process for candidates - Complete
- increasing the number of Authorized Training Supervisors (ATSs) – Complete – with rotations from the plant
- improving documentation – Continuing requirement
- provision of desktop simulators for use by ATSs to reduce loading on the full scope simulator - Complete
- split mode operation of the simulator to allow concurrent U0 and reactor unit training - Complete
- development of schedules to allow simulator use from 6:00 a.m. to 12:00 a.m., 7 days a week – Complete. In addition interim training classes are scheduled until 04:00, but are not expected to continue due to Society and PWU agreements.
- increasing class sizes to makeup for loss of candidates - Complete

These initiatives, although expected to improve the short term success of training, have not been sufficient to maintain adequate staffing levels.

Since these initiatives have been implemented several issues have developed that are driving the amount of simulator hands-on time required to meet mandatory training and testing programs above the time available on the current Simulator located at the PLC. High attrition rates, and increases in shift minimum complement both contribute to the increase in simulator hands-on time.

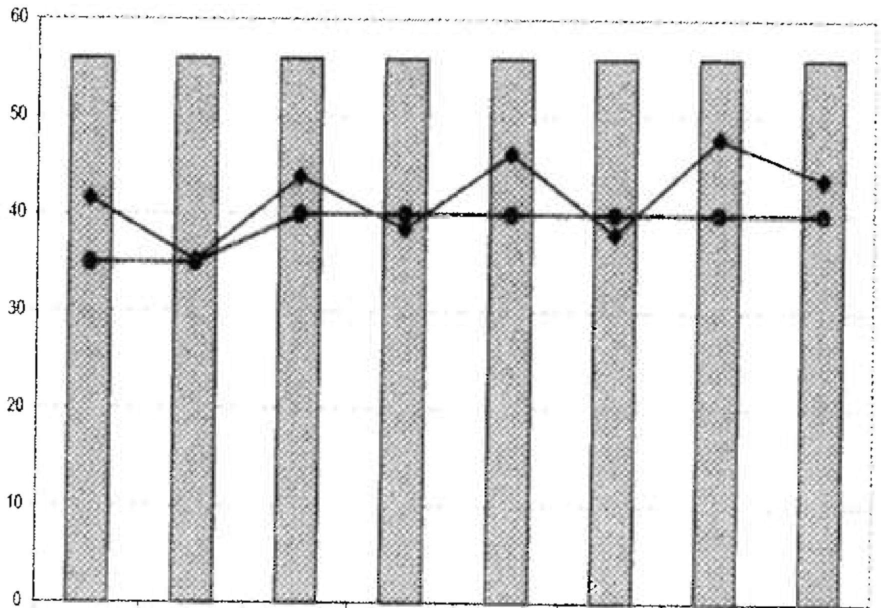
The following charts model the projected staffing scenarios based on both 1 and 2 simulators. Based on the staffing plans and current assumptions, without the second simulator, the sustainable ANO staffing levels of 56 required to run the business will not be accomplished within the current Business Planning Cycle. With this, comes a significant risk for the next 7 to 8 years, as the staffing levels are extremely low. Note, staffing plans since 2005 are based on a 2nd simulator being in full operation by Q1 2009 based on approvals obtained from the NEC.

Graph A: One Simulator Only

Assumptions & Notes

- ANO retirement is 100% uptake within one year of achieving an undiscounted pension (N-CORR-00531-03850)
- Only certified ANOs are shown
- 70% success rate on certification program (N-CORR-00531-03850)
- Internal staff movement occurs only to ATS and SSIT positions
- Supply is taken from SAP as of YE 2006 and includes regular staff in their home base assignment
- Retirements of ATS staff will be filled by promotion of ANOs
- Reflects current business plan submissions for 2007

Certified ANOs
Darlington Supply vs. Business Plan Demand

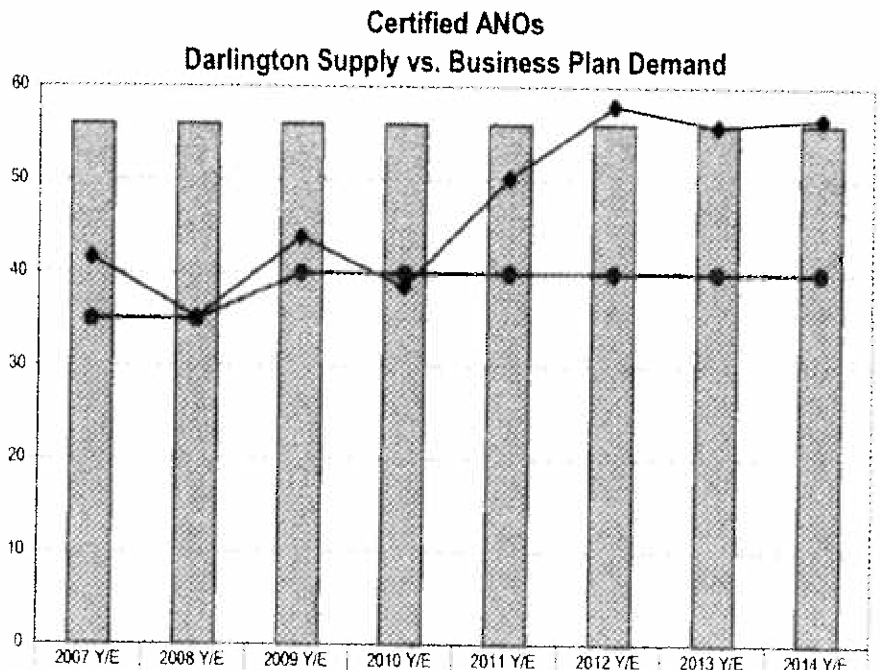


	2007 Y/E	2008 Y/E	2009 Y/E	2010 Y/E	2011 Y/E	2012 Y/E	2013 Y/E	2014 Y/E
Target ANOs - Base positions per Bus plan	56	56	56	56	56	56	56	56
CNSC Commitment - ANOs on shift	35	35	40	40	40	40	40	40
Projected Supply of Certified ANOs	42	35	44	39	46	38	48	44
Projected ANO certifications	8	0	12	0	12	0	12	0
ANOIT Starts	16	0	16	0	16	0	16	0

Graph B: Darlington Second Simulator

Assumptions & Notes

- ANO retirement is 100% uptake within one year of achieving an undiscounted pension (N-CORR-00531-03850)
- Only certified ANOs are shown
- 70% success rate on certification program (N-CORR-00531-03850)
- Internal staff movement occurs only to ATS and SSIT positions
- Supply is taken from SAP as of YE 2006 and includes regular staff in their home base assignment
- Retirements of ATS staff will be filled by promotion of ANOs
- Reflects current business plan submissions for 2007



	2007 Y/E	2008 Y/E	2009 Y/E	2010 Y/E	2011 Y/E	2012 Y/E	2013 Y/E	2014 Y/E
Target ANOs - Base positions per Bus plan	56	56	56	56	56	56	56	56
CNSC Commitment - ANOs on shift	35	35	40	40	40	40	40	40
Projected Supply of Certified ANOs	42	35	44	39	50	58	56	57
Projected ANO certifications	8	0	12	0	16	16	0	5
ANOIT Starts	16	24	0	24	10	0	10	0

Note: Both Graphs A and B above assume that all licensed staff will become recertified each year. Currently each certified ANO receives only 30-35 hours of hands-on time and OPG has committed to the CNSC to follow the requirement of the ACAD 07-001 document as per correspondence from G. Preston, Executive VP & CNO to G. Schwarz, Dr. Personal Qualification Assessment Division CNSC, N-CORR-00531-00948, Sept. 29, 2000 (Attachment F).

The chart in Attachment D (ANO Deployment based on Certified Staff Numbers) describes the risks due to attrition for licensed ANOs.
As stated, once the number of 44 certified ANOs is reached the business will not be able to recover from this without significant impacts to running the units. Prior to this point however, risks to the safe and effective operation of the station are also present as we deviate from the business plan number of 56 ANOs.

The delta between the projected CNSC commitment of ANO's on shift and the target number of ANO's defines the number of ANO positions in the Darlington organization to support the safe operation of the station and the continuation of the initial and continuing training programs. The roles of these positions are defined in the various governances related to Outage Planning and assessing, Integrated planning processes, Fix it now (FIN) team composition and Training programs development and execution. Significant adverse affects on station performance will result should these roles be omitted and the accountabilities not be carried out. The nature of the programs is such that an individual with the training knowledge and skills of an authorized person are required to make these processes effective. The accountabilities range between functional group but include:

- Operations and License review and approval of scheduled and planned maintenance work programs, procedures, and work plans on Nuclear Units in accordance with department governance and procedures.
- Operations and License review of the schedules coordinating work and outage activities.
- Outage Management oversight.
- License review of Reactor Alignment changes during outage and routine planned maintenance activities.

- CNSC mandated continuing training program execution. Development and delivery of training in both initial and continuing training programs.

Another issue contributing to the demand for a second simulator is that DNGS is currently only at 30-35 hours of continuing training simulator hands-on hours. OPG has committed to the CNSC to follow the requirement of the ACAD 07-001 document issued by INPO and deliver 200 hours of simulator focused continuing training, of which 60 hours is simulator hands-on hours.

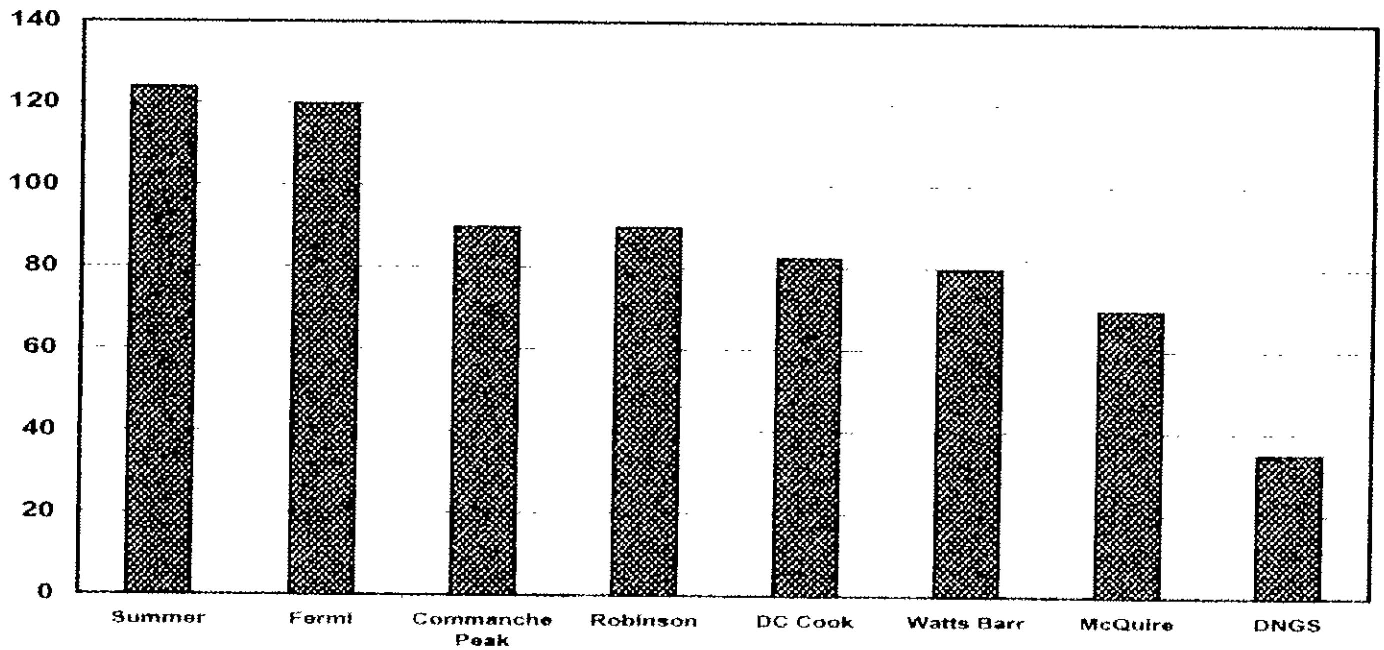
As the experienced operators retire and are replaced by new less experienced license holders, simulator training will be a critical factor in preparing operators to effectively respond to unit transients and prevent them from escalating to more severe events. As operating experience decreases there is a risk of more events occurring due to operator errors. The average experience of Darlington's certified staff is expected to drop over the next couple years. Details can be seen in the chart below:

Table 1: Average Licensed Operator Experience

2005	2006	2007	2010	2012
7	7.7	6.3	6	5

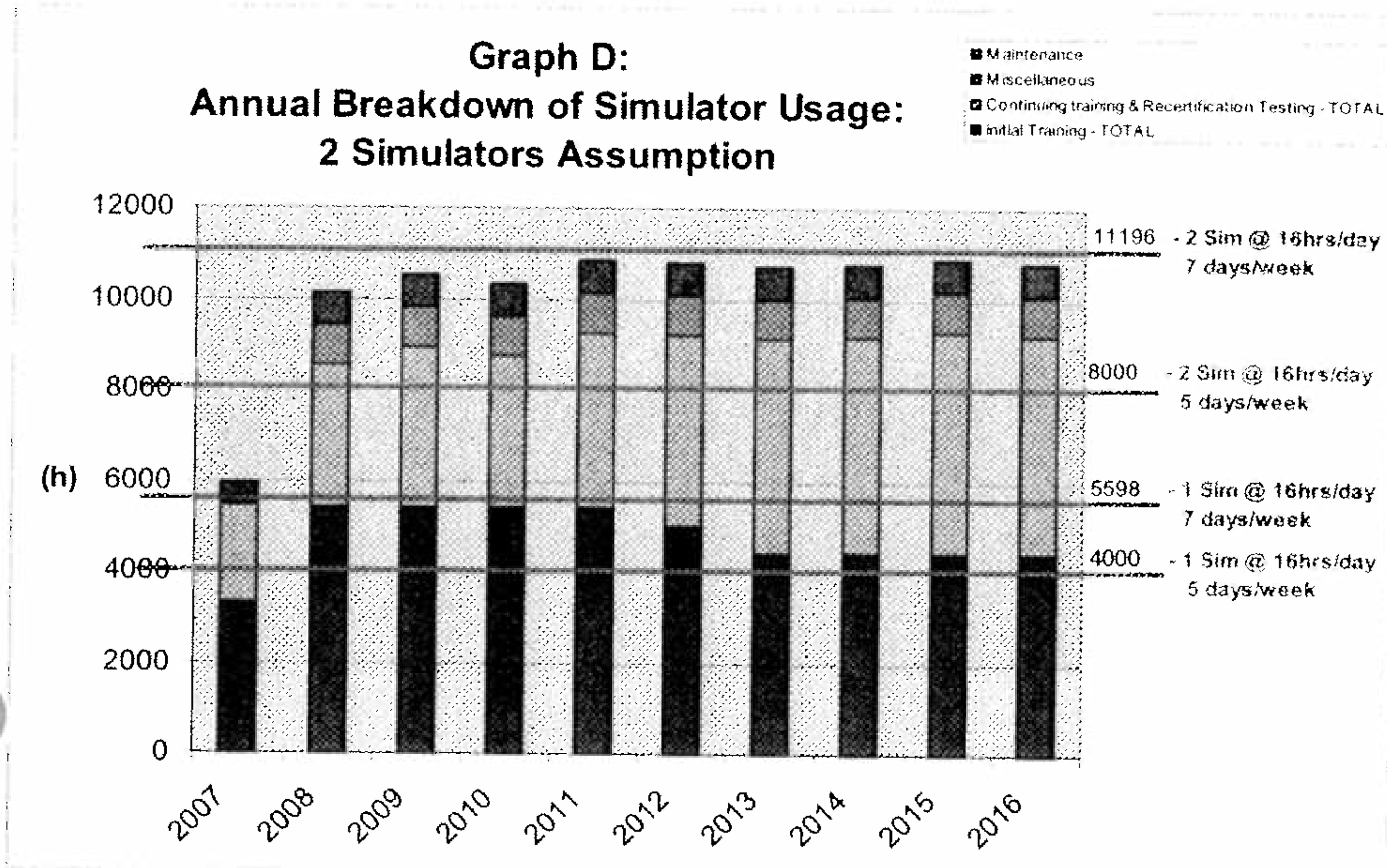
Industry experience has shown that qualified but inexperienced certified staff needs 80 hours of contact time to ensure they maintain the skills and knowledge to respond to transients and events and in fact the majority of other utilities are training on average approximately 95 hours per year.

Graph C: Simulator Hands-on Hours per Year per Operator



Currently, DNGS licensed staff are receiving 30-35 hours of simulator hands-on hours. This does not meet our regulatory commitment, and there is an inherent risk to the safe operation of the plant.

A simulator hands-on demand analysis was performed to determine the total amount of hands-on hours required to maintain the certified staffing plan shown in Graph B above for safe operation.



Assumptions:

- Available Simulator training / testing usage between 08:00 to 24:00 for 5 days a week without weekends and holidays results ~ 4,000 hours of simulator time a year.
  - 365 days -104 days [weekends] – 8 days [holidays] = 253 days -2% breakdown = 3967 hours @ 16 hrs/day.
  - This does not include the 30 days for annual maintenance outage, where 320 hours are lost from training and testing or the regular day to day maintenance where an additional 384 hours are lost over the year.
- For continuing training of currently certified ANOs, to calculate the amount of hands-on time, the number of projected ANOs is divided into groups of 3 and then multiplied by 60 hrs (as only 3 can be credited with actual "hands-on" time per training event). 1/3 of the number of delivery hours is added due to efficiency of simulator usage (set-up time, turnaround, etc.). This has been scaled up/down as applicable in the table for years where the number on ANOs is greater or less than 60.
- All types of training (initial and continuing), all types of testing (initial and recertification) for all types of certified staff (ANOs, U0CROs, CRSSs and SMs) require a large amount of simulator time for both development and delivery (and a smaller component of simulator time for remedials).

As highlighted in the graph, only approximately 4000 simulator hours are available per year for training, testing, maintenance and miscellaneous activities and DNGS needs already far exceed this. Because of CNSC commitments for 2009, the amount of hours required to meet the current Business Planning Cycle for certified staff is more than double.

Actions have been taken to mitigate the hands-on time delta between supply vs. demand. For example, DNGS Operations have tried to retain the current certified staff beyond early eligible retirement date, but this does not eliminate the long term attrition and in the future this option will not be viable due to reluctance from a bargaining position. As well, to accommodate for these extra hours currently in 2007, training is scheduled on midnight shifts and weekends. However, this poses a risk to the safe operation of the nuclear reactors in the future if OPG decides to continue with this option and not proceed with the second simulator. Based on the collective agreement, Letter Of Understanding (Attachment H: LOU - 119) for CRSS CRSOS, ATS, UOTS and SSIT, if overtime cannot be filled on a voluntary basis, forced overtime will be limited to 3 non-consecutive weeks per employee (and is even more restrictive for ANOs, CROs, ANOITs and CROITs in the PWU).

PNGS B is currently not in the same position as DNGD and has not requested the need for a second simulator in the current Business Plan. The current CNO accepted business assumption is that there will not be a refurbishment at PNGS B. In addition, PNGS B currently has a younger demographic and do not require unit zero certifications.

OPEX and planning for a second simulator at Bruce B was investigated. Response to date with regards to Bruce B has been limited due to the sensitivity of information and they have not stated whether they are including the requirement for a second simulator in their current business plan. It was released however, that if the decision to refurbish Bruce B is made, a Full scope second simulator will be included in that Business Case.

Currently Bruce A, and two US three-unit stations, Palo Verde and Browns Ferry, have a second simulator. Oconnee's is pursuing a second simulator (approval pending).

Developmental Release of $933k was obtained in September 2006. The project has completed Preliminary Design for DLC Modifications in May 2007. Completed Technical specification, Request for Proposal, Bid evaluation to Engineer, Procure and Construct a second full scope simulator, and awarded contract in June 2007 to complete Preliminary Engineering for Main Simulator by Oct 2007.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$000's	No Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay 1 Year			PLC Option
Revenue	(360,337)	0	0	(11,868)	0	0	4,772
OM&A	(94,054)	(109,514)	(109,514)	(107,547)	0	0	(110,342)
Capital	0	(27,963)	(27,030)	(28,358)	0	0	(32,030)
Present Value (PV)	(91,027)	(46,078)	(45,300)	(48,529)	0	0	(46,655)
Net Present Value (NPV)	N/A	44,949	45,727	42,498	0	0	44,372
IRR%	N/A	16.0%	16.4%	17.5%	N/A	N/A	15.7%
Discounted Payback (Yrs)	N/A	10.15	9.94	10.85	N/A	N/A	10.32

Status Quo - Not Recommended

This is not an acceptable option and there are many unfavorable impacts. Operator simulator continuing training contact hours for simulator "hands-on" will drop further away from the ACAD minimum industry standard of 60 hours per year per operator. The industry median is estimated to be approximately 95 hours. DNGS is currently at 30-35 hours which is half of the minimum. The lack of an additional simulator will result in less than 30 hours and make this situation worse.
There is a risk to continued full operation of the plant if the required number of authorized staff is not maintained. A cascading negative affect on plant operation will occur when the training program no longer has authorized staff to support training and evaluation of currently certified staff and new initial trainees. Once this level is reached, the business will not be able to recover without significant business impacts. (See Attachment D).

There is a risk of Outage delays because there will not be enough certified staff to be assigned to the outage program, a possibility of an increase in preventive and corrective maintenance backlogs due to the inability of Operations to staff the work control area, staffing to support IPG and FIN will not be maintained, the procedural backlog will increase and the quality will decrease, and the issuance will have to be by duty ANO's. More importantly, there is a potential impact to the safe operation of DNGS nuclear reactor due to reduction of experienced operators.

The Regulatory body may order DNGD to comply to what was committed, should training and operational programs be found less than acceptable when evaluated against industry standards. There is a potential failure to meet OPG production targets, and to meet OPG business objectives to advance DNGS Operations and training programs to top industry standards.

With not building the second simulator at DNGS, continued travel costs of $125k/year and overtime costs of $1.1M/year (For 1 extra ANO coverage: $125k/h x 24 h/d x 365 d/year) would be incurred to increase shift complement which is currently only at 30 ANOs, to 45 ANO's (40 minimum complement and 5 ATS) starting in 2009 (See Graph A). This cost does not include ANOs in support of work control, outage, FIN etc.

Considering all the risks to OPG stated above, status quo option is not recommended.

Alternative 1 - Second Darlington Full Scope Simulator - Recommended

Provision of a Second Full Scope Simulator at the DLC will meet the four key business objectives for this project. It will address the staffing plan targets and ensure that sufficient certified staff are available (and maintained) to safely operate all Darlington units, meet OPG production targets, as well as provide necessary certified staff in support of other operational programs (e.g., training, outages, integrated operational planning, work control area, fix-it-now (FIN) teams, ...etc). It will also provide the means to develop and deliver "hands-on" training to meet industry standards and thus further OPG's objective to be a leader in the industry. The DLC structure currently has space provisions to house the new Simulator. Internal capital modifications will be required to create the new simulator training facility. This includes upgrades/installation of HVAC, Fire Protection, electrical, LAN, telephone, PA, structural, training classrooms, conference/maintenance rooms, etc.

Alternative 2 - Delay Project - Not Recommended

The decision to install a second simulator could be delayed until early 2009 when a final decision will be made whether to support station refurbishment to extent DNGD's service life beyond the current assumed date of 2018

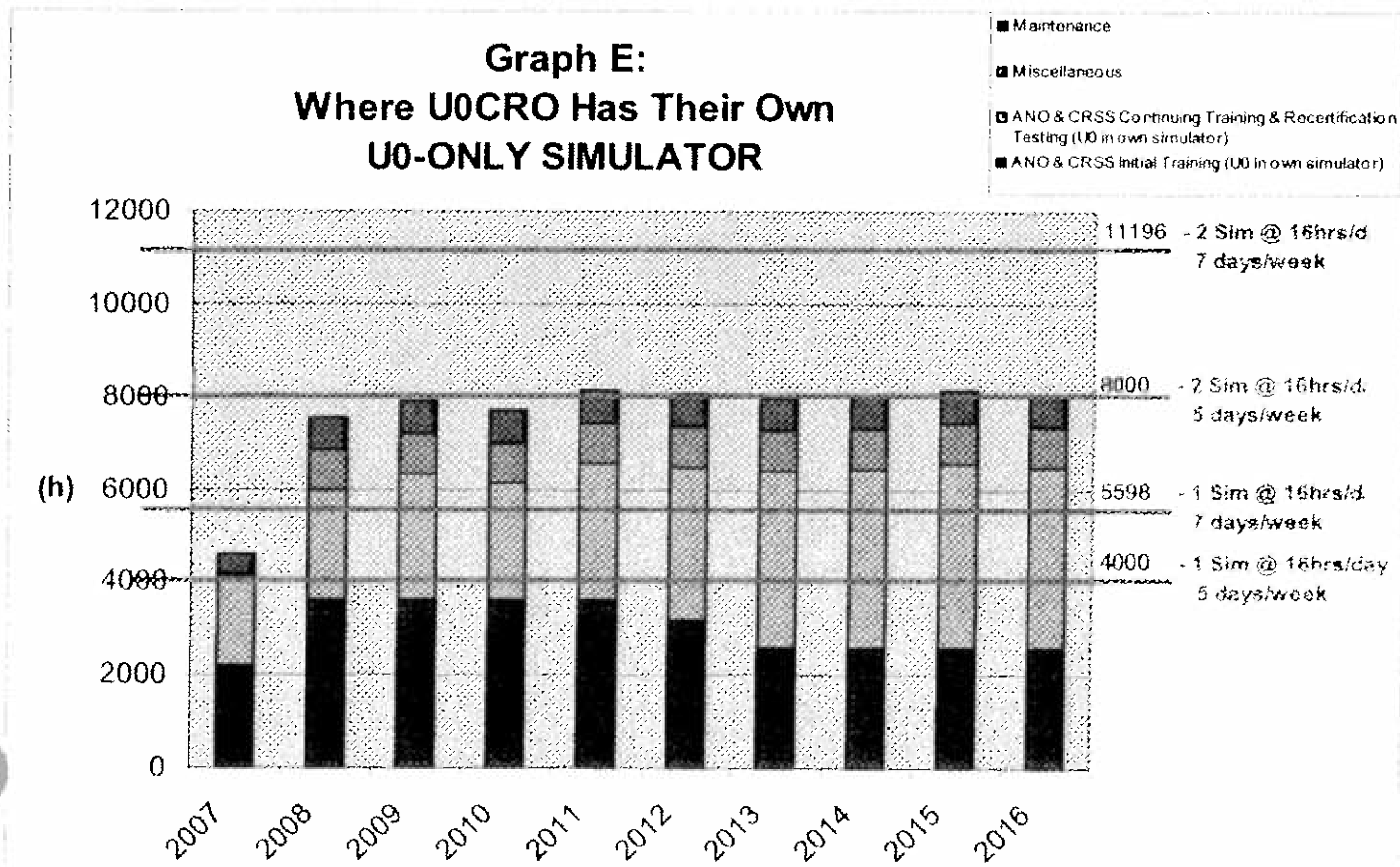
The advantage of delaying the project will be that the capital costs could be rolled into the cost of station refurbishment. However it should be noted that the costs of a second simulator will still need to be paid and the future costs may well be higher due to inflation. In addition the risk of delaying the decision for a second simulator will push back the time period for building the simulator. As time advances the obsolescence of hardware to support construction of the simulator will become more of an issue.

In short, delaying the decision to build a second simulator will result in the same adverse and unacceptable consequences as acceptance of the status quo. The delay of the decision will also further delay the eventual in service date for training purposes until Q1 2011 at the earliest. The primary drivers for an additional simulator are of concern today and will continue to drive the need for a second simulator into the foreseeable future. In addition there is a potential increased risk to procurement of the correct materials and components to construct the simulator due to aging and obsolescence.

Alternative 3 – Second Darlington Simulator – Unit 0 only - Not Recommended

The alternative of constructing the Unit 0 Simulator for Darlington was assessed as a reduced scope option. This may partially offset new U0 certification requirements, however the U0 simulator cannot be split in whole from the Unit training as the team has to practice and be tested together, similar to the station MCR environment. This option will also not address the larger area of need; reactor unit staff planning and training preparation/delivery issues. Improvements in the area of staffing rotational positions, increasing training development time and "hands-on" training time cannot occur with one simulator plus a new U0 simulator only.

Graph E below shows the remaining simulator usage hours still required for ANOs, CRSSs and SMs; where U0 CRO initial and continuing training has been extracted due to building a U0-ONLY simulator. While total overall usage did decline for the ANO/CRSS/SM when compared to Graph D, this new graph shows that the remaining simulator hours are equal to 2 simulators @ 16 hours/day for 5 days a week. To achieve this alternative a Full Scope U0-ONLY simulator (hardware and software) would still have to be built and commissioned. Even then, U0 would not be getting any overall control room practice in initial training and as discussed, the ANO/CRSS/SM needs would not be met.



Again, this option would not allow us to even start to address increasing regulatory and industry standards, expectations and requirements, or the requirement to increase "hands-on" time and other activities necessary to reach top industry standards. In fact, compensatory actions such as the recall of certified staff from current support programs would significantly and adversely impact areas essential to plant operation and is neither sufficient nor sustainable. On these bases, this alternative is not recommended.

Alternative 4 – Increase training hour to 24/7 - Not Recommended

By increasing training to 24/7, it slightly improves the simulator demand situation; however this option would require negotiation with both labour unions. A one time agreement with Society was already exhausted and would be very difficult to obtain again. Based on LOU – 119 for CRSS CRSOS, ATS, UOTS and SSIT, forced overtime is limited to 3 non-consecutive weeks per employee if voluntary overtime is not an option. Training during these off hours has also already been identified as a contributing factor to current failures as it leads to a lack in management oversight during training and leads to insufficient use of ATS resources.

Even if an agreement with labour unions is obtained, this option is insufficient to makeup for the shortfall in simulator hours (See Graph D, starting in 2008). Training 24 hours 7 days a week, and taking into consideration a 2% breakdown rate, a total of 8585 simulator hands-on hours are available. Again, this option would not allow us to even start to address increasing regulatory and industry standards, expectations and requirements, or the requirement to increase "hands-on" time and other activities necessary to reach top industry standards.
On these bases, this alternative is not recommended, however, may be required in the interim until such time as an additional Full scope simulator becomes available.

Alternative 5 – Second Darlington Full Scope Simulator at PLC - Not Recommended

The alternative of constructing the second full scope simulator at the PLC was assessed; however it is not considered a viable option. It may create continuity from a maintainability perspective and will eliminate the need for additional maintenance staff. However, placing the second simulator at the PLC would require an extension to the PLC. This requirement will cause the in service date of the second simulator to be delayed by 1 year due to design/permit/build durations. Modifying the DLC to accommodate the simulator allows a capital savings and an in service date which is acceptable to the stakeholders.

There would also continue to be a burden of $125k/year in travel costs for trainees to travel to Pickering for training. Constructing the simulator at the DLC reduces this cost, eliminates possible driving safety issues, and allows more effective training due to proximity to the station. This alternative is therefore not recommended.

I THE PROPOSAL

Engineering, Procurement, Installation, and Commissioning of a second simulator in the existing footprint of the DLC facility. The DLC structure currently has space provisions to house the new Simulator. Internal capital modifications will be required to create the new simulator training facility. This includes upgrades/installation of HVAC, Fire Protection, electrical, LAN, telephone, PA, structural, training classrooms, conference/maintenance rooms, etc.

A fixed price bid has been agreed to for the purchase of the new simulator and the preliminary engineering portion of the contract is in progress under the current release. Once additional funding is approved via this release, the remainder of the PO will be enacted to ensure delivery in Q2 2009.

Preliminary Engineering has been completed for the DLC modification portion of the project.

This full release will fund the following key deliverables:

- Full Scope Simulator Project # 16-28452
    - Conforming fixed priced contract with Engineer, Procure, Construct (EPC) vendor
    - Work plans, and project schedule
    - Quality and control manuals, quality, safety, and environmental plan
    - Design plan, and engineering documentation
    - Inspection and testing plan, Factory Acceptance Testing, Site Acceptance Testing, and documentation
    - Training plan
    - Delivery of main simulator components and spare parts
    - Commissioning, turnover including AFS
    - Simulator fidelity assurance enhancements post AFS including technical support, material, and minor refinements. The accountability of the Fidelity assurance work will be transferred from P&M to Simulator and e-learning Technology Department upon completion of AFS in July 2009. P&M will update Project Closeout and Lessons Learned reports if required upon completion of fidelity assurance work.

- DLC Modifications Project # 16-28543
    - Contract for detailed engineering
    - Contract for construction of modifications
    - Work plans, assessments, and project schedule
    - Design Plan and NEF ECC documentation including new drawings
    - Quality and control manuals, quality, safety, and environmental plan
    - Design plan, and engineering documentation
    - Inspection and Testing Plan
    - Detailed commissioning specification
    - Commissioning report and plan

- AFS and lessons learned for both Projects # 16-28452/28453
- Project close out and PIR for both Projects # 16-28452/28453

5/ QUALITATIVE FACTORS

Constructing the Second Full Scope Simulator for Darlington has additional benefits that will specifically have an impact on:

Training Quality

Having a second full scope simulator provides greater flexibility for training and testing schedules including remedial training and testing for failed test results (that will not have to take away from other mandated training and testing programs, as currently occurs). It provides opportunity for greater Line Management involvement and ownership of training as the new facility will be located on site, and provides on-site opportunities for support of Provincial Emergency Exercises. In the future, when the initial training requirements will slightly decrease, it provides opportunity for training programs that are currently not running, to be incorporated to increase our chances in reaching top industry standards.

Employee Engagement

Having the opportunity to train additional licensed staff allows for employee movement throughout the organization and provides different career paths for employees. As well, it benefits the organization as it distributes operational and focused knowledge which supports other job positions at OPG. In addition, it will help with the quality of life for the instructors and trainees by reducing the weekend and early morning (12:00 to 4:00 am) training time and reduces the amount of traveling time during work hours.

Safety Events

Having the opportunity to increase the amount of hands-on time above the minimum will give the licensed staff confidence while working at the panel and this in turn will reduce the risk of operator error.
Driving from site to site contributes to an increased risk to personnel. By having a second simulator at Darlington, this risk will be eliminated and will reduce the exposure to OPG.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Exceeding release limit	Cost overrun	**Medium**	A fixed price bid has been received for the purchase of the new simulator. Preliminary Engineering is complete for the DLC Mods and an estimate of remaining engineering costs has been obtained from the Design Agent. A third party estimate has been obtained for the DLC capital modifications. This estimate was based on the previous simulator move project and the known differences have been accounted for in the BCS estimate. A specific contingency of [redacted] has been allocated for this phase of the project (16-28453) for execution coordination between several contractors to ensure compliance to schedule and expenditure does not exceed the release limit.	**Low**
Architectural/engineering agency utilized for the detailed design of the DLC for the move project unavailable to perform the work for this project.	This release assumes that much of the previous design, still owned by the AE firm can be re-used for this project. If not, both cost and schedule will increase.	**Medium**	Existing documentation is available and will be utilized to the greatest extent possible to reduce design costs. Schedule float associated with the DLC modification portion of the project will be used to accommodate their resourcing if required.	**Low**

Scope				
Scope for the DLC Mods may be increased by the Design Agency	Schedule and cost overrun	**Medium**	Design information developed during the Simulator Move Project will be utilized to ensure the scope is well defined taking into consideration identified preliminary design changes	**Low**
Schedule				
Schedule for completing the milestones may be delayed due to long lead material delivery	Schedule delay due to size and complexity of long lead materials and some obsolete parts.	**Medium**	Long lead materials have been identified in fixed price EPC for the Main Simulator. The schedule will be frozen upon award of contract	**Low**
Schedule may be delayed due to coordination among several contractors.	Cost overruns due to stand down time or delays. Delays to schedule.	**Medium**	Implement a phased execution for DLC Mods to lineup with the installation and commissioning of the simulator with OPG oversight and contract management	**Low**
Resources				
Lack of experienced Design support for this phase of the	Delay in completion of this phase	**Medium**	The design work will be completed by Design Agencies. Regular interface	**Low**

project			meetings will be held with the Design Agencies to ensure threats to schedule are mitigated and design requirements for both projects are met.	
Lack of experienced Project Engineering/Management support	Delay in completion of this phase	**Medium**	Project Leader II has been hired and group is staffing MP2/3/4 positions. Expected to be complete by end of June 2007.	**Low**
Technical				
Based on Previous simulator acquisition projects, the Second DNGS Simulator will have fidelity challenges which will impair its functions. 1. Station Changes made during the simulator project phases will be missing. 2. Fidelity of some Instruments will be inconsistent with the station.	1. Simulator training and Testing of Operations Staff at the DLC will not be possible on station changes because of the project design data freeze date (i.e controller replacements, device replacements, and Station Computer changes). 2. Differences in fidelity of some instruments between the simulator and the reference unit at the station may result in Auditor findings (i.e WANO AFIs). Experience from the Second Bruce A Simulator project was that some panel instrumentation as finally installed differed from the station equivalent which impaired panel fidelity.	**Medium**	Lessons Learned from experience on past simulator acquisition projects will be incorporated into the Second DNGS Simulator project's plan as follows. An allowance of [redacted] has been added to the project base cost to mitigate these technical risks. Project execution will be in phases to expedite the Ready for Training schedule: 1) a) Initial training and testing of Operations Staff on station changes can be performed on the DNGS Simulator at the PLC. b) Project resources are assigned to Simulator & eLearning Technology Dept to implement expected new changes to "catch-up" to the station. 2) Simulator Vendor purchanse orders will be staged to allow for: a) Design and Development b) Manufacture through Initial Installation at the DLC c) All instruments will be functional to enable	**Low**

			Simulator Training after comissioning. d) Required instruments will be re-engineered and supplied to ensure fidelity with the station	
Regulatory				
CNSC may request an evaluation of our training program and enact a tighter timeline for in service to meet Industry Standards	Increased costs to meet requirements	**Medium**	Start project to demonstrate that OPG is moving to correct the deficiency of training and bring the training program up to industry standards.	**Low**
Environmental				
No significant risk for this release.				
Health & Safety				
There are health and safety risks to regular OPG employees and contractors during the construction phase. (Air quality, noise, electrical, craning, working at heights, etc..)	Potential harm to OPG emplyoees and contractors.	**Medium**	Implement control under OPG Health and Safety Plans. Pre and Post Job Briefs will be performed to inform workers of all hazards. Limited and controlled access to DLC working area will be inforced and only qualified personnel will have access	**Low**
Investment				

A decision may be made not to extend DNGS service life to 2044.	Decrease in IRR and NPV for project	Low	Risk Magnitude is too large to be managed at the Project level. Pending Coorporate Decision.	Low

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Comprehensive	Jul 2009	Jun 2011	Manager Operations

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Simulator Training hours	30-35 hrs/year/per	>60 hrs/year/per	Training stats	Training
2.	Meet minimum complement on each shift crew	6 ANO's per crew	8 ANO's per crew, and 15 ANO's for supporting roles	Operations shift schedules	Operations
3.	Reduction in OM&A travel time to PLC and Overtime costs to maintain shift complement	$125k/yr + $1.1M/yr	$0/yr	Cost reports	Operations
4.	Simulator Availability for Training	N/A – new simulator	Exceeds 98% [standard for all simulators]	Statistics on forced outages during Simulator Training for 6 months after AFS Completion 16-28452	Simulator & eLearning Technology Dept
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

ANO – Authorized Nuclear Operator
ATS – Authorized Training Supervisor
CRSS – Control Room Shift Supervisor
CRSSIT – Control Room Shift Supervisor In Training
EPC – Engineer, Procure, Construct
FIN – Fix It Now
INPO – Institute of Nuclear Power Operations
IPG – Integrated Planning Group
MCR – Main Control Room (Station)
NANT – National Academy for Nuclear Training
NPT – Nuclear Programs and Training

Appendix "B" Project Funding History

Choose Project 28452 Release Type	Month	Year	All Existing and Planned Releases (incl contingency) Cumulative Values 2006	2007	2008	2009	2010	2011	2012	Later	Total
Developmental	Sep	2,006	69	864							933
Full	Aug	2,007		641	11,676	2,347	628				15,292
											0
											0
											0
											0
											0
											0
LTD Spent	Jun	2,007		339							339

$ 000's Project 28453 Release Type	Month	Year	All Existing and Planned Releases (incl contingency) Cumulative Values 2006	2007	2008	2009	2010	2011	2012	Later	Total
Developmental	Sep	2,006	0	0	0						0
Full	Aug	2,007		838	7,136	3,757					11,731
											0
											0
											0
											0
											0
											0
LTD Spent	Jun	2,007		220							220

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

- Based on agreed upon fixed price contract for EPC (Main Simulator).
- Based on Altus Helyar estimate for Simulator Move Project with considerations to known preliminary engineering changes (DLC Mods).
- Interest of 5.9% with allocated yearly cashflows up to 2009.
- Identified specific contingencies to manage risks
- 15% general contingency for accuracy of estimates
- Allowance for overtime and travel costs for Factory Acceptance Tests (FATs) and Site Acceptance Tests (SATs) to meet schedule and the phased approach implementation.
- AFS for Project 16-28453 in Q2 2009.
- AFS for Project 16-28452 in Q3 2009 and 100 % declaration report of equipment in service in Q3 2009
- Transfer of $100K for materials, 150K for FTE coverage, and $750K for Contract work to NPT in Q3 2009 to complete post AFS fidelity assurance work in 2009 and up to Q2 2010 based on OPEX. This work will be part of Project closeout activities without interest.
- Project closeout (ECC) in Q4 2009.
- Final Project closeout in Q4 2010.

Financial Assumptions:

- Escalation – 1.5%
- Discount Factor – 0.07
- Outage Overheads (k$/PO day) - $300

Project / Station End of Life Assumptions:

Currently end of life for DNGS is 2020, however a decision will be made in 2009 whether to support station refurbishment to extend DNGS service life to 2044. Based on CNO expectations, OPG is to plan DNGS investments assuming a life extension (End of Project Life 2044).

Energy Price / Production Assumptions:

- Unit MW Output - 878 MW
- Unit Energy Cost - $49.50 per MW

Operating Cost Assumptions:

N/A

Other Assumptions:

Additional ongoing Nuclear Programs and Training OM&A resources are required to operate and maintain a second simulator site and associated facilities. The incremental ongoing costs are based on 2010 and 1.5 % escalation onwards

The incremental OM&A resource increase for Simulator & e-Learning Technology Department required to maintain the Second Darlington Simulator includes two FTEs in 2008 and three FTEs afterwards[two extra M&P engineers and one extra PWU control technician] plus $100k per annum for material/spares/consumables. These ongoing costs are included in the 2008-2012 issue paper # 44 pending business plan and are estimated to be:

2008: $269,000
2009: $518,000
2010: $537,000
2011: $550,000
2012: $560,000
on-going

The incremental OM&A resource increase for Authorized Training to increase the amount of ATS Simulator Instructors to support the staffing for the current Business Plan includes five FTEs. These ongoing costs are included in the 2008-2012 issue paper # 44 pending business plan and are estimated to be:

2009: $1,125,000
2010: $1,177,000
2011: $1,194,000
2012: $1,212,000
on-going

The incremental OM&A resource increase for Nuclear East Facilities to maintain the DLC facilities includes 2 FTEs (one janitor and one control tech), and $300k for spare parts and supplies to support the additional facility. These ongoing costs are included in the 2008-2012 issue paper # 44 pending business plan and are estimated to be:

2009: $600,000
2010: $627,000
2011: $636,000
2012: $646,000
on-going

All the incremental OM&A costs presented are included in the 2008-2012 issue paper # 44-pending business plan and have been used to calculate the Net Present Value of the project.

Darlington Second Simulator 16 - 28452 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	2007	This Release 2008	This Release 2009	This Release 2010	2011	2012	Later	Total
Project Management (OPG)	6	237	336	275	16				870
Engineering & Drafting (OPG)	41	165	744	302	130				1,382
Material	[redacted]								
Installation -- PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
									-
									-
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	47	1,505	11,676	2,347	628	-	-	-	16,204
2007-2011 Business Plan	250	1,350	11,050	2,253	-				14,903
Variance to Business Plan	(203)	65	(897)	(212)	546	-	-	-	(701)
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	47	1,415	10,153	2,041	546	-	-	-	14,202
Total Release (incl contingency)	47	1,505	11,676	2,347	628	-	-	-	16,204
Ongoing OM&A (non-project)			269	1,643	1,714	1,744	1,772	73,485	80,627
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Up to ~ 15%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Sep 2007.

Reviewed By:

Vince Tzambazis
ince Tzambazis
roject Manager

July 17, 2007
Date:

Approved By:

Dianne Gaine
Dianne Gaine
Eng & Mods Manager (Strat IV)

July 17/07
Date:

DLC Modifications 16 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	2007	This Release 2008	This Release 2009	2010	2011	2012	Later	Total
Project Management (OPG)	22	191	286	103					601
Engineering & Drafting (OPG)		64	114	71					249
Material	[redacted]								
Installation – PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
Project Costs (incl contingency)	22	838	7,136	3,757	-	-	-	-	11,752
2007-2011 Business Plan	250	849	5,006						6,105
Variance to Business Plan	(228)	(120)	764	3,267	-	-	-	-	3,682
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	22	729	5,770	3,267	-	-	-	-	9,787
Total Release (incl contingency)	22	838	7,136	3,757	-	-	-	-	11,752
Ongoing OM&A (non-project)				600	627	636	646	26,866	29,375
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	N/A	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Sep 2007.

Reviewed By: July 17, 2007

Vince Tzambazis
Project Manager

Approved By: July 17/07

Dianne Gaine
Eng & Mods Manager (Strat IV)

Second Darlington Full Scope Simulator Project 16 - 28452 Capital 16 - 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Attachment "B"

Project Variance Analysis

	LTD Jun 2007	Choose One: Last BCS Sep 2006	Choose One: This BCS Jul 2007	Variance	Comments
Project Management (OPG)	210	1,000	1,471	471	
Engineering & Drafting (OPG)	100	731	1,631	900	
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	558	23,893	27,206	3,313	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	558	23,893	27,206	3,313	
Total Release (excl contingency)	558	20,784	23,240	2,456	
Ongoing OM&A (non-project)			109,514	109,514	
Removal Costs (incl in above)				0	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
15	June	2007	Purchase Order Issued - Preliminary Design 16-28452
04	Sept	2007	Full Release BCS Approved 16-28452/28453
02	Oct	2007	Design Agency Contract for Detailed Engineering Awarded 16-28453
11	Oct	2007	Purchase Order Issued - EPC 16-28452
21	Jan	2008	Contractor - Start Pre-fabrication of Panels 16-28452
09	April	2008	Contractor - Final Design Complete 16-28452
23	May	2008	Contractor - Final Design Complete 16-28453
23	May	2008	Award Installation Contract 16-28453
09	June	2008	Start Installation 16-28453
29	Sept	2008	Contractor - Start Installation of Panels 16-28452
08	May	2009	AFS Complete 16-28453
15	July	2009	AFS Complete 16-28452 (Ready for Training)
31	Dec	2010	Project Closeout Complete 16-28452/28453

A Project Execution Plan (PEP) will be approved by Aug 2007

Comments:

ONTARIOPOWER GENERATION

33925
DUFDS
Final Release

OPG Confidential	Page 1 of
BUSINESS CASE SUMMARY	

Darlington Used Fuel Dry Storage Facility Project: In-Station Modifications (Fuel Facility Auxiliary Area (FFAA) East) Business Case Summary for Final Release of Funds 16-33925 Capital Final Release Business Case Summary 00044-FCS-00120.3-00003.

Routing	**Location**	**Action**	**Signature**	**Date**
G. Gordon Acting Section Manager, Design Projects – 703-3558	BW7-02	Review BCS	[signature]	Dec 12/07
G. Kotwa Section Manager, PMO 703-3528	BW7-02	Review BCS	[signature]	Dec 12th 07
P. Floyd Manager, Design Projects – Darlington 703-3563	BW7-02	Review BCS	[signature]	Dec 12/07
J. Pinnegar Manager, Fuel Handling – Darlington 703-7493	D08 OSB-2	Review BCS	[signature]	Dec 19/07
D. Zerkee Manager Investment Management 702-5058	P82-3	Review BCS	Released for Acct Klein by phone.	Dec 21 2007
M. Arnone Director, Projects and Mods 710-6063	P72-2	Review BCS		
J. Lehman Director Station Enging – Darl. (Acting) 703-7584 S. Parks Linda B Spot	D08 ES2	Review BCS	[signature] S Park	Dec 20/07 Dec 21/07
R. Leavitt Director, Investment Management 702-5085	P823-315	Review BCS	[signature]	Dec 21, 2007

ONTARIOPOWER GENERATION

OPG Confidential	Page 1 of
BUSINESS CASE SUMMARY	

Darlington Used Fuel Dry Storage Facility Project: In-Station Modifications (Fuel Facility Auxillary Area (FFAA) East) Business Case Summary for Final Release of Funds 16-33925 Capital Final Release Business Case Summary 00044-FCS-00120.3-00003.

Routing	Location	Action	Signature	Date
G. Gordon Acting Section Manager, Design Projects - 703-3558	BW7-02	Review BCS	[signature]	Dec 12/07
G. Kotwa Section Manager, PMO 703-3528	BW7-02	Review BCS	[signature]	Dec 12th/07
P. Floyd Manager, Design Projects - Darlington 703-3563	BW7-02	Review BCS	[signature]	Dec 12/07
J. Pinnegar Manager, Fuel Handling - Darlington 703-7493	D08 OSB-2	Review BCS	[signature]	Dec 12/07
D. Zerkee Manager Investment Management 702-5058	P82-3	Review BCS	[signature] for Dwight Zerkee	Dec 20, 2007
M. Arnone Director, Projects and Mods 710-6063	P72-2	Review BCS	[signature]	19 Dec 2007
J. Lehman Director Station Enging - Darl. (Acting) 703-7584	D08 ES2	Review BCS		
R. Leavitt Director, Investment Management 702-5085	P823-315	Review BCS	[signature]	Dec 20, 2007
G. Gordon Acting Section Manager, Design Projects - 793-3558	BW7-02	Approve BCS		

1. RECOMMENDATION:

Approval is requested for a final release of $11.9M for installation of equipment and modifications to the Darlington Fuel Facility Auxiliary Area (FFAA) East, in order to complete the Darlington Used Fuel Dry Storage (UFDS) Project. This release includes the installation of equipment and modifications to the Darlington FFAA East (also described as water pools, or irradiated fuel bays).

Project funding of $93.8M has been previously approved for the detail design, regulatory approvals, installation of equipment and modifications to the FFAA West, and the acquisition of long-lead material items required for Fuel Facility Auxiliary Area – East; as well as the regulatory approvals, detail design and construction of the Darlington UFDS Facility. The total project cost estimate is $105.7M, which is $2.5M less than the original estimate provided to the Ontario Power Generation (OPG) Board of Directors in 2004 at the time of the first release of funds requiring their approval.

This project is categorized as a Sustaining investment, required for the continued operation of the station past 2009. Funding is included in the approved business plan consistent with this proposal. Project cash flows are provided in Appendix B.

2. SIGNATURES

Submitted by:	Recommended by:
K. E. Nash 9-Nov-2007	12-18-07 2007-12-21
K. Nash — Date Senior Vice-President, Nuclear Waste Management	W. Robbins — Date Senior Vice-President, Darlington
Recommended by:	Recommended by:
18 Jan 08	Jan 21/08
T. Mitchell — Date Chief Nuclear Officer	P. Charlebois — Date Executive Vice-President & Chief Operating Officer
Financial Approval by:	Line Approval per OAR Element 1.1
Feb 8/08	Feb 11/08
D. Hanbidge — Date Senior Vice-President & Chief Financial Officer	J. Hankinson — Date President & Chief Executive Officer

3. BACKGROUND & ISSUES

Used nuclear fuel arising from Darlington Nuclear Station is currently stored in the east and west irradiated fuel bays (water pools) located inside the station. The west water pool will become full in 2009 and the east in 2010. The purpose of the Darlington UFDS Project is to provide additional used fuel interim storage capacity to allow continued operation of the station. The project consists of modifications to the station water pools to allow Dry Storage Containers (DSC's) to be loaded, design and construction of a UFDS Facility and upgrades to site roads to allow the DSC's to be transferred to the UFDS Facility.

The original schedule established in 2001 for initial used fuel transfers to dry storage was October 2007. This allowed for a one-year contingency in project schedule, plus a one-year buffer capacity in Darlington water pools. Both OPG and Bruce Power operate with a minimum of one-year water pool buffer capacity to accommodate unforeseen operating and production problems in water pools, the UFDS Facility and at the Dry Storage Container (DSC) manufacturing plant. The first used fuel transfers to dry storage are now expected to occur at Darlington by January 2008.

The release history/plans for this project are summarized below:

1) Work under previous Releases	
Jan 2001	- developmental release of $2.4 M approved by VP, Nuclear Waste Management Division to submit a Comprehensive Environmental Assessment (EA) Study to the Canadian Nuclear Safety Commission (CNSC). EA approval was granted in November 2003 for a Used Fuel Dry Storage (UFDS) Facility and up to 3 storage buildings (total capacity for 1,500 DCS's). This should provide used fuel storage capacity for a 40 year operating life for the four Darlington units.
Nov 2002	- developmental release of $5.4 M approved by VP, Nuclear Waste Management Division (bringing the total release to $7.8 M) for (a) preliminary engineering of a UFDS Facility and In-Station Modifications, and (b) to prepare and submit an application for a Construction License to the CNSC. Construction license was granted in August 2004.
Jun 2004	- partial release of $12.2 M approved by OPG Board of Directors (bringing the total release to $20.0 M) to complete the detailed design and specifications of the in-station modifications, together with the CNSC approval. This work has been completed.
Mar 2005	- partial release of $52.5 M approved by OPG Board of Directors (bringing the total release to $72.5 M) for detailed design and construction of the UFDS Facility, including the processing building, one storage building for 500 DSC's in a new security protected zone, and road upgrades at the Darlington site. This work has been completed.

Jun 2006	- partial release of $21.3 M approved by OPG Board of Directors (bringing the total release to $93.8 M) for installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) West and the acquisition of long-lead time items for the FFAA East. The FFAA West is targeted for service by Dec. 2007, 4 months ahead of schedule.
2) Work to be done under this Release	
Nov 2007	- final release of $11.9 M for installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – East with a projected completion date of Dec. 2008. Total project releases will be $105.7 M.

Project cost estimates are included in Appendix C.

4. ALTERNATIVES

Dry storage is the preferred method of providing additional interim storage capacity for used nuclear fuel. The rationale for this alternative was established in earlier project releases (see notes 1 & 2). Dry storage is used at the Pickering Waste Management Facility and at the Western Waste Management Facility (located at the Bruce Nuclear Site). The same Dry Storage Container design is also being used at all these facilities.

5. THE PROPOSAL

This final phase of the overall project includes the installation of equipment and modifications to the FFAA East by December 2008. The project milestones include:

- Dec 2007 – Final contractual arrangements in place
- Apr 2008 – Concrete demolition complete
- May 2008 – Complete installation of impact pads (2)
- Dec 2008 – FFAA – East available for service (AFS)
- Oct 2009 – Project Closeout

[1] Business Case Summary (BCS), Darlington Used Fuel Dry Storage (DUFDS) Project - Release #3 - Detailed Engineering of In-Station Modifications, June 2004

[2] BCS, DUFDS Project - Release #4 - Detailed Design & Const'n of Dry Storage Facility March 24 2005

6. QUALITATIVE FACTORS

The use of DSC's is consistent with the long-term management recommendations for used nuclear fuel submitted by the Nuclear Waste Management Organization to the Federal government.

The completion of the Darlington UFDS Project will allow the Darlington Nuclear Generating Station to continue to operate beyond 2009.

A Sustainable Energy Development Impact Assessment was conducted for the Western Used Fuel Dry Storage Facility in 2000. For a similar installation, the assessment concluded that the approach of using DSC's has the least impact on the environment when compared to the assessed alternatives.

7. RISKS

The current estimate is based on detailed design work conducted by an experienced Canadian nuclear engineering company, with a competitively-bid construction contract. The modifications to the west pool are anticipated to be completed by December 2007, and the lessons learned are being applied to finalize the funding/scheduling requirements for the east pool.

The risks built into the contingency funds are presented in Appendix A.

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

A Comprehensive Post Implementation Review (PIR) will be carried out for the overall project ($105.7 M) within one year of the in-service dates of both Fuel Facility Auxiliary Areas (by Dec. 2009), consistent with the corporate PIR Procedure. It will be conducted by an Independent Team with the Team Leader appointed by the Project Approval Authority. The Comprehensive PIR will be an independent and systematic performance evaluation of the project for these objectives:

(a) assess the realization of the project benefits consisting of:

 (1) the detailed design and specification of the in-station modifications; and

 (2) the installation of equipment and modifications to the FFAA.

(b) review project plan, implementation and operational performance;

(c) review BCS - major assumptions, economic and financial evaluation looking back from results, for future decisions;

(d) review project risk management; and

(e) Identify over-all lessons learned, in addition to those documented by the project team, for future improvement.

APPENDIX A: Risk Summary – 2008 to 2009

Reference	Risk	Probability	Impact	Mitigation Measures	Contingency		
					Exposure ($k)	Risk Factor	Total ($k)
1	Cost - Material costs escalate in 2008.	H	M	Advance purchase and fabrication where possible.	[redacted]		
2	Schedule - Regular or emergent fuel handling/station work requires the project to vacate the work area. Potential schedule delays of up to 6 days per month.	M	M	Signed coordination agreement between the station and the project.	[redacted]		
3	Cost - Costs higher due to design errors, plant configuration issues. Design contract extension amount higher than estimated.	H	M	Contract change process and process for field changes and installation package release. Definition of design scope of work	[redacted]		
4	Schedule/Cost - Closeout activities longer in duration due to contractual terms and conditions.	H	L	Project closeout process in place. Start closeout early.	[redacted]		
5	Cost - Concrete has radioactive contamination, causing higher waste costs. Risk of "clean" disposal site shutdown increases cost.	H	M	Lessons learned from FFAA - West waste handling (>$800k cost) used to lower costs for FFAA - East. Contingency plan for waste site.	[redacted]		
6	Resourcing - Future contractor labour shortage occurs, resulting in inability of contractor to maintain schedule and quality.	M	M	Contract award to secure resources.	[redacted]		
				SUB-TOTAL			[redacted]
7	Unforeseen miscellaneous items (unknown unknowns)			Communication and project meetings.	[redacted]		
				TOTAL			[redacted]

Note:

The risk summary applies to the balance of work required to complete the in-station modifications for FFAA – East.

For Internal Project Cost Control

APPENDIX B: PROJECT CASH FLOWS & BUSINESS PLAN

The project cash flows and approved business plan funding are provided in the table below. The additional funding required to implement the In-Station Modifications can be accommodated within OPG Nuclear's approved business plan envelope.

Table 2: In-Station Modifications (Capital)

	Year				Totals
	2001 - 6	2007	2008	2009	
Current Estimate ($M)	15.4	16.6	14.0	1.8	47.8
Current Estimate w/o Contingency ($M)	[redacted]				
Business Plan ($M)	15.4	11.2	16.1	0.9	43.6
Variance to Business Plan (including contingency) ($M)	-	5.4	(2.1)	0.9	4.2
Variance to Business Plan (excluding contingency) ($M)	-	[redacted]			

Table 3: Dry Storage Facility (Nuclear Waste Provisions)

	Year				Totals
	2001 - 6	2007	2008	2009	
Current Estimate ($M)	35.3	20.5	0.5	-	56.3
Business Plan ($M)	35.3	25.2	0	-	60.5
Variance ($M)	-	(4.7)	0.5	-	(4.2)

APPENDIX C: PROJECT COST ESTIMATES

Darlington Used Fuel Dry Storage Project - Cost Estimates ($k)

	($k)	Y/E 2006	2007	2008	2009	Totals
1	Design-Owners Agent	[redacted]				
2	Design Agency	[redacted]				
3	Other contracts	[redacted]				
4	OPG Project Management	[redacted]				
5	OPG CMO / FE / Support	[redacted]				
6	Construction Labour and Fabrication	[redacted]				
7	Waste Handling	[redacted]				
8	Long Lead (LL) Materials	[redacted]				
9	Advance EFFAA LL Materials	[redacted]				
10	Advance EFFAA construction	[redacted]				
11	General Material	[redacted]				
12	Travel and Board	[redacted]				
13	Letter of Credit	[redacted]				
14	Specific Contingency	[redacted]				
15	Interest	[redacted]				
	Subtotal	[redacted]				
16	Contingency	[redacted]				
	In-Station Totals	15,400	16,620	13,980	1,790	47,790

Dry Storage Facility	32,668	25,232	0	0	57,900
Project Totals	48,068	41,852	13,980	1,790	105,690

Approved by:

Greg Gordon, Acting Section Manager
Design Projects, Darlington

4-DEC 2007
Date

33925
DUFDS
Partial
Release

DARLINGTON USED FUEL DRY STORAGE PROJECT – RELEASE #5 – IN-STATION MODIFICATIONS – FUEL FACILITY AUXILIARY AREA (FFAA) - WEST

1. RECOMMENDATION:

Approval is requested for a partial release of $21.3M, for the installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – West at the Darlington plant, and the acquisition of long-lead material items required for FFAA – East. Subject to approval of this current release, and including previous funding approval of $72.5M, the total releases to date for the Darlington Used Fuel Dry Storage Project would be $93.8M. The total project cost is currently estimated at $108.2M.

The In-Station Modification work initiated to date includes the detail design and CNSC approvals work associated with the fuel facility auxiliary areas. The current cost estimate for the In-Station Modifications is $50.3M, funded from the capital program. The expected in-service date for the FFAA – West has been revised to April 2008. A final funding release for the FFAA - East is planned for September 2007. The current estimate for the final release is $14.4M. The expected in-service date for the FFAA – East has been revised to April 2009.

The Dry Storage Facility work initiated to date includes the regulatory approvals, detail design and construction of the facility. A total of $57.9M has been released for this work, funded from Nuclear Waste Provisions. The expected in-service date for the Dry Storage Facility is 2007.

This project is categorized as a *Sustaining* investment, required for the continued operation of the Darlington plant. The project is listed in the approved business plan for 2006. The project cash flows are provided in Appendix 1.

2. SIGNATURES

Submitted by:

Ken Nash Jun 15/06

Ken Nash — Date
Vice-President,
Nuclear Waste Management Division

Recommended by:

Gregory Smith June 14, 2006

Gregory Smith — Date
Senior Vice-President, Darlington

Recommended by:

Pierre Charlebois June 15/06

Pierre Charlebois — Date
Chief Nuclear Officer

Financial Approval by:

Donn Hanbidge June 29/06

Donn Hanbidge — Date
SVP & Chief Financial Officer

Line Approval per O.A.R. Element 1.1:

Jim Hankinson July 7/06

Jim Hankinson — Date
President and CEO

3. BACKGROUND AND ISSUES

Used nuclear fuel arising from Darlington Nuclear Station is currently stored in east and west water pools (also referred to as *irradiated fuel bays*) located inside the station. The west water pool is projected to become full in February 2009, and the east water pool in 2010. The purpose of the Darlington Used Fuel Dry Storage Project is to provide additional used fuel interim storage to allow continued operation of the station.

The total project consists of modifications to the station water pools to allow DSC's to be loaded, design and construction of a DSF, and upgrades to site roads to allow the DSC's to be transferred to the DSF. The DSF approved for construction by CNSC comprises a processing building where the DSC's are welded, x-rayed and prepared for storage, and up to three storage buildings with a total capacity of 1,500 DSC's. This capacity, together with existing water pool storage, is sufficient to accommodate used fuel from a 40-year operating life for all four Darlington reactors. It is projected that the second and third storage buildings will be needed by 2015 and 2023, respectively and at a cost in the order of $10M to $15M per building.

The original target in-service date of 2007 allowed for a one-year contingency in project schedule, plus a one-year buffer capacity in the Darlington water pools. Both OPG and Bruce Power operate with a minimum of one year water pool buffer capacity to accommodate unforeseen operating and production problems in water pools, the dry storage facility (DSF), and at the dry storage container (DSC) manufacturing plant. It is currently projected that the first fuel will be moved from the west bay in April 2008, ten months ahead of its projected fill date.

Dry storage at Pickering Waste Management Facility (PWMF) became operational in 1995, and at the Western Waste Management Facility (WWMF) (located at the Bruce Nuclear Site) in 2002. All fuel bundles are stored in standard DSC's. Each DSC holds 384 fuel bundles and weighs 70 tonnes. It is planned to use the same dry storage container design at Darlington and to use similar processing equipment in the DSF. A total of 550 DSC's are currently in storage. Operational experience has been excellent.

The release history/plans for the different phases of this project follow:

I) **Work In Progress/Completed to Date**	
Jan 2001	A development release of $2.4M was approved under the authority of the Vice President, Nuclear Waste Management Division to submit a Comprehensive Environmental Assessment (EA) Study to the Canadian Nuclear Safety Commission (CNSC). EA approval was granted in November 2003 for the Dry Storage Facility and up to three storage buildings.
Nov 2002	A development release of $5.4M was approved under the authority of the Vice President, Nuclear Waste Management Division (bringing the total release to $7.8M) for preliminary engineering for the Dry Storage Facility and In-Station Modifications, and to prepare and submit an application to the CNSC for a Construction Licence. The construction licence was granted in August 2004.
Jun 2004	A partial release of $12.2M was approved under the authority of the OPG Board of Directors (bringing the total release to $20.0M) for the completion of detail design and specifications of the in-station modifications, together with CNSC approval. This work has been completed.
Mar 2005	A partial release of $52.5M was approved under the authority of the OPG Board of Directors (bringing the total release to $72.5M) for the detail design and construction of the Dry Storage Facility. The work scope includes the processing building, one storage building for 500 DSC's in a new security protected zone, and upgrade of the roadways at the Darlington site. The work is targeted for completion by the end of 2007.

II) **Work to be Done Under this Release**	
Mar 2006	A partial release of $21.3M is the subject of this business case (bringing the total release to $93.8M), and comprises the installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – West, and the acquisition of long-lead material items required for FFAA – East. The FFAA – West is now targeted for service by April 2008.

III) Future Work	
Sep 2007	A final project release of $14.4M (bringing the total release to $108.2M) will be sought to complete the installation of equipment and modifications to the FFAA – East. The FFAA – East is now targeted for service in April 2009.

4. ALTERNATIVES

The previous releases for this project established the scope and direction for interim dry storage at Darlington.[1, 2, 3, 4] Dry storage is the preferred method of providing additional capacity. The total project cost is estimated at $108.2M, with an in-service date of April 2009. The completion of the Darlington Used Fuel Dry Storage Project will allow the Darlington Nuclear Generating Station to continue to operate beyond 2009.

5. THE PROPOSAL

This current phase of the overall dry storage project will allow for the installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – West, and the acquisition of long-lead material items required for FFAA – East. The cost estimate for this phase is based on a competitively-bid construction contract. The overall project estimates are summarized in Appendix 2.

This phase of work is expected to start in July 2006, with the following milestones:

- Jul 2006 – All long-lead material item purchase orders placed for both fuel bays; and award major construction contract
- Sep 2006 – Start of services relocation work to FFAA-West
- Nov 2006 – Start of major construction/construction zone set-up
- Mar 2008 – Complete FFA-West installation
- Apr 2008 – FFAA – West available for service complete.

[1] Business Case Summary, Darlington Used Fuel Dry Storage Project – Development Release for Environmental Assessment Submission, January 9, 2001

[2] Business Case Summary, DUFDS Project – Development Release for EA Approval, Construction License & Preliminary Engineering, November 26, 2002

[3] Business Case Summary, Darlington Used Fuel Dry Storage Project – Release #3 – Detailed Engineering of In-Station Modifications, June 2004

[4] Business Case Summary, Darlington Used Fuel Dry Storage Project – Release #4 – Detailed Design & Construction of Dry Storage Facility, March 24, 2005

6. QUALITATIVE FACTORS

The use of DSC's is consistent with the long-term management recommendations submitted by the Nuclear Waste Management Organization to the federal government.

A Sustainable Energy Development Impact Assessment was conducted for the Western Used Fuel Dry Storage in 2000. For a similar installation, the assessment concluded that the approach of using DSC's has the least impact on the environment when compared to the assessed alternatives.

7. RISKS

7.1 Current Release Risks

Modification of Water Pools

The current estimate is based on detailed design work conducted by an experienced Canadian nuclear engineering company, with a competitively-bid construction contract. Because of a substantive number of outstanding design considerations and logistical complexities, the equipment and modification work will be conducted in two phases. The lessons learned from the west pool can be used to finalize the design and funding requirements for the east pool. An overall contingency factor of [redacted] has been applied to this phase of the project cost estimate. A risk matrix summary is included in Appendix 3.

7.2 Other Risks

Construction of the Dry Storage Facility

A turnkey design-build contract has been awarded, and is progressing on schedule and within budget. A 95% design stage has been achieved and several risks eliminated. There is a high level of confidence that the facility will be completed within the approved funding of $52.5M (as approved by Release #4) for this part of the project. The Dry Storage Facility is expected to be available for service in accordance with the original schedule of 2007. As of April 2006, $15.8M has been spent on the Dry Storage Facility.

Facility Location

The location of the Dry Storage Facility was previously assessed for potential conflict with new-build nuclear units on the Darlington site. It has been confirmed that it should be possible to locate up to four units on the site without encroaching on the DSF. The location of future dry storage buildings will be dependent on any plans for additional new-build nuclear units.

8. POST IMPLEMENTATION REVIEW PLAN

- A Comprehensive Post Implementation Review (PIR) will be carried out within one year of the project in service of both Fuel Facility Auxiliary Areas (by April 2010), consistent with the corporate PIR Procedure. It will be conducted by an Independent Team with the Team Leader appointed by the Project Approval Authority.

- The Comprehensive PIR will be an independent and systematic performance evaluation of the project for these objectives:

  - Assess the realization of the project benefits consisting of:

    i. The detailed design and specification of the in-station modifications, and

    ii. The installation of equipment and modifications to the Fuel Facility Auxiliary Areas,

  - Review project plan, implementation and operational performance.

  - Review BCS - major assumptions, economic and financial evaluation looking back from results, for future decisions.

  - Review project risk management.

  - Identify over-all lessons learned, in addition to those documented by the project team, for future improvement.

Appendix 1 – Project Cash Flows & Business Plan

The project cash flows and approved business plan funding are provided in the table below. The additional funding required to implement the In-Station Modifications can be accommodated within OPG Nuclear's approved business plan envelope.

In-Station Modifications (Capital)

Year →	2001 – 5	2006	2007	2008	2009	Total
Current Total Estimate ($M)	9.5	8.1	18.3	13.4	1.0	50.3
Current Estimate w/o Contingency ($M)	[redacted]					
Business Plan ($M)	9.5	19.1	12.0	1.2	-	41.8
Variance ($M)	[redacted]					

Dry Storage Facility (Nuclear Waste Provisions)

Year →	2001 – 5	2006	2007	2008	2009	Total
Current Estimate ($M)	12.4	20.3	25.2	-	-	57.9
Business Plan ($M)	12.4	21.5	25.2	-	-	59.1
Variance ($M)	-	(1.2)	-	-	-	(1.2)

Appendix 2

Darlington Used Fuel Dry Storage Project – Cost Estimates

($k)	Y/E 2005	2006	2007	2008	2009	Total
1. IN-STATION MODIFICATIONS						
Owner's Agent	[redacted]					
Design Agency						
Licencing Support						
Other Contracts						
OPG Project Management/Support						
OPG DSF/Calandria Road Support						
Construction Labour						
Material						
Outstanding Claims/Contract Scope						
Interest						
Contingency						
Sub-total	9,549	8,140	18,263			35,952
Final Release - East Fuel Bay				13,368	983	14,351
IN-STATION MODIFICATIONS ESTIMATE	9,549	8,140	18,263	13,368	983	50,303

In-Station Modifications Estimate

Approved by:

Ray Balachorek, Project Manager, Design Projects

Date: May 30, 2006

2. DRY STORAGE FACILITY	12,376	20,262	25,232	-	-	57,870

3. PROJECT TOTALS	21,925	28,402	43,495	13,368	983	108,173

Appendix 3 - Risk Summary

Reference	Risk Description/ Consequence	Probability	Impact	Mitigation Measures	Contingency Exposure ($k)	Contingency Probability	Contingency Total (k$)
1	Schedule - West fuel bay fills faster than predicted. Reduced storage buffer could impact unit operation, with potential deratings.	M	H	Manage the buffer by maintaining preferential fuel deliveries to the FFAA-East. Reconfiguration of the fuel bays will also increase buffer.	[redacted]	[redacted]	[redacted]
2	Schedule - Regular or emergent fuel handling/station work requires the project to vacate the work area. Potential schedule delays of up to 3 days per month.	M	M	Sign coordination agreement between the station and the project.	[redacted]	[redacted]	[redacted]
3	Schedule - Late delivery for long lead material items, resulting in delay for FFAA-West completion.	M	M	Purchase Orders for long lead items to be issued immediately following project release.	[redacted]	[redacted]	[redacted]
4	Cost - Installation costs higher than estimated due to sole source or schedule compression.	H	M	Contract requests fixed price, and negotiation with 2 lead bidders.	[redacted]	[redacted]	[redacted]
5	Cost - Project costs increase due to field changes, and late design package approval. Field changes could cause up to 2 days per week schedule loss/cost increases.	H	M	Walkdown of design to identify field changes. Implement an efficient field change approval process.	[redacted]	[redacted]	[redacted]
6	Cost - Concrete has radioactive contamination, causing a major delay for handling radioactive waste, and higher waste costs.	L	M	Identify contamination ahead of construction, together with contingency process for handling radioactive waste.	[redacted]	[redacted]	[redacted]
7	Resourcing - Future contractor labour shortage occurs, resulting in inability of contractor to maintain schedule and quality.	M	M	Contract award to secure resources.	[redacted]	[redacted]	[redacted]
						SUB-TOTAL ►	[redacted]
8	Unforeseen miscellaneous items (unknown unknowns).	M	M	Communication and project meetings.	964	1	964
						TOTAL ►	[redacted]

ONTARIOPOWER GENERATION

ENGINEERING & MODIFICATIONS
BUSINESS CASE SUMMARY

Auxiliary Heating System Project 16 - 34000

Developmental Release Business Case Summary D-BCS-73110-10001-R000

Routing	Location	Action	Signature	Date
derek fung Project Engineer, Design Projects, DND 703-3535	BW7-02	Prepare BCS	25 2006	23 Feb 2006
Nahil Rahman Section Manager, Design Projects, DND 703-3527	BW7-02	Review BCS		23 FEB 2006
John Taras Section Manager, PMO, DND 703-3528	BW7-02	Review BCS	for J Taras	24 Feb 2006
Robert Black Manager, Design Projects, DND 703-3520	BW7-02	Review BCS		27 FEB 06
Bill Qualtrough Manager,Performance Engineering, DND 703-7484	D08-ES2	Review BCS		MARCH 15/06
Ron Ball Senior Financial Advisor 702-4084	P82-3B6	Review BCS		20 Mar 06
rk Arnone ector, Projects & Modifications 701-6063	P72 E4.4	Submit BCS		21 Mar 2006
Gord Brown Controller, Engineering & Modifications 702-5059	P82 F3-A6	Approve BCS		20 Mar 06
Stu Seedhouse Director,Station Engineering, DND 703-7464	D08-ES3	Approve BCS		23 Mar 2006
Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Auxiliary Heating System Project 16 - 34000

Developmental Release Business Case Summary D-BCS-73110-10001-R000

1/ RECOMMENDATION:

We recommend a release of $2.2M (including [redacted] contingency) of developmental funding to complete the 'Definition Phase' of the Auxiliary Heating System (AHS) Project with the intention of placing a new system in service by the Fall of 2008.

The business objective of this project is to provide a reliable back-up supply of heating steam to prevent major equipment damage and thereby support the safe return of Darlington units to service following a four unit shutdown during the winter months. This will be achieved by replacing the existing Construction Boilerhouse with a facility that can, in the event of a four unit shutdown, maintain the temperature inside the Powerhouse and TRF/HWMB above 10°C to prevent impairment of both safety and non-safety related systems due to heavy water freezing (heavy water freezes at +4.8°C).

The existing Construction Boilerhouse (CBH) cannot continue to provide this capability because:

- it does not have sufficient installed capacity
- the building and oil feeder piping are not fully compliant
- it was never designed as a permanent system and is costly to maintain.
- it does not meet reliability requirements from both a nuclear safety and conventional risk assessment

Refurbishment of the CBH is not recommended because:

- it would cost at least as much as replacement with greater cost and schedule risks.
- it would result in the unavailability of a back-up system for up to two heating seasons.

is project is consistent with the approved 2006-2010 Business Plan with $2M budgeted for 2006.

A Project Execution Plan (PEP) will be prepared as a deliverable of this release and submitted for approval by 30 Nov 06.

$000's Capital		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Developmental	0	[redacted]	Feb.06	Spent Life to Date:	0
Requested Now:	Developmental	2,200	[redacted]	2006-2010	Appr'd Business Plan (Tot Proj):	[redacted]
Cumulative Release:	Total to Date	2,200	[redacted]	2006-2010	Business Plan Variance:	[redacted]
Total Project Estimate:	+60% to -25%	23,505	[redacted]	2006	Budget (Current Year)	[redacted]
Current Year Estimate:	2006	2,200	[redacted]	2006	Budget Variance (Current Yr)	[redacted]
Type of Investment:	Sustaining	N/A	[redacted]	Cumulative Release Remaining:		[redacted]
NPV:		N/A	[redacted]	Contingency on Remaining Release:		[redacted]
IRR:		N/A	[redacted]	Contingency % on Remaining Release:		[redacted]

Submitted By:

21 Mar 2006

M. Arnone
Director, Projects & Modifications

Date:

Finance Approval:

20 Mar 06

G. Brown
ntroller, Engineering & Modifications

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

S Seedh... 23 Mar 2006

Stu Seedhouse
Director, Station Engineering, Darlington

Date:

2/ BACKGROUND & ISSUES

Purpose of the AHS

Extraction steam from any one single operating unit provides adequate heating steam to meet the needs of the station. However, when all four units are shutdown and there is a possibility of heavy water freezing, an alternate supply provided by the AHS is required to maintain general heating and the availability of Group I safety systems. Group II systems are protected with electric heaters fed from the Emergency Power System and are therefore not impacted.

Planned station outages requiring the use of the AHS typically occur every 6 years with the next in 2009, however, there is a real and ongoing risk of a forced shutdown should any of the following events occur:

- A Design Basis Accident (DBA).
- A common safety system fails.
- Darlington is found to be operating outside of the boundaries of the Safe Operating Envelope (SOE) and is un-repairable.
- The design of Darlington is found to be inadequate to meet the safety basis of the plant.
- A generic problem is found on a significant production component.
- A labour disruption, regulatory order or other external disruptions.

A system with an unavailability of approximately $1x10^{-2}$ has been deemed necessary to mitigate the risks of such an unplanned event.

Regulatory Issues

In 1987, the AECB questioned Darlington's crediting of reactor decay heat and heat transport thermal energy to provide sufficient building heating until such time as portable heaters could be distributed throughout the station. The ability of portable heaters to heat such a large area was also further questioned. In response, Darlington committed to maintaining a sufficient number of construction boilers until a permanent solution was put in place. Reference Action Item AI#851312.

During the 1997 vacuum building outage, a capacity test of the CBH was performed which demonstrated the ability of the facility to provide adequate heating. AI #851312 was subsequently closed out.

Due to ongoing legacy issues with the CBH, routine project status reports are provided to the CNSC to demonstrate Darlington's commitment to a long term action plan to ensure a reliable supply of auxiliary heating. The latest of these are NK38-CORR-00531-12553, NK38-CORR-00531-12666 and NK38-CORR-00531-12915 associated with REG M Action Items #28060617 and #28060618. The next required update is at the end of Q1 2006.

CNSC correspondences, NK38-CORR-00531-12240 and NK38-CORR-00531-12358, document CBH compliance issues (see SCR D-2004-00415 & D-2004-01239) and Darlington's commitment to resolving the issue of the Backup Heating Fuel System by December 2007.

Existing Conditions

The current CBH facility, consisting of four electric boilers and eight oil-fired boilers, is approaching its end of life. It was placed into service at the time of site construction (some 27 years ago). Even at that time, the oil-fired boilers were previously used (average age is now >40 years) and were obtained from other construction sites. Several of these boilers require major repairs and/or re-tubing. The electric boilers which supply the majority of the load are also aged and will require major refurbishment in the coming years.

For the short term, compensatory actions are implemented every fall to survive the impending winter. This is very expensive (in excess of $0.5M base OM&A costs per year in corrective maintenance alone and in 2003/ 2004, an additional $1.2M for a rental boiler) and imposes unacceptable risk to the station.
It is projected that at least $0.5 M per year in corrective maintenance will continue until the CBH is replaced.

In 2004, SCR D-2004-08451 was initiated due to concerns about the structural adequacy of the CBH. The assessment of the building concluded that the building structure had degraded and will not support all loads required by the Building Code. Until a new facility is constructed, work request (WR# 449004) has been initiated to have the CBH structure strengthened.

It has also recently been determined that it is not possible to establish a realistic unavailability for the CBH since the equipment is old and the design documentation is minimal and in some cases non-existent. It is also very time consuming with minimal potential for returns.

Refurbishment of CBH

A detailed conceptual study examining possible alternatives, including refurbishment of the existing CBH, was performed in 2000. At that time, limitations of the existing facility were recognized and the preferred alternative was a system which predominately relied on the bulk electrical system, i.e. electric heaters/boilers, due to its perceived reliability. However, as a result of the LOBES event of 2003, a new study was undertaken in 2004 to examine alternatives which did not rely on the bulk electrical system. Two main options were identified; co-generation and oil fired. Due to the much higher cost and timeline and the need for an environmental assessment, co-generation was ruled out. Although black start capability is currently not a design requirement of the AHS, it can be economically retrofit into an oil fired system if the need should arise.

A draft report recently prepared by Darlington Projects Design also concluded that refurbishment of the existing facility while technically feasible was not recommended due to the high cost and risks involved. (Ref. draft Engineering Report NK38-REP-73110-10001)

Links to Other Projects

Both Darlington and Pickering have similar requirements to provide auxiliary heating steam. However, due to different plant configurations, the final solution is expected to be tailored to suit the specific station configuration. Pickering requires a minimum capacity of 21,000 Kg/hr of heating steam, whereas Darlington requires approximately double that capacity.

The Design Units from both Darlington and Pickering are in consultation with each other to maintain a consistent approach and design basis.

There are no direct links to other projects. However, maintaining turbine hall roof dampers of the Powerhouse Steam Venting System (PSVS) open, as is the current practice will necessitate an increase of approximately 10% of AHS capacity.
Project #34002 is currently addressing deficiencies with PSVS including the need to maintain these dampers open.
Although, the decision to close these dampers when the AHS is required is a possibility, it is not currently practical. These dampers are not maintained and tested (air supply is disconnected in the field) and may not close when required. In addition, it will take a team of operators (a commodity that is not available when the station is in an emergency four unit shutdown and the weather is freezing outside) and control maintenance personnel (who may be in a similar position) to make this happen.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Do Nothing (Not Recommended)

This is not recommended as:

- the risk of severe equipment damage exists should the AHS be required under very harsh conditions due to the limited capacity and unknown reliability.
- Regulatory issues will not be addressed as the building and oil feeder piping are not fully compliant.
- the CBH was never designed as a permanent system and is costly to maintain.

Alternative 1 – Install new Auxiliary Heating System (Recommended)

We recommend installing a completely new Auxiliary Heating System Facility located adjacent to the existing Construction Boiler House, outside of the protected area.
The new facility will be primarily oil-fired and will utilize existing services and infrastructure to the extent possible. 'Black start' capability, if required in the approved design requirement, will be provided, otherwise, the design will be conducive to a retrofit should the need arise in the future.

This is the recommended alternative as it is the lowest cost option that satisfies the business objective. It provides for 'black start' capabilities and is expandable to accommodate future needs (i.e. station de-commissioning and/ or new construction).

This Developmental Release BCS will be utilized to complete the Preliminary Engineering (Project Definition Phase) and the Full Release BCS. The PEP will also be prepared as a deliverable of this release.

Alternative 2 - Delay the Recommendation (Not Recommended)

This is not recommended as the station will continue to:

- be at risk of severe equipment damage should the AHS be required under very harsh conditions.
- not address regulatory issues associated with the building and piping system for which we have committed to resolve by December 2007.
- perform costly annual maintenance of CBH as it was never designed as a permanent system.

Alternative 3 - Do Less (Not Recommended)

The 'Do Less' alternative involves partial refurbishment of the existing facility which is costly and will not meet the business objectives of the project.

Alternative 4 - Do More (Not Recommended)

This is not recommended as there is no way to include additional features without adding cost. The recommended alternative satisfies the business objectives

Alternative 5 – Other - Co-generation Plant (Not Recommended)

A Co-Generation plant, estimated at $100M is not recommended as the break even rate is estimated to be not achievable. There also does not appear to be any corporate drivers to merit this alternative at this time.
In addition, it is unlikely that real estate will be available at Darlington to site the cogeneration plant in such a way that the steam transmission lines can be kept reasonably short. Also, delays due to the likely need for an environmental assessment will make meeting the project schedule impossible.

Alternative 6 – Other – Electric boilers in Unit 4 (Not Recommended)

We do not recommend the installation of electric boilers in the Unit 4 Powerhouse Extension Bay, with power supplied from the Bulk Electric System (BES) as the space available in the Unit 4 Powerhouse Extension Bay is not adequate. In addition, this alternative does not cater to a black start capability should that be deemed as necessary.

Alternative 7 – Other – Relocate the REPG from PND to DND (Not Recommended)

We do not recommend using the Pickering REPG (22.5 MW) turbine generator as:

- this system is undersized.
- it still requires a boiler facility and associated costs to produce steam.
- it is an inefficient method of producing steam (using jet-engine fuel to produce electricity, to produce heat to produce steam).
- it is very complex and costly to operate and maintain.

As this system is owned by OPG and is available in 2007, it will be explored further as part of this release and considered a potential alternative until proven otherwise.

Alternative 8 – Other – Use of Gas Fired Boilers (Not Recommended)

We do not recommend the use of a gas fired boiler facility since natural gas is currently not available on site and would be very costly to supply. Since the facility operates very infrequently, the higher cost of fuel oil is far outweighed by the capital cost of supplying natural gas. The use of natural gas would also introduce a hazard to the site which currently does not exist.

4/ THE PROPOSAL

This Developmental Release BCS will be used to:

- validate the recommended alternative.
- complete the necessary design and procurement documentation to secure an external design contractor i.e. Design Plan, Design Requirements, Technical Specifications, Design Agency Interface Agreements, Request for Proposals
- complete all required assessments and sufficient detailed design to support preparation of a Full Release BCS
- fund the use of a third party estimator (Helyar).
- complete all necessary project management documentation required for this phase of the project including the Project Execution Plan
- Prepare a Full Release BCS.

Milestones below are for this Developmental Release BCS only.

Milestones Finish Date (D/M/Y)	Description
31-Mar-06	Developmental Release BCS approved
30-May-06	Issue the RFP for an external design agency
30-Jul-06	Award design agency contract (PO)
30-Nov-06	PEP approved
28-Feb-07	Full Release BCS approved

5/ QUALITATIVE FACTORS

N/A

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Project requires additional funding	The funding requested may not be adequate to complete necessary design activities.	**Medium**	Competitive bid process will be used to secure the design contractor. PO will be awarded as a 'Fixed Price' contract. A general contingency of [redacted] is available.	**Low**
Scope				
Increase in project scope.	Higher cost/ longer schedule	**Medium**	Original project scope was larger than is now being proposed. The current scope as defined in the preliminary design requirements has been fine tuned and agreed to by all stakeholders as the minimum required to meet station and regulatory requirements. A formal scope change control process will be used to control scope.	**Low**
Schedule				
Piping (oil-feeder from SG tanks) will not be code compliant by Dec. 2007	CNSC commitment will not be met. Darlington will not be allowed to use fuel oil piping from the SG tanks to the existing boilerhouse.	**High**	Seek a deferral that can be achieved on the present schedule and/ or ensure that the piping is completed first.	**Low**
Resources				
Lack of Project Designers.	Project deliverables delayed, with a delay in the project schedule.	**High**	Design activities will be contracted out to the extent possible to a known design agency to minimize the involvement of station resources.	**Medium**

Technical				
Commercially available boiler systems are very mature and widely used in other industries. Technical risk is considered low.		**N/A**		
Regulatory				
See Schedule Risk.		**High**		**Low**
Environmental				
New Certificate of Authorization may be required for new facility.	Not granted due to increased emissions.	**Medium**	Environmental Group has been consulted. Initial assessment is that a new C of A will not be required. If conditions support this assessment change, an application will be submitted as early as possible in the design phase.	**Low**
Health & Safety				
N/A				
Investment				
System may not meet requirements	Solution is known and technology is very mature.	**Low**	No mitigation required.	**N/A**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
N/A	Choose Month Choose Year	Choose Month Choose Year	N/A

Comments:
This is a Developmental Release BCS only. PIR will be developed for Full Release.

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Auxiliary Heating System Project 16 - 34000

Developmental Release Business Case Summary D-BCS-73110-10001-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Years 2005	2006	2007	2008			Total	LTD This Mth	LTD %
Project Management (OPG)		270	397	517			1,184	-	0.0%
Engineering & Drafting (OPG)		360	289	323			972	-	0.0%
Material	[redacted]								
Installation – PWU, BTU									
Contract – Project Mgmt									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Sub Total (excl Contingency)									
General Contingency									
Specific Contingency									
Grand Total		2,200	10,350	10,955		-	23,505	N/A	N/A
2006-2010 Business Plan		2,000	9,000	9,525			20,525	N/A	N/A
Variance to Business Plan (excl Contingency)		-	-	-	-	-	-	N/A	N/A

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Conceptual Estimate +60% to -25%**
Design Complete:	**Zero to Minimal**

Reviewed By:

23FEB2006
Date:

[illegible]ahil Rahman
[illegible]oject Manager P 24feb06

Approved By:

27 FEB 06
Date:

Robert Black
Manager (Strat IV), Design Projects

ONTARIOPOWER GENERATION

Calandria Vault Inspection 13 - 46537

Full Release Business Case Summary N-BCS-30673-10000-R000

Routing	Location	Action	Signature	Date
Carl Daniel Manager, Components & Equipment	P42-E2	Submit BCS	see BCS	
Martin Reid Director, Station Engineering	P42-E3	Review BCS	see BCS	
John Coleby Senior VP, Pickering A	P42-E3	Review BCS	see BCS	
Pierre Charlebois Chief Nuclear Officer	P826A-1	Review BCS	[signature]	July 21/06
Don Power Director, Investment and Business Planning	H07-J20	Approve BCS	[signature]	Aug 1/06
Jim Hankinson President and Chief Executive Officer	H19-A24	Approve BCS	[signature]	Aug 22/06
		Choose One		
		Choose One		
		Choose One		
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		Choose One		
		Choose One		
P. Ball Senior Financial Analyst 2-4084	P82-3B6	Return For Distribution		

RECEIVED
by P. R. Charlebois
JUL 1 2006
Refer to:

ONTARIOPOWER GENERATION

July 18, 2006

Jim Hankinson
President and Chief Executive Officer

Funding Release for Pickering A Calandria Vault Inspection Tooling

Your approval is requested for a release of $23.9 Million to develop and fabricate tooling for the Pickering A Calandria Vault Inspection Program. This work is included in the OPG Nuclear project portfolio as Capital Project 46537 in the 2006 Business Plan.

Recommended by:

John Coleby
Senior Vice President
Pickering A

Pierre Charlebois
Executive Vice President and
Chief Nuclear Officer

Approved:

Jim Hankinson
President and Chief Executive Officer

1. Background

The Pickering A calandria vaults were originally designed to be vented to atmosphere through the station stack, but early in the life of the reactors these vents were sealed off to reduce station noble gas emissions. As a result, humidity levels within the stagnant vaults became high, which was worsened by chronic leakage from the biological shield cooling system within the vaults. The combination of high humidity, air and radiation created a nitric acid environment, resulting in substantial corrosion of carbon steel components within the calandria vault of each unit. The extent of this corrosion was such that, in the mid-1990s, the carbon steel ring thermal shield inlet and outlet lines had to be removed and replaced with stainless steel flexible hoses using remotely operated robotic equipment.

Uncertainty in the health of the carbon steel components within the calandria vaults was a factor in the decision not to refurbish Pickering Units 2 and 3 and return the units to service.

For Units 1 and 4, the OPG Reactor Assembly Aging Management Plan has identified several components within the calandria vault for inspection to assess their continued fitness for service. To complete these inspections, and to implement repairs should the need be identified, remote tooling must be developed to deliver inspection and repair end-effectors to the internal areas of the calandria vaults. Capital Project 46537 has been included in the OPG Nuclear project portfolio to design, fabricate, and test the calandria vault inspection and repair delivery system. The estimated cost of this capital project, including the design but not fabrication of repair end-effectors, is $23.9 Million. The decision to proceed with the fabrication of repair end-effectors will be made after initial inspection results are available.

In 2005, $350k was released to secure developmental proposals for the inspection and repair delivery system from vendors. Two vendors, MacDonald, Dettwiler and Associates (MDA) and Areva provided proposals, and a decision has been made to establish a fixed-price contract with MDA for the design and fabrication of the tooling.

2. Preparatory Timeline

A high-level timeline for Pickering A calandria vault inspection is provided in Appendix A, showing all elements of the program from tooling design through fabrication to ultimate use in the field.

Delivery of the complete remote inspection tooling is linked to the Fall 2008 planned outage on Unit 4, when the first comprehensive inspections are planned. In order to meet this schedule, it is necessary to initiate the design and fabrication of the delivery system at this time.

In parallel with the design of the delivery system, the design, fabrication and in-service testing of non-delivery system inspection equipment (inspection end-effectors, etc) will take place. During tool proving, inspection of selected Unit 2 calandria vault components (those which do not require the remote delivery system for access) will allow engineering staff to gauge the general condition of calandria vault components and assess the risk of failure. It is possible that unfavourable inspection results from Unit 2 could drive a decision to initiate the design and fabrication of vendor designed end effectors for repair of high risk piping.

If Unit 2 inspection results do not lead to initiation of the repair tooling development, this decision can be deferred until Unit 4 and Unit 1 are inspected with the new delivery system. The risk associated with the failure of carbon steel components in the calandria vault is primarily economic. As such, should components be found to be in a degraded condition requiring repair, it is assumed that a case could be made to restart the unit following the inspection campaign and that fabrication of the repair end-effectors would proceed with the unit in operation. In the event that inspection results that do not permit restart of the unit, fabrication and testing of the repair tooling would be required on outage critical path.

Key decision points in the timeline include:

- Release of funding for inspection equipment design and fabrication (this request), which includes design of the remote delivery system, design and fabrication of inspection equipment and in-service testing of inspection equipment in Unit 2.
- Selection of a suitable vendor and contract award for remote delivery system design and fabrication. (MDA will be awarded a fixed-price contract upon approval of funding.)
- Decision to proceed with design and fabrication of repair end-effectors, based on preliminary inspection results from Unit 2 calandria vault. If design and fabrication of repair tooling does not proceed at this point, this decision will be repeated after Unit 1 and 4 inspections.

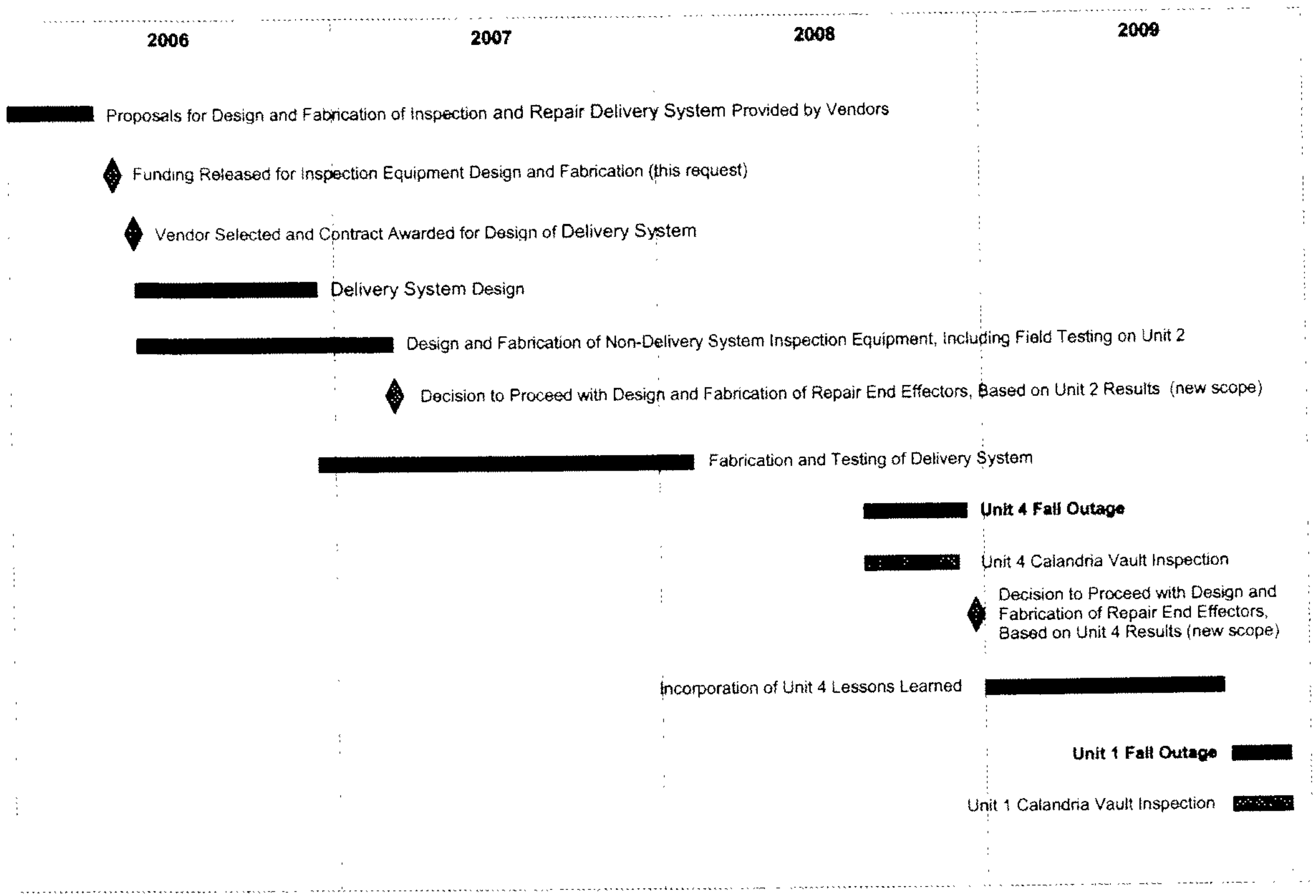
3. Funding Requirements and Recommendation

The OPG Nuclear Business Plan for 2006 – 2010 includes a capital project entry of $23.9 Million for development of calandria vault inspection tooling.

With fixed-price proposals now in-hand from two vendors, we have been able to confirm the cost projection of $23.9 Million for design and fabrication of the remote delivery system and the inspection tooling. A detailed breakdown is provided in the attached Business Case Summary. It is recommended that approval be granted for full release of this project funding.

Depending on inspection results, future requests may be made to release project funding for repair end-effector design and fabrication.

Appendix A – Timeline for Pickering A Calandria Vault Inspection Project



CALANDRIA VAULT INSPECTION 13-46537
BUSINESS CASE SUMMARY FOR FULL RELEASE N-BCS-30673-10000-R00

1. RECOMMENDATION:

Full release of 23.9M$ in Capital funding is recommended for implementation of the Calandria Vault Inspection (CVI) Project at Pickering A. This project will provide the capability to reach and deliver inspection and repair end effectors to all the specified calandria vault components. The inspection data acquired with this equipment will allow OPG to determine the condition of the Pickering A calandria vaults and assess the risk of future component failure.

Background

The Pickering A calandria vaults (CVs) have been exposed to moist corrosive environments since shortly after the reactors were placed in service. Corrosion has resulted in past leaks requiring repairs using remote tooling. Inspections were last performed in the mid 1990s, hence the current condition of the Pickering A Calandria vaults is uncertain. Reliability of the Calandria vault drying system which was placed in service in the early 1990s to mitigate against the moist corrosive environment has been inconsistent.

Previously, approximately $660K was spent on Project scoping using funding from the Pickering A Return to Service budget. Subsequently, a developmental release of 350K$ was issued to complete Phase 1 of the Project under Project #46552. The major deliverables for Phase 1 were two vendor conceptual proposals for the design and fabrication of a CV manipulator arm for inspection and repair of CV components.

Capital Project 46537 has been included in the OPG Nuclear project portfolio to develop calandria vault inspection capability. The strategy is to develop the tooling in time to carry out an inspection on Unit 2 (a laid-up Unit), then on Unit 4 in 2008. The expected capital cost of this project is 23.9M$, consistent with the current approved Business Plan amount. The cost of executing the inspection campaigns in Units 1 and 4 will be separately funded (cost estimated to be 1.5M$ for Unit 4 and 2.5M$ for Unit 1). As well, any required development of repair end effectors, the need for which will not be known until the inspections are complete, is not within the scope of this project (cost to design, build and test repair tooling is estimated to range between 10-12M$).

An NPV and IRR are not applicable; however an assessment has been done which shows that the cost of developing the inspection capability is far out-weighed by the risk-adjusted loss should a calandria vault component fail before the capability to deliver repair tooling is available.

Project 46537 Cash Flow for Recommended Alternative	2006	2007	2008	2009	2010	Total
Estimated Capital	8,132	12,759	2,982	-	-	23,873

* *includes 350K$ developmental release under Project #46552 to be capitalized under Project #46537*

2. SIGNATURES

Submitted By:

July 5/2006

Carl Daniel — Date
Components & Equipment Mgr, Pickering A

Recommended By:

July 21/06

Pierre Charlebois — Date
Chief Nuclear Officer

Reviewed By:

July 10 2006

Martin Reid — Date
Director Engineering, Pickering A

Finance Approval By:

Aug 1/06

Don Power — Date
Director Investment and Business Planning

Reviewed By:

for July 8, 2006

John Coleby — Date
SVP Pickering A

Line Approval per OAR Element 1.1.2:

JHankinson Aug 22/06

Jim Hankinson — Date
President and Chief Executive Officer

Aug/06

3. BACKGROUND & ISSUES

Background

The Pickering A calandria vaults (CVs) were originally designed to be vented to atmosphere through the station stack, but early in the life of the reactors these vents were sealed off to reduce station noble gas emissions. As a result, humidity levels within the stagnant vaults became high, which was worsened by chronic leakage from the biological shield cooling system within the vaults. The combination of high humidity, air and radiation created a nitric acid environment, resulting in substantial corrosion of carbon steel components within the calandria vault of each unit. The extent of this corrosion was such that, in the mid-1990s, the carbon steel ring thermal shield inlet and outlet lines had to be removed and replaced with stainless steel flexible hoses using remotely operated robotic equipment (the CV is an inaccessible room with high radiation fields that houses the reactor vessel and dump tank in the Pickering-A units - remote tooling is the only option for inspection and repair work in this area).

To minimize further corrosion in the Unit 1 and 4 calandria vaults, a project has been initiated to improve the reliability of the Calandria vault drying system by replacing the drying units. The new dryers are expected to be installed in the Spring of 2007. In addition, on-power leak sealant will be proactively added to the biological shield cooling system in the hope of minimizing minor leakage into the Calandria vault. These actions will not reduce the ingress of moisture into the CV from other paths.

For Units 1 and 4, OPG's Reactor Assembly Aging Management Plan has identified several components within the calandria vault for inspection. To complete these inspections, and to implement repairs should the need be identified, remote tooling must be developed to deliver inspection and repair end-effectors to the internal areas of the calandria vaults.

The need to inspect Units 1 and 4 is driven by:

a) OPG's desire to re-assure itself that the Calandria Vault components are not in danger of imminent failure, thereby potentially resulting in serious process or structural failures in the Pickering A units.
b) OPG's commitment to manage its nuclear fleet in a manner which enhances the confidence of employees, the public and regulatory authorities in the safety of its nuclear reactors.
c) OPG's desire to make commercially sound decisions about future investments in Pickering A, by assuring itself of the condition and life expectancy of all of the major components in the Units, prior to making significant on-going investments in other components (e.g. execution of boiler chemical cleaning and large scale feeder replacement).

Based on these priorities, the key decision to be made in this Business Case is not whether or not to invest in equipment which would facilitate the inspections (and potential repairs) of the Calandria Vault components in Pickering A, but how quickly should the capability be developed in light of the risks which may arise. The recommended Option attempts to balance the risk of not being ready to repair an unexpected failure in a Calandria Vault component with the potential costs of spending too much up-front to mitigate the risks, only to find that conditions are better (i.e. no need for repairs) or worse (i.e. irreparable flaws) than expected[1].

There are two reasons for initiating this project in time to allow inspections in the P841 outage. Firstly, there is a pressing need to understand the condition of Pickering A calandria vaults before significant expenditures are made on other large sustaining projects (execution of boiler chemical cleaning and large scale feeder replacement). Secondly, the lack of recent calandria vault condition information leaves OPG open to unexpected leaks and/or failures of CV components. Initiating the project as soon as possible will reduce the window of exposure where OPG does not have the ability to locate failures and initiate repairs activities.

[1] Repairable failures include most cooling water lines, RTS segment vent lines, helium line anchors, shielding plate supports. Failure of an RTS bracket resulting in displacement of the RTS segment is considered irreparable.

Previously, approximately $660K was spent from the Pickering A – Return to Service budget in 2005 on the project scoping. Subsequently, a developmental release of 350K$ was issued to secure concept proposals for the inspection and repair delivery system from Areva and MacDonald, Dettwiler and Associates (MDA). These proposals have been received and evaluated by the project team.

4. ALTERNATIVES AND ECONOMIC ANALYSIS

Base Case: Do Nothing - Not recommended

The Do Nothing option makes no attempt to prepare for the possibility of catastrophic component failure in the calandria vault. As such, the risk is that a catastrophic failure[2] of a critical component forces the unit down with essentially no forewarning. The resulting impact is an outage of approximately 20 months for a repairable failure or permanent shutdown for an irreparable failure.

In the event of a biological shield cooling line leak that is within the operating limits but not sealable with on-power leak sealant, the unit would continue to be operated until the leak exceeds operating limits. This would result in an increase in calandria vault dewpoint and would increase the corrosion rate of carbon steel components in the vault if the dewpoint exceeds the critical value, thus increasing the probability of subsequent catastrophic failures[2].

The 'do nothing' option subjects OPG to ongoing uncertainty in assessing the probability of Calandria vault component failures between now and the planned end of life for Units 1 and 4 (early to mid-2020s).

There is regulatory risk associated with the "do nothing" option as the CNSC has expressed an interest in the state of the Pickering A Calandria Vaults. While the overall risk to the public is judged to be acceptably low, certain failures could result in a serious process failure and the probability of serious process failures must be kept acceptably low as part of our licensing requirements. For example, failure of certain RTS brackets could lead to an RTS segment falling on moderator system piping inside the calandria vault resulting in a loss of moderator inventory accident.

There is reputational risk associated with the "do nothing" option. Should a CV component fail requiring a protracted outage to repair there could be negative public perceptions of OPG ability to manage the nuclear fleet, especially in light of the recent large expenditure in returning Pickering Units 1 and 4 to service.

Engineering has estimated that the probability of failure is likely to remain above 20% over the balance of plant life. If a failure were to occur in one unit, this would indicate that the CV conditions are such that the probability of a failure on the other unit is also high. In order to estimate the financial consequences of failure, it was assumed that there is a 20% probability of a failure resulting in a 20 month outage while the inspection and repair tooling is designed, fabricated, tested and crews are trained and deployed for inspection and repair activities. The cost of this initial failure is the lost revenue over 20 months plus the escalated cost of the inspection tooling being developed for this project (23.9M$ estimated price of the project plus a 30% premium for fast tracking escalated by CPI). It is then assumed that there is an 80% probability of a failure on the other unit one year later which would require a 4 month inspection/repair outage (shorter duration attributed to availability of tooling and trained staff).

The cost of repair tooling is not included in the consequence of a future failure because the cost will be roughly the same and will be incurred in roughly the same timeframe, either shortly after a failure in the do nothing case, or in the preceding period in the case where the CVI project is pursued and the inspection capability allows planning for pre-emptive repair.

Performing the initial inspection and repair does not reduce the probability of future failures to zero. For earlier failures, the probability of a subsequent failure on the same unit will be higher as the

[2] Catastrophic failure defined as a failure that requires immediate shutdown of the unit. The failure itself may be repairable or irreparable (see Footnote 1 on previous page).

window of exposure is larger. In order to avoid further complicating this financial evaluation which already contains a relatively large number of assumptions, the financial evaluation conservatively does not take into account the impacts of subsequent failures on the same unit.

The financial evaluation compares the Net Present Cost of the risk of a future failure in a given year (calculated by multiplying the cost of the failure times the probability of failure) to the Net Present Cost of developing the inspection capability. The Do Nothing option would be considered only if the Net Present Cost of the failure is lower than the Net Present Cost of the CVI project. Table 1 shows that the Net Present Cost of the Do Nothing option exceeds the Net Present Cost of the CVI project for postulated failures in Years 2008 and 2014[3]. The Net Present Cost of failure declines with time, because of discounting; however, the analysis showed that it remained higher than the Net present Cost of the CVI project throughout the life of the Units. However, near the end of life of the units, should there be a major failure, OPG would be unlikely to invest in major tooling to fix the failure unless there was a strong financial case to be made, hence the Net Present cost of the failure is shown only until 2014.

Table 1: Net Present Cost of Calandria Vault Component Failure compared to CVI Project

	2008	2014
NP Cost of CVI Project (2006$ PV)	$17.8 M	$17.8
NP Cost of Failure (2006$ PV)	$44.2 M	$32.6 M
Difference	**$26.4 M**	**$14.8 M**

This table shows that, should OPG develop the calandria vault inspection tooling and be ready to repair a failure, OPG would be approx $26 Million ahead should the failure occur in 2008 or $15 Million ahead, should the failure occur in 2014.

The sensitivity of this analysis to critical parameters is discussed in Section 6.

Alternative 1: Full Project Release –Recommended

In this preferred alternative, the inspection tooling is designed, fabricated and tested in time to carry out the full inspection scope in the P841 and P911 outages. With this alternative, a remote manipulator will be developed to reach all required inspection locations in the calandria vault, including the previously inaccessible North side. The deliverables for this alternative include:

- 2 CV manipulator arms,
- ultrasonic and video inspection end effectors for the CV manipulator arm,
- mock-ups for tool testing, and training,
- horizontal and vertical video on extension booms to provide overview visuals of the CV internals and for field of view cameras during CV manipulator arm operations,
- A robotic vehicle and associated video and ultrasonic inspection end effectors,
- Site preparations for unit inspections,
- Field testing of all inspection equipment in Unit 2,
- Training and procedures,
- Project management and engineering.

All inspection equipment will be tested in mockups and then field tested in Unit 2 prior to deployment in Units 1 and 4. The field testing of non arm based inspection equipment in Unit 2 will take place in early to mid 2007. This will provide Engineering with some general information on the condition of the Pickering A calandria vaults. The most likely outcome is that conditions will be similar to those observed in the mid-1990s, reaffirming the need for detailed inspections of the

[3] Note that all costs are presented in net present values and have been adjusted for tax implications of lost revenues or capital expenditures.

calandria vault components. All 4 possible outcomes to these Unit 2 field trials are described in Table 2.

The decision regarding the need to proactively develop repair tooling will be made following the Unit 2 field trials of non-arm based inspection tooling. The estimated cost for design, build and testing of repair end effectors for the most likely failure modes is 10 to 12M$.

In this proposal, two CV manipulator arms are being purchased, one for field use and the second for training of inspection staff. This second arm will also be used to test inspection and repair end effectors and will be available as a spare in the event of a significant failure of the first arm. Finally, the staggered delivery of the arms may allow sufficient time to make modifications to the second arm at the manufacturer's facility in the event that problems are uncovered during commissioning of the first arm.

The cost for conducting the inspection campaigns on Units 1 and 4 will be covered by Outage OM&A and is estimated to be 1.5M$ for P841 and 2.5M$ for P911 (part of the P841 training cost covered by the project to provide initial training to IMS execution personnel).

As discussed in the do-nothing option, the 20%+ probability of future repairable catastrophic failure and the resulting financial consequences make the project viable for all failures out to near the end of unit life.

Table 2

Possible Outcomes of Non Arm Based Inspections in Unit 2

Potential Unit 2 inspection results	OPG response	Probability
Calandria vault conditions much better than expected	Decision not to proceed with the CVI project	Extremely low Calandria vault conditions were poor in the mid-1990s and they will not have improved in the intervening period of time.
Calandria vault conditions much worse than expected. Irreparable failure is likely and/or scope of observed damage puts into question ability to operate the unit reliably until the planned end of unit life	Decision not to proceed with the CVI project. Large sustaining expenditures on Pickering A units 1 and/or 4 would be reconsidered to take into account the potential that the calandria vault structures may limit the lives of the units.	Low. The non-arm based inspections will provide only limited information on the calandria vault conditions: - only general visual information will be required from stand off cameras - only limited pipe wall thickness measurements possible - difficult to estimate degradation rate due to limited previous inspection data, The CV manipulator arm is required to obtain information on the condition of RTS brackets, which represents the biggest concern to future operation of the unit
Calandria vault conditions reveal minor localized leaks or wall thickness measurements significantly below those obtained in the 1990s, indicating continued progression of corrosion despite the operation of the calandria vault dryers and imminent component failure requiring unit shutdown (i.e. catastrophic repairable failure).	Proceed with CVI project. Initiate design/build/test of repair end effectors (as a separate project or a superseding BCS for this project)	Medium - Low
Calandria inspection conditions similar to that observed in the mid 1990's	Proceed with CVI project. Assess need for proactive development of repair end effectors.	Medium - High

Alternative 2: Design Only of the CV Manipulator Arm and Inspect Unit 2 with Non-Arm Equipment – Not Recommended

In this alternative, the design of the CV manipulator arm would be completed but the decision on fabrication would not take place until the Unit 2 inspection results are evaluated.

In order to meet the current P841 outage, the CV manipulator arm design must be completed in December 2006, fabrication must begin immediately thereafter and long lead materials must be ordered and received by the vendor in January 2007. The Unit 2 inspections are scheduled to take place between January and April of 2007. A decision to limit spending to the design of the CV manipulator arm would have several significant negative consequences on the project:

- The delay of up to 5 months would increase the cost of the arm and the project, and would likely result in the loss of key members of the vendor project team,
- The delivery of the CV arm would be delayed by at least 5 months, depending on the delivery times for critical path long lead items,
- The arm would not be ready for a Spring P841 outage, and in fact would be at significant risk for a Fall P841 outage.
- Delaying the front end of the project reduces the time available for critical training and field trials in Unit 2 prior to performing the Unit 1 and 4 inspections.

The perceived benefit of this option is that it would limit OPG expenditures until some Unit 2 inspection results are available to provide some indication of the current conditions in the Pickering A Calandria vaults. As discussed in the previous alternative and presented in Table 2, the likelihood that the Unit 2 inspections will suggest that no further inspections are required in Units 1 and 4 is considered to be very low. Inspection is the only means by which the current state of degradation in Units 1 and 4 can be determined with any degree of confidence.

In light of the very high probability that the CV manipulator arm will be required and the detrimental impacts of this option on the delivery schedule for the CV manipulator arm, this option is not recommended.

Alternative 3: Design Only of Inspection and Repair Equipment (No Fabrication) - Not Recommended

This option involves the design of the CV manipulator arm and all other inspection equipment. Since there would be no Unit 2 inspection in this option, the decision would be made upfront to proactively design repair end effectors for repairable components deemed to be most at risk of failure. Actual fabrication and deployment of the equipment would be deferred until the first catastrophic failure (i.e. failure requiring a unit shutdown). The perceived benefits of this option are to:

- defer the cost of fabrication, inspections and repairs to the future, and
- reduce the duration of a repair outage by approximately 5 months (assuming that the failure is repairable with one of the pre-designed end effectors).

The cost of this option is estimated to be in the order of 8M$ (2006 dollars) and the project would not result in the acquisition of a fixed asset. The design would provide a financial benefit to OPG if it were to reduce the duration of a future repair outage. In reality there are several factors that could affect the value of this "design asset":

- the design would likely be considered obsolete within 5-8 years,
- the length of time required for procurement of long lead items and fabrication of the CV manipulator arm would be longer than in Alternative 1 because of the lack of continuity of the vendor project team members,
- the cost of fabrication would likely be significantly higher than in Alternative 1
- Fabrication of inspection equipment would be required before the actual failure could be located,
- The failure could be to a component for which a repair end effector had not been pre-designed,

- The actual time savings would be reduced by the time required place a PO for the fabrication of the inspection and repair equipment,
- The vendor could become unavailable to fabricate the designed equipment due to insolvency or unavailability of resources,
- The critical phase of assembly, testing and troubleshooting would not have taken place in the design phase.

This option would not allow small non-catastrophic leaks to be detected and repaired in a planned way to minimize the ongoing degradation of CV components. In the absence of inspection information, it is quite possible that the first indication of a significant leak could occur after significant degradation has taken place in the calandria vault, at which point the need for repair could be widespread, thus increasing the duration of a repair outage.

This option subjects OPG to ongoing uncertainty in assessing the probability of Calandria vault component failures between now and the planned end of life.

There is regulatory risk associated with this option as the CNSC has expressed an interest in the state of the Pickering A Calandria Vaults. While the overall risk to the public is judged to be acceptably low, certain failures could result in a serious process failure and the probability of serious process failures must be kept acceptably low as part of our licensing requirements.

This option is not recommended as it does not provide OPG with a tangible asset nor does it provide any information on the condition of the calandria vaults and the probability of future failures resulting in protracted outage(s).

Alternatives considered but rejected

Use of old manipulator arm with new inspection end effectors

- The old arm was unable to access many components on the South side of the calandria vault, and none of the components on the North side
- Control of old arm was very coarse. While it was used out of necessity when repairs to the RTS inlet and outlet lines were required to return the units to service, the risk of damage to components during inspection activities is deemed to be far too great.
- The dexterity of the manipulator was very limited

5. THE PROPOSAL

It is recommended that OPG proceed with Alternative 1, Full Release of funding for the CVI project. With this alternative, a remote manipulator will be developed to reach all required inspection locations in the calandria vault, including the previously inaccessible North side. The deliverables for this alternative include:

- 2 CV manipulator arms,
- ultrasonic and video inspection end effectors for the CV manipulator arm,
- mock-ups for tool testing, and training,
- horizontal and vertical video on extension booms to provide overview visuals of the CV internals and for field of view cameras during CV manipulator arm operations,
- A robotic vehicle and associated video and ultrasonic inspection end effectors,
- Site preparations for the unit inspections,
- Field testing of all inspection equipment in Unit 2,
- Training and procedures,
- Project management and engineering

6. QUALITATIVE FACTORS

Proceeding with the recommended option will allow OPG to proceed expeditiously with the development of inspection capability for Pickering A Calandria vault to address the risk of potential failures of Calandria vault structures. Notwithstanding the significant cost ramifications of such a failure, there would be significant negative consequences on OPG's public image in the event of a significant failure.

Expeditious development of non-arm based inspection capability in parallel with development of the arm will provide management with some urgently needed information on the general condition of the calandria vaults. This information would allow OPG to better understand the risk of premature shutdown of the Pickering A units and the potential impacts on other large Pickering A sustaining projects.

OPG has other evolving inspection needs which may be able to use some of the robotic equipment developed for CVI. Feeder and Calandria *vessel* inspections at Pickering and Darlington are the most obvious examples.

7. RISKS

Risk category	Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost	Cost of project significantly higher than $23.9M.	Need to obtain further capital funding to complete project	Medium	Estimates generated by project team members with extensive experience. Fixed price contract for CV manipulator arm.	Low
Cost	Vendor not able to obtain SR&ED* tax credit which was assumed in proposal pricing (due to OPG tax status, or other limitation) *Scientific Research and Experimental Development	Vendor price for manipulator arm would increase by SR&ED tax credit assumed in proposal. If OPG is eligible to obtain the SR&ED tax credit but unable to transfer it to the vendor, it would be applied at the corporate level and would not be transferred down to the project. As such, the required funding to the project would have to be increased by this amount although the net cost to the corporation would be zero.	Medium	Obtaining clarification from OPG tax specialist.	Low
Scope	Deliverables not clearly defined	Additional schedule and cost pressures	Medium	Prepare detailed design requirement documents for major deliverables and include key stakeholders in reviews.	Low
Scope	Manipulator arm may cause loads on south accessible area structural steelwork that exceeds limits	Modifications could be required to south accessible steelwork	Medium	Vendor to provide manipulator arm loads at preliminary design review to allow station civil engineering to assess load capability of existing steelwork and identify any required modifications in advance of the P841 outage. Any such modifications are not within the current scope of the project.	Med-Low
Schedule	CV manipulator arm not ready for P841 Spring outage	Unable to properly assess probability of failure in Unit 4 RTS bracket and hairpins until 2010	High	Fixed price and schedule contract with vendor. Potential to move Unit 4 Spring 2008 outage to Fall 2008. Thorough review of requirements, constraints and risks with vendor upon awarding of contract.	Medium

Risk category	Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Schedule	Outage extension as a result of CV inspection activities	If the duration of the inspection window extends beyond the available float, the outage could be extended, resulting in significant lost revenues to the station.	Medium	Will demonstrate feasibility of assumed durations in mockup training and Unit 2 field trials. Second arm will be available as a contingency in the event of failure of the first arm. Sequence of inspection targets will be optimized to ensure highest value data is acquired as early as possible in the inspection window.	Med/Low
Schedule	Vendor labour disruption	Vendor schedule delay resulting in delayed delivery to OPG. The marginal float in the schedule means that this would likely result in an inability to meet the P841 outage.	Medium	Vendor is currently in a labour disruption with the engineering union at its Brampton facility. It is anticipated that resolution of this disruption should result in a 3 year collective agreement which will bracket the CVI arm contract with the vendor.	Med-Low
Resources	Limited availability of key IMS personel for development of inspection end effectors.	Delay in completion of P2 field trials and threat to ability to complete P841 inspections	Medium	Assign top priority to CVI project for critical IMS technical staff.	Low
Technical	Inspection equipment unable to provide required results due to CV conditions	Inadequate inspection information reduces confidence in ability to operate Pickering A units to end of design life	Med-High	Mock-ups will be prepared to attempt to simulate actual conditions including corrosion and required surface preparation	Med-Low
Technical	Inspection equipment fails to meet design specifications during Unit 2 field trials	Deficiencies identified at this late stage will put the Unit 4 inspection at risk due to the very short period of time available to take corrective actions.	Med-Low	The arm will be extensively tested in a full scale mock-up prior to acceptance from the vendor. Design deficiencies are expected to be identified at this point. The arm will then be used for training in the same representative mockup. Problems with equipment reliability are expected to be identified at this point. Disassembly and assembly of the arm for transportation between inspection points during training will demonstrate the capability of the inspection crews, the quality of the procedures and the robustness of the arm.	Low

Risk category	Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Technical	Repair end effectors are not going to be built by the arm manufacturer	There is the possibility of interface problems between the arm and end effector manufacturers.	Med	The design requirement for the manipulator arm specifies the need for services for potential repair end effectors. Dexterity at the end of the manipulator arm should be maximized to allow greater simplicity in the repair end effectors. The manufacturer for repair end effectors will be provided with the necessary interface information during their design process. The project will request that prototype tooling be developed and tested in the mockups prior to finalizing the design. Integration testing will be performed in the full scale mockup prior to field trials in Unit 2 and deployment in Unit 4.	Med-Low
Regulatory	CNSC could request additional inspections	Additional schedule and cost pressures	Low	Inspection scope basis is sound and well documented in the appropriate engineering documents.	Low
Environmental	No significant environmental risks associated with this project				
Health &Safety	Certain Calandria vault failures could result in operational transients	Damage to station structures and/or components. Significant outage and project costs to locate and repair	Low	Past inspection results and analysis have concluded that the risk is low. Proceeding expeditiously with full scope of inspection will further reduce this risk.	Low
Health &Safety	Unit 2 CV inspections will be scheduled in parallel with Unit 2 Safe Storage work	Unique hazards may exist during specific activities such as defuelling or dewatering of Unit 2.	Low	The CVI project work will be scheduled and assessed by the Safe Storage organization, thus ensuring proper precautions are built into the execution work packages.	Low
Investment	Project is cancelled after Unit 2 field trials	Costs incurred up to that point (up to 12.7M$) may need to be written off to OM&A	Low	Engineering judgement is that results from Unit 2 trials are very unlikely to result in cancellation of inspections in Units 1 and 4	Low
Investment	Vendor bankruptcy during design of CV manipulator arm	Recovery of design information from bankrupt company will be of limited value and would be complicated by Intellectual Property issues. May need to return to competing vendor likely at higher cost.	Med-Low	Supply chain will confirm financial viability of the winning vendor during commercial review of proposals.	Low

7.0 RISKS (continued)

The information presented in this BCS is most sensitive to the following parameters:

Duration of Forced Outage. The base financial analysis was performed using a 20 month outage duration from failure to return to full power. This span of duration is a best guess estimate. From the time of failure, video inspection capability would have to be developed to locate the failure and determine its repairability and the extent of condition. From that point, repair tooling would need to be designed and constructed, and site modifications and training would have to take place prior to execution of the repairs in situ. Repairs may need to be performed to many components to maximize the reliability of unit operation going forward. A sensitivity case was run assuming an outage duration of 14 months instead of 20 months. This represents a 30% decrease in lost revenue and therefore has a significant impact on the risk adjusted NPV of a future failure. Despite the significant decrease in lost revenue, the project continues to be economically justifiable for postulated failures out to near the end of lives of the Pickering A units.

Probability of Failure. The financial analysis was performed using a constant 20% probability of failure. As a sensitivity case, the probability can be assumed to vary with time, starting at 10% in 2008 and increasing to 30% to end of life. With a 10% probability of a 2008 failure, the Net Present Cost of failure is higher than the Net present Cost of the CVI project. Even if the probability were only to increase to 11% by 2014, the Net Present Cost of failure for a 2014 failure would still remain higher than the Net Present Cost of the project. The Net Present Cost of failure is higher than the base case for any failure beyond in 2015 as the probability of failure continues to increase to 30% at station end of life.

The probability of failure does not go to zero after an initial failure and subsequent repair outage. The conditions that resulted in the initial failure will continue to exist and degrade unrepaired components. The financial evaluation in this BCS conservatively does not consider repeated forced outages or outage extensions as a result of ongoing failures.

Timing of a Failure. The cost benefit of this project depends largely on the assumed timing of a postulated calandria vault component failure. Failures near the end of life naturally present less and less of a financial risk to OPG, not taking into account the potential for life extension of Pickering A units.

Electricity prices. The cost implication of a future failure is significantly affected by the assumed price of electricity. The current price of electricity is simply escalated by the CPI rate. However, should electricity prices prove to be higher, the financial case for the recommended alternative becomes stronger.

8. PIR PLAN

A comprehensive PIR will be conducted within 6 months of the Unit 2 field trial of the manipulator arm. The PIR will focus on:

- Ability of manipulator arm to access all required locations within the calandria vault
- Ability of inspection equipment to demonstrate compliance with established acceptance criteria
- Adherence to project budget and schedule as measured by project CPI and SPI.

Appendix A

Table A.1 Sensitivity to Lower Outage Duration
(14 months first unit & 3 months 2nd Unit)

	2008	2014
NP Cost of CVI Project (2006$ PV)	$17.8 M	$17.8
NP Cost of Failure (2006$ PV)	$33.6 M	$24.3 M
Difference	**$15.8 M**	**$6.5 M**

Sensitivity to Probability of Failure

The probability of failure is impossible to quantify precisely. The limited inspections completed in the mid 1990s indicate that significant corrosion had occurred and attempts to quantify the wall loss in carbon steel piping provided marginally credible results. No additional Non Destructive Examination (NDE) has been completed since this time, therefore the current state of Calandria vault components is unknown and corrosion rates and possible progression of stress corrosion cracking cannot be quantified. If the environmental conditions in the vault had remained at pre-1990's levels the probability of such a failure prior to end of life would be 100%, i.e. severe leakage was observed in all the units in the early 90's and in Unit 3 as late as 1997. The beneficial effect of installing driers in the units in 1992 and the future improvements when additional driers are installed in 2007 will reduce the probability of future failures significantly. However, an improvement greater than 80% is deemed to be unlikely, i.e. the residual failure risk after improving the drier system is judged to be unlikely to be below 20%, as such the base case was done with a 20% probability.

A sensitivity case was done with an increasing probability from 10% in 2008 to 30% at near end of plant life. The results are shown below in Table A.2. A probability of 11% is used in 2014 for illustration purposes to demonstrate that only a slight increase in probability is required to keep the project viable. In reality, a linear increase would make the 2014 probability closer to 20% which would make the case very similar to the base case (a net benefit to OPG of $14.9M). With a 30% probability of failure in 2018, the Net Present Cost of a failure is significantly larger than the Net Present Cost of the CVI project.

Table A.2 – Sensitivity of Results to Varying Probability of Failure

	2008	2014	2018
NP Cost of CVI Project (2006$ PV)	$17.8 M	$17.8 M	$17.8 M
Assumed probability of failure	10%	11%	30%
NP Cost of Failure (2006$ PV)	$22.1 M	$17.9 M	$32.1 M
Difference	**$4.3 M**	**$0.1 M**	**$14.3 M**

Appendix B

Table B-1: Project Summary of Estimate

ONTARIO POWER GENERATION	PROJECT Summary of Estimate	Date	29 June 2006
		Project #	13-46537

Facility Name:	Pickering A
Project Title:	Calandria Vault Inspection

Years (k$)	**2006**	**2007**	**2008**	**TOTAL**	%
Project Management	[redacted]				
Engineering	[redacted]				
Permanent Materials	[redacted]				
2 Manipulator Arms	[redacted]				
Arm NDE End Effectors	[redacted]				
Non Arm Equipment	[redacted]				
Other	[redacted]				
TOTAL Permanent Materials	[redacted]				
Augmented Staff	[redacted]				
Testing/Commissioning	[redacted]				
Expenses	[redacted]				
Training	[redacted]				
Interest	[redacted]				
Contingency	[redacted]				
TOTAL	**8,132**	**12,759**	**2,982**	**23,873**	

Notes: 1 Schedule Start date: June 2006
In-service dates(s): Feb 2008
(include % for partial in service)
2 Interest and Escalation rates are based on current allocation rates provided by Corporate Finance
3 Includes Removal Costs of: 0
4 Includes Definition Phase Costs of: 350

Prepared by:

Project Engineer

Approved by:

Project Manager

Table B-2: Comparison of Estimated Cost Versus Approved Business Plan

Project 46537 Cash Flow for Recommended Alternative	**2006**	**2007**	**2008**	**Total**
Estimated Capital	8,132	12,759	2,982	23,873
Approved Business Plan (2006-2010)	8,057	12,734	3,083	23,874
Variance Over Plan	75	25	(101)	(1)

Appendix C

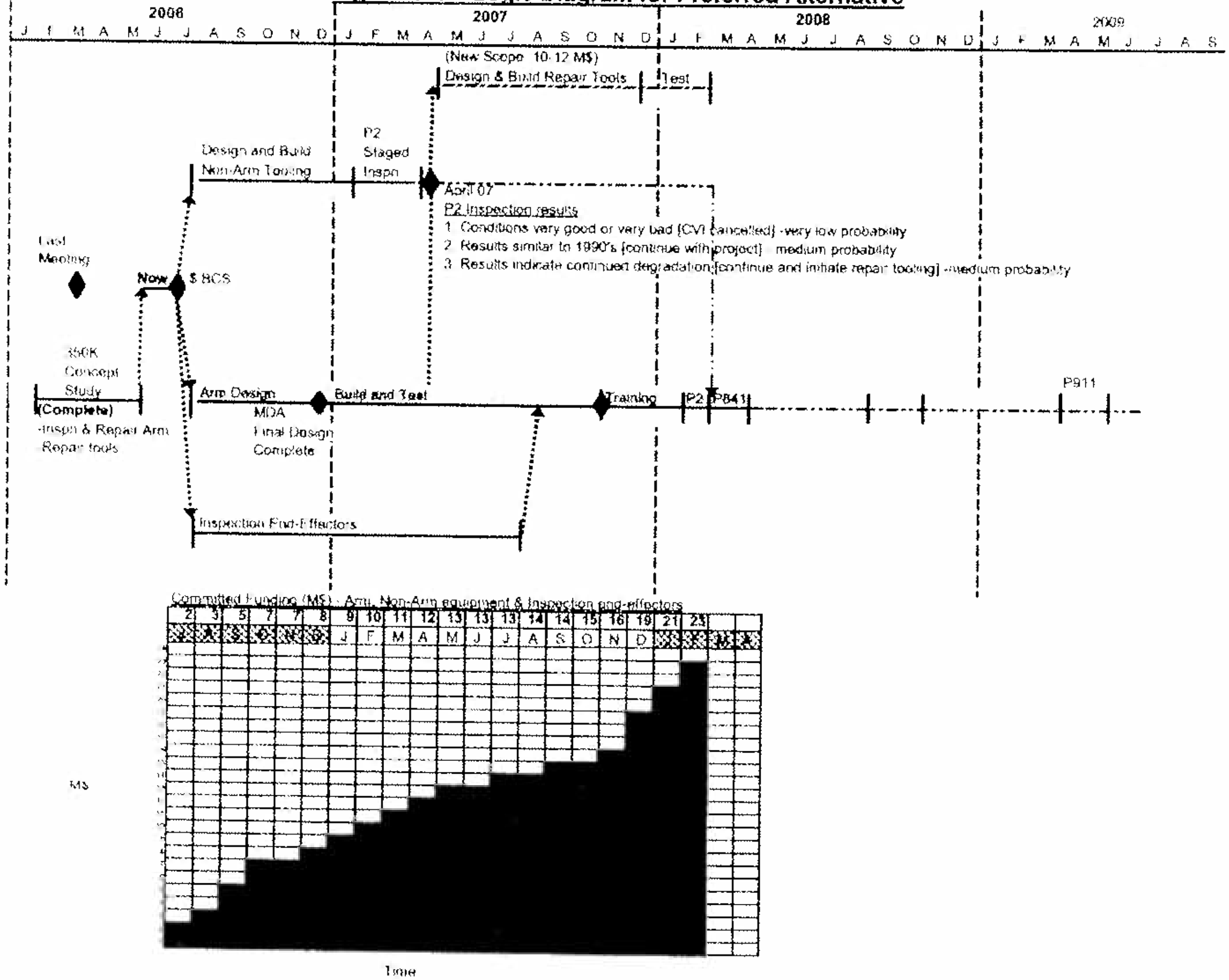
Project Efforts to Limited Committed Costs Before Unit 2 Inspections are Complete

There is a small probability that the Unit 2 inspections could result in a decision not to proceed with the CVI project. As such it is prudent to limit the amount of money that OPG is committing prior to obtaining some inspection data on calandria vault conditions. OPG's standard contract wording allows cancellation for convenience at any point at OPG's discretion.

To limit OPG's committed costs before the Unit 2 inspections are complete, Supply Chain will negotiate down the front end loading of vendor proposed payment schedule. The project will also give priority to early development of non-arm inspection equipment that will provide the most meaningful information on CV conditions to allow a decision to be made as early as possible.

The attached Figure D-1 shows the logic for the Alternative 1 (recommended) and the forecast of committed funds at monthly intervals. The expected committed amount at the end of the Unit 2 inspections is 12.6M$.

Figure C-1 – Logic Diagram for Preferred Alternative



Appendix D

Key Project Milestones

TCD	Description
May 2006	Winning bid selected - **COMPLETE**
July 2006	PO issued to vendor
December 2006	Final Design of Manipulator arm complete
January - April 2007	Field trial of non-arm inspection equipment in Unit 2
September 2007	Delivery of first CV manipulator Arm
November 2007	Delivery of second CV manipulator Arm
February 2008	Field trial of CV manipulator Arm in Unit 2 and in-service declaration
March 2008	Inspection of Unit 4 (inspection costs not in the project)
September 2009	Inspection of Unit 1 (inspection costs not in the project)

DNGS Construction Change Room 16 - 31718

Full Release (Phase 1) Business Case Summary D-BCS-28200-10004-R000

Routing	Location	Action	Signature	Date
Joe Walshe Mod Team Leader, Design Projects 701-3661	P72-3	Prepare BCS		Jan 21/08
Ian Fung PL, Design Projects 701-3866	P72-3	Review BCS		Jan 21/08
Stephanie Tham Section Manager, Design Projects 701-4203	P72-3	Review BCS		Jan 21/08
Dianne Gaine Manager, Design Projects 701-4181	P72-1	Review BCS		Jan 22/08
Mark Arnone Director, Projects & Modifications 701-6063	P72-1	Review BCS		5 FEB 2008
Axel Kleer Business Planning & Strategic Support 400-7720	TCHH7-A5	Review BCS		14 Feb 08
James Whyte Manager, Maintenance Production 703-7505	D01-A2	Review BCS		11 Feb 2008
Stu Seedhouse Director, Operations & Maintenance 703-7496	D01-OSB2	Review BCS		12 Feb 2008
Wayne Robbins Site VP, Darlington 703-7499	D08-ES3	Submit BCS	for	12 Feb 2008
Randy Leavitt Director, Nuclear Investment Management 702-5085	P823-315	Approve BCS		Feb 25, 2008
Jim Beech VP, Nuclear Finance 400-7226	TCH07E19	Approve BCS		[illegible]
Tom Mitchell Chief Nuclear Officer	P826A-1	Approve BCS		3 Mar 08
Don Power, VP Corporate Investment Planning	TCH07D06	Approve BCS		Mar 18/08
Pierre Charlebois Chief Operating Officer	TCH19A21	Approve BCS		[illegible] 19/08
Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

DNGS Construction Change Room 16 - 31718

Full Release (Phase 1) Business Case Summary D-BCS-28200-10004-R000

1/ RECOMMENDATION:

Approval is requested for this Full Release of a total $13,304 K Capital, (including [redacted] contingency) to complete both the construction of a new "mobile" Construction Change Room (CCR) c/w Lunchroom facility and the de-engineering of the removal of the old CCR. The new CCR is to be constructed in time to support the 2009 Vacuum building outage (VBO) at Darlington. The timeline for the new CCR is extremely tight and full station and vendor support will be required to complete this project on time.

The objective of this project is to decommission and remove the existing CCR and construct a new CCR for DNGS maintenance and contract staff to provide a safe and effective work environment. The new CCR will have an increased capacity over the previous change room, which will relieve overcrowding and congestion, improving current health and safety inefficiencies.

A construction estimate based on a substantially completed design package is used as the basis for this cost estimate. This is used in lieu of a third party Helyar estimate due to the time constraints involved.

This Full release (phase 1) will cover:

- Issuance of a Request for Proposal (RFP) for a construction contract for the proposed new CCR
- Issuance of a construction PO for buried service relocation & construction of the new CCR
- OPG support of construction of the new CCR
- Partial AFS of new CCR prior to 2009 VBO. Construction of the building will be complete enough that it will be used in support of the 2009 VBO
- Final AFS of the new CCR following the VBO and outage D931 to ensure completion of Engineering Change Control process, and full station turn-over
- The issuance of a Full release phase 2 BCS to support the demolition of the old CCR
- A Constructor's estimate for the demolition of the old CCR to support the full release phase 2 BCS

The Full Release Phase 2 BCS in Q1 2009 will incorporate the removal and decommissioning of the existing CCR.

This project will be executed in several phases between 2007 and 2009:

- 2007/2008 – Detailed Design has been completed
- 2008/2009 – Construction of new CCR and turnover to OPG
- 2009 – Removal and decommissioning of existing CCR

The timeline for the completion of the new change room is extremely tight. Full station management support, including relaxation of certain activities milestones in station work processes is required to adhere to the schedule as planned. Approval has been obtained from the Director of Operations & Maintenance for the project to be exempt from Integrated On-line Work Scheduling per N-PROC-MA-0022. However, it is the intent of the project to follow N-PROC-MA-0022 to the extent possible.

Furthermore, due to the risks associated with this accelerated implementation schedule, it is recommended that a station contingency plan be available for the 2009 VBO to mitigate contractor change facility needs should this project be delayed.

ONTARIOPOWER GENERATION

OPG Confidential	Page: 3 of 17
BUSINESS CASE SUMMARY	

$000's (incl contingency)	Funding	LTD 2007	2008	2009				Later	Total
Currently Released	Developmental	1,204	426						1,630
Requested Now	Full - Phase 1	(693)	11,685	2,312					13,304
Future Funding Req'd	Full - Phase 2			1,086					1,086
Total Project Costs		**511**	**12,111**	**3,398**	-	-	-	-	**16,020**
Other Costs									-
Ongoing Costs									-
Grand Total		**511**	**12,111**	**3,398**	-	-	-	-	**16,020**
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Value Enhancing		Capital				18.3%		N/A	

Submitted By:

S Seedhu for 22 Feb 2008

Wayne Robbins
Site VP, Darlington

Date:

Finance Approval:

Mar 18/08

Donald Power
~~Director, Investment & Business Planning~~
VP - Corporate Investment Planning

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Jan 29/08

Pierre Charlebois
Chief Operating Officer

Date:

2/ BACKGROUND & ISSUES

The existing CCR was installed in the early 1990's and is nearing its end of useful life nominally rated at a maximum of 20 years for a mobile type building design. This facility was not designed for its current capacity and hence is congested and inefficient when utilized at or near capacity during outages and major projects. The Design Agency that performed the Conceptual Study for the new Maintenance Facility and new CCR had recommended that a new change room be constructed instead of relocating or refurbishing the existing CCR due to doubt that the existing CCR could survive relocation.

Due to changing work force demographics since DNGS was first built, many of the permanent staff and contractors hired for project and outage work are more regularly women. The current CCR does not have sufficient women's change room facilities. There are insufficient lunchroom facilities to accommodate the required contractor staff to support station activities such as major outages or large projects. The proposed new CCR will be approximately 19,000 sq. ft. and as per the project charter (D-PCH-28200-10002) developed by Darlington Maintenance, the capacity is required to increase from the old CCR as follows:

- Women's change room – from 24 to 150 personnel
- Men's change room – from 450 to 500 personnel
- Lunchroom – from 125 to 225 personnel fixed seating capacity

The expected occupancy level of the new CCR is 100 – 150 people during low periods, and 350 – 500 people during peak (unit outage) periods. The timeline for peak periods is about one month prior to an outage to the end of the outage, based on a 3 month planned outage. These capacity estimates were provided by the DNGS Contract Management Office (CMO) and are based upon the current occupancy of the existing CCR and the current outage schedule at Darlington.

A Design Agency, Acres Sargent & Lundy (ASL) was commissioned to perform a conceptual study on the project. ASL provided one conceptual layout and three cost estimates for the different construction methods selected to provide a permanent CCR in the most cost effective and expeditious manner to meet our tight timeline. The construction options provided by ASL are "Modular", "Relocatable", and "Mobile" and are identified in section 3 "Alternatives and Economic Analysis.

- The "Modular" building will be constructed as uniform structure throughout. It will be constructed on site using prefabricated wall sections, which will provide better control of quality and specification compliance at all phases of construction.
- The "Relocatable" building will be assembled on site from prefabricated structures that are built, cut and transported in large sections from the manufacturing site. This will not allow full quality control and specification compliance on the construction site. The sections joints will be sealed, and depending on the quality of seals installation, the structure may be susceptible to leaks.
- The "Mobile" building will also be assembled onsite; however it will consist of prefabricated trailers attached together to meet OPG's specification. This is the preferred option.

The new CCR is required to be completed before the start of the DNGS 2009 Vacuum Building Outage (VBO) and the demolition and decommissioning of the existing CCR will be scheduled after the 2009 VBO Outage. The basis for this time frame is to ensure both the old and new Construction Change Rooms are available to facilitate the expected large influx of contract staff during the 2009 VBO Outage. The "Mobile" building design selected for the change room has a life span of approximately 20 years and will be able to support maintenance activities for DNGS beyond the current expected end of life of 2018 to approximately 2029. Decisions will need to be made in regards to continuing maintenance costs to extend the mobile CCR life beyond its expected 20 year lifespan.

A Design Agency, Wardrop Engineering Inc (WEI) has been commissioned to perform the preliminary and detailed design for the project. Upon stakeholder COMS review of the preliminary engineering package provided by WEI, it was determined that greater provisions for security are required [redacted] The scope of the project shall be expanded to include these security elements.

Estimates for 6 new Whole Body Monitors are also included in this release, and these were not included in the developmental release.

A construction estimate based on a substantially completed design have been used for this estimate instead of a normal third party estimate based on full design due to very limited time constraints.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3 "Modular"	Alt 4 "Relocatable"	Alt 5
Revenue							
OM&A	-						
Capital	-	(12,440)			(14,892)	(13,666)	
NPV (after tax)	(5,276)	(10,221)			(12,010)	(11,115)	
Impact on Economic Value (IEV)	N/A	(4,945)			(6,734)	(5,839)	
IRR%	N/A						
Discounted Payback (Yrs)	N/A						

Status Quo - Not Recommended

This option is not recommended as the necessary change room and lunchroom capacity will not be in place to support the large number of contract staff expected to be onsite during the 2009 VBO. Other station contingency plans will have to be in place to mitigate the large influx of contractors. Furthermore major repair and renovations will have to be considered for the existing change room for it to continue to operate. A new CCR will be required in the future as the existing CCR is not expected to survive beyond 2012.

Alternative 1 - Build a new "Mobile type" CCR and remove existing CCR - Recommended

This option is recommended as a new CCR is required to replace the existing life expired CCR and provide a safe and effective work environment for the next ~ 20 years. The "Mobile" type building option (consisting of pre-fabricated trailers) has a manufacturer recommended nominal life of 20 years and will be available to support future maintenance activities should DNGS life extension become a reality to ~ 2029. It will also increase the capacity of the women's change room to address this identified demographic deficiency and provide a larger lunchroom to meet the projected future DNGS contractor needs with regard to outages and large projects as identified by stakeholders. The new CCR will be available to support future outage, project, and VBO maintenance activities. The "Mobile" building meets the requirements of the charter and is the estimated least costly option.

There are significant risks associated with this implementation schedule as the timeline for the completion of the new change room is extremely tight. The "Mobile" construction option provides the lower schedule risk, based on timelines provided by constructor during conceptual study. The Mobile building will also provide the lowest cost risk as the entire structure of the new CCR will be assembled offsite; therefore contractor delays associated with work performed inside the protected area are minimized. Decisions will need to be made in regards to continuing maintenance costs to extend the mobile CCR life beyond its expected 20 year lifespan.

Alternative 2 - Delay Project - Not Recommended

Delay Project 1 year

This option is not recommended as the CCR would not be available for the VBO. Furthermore, major repair and renovations will have to be considered for the existing change room for it to continue to operate. The full cost of such renovation cannot be accurately determined at this point. A new CCR will be required in the future as the existing CCR is not expected to survive beyond 2012.

Alternative 3 – "Modular Type Building Option" - Not Recommended

Build a new Construction Change Room / Lunchroom Facility (CCR) using "Modular" Construction

This option is not recommended. Although the Modular type building would provide a safe and effective work environment for the next 30+ years, it is estimated as the most costly option. It also carries a higher schedule and cost risk than the mobile option as the majority of the work is required to be performed onsite inside the protected area.

The NPV for this option has been calculated using the 20 year life span of the new Mobile facility, until 2029

Alternative 4 – "Relocatable Type Building Option" - Not Recommended
Build a new Construction Change Room / Lunchroom Facility (CCR) using "Relocatable" Construction

This option is not recommended although the "Relocatable" type building will provide a safe and effective work environment for the next 30+ years. It is more costly than the recommended "Mobile" option. This option also carries a higher schedule risk than the mobile option.

The NPV for this option has been calculated using the 20 year life span of the new Mobile facility, until 2029.

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

The Following are the objectives and deliverables for this Full Release Phase 1 BCS:

- Issuance of a Request for Proposal (RFP) for a construction contract for the proposed new CCR
- Issuance of a construction PO for buried service relocation & construction of the new CCR
- OPG support of construction of the new CCR
- Partial AFS of new CCR prior to 2009 VBO. Construction of the building will be complete enough that it may be used in support of the 2009 VBO
- Final AFS of the new CCR following the VBO and outage D931 to ensure completion of Engineering Change Control process, and full station turn-over
- The issuance of a Full release phase 2 BCS
- A Constructor's estimate for the demolition of the old CCR to support the full release phase 2 BCS

5/ QUALITATIVE FACTORS

The successful completion of this project will improve the following

Staff Relations

- New larger capacity change rooms and a lunchroom which will relieve overcrowding and congestion and result in improved staff morale.

Health and Safety

- Increased site capacity of DNGS women's change room to reflect changing demographics to ensure compliance with Occupational Health and Safety requirements.
- New improved larger capacity change rooms and lunchroom will relieve overcrowding and congestion and hence improve health and safety inefficiencies.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Cost for demolition of existing CCR exceeds conceptual estimate of [redacted]	Potential increase in cost of the project	**High**	Cost to remove the CCR was estimated by ASL in the 2006 conceptual study. -Constructor estimate will be obtained upon completion of detailed design of the CCR demolition -Full Release Phase 2 BCS will be issued for the demolition portion of the project	**Medium**
The tight timeline may prevent the project from obtaining an accurate estimate for the demolition of the existing CCR	Potential increase in cost of the project	**Medium**	Adopt a phased funding release strategy. -Full Release Phase 1 BCS in Q1 2008 for the construction of the new CCR, and the -Full Release Phase 2 BCS in Q1 2009 for the removal and decommissioning of the existing CCR.	**Low**
Construction estimate based on substantially complete design is used for full release BCS	Potential increase in scope and cost	**High**	-Draft construction specification and design packages used for estimates -Rough scope description used for design packages not yet available to ensure the items at a minimum be considered in the cost estimate	**Medium**
Scope				
*** Cost, Scope and Schedule Risk *** Limited Implementation timeline could result in discovery items in both design and construction phases	Potential increase in the cost, scope and schedule of the project	**High**	-Close involvement with constructor and design agency during both design and installation phases -Mitigation actions to be considered for outstanding items for partial AFS	**Medium**
Unanticipated Buried services may require additional relocation effort	Increase in cost and schedule	**Medium**	Cursory drawing review has been conducted to identify any possible services that may require relocation. Field survey was completed during Preliminary Engineering.	**Low**

			Foundation design to require minimal excavation.	
		Medium		Low
Schedule				
Overall schedule is too tight to complete implementation of the new CCR	Inadequate change room facilities available to support DNGS VBO	High	-Constructor Estimate acquired for Full Release (Phase 1) BCS -Management support required to relax certain milestones for work processes -Stage design and construction activities to maximize parallel work activities -Using prefabricated mobile design to construct the new CCR -Station contingency plan to be available to mitigate 2009 VBO requirement	Medium
Lead time for CCR material unknown	CCR pre-fabricated components not procured in time to meet construction schedule for new CCR prior to VBO	Medium	Prepare Full Release BCS in Q1 2008 to secure funding for LLM, as building estimates and lead times will be known	Low
Design deliverables not on time.	Delay to schedule.	Medium	Select approved vendor, provide clear scope & deliverables. Review progress regularly & establish and monitor effective design performance metrics.	Low
Resources				
*** Schedule Risk *** Complications in regards city building inspection of new CCR	Delay in schedule	High	-Contact Clarington township regarding inspection -Pre-arrange inspection -Delegate construction vendor to contact the city directly for inspection	~~Medium~~ * LOW * (DJP)
*** Schedule Risk *** Complications in regards to acceptance of non-unionized fabricated structure onto our site	Delay in Schedule	High	-Specify EPSCA considerationto be built into the construction contract -Consult with CMO SPOC early	Low
			* AS PER EMAIL FROM J. BEECH	MAR 17/08
Technical				

Regulatory				
Regulatory or IAEA Approval may be required to add a building to the site layout	Delay to project schedule for approvals	**Medium**	All required CNSC correspondance and approvals will be obtained as required so as not to impact the overall project schedule	**Low**
CNSC's concurrance for commercial build	Delay to project	**Medium**	-Preliminary briefing with CNSC -Station management concurrance -Submit CNSC correspondance early	**Low**
Environmental				
Hazardous materials may be present in existing life-expired CCR	Waste Disposal could have environmental impact	**Low**	Waste Disposal Plan to be developed by design agency to ensure proper disposal of all material	**Low**
Health & Safety				
Hazardous materials may be present in existing life-expired CCR	Health and Safety Hazards are possible (Asbestos, PCBs, mold etc.)	**Medium**	-All health and safety hazards will be identifed, as testing and analysis will be performed on the existing CCR materials prior to demoliton	**Low**
Investment				
Cost benefit information cannot justify proceeding with the project.	Value of invested capital not fully realized	**Medium**	-Engage investment finance and long term strategic planning group in reviewing cost and benefit calculation -Clear identification of cost and benefits of new CCR -Seek cost efficiency in both design and construction phases	~~**Medium**~~ LOW * (DJP)

* AS PER E-MAIL FROM J. BEECH MAR 17/08

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	**Dec 2009**	**Dec 2010**	**Director, Operations and Maintenance**

The final AFS for the removal of the existing CCR will be determined for the Full Release Phase 2 BCS, therefore the targeted PIR approval date will be implemented in the next BCS.

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Construction of new CCR	Not in service	New building will be available in time to support VBO	Successful Partial AFS	DNGS Maintenance
2.	Demolition of existing CCR	In Service	Demolition complete following D931	Successful AFS	DNGS Maintenance
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

Acronyms

BCS	Business Case Summary
CCR	Construction Change Room
PHA	Power House Annex
RFP	Request For Proposal
QC	Quality Control
SCR	Station Condition Report
ASL	Acres Sargent and Lundy
NPV	Net Present Value
CM	Control Maintenance
PO	Purchase Order
DTL	Design Team Leader
OPEX	Operating Experience
LLM	Long Lead Material
TBD	To Be Determined
PIR	Project Implementation Report
PWU	Power Workers Union
VBO	Vacuum Building Outage
BTU	Building Trades Union
PEP	Project Execution Plan
AFS	Available For Service
IEV	Impact On Economic Value
IRR	Internal Rate of Return

Appendix "B" **Project Funding History**

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
Developmental	Jul	2007		1,204	426						1,630
Full (Phase 1)	Feb	2008		(693)	11,685	2,312					13,304
Full (Phase 2)	Oct	2008				1,086					1,086
											0
											0
											0
											0
											0
LTD Spent	Dec	2007		511							511

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

- OPG staff will provide project management and support role during design and implementation
- Design and Installation work will be performed by contractors
- Estimated costs include utility tie-ins.

Financial Assumptions:

- Current P3 resource costs were used thru 2009. Escalation rate of 3% was used for 2010 and 2011

Project / Station End of Life Assumptions:

- Darlington end of life ~ 2018, *(2040+ with refurbishment)*

Energy Price / Production Assumptions:

Operating Cost Assumptions:

- Additional ongoing Utility costs new CCR to old CCR:
  - Acres Sargent & Lundy calculated Delta of 100KW electrical consumption - Current Energy Cost of $0.0466/kWh @ escalation rate of 2% per annum.
  - Acres Sargent & Lundy calculated Delta of 27,000 ft3 water consumption - Current Regional Municipality of Durham rate of consumption of $0.437/m3 @ escalation rate of 2% per annum.

- Any extra janitorial costs have not been included.

Other Assumptions:

- Construction estimate is a constructor's estimate based upon substantial completion of the detailed design, and a construction specification provided by the design agency WEI.
- Construction Material costs are included in the cost of the installation contract.
- Costs for appliances and furniture are not included.
- Costs of providing walkways, parking lots, external lighting and landscaping, are not included.

DNGS Construction Change Room 16 - 31718

Full Release (Phase 1) Business Case Summary D-BCS-28200-10004-R000

Attachment "A" **Project Cost Summary**

$000's Capital & OM&A	LTD Prior Yr 2007	This Release 2008	This Release 2009	Future Release 2009				Later	Total
Project Management (OPG)	71	639	116	299					1,125
Engineering & Drafting (OPG)	21	210	41	64					335
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Security									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	511	12,111	2,312	1,086	-	-	-	-	16,019
2008-2012 Business Plan									-
Variance to Business Plan	511	9,316	1,778	835	-	-	-	-	12,440
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	[redacted]								
Total Release (incl contingency)	511	12,111	2,312	1,086	-	-	-	-	16,019
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)	148	41	120	602					910

Basis of Estimate					
Design Complete	Up to - 40%		Quality of Estimate	Budget + 30% to - 15%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	N/A
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects	No	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process. A PCRAF is not required

Reviewed By: Jan 21/08

Stephanie Tham
Project Manager
Date:

Approved By: Jan 21/08

Dianne Gaine
Eng & Mods Manager (Strat IV)
Date:

DNGS Construction Change Room 16 - 31718

Full Release (Phase 1) Business Case Summary D-BCS-28200-10004-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD	Choose One		Variance	Comments
	Nov 2007	Last BCS Jul 2007	This BCS Jan 2008		
Project Management (OPG)	71	947	1,125	178	
Engineering & Drafting (OPG)	21	254	335	81	
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Security					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	510.514	11497	16172	4675	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	510.514	11497	16172	4675	
Total Release (excl contingency)	[redacted]				
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

A new constructor's estimate based on the significant completion of the change room design. The estimate is [redacted] greater than the initial conceptual estimate of the new CCR.

There have been changes to the design contract for the new CCR, as provisions for new security requirements, the requirements for the electrical tie-ins and requirements for the foundation have been revised from the initial scope of the contract. The additional cost has not been determined however it is estimated to be [redacted] and has been included in this release.

The developmental release did not account for security personnel that will be required during construction of the new change room. Security must be present during [redacted] activities that occur within the vicinity of the site security fence.

Cost increase in Material is represented by the Whole Body Monitors that are required for new CCR. At the time of the developmental release, the project was not accountable for the cost of these items [redacted] All other material costs are to be included in the installation contract price.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth.	Yr	
29	Feb	2008	Full Release Phase 1 BCS (FR1)
29	Feb	2008	Detailed Design Complete
1	Apr	2008	Installation Work Plans Assessed (Preparation for Trailers)
3	Apr	2008	Installation Contract Awarded (ICA)
14	Apr	2008	Long Lead Items Ordered
14	Apr	2008	Start of Installation (SOI)
18	Jul	2008	Installation Work Plans Assessed (Installation of Trailers)
26	Sep	2008	Commissioning Workplans Assessed
15	Mar	2009	Full Release Phase 2 BCS (FR2)
23	Mar	2009	Partial AFS (New CCR)
23	Sep	2009	Final AFS (New CCR)

A Project Execution Plan (PEP) will be approved by Feb 2008

Comments: Milestones associated with the demolition of the existing CCR will be incorporated into the Full Release Phase 2 BCS when an accurate timeline for demolition activities can be established.

Main Control Room HVAC 16 - 33293

Superseding Business Case NK38-BCS-73920-10002-R000

Routing	Location	Action	Signature	Date
Luke Frawley Project Leader II Design Projects 8-703-3564	BW7 02	Prepare BCS		24 April/07
Tom Cvitkovic Section Manager Design Projects 8-703-3571	BW7 02	Review BCS		24 April/2007
John Taras Section Manager Project Management Office 8-703-3528	BW7 02	Review BCS		24 Apr 07
Terry Chong Manager Design Projects 8-703-3520	BW7 02	Review BCS		25 Apr-2007
Steve Cochrane Section Manager Field Engineering 8-703-3704	D06 PO	Review BCS		26 APR 07
ff Lehman anager erformance Engineering 8-703-7325	D08 ES2	Review BCS		01 MAY 07
Don Williams Manager Projects Design 8-703-1963 [illegible] 2007/05/[illegible]	D08 ES3	Review BCS		08 May 2007
Axel Kleer Senior Financial Analyst Nuclear Finance 8-400-7720	P82	Review BCS		15 May 07.
Stu Seedhouse Director Station Engineering 8-703-7584	D08 ES3	Review BCS		13 May 2007
Mark Arnone Director Projects and Modifications 8-701-6063	P72	Review BCS		18 MAY 2007
Randy Leavitt Director Corporate Investment Management 8-702-5085	P82	Review BCS		May 17, 2007
Wayne Robbins Senior Vice President Darlington Nuclear 8-703-7499	D08 ES3	Submit BCS		2007-05-23
on Power ce President Corporate Investment Planning 8-400-7172	H07 D06	Review BCS		June 1/07

Jim Beech Vice President Nuclear Finance 8-400-4226	H07 E19	Approve BCS		June 4/07
Tom Mitchell Chief Nuclear Officer 8-702-5294	P82 6A1	Approve BCS		June 5/07
R. Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Main Control Room HVAC 16 - 33293

Superseding Business Case NK38-BCS-73920-10002-R000

1/ RECOMMENDATION:

Approval is requested to reduce the scope of the planned modifications to the Main Control Room (MCR) HVAC system, to focus on absolute requirements to meet the project objectives, and remove optional elements that would otherwise drive costs beyond the previously released amount of $11M. No additional funding is requested under this superseding BCS.

The original business objective for this project was to address the following deficiencies in the MCR HVAC system:

- High temperature excursions that threatened reliable operation of the units
- Health and Safety concern with the lack of proper filtration and humidification

Much of the work to meet these objectives has been completed to date, and real benefits have been confirmed in the current MCR environment.

A Full Release BCS releasing $6M for this project was approved in May 2001. Subsequently in July 2003, a Superseding BCS for a total release of $11M was approved. By June 2005, it became apparent that up to an additional $3M would be required to fully complete all required and optional elements of the project scope.

To mitigate this cost increase, a review of the project was initiated to separate the absolute requirements (needs) from the optional requirements (wants). As the result of the review, in April of 2006, the Darlington Project Approval Committee approved a plan to reduce the number of modifications, thereby keeping the estimated cost of the project within the currently released amount of $11M. (See the Background section for a summary of the changes to this project). The reduced scope will still address the business objectives of the Main Control Room HVAC project.

The Life-to-Date actual cost of the project is $9.750M vs. $11.0 M full release. The remaining field work and closeouts in this proposal are well understood and defined. The risks associated with this plan of action have been assessed and mitigated to provide assurance that the remaining funds will be sufficient to complete the reduced scope of this project.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Superseding	9,750	983	237	30				11,000
Requested Now	Superseding								-
Future Funding Req'd	None								-
Total Project Costs		9,750	983	237	30	-	-	-	11,000
Other Costs									-
Ongoing Costs									-
Grand Total		9,750	983	237	30	-	-	-	11,000

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	Capital			

Submitted By:

Wayne Robbins 2007-05-23
Wayne Robbins Date:
Senior Vice President, Darlington Nuclear

Finance Approval

Jim Beech Date
Vice President, Nuclear Finance

Line Approval (Per OAR Element 1.1 Project in Budget):

Tom Mitchell Date
Chief Nuclear Officer

2/ BACKGROUND & ISSUES

The project originated in late 1999 as a post construction clean up work order and continued under OM&A Project # 38276 for definition and scoping and for certain maintenance activities to ensure continued operation of the major system components.

It was soon determined that replacement / installation of major equipment such as cooling coils, humidifiers and filters were essential to address the issues related to temperature, humidity and air quality in the Main Control Room (MCR) and the adjacent Computer Equipment Rooms (CER).

In May of 2001 a Full Release BCS was approved for $6,040k for the aforementioned modifications as well as provision of required redundancy for Glycol System RV and Pump Seal Supply (absolute requirements) and major modifications to the ducting, systems and controls and a comprehensive monitoring and diagnostic system (optional requirements).

In July of 2003 a cost variance Superceding BCS was approved for $11,000k. The variance in cost was mainly due to low original estimates. (A full explanation of variances was provided in that BCS).

In June of 2005 the balance of the project scope was reviewed and the forecast to complete was estimated to be $14,000k excluding contingency. Upon this estimate the project status in the Major Projects Status Report turned "Red" indicating major project cost and schedule issues. To recover the project back to "green" status a project recovery process was initiated. In this process the balance of the scope of the project was analyzed against the following absolute requirements:

- Temperature and Relative Humidity
- Address Toxic Gas report by positive blocking of the Maximum (90%) Air Dampers
- Redundant RV and Pump Seal supply to resolve the singleton issues associated with these components – failure of any of these singletons would have resulted in MCR HVAC shut-down

At present the major modifications (cooling coils, humidifier and filter replacements) and the Glycol System redundant RV and Pump Seal supply have been completed. Temperatures have decreased in the target areas and Relative Humidity values have increased especially during dry winter months. The new filters are performing as expected and the ergonomic and employee health and safety issues with the old electrostatic filters have been eliminated.

Those elements of the remaining scope which met the above requirements were classified as "needs" or absolute requirements and the rest as "wants" or optional requirements. In April of 2006, the station Project Approval Committee (PAC) accepted the following recommendations:

- Complete positive blocking of the Maximum (90%) Air Dampers
- Replace Minimum (10%) Air Dampers
- Review Temperature and Relative Humidity measuring instruments in the Control Room and provide field instruments if needed

Subsequent to PAC meeting, the requirements for Temperature and Relative Humidity measuring in MCR and CER were reviewed and it was determined that additional field instruments were not warranted.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue							
OM&A							
Capital	(9,282)	(6,281)	(540)				
NPV (after tax)	(7,369)	(5,116)	(420)				
Impact on Economic Value (IEV)	N/A	2,253	6,949				
IRR%	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	N/A				

Status Quo - Not Recommended

Continuing with the full scope and requesting an additional $3.0M is not recommended. In April of 2006 the Station Project Approval Committee approved the reduce scope to meet the absolute requirements only, and complete the project within the previously-approved release of $11M.

Alternative 1 - Complete the Reduced Scope and Close-out - Recommended

It is recommended that the scope be reduced to the following absolute requirements:

- Disable free cooling feature by capping the maximum outside air dampers, this will address the requirements set forth in Senior Vice President's memo to CNSC: "Darlington NGS – Safety Report Analysis Update: Toxic Corrosive Chemical Rail Line Accident", dated Oct 12, 2004.
- Replacement of the minimum outside air dampers.
- Documentation clean-up and close-out – significant engineering effort is required to revise design documentation associated with the reduced optional scope and to close out the project.

A rigorous scope analysis was done in 2005 and recommendation was made to eliminate the optional requirements from the scope of the project. The elements of the scope that have been eliminated are of discretionary nature, as approved by the DNGS PAC in April 2006.

Alternative 2 - Delay Project - Not Recommended

N/A

Alternative 3 – N/A - Not Recommended

Alternative 4 – N/A - Not Recommended

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

1) Complete the following scope within the remaining funds of the project:

- Disable free cooling feature by capping the maximum outside air dampers, to address the requirements set forth in Senior Vice President's memo to CNSC: "Darlington NGS – Safety Report Analysis Update: Toxic Corrosive Chemical Rail Line Accident", dated Oct 12, 2004.

- Replace the minimum outside air dampers.

- Complete the documentation clean-up (revise design packages for the optional scope) and close-out the project.

2) Delete the following scope:

- Ducting Systems and Control Modifications
- Comprehensive Monitoring System
- Removal of obsolete equipment (tanks and pumps).

The project will be closely monitored and controlled to ensure that the remaining scope is completed within the approved funds.

5/ QUALITATIVE FACTORS

The main qualitative factor of this initiative (cost growth reduction) is to drive a business type behaviour in the organization and encourage all the project teams/stakeholders to limit the project scope on the absolute requirements of the station

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Cost increase - negligible risk	Cost growth may cause project costs to exceed release.	**Medium**	The reduced scope is well defined. The estimate is based on commitments from supporting departments and input from third party estimating group. Approx [redacted] contingency is still available.	**Low**
Scope				
Scope is defined and 90% designed. Risk of scope growth is low	Scope growth may cause cost increases and schedule extensions to exceed the release limits.	**Medium**	The scope is limited to blocking max outside air dampers and associated exhaust dampers, replacement of the minimum air dampers and documentation clean-up. The risk of scope growth is negligible and approx [redacted] is still available within current release for any unforeseen work.	**Low**
Schedule				
Station emerging priorities.	Emerging Station priorities may cause schedule extensions resulting in slippage of milestone dates in release.	**Medium**	The schedule is based on resource commitments, (e.g., Design, Field Engineering and installation contracts), Work Management procedures with some float. WOs are scheduled on IPG Plan. This will minimize schedule risk.	**Low**
Resources				
Re-allocation of key resources such as design and field engineering to other projects.	Key resources not available when required may cause schedule extensions and cost growth.	**Medium**	Commitments obtained from key resource providers. The project will maintain close communication with IPG to ensure the priority is maintained.	**Low**

Technical				
Relative Humidity target levels may not be achievable.	Possible scope growth may cause cost increases and schedule extensions to exceed the release limits.	**Medium**	Agreement reached with Design and key stakeholders to revise RH targets to reflect achievable humidity levels.	**Low**
Regulatory				
		N/A		
Environmental				
		N/A		
Health & Safety				
Conventional Heath & Safety risks during implementation.	Conventional Heath & Safety risks will be present during the implementation of the project but will be closely monitored and controlled.	**Low**	COMS and JSA as well as adherance to all station safety procedures will eliminate/ minimize this risk.	**Low**
Investment				
		N/A		

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Mar 2008	Jun 2009	Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Maximum Air (90%) Dampers: -leakage rate	Max Air Dampers are jumpered closed but not capped, leakage rate unknown	Max Air Dampers covered with zero leakage	Testing as per design documents	Field Engineering/ Performance Engineering
2.	Minimum Air (10%) Dampers: -leakage rate -closing time	-leakage rate unknown -closing time <20sec	-leakage rate 1% or less -closing time <20sec	Testing as per design documents	Field Engineering/ Performance Engineering
3.	Temperature	Exceeds 22 Deg C	20 to 22 Deg C	Testing as per design documents	Field Engineering/ Performance Engineering
4.	Relative Humidify (RH)	Below 20% RH	Target minimum 35%, maximum 45% RH	Testing as per design documents	Field Engineering/ Performance Engineering
5.	Air Filtration	Pre-filtration only. Electrostatic agglomerator not functional. Ingress of poorly filtered air into MCR and CER.	Filtration efficiency of 90% to 95% as per manufacturer test reports. Pressure drop during operation less than 625 Pa.	Efficiency as per test reports verified by Design. Pressure drop measured during testing and commissioning.	Field Engineering/ Performance Engineering

Appendix "A" — Glossary (acronyms, codes, technical terms)

CER	Computer Equipment Room
AFS	Available for Service
HVAC	Heating Ventilation & Air Conditioning
MCR	Main Control Room
RV	Relief Valve
BCS	Business Case Summary
PAC	Project Approval Committee
RH	Relative Humidity
PIR	Post Implementation Review
ASHRAE	American Society of Heating, Refrigeration & Air Conditioning Engineers

Appendix "B" — Project Funding History

$ 000's Release Type	Month	Year	2001	2002	2003	2004	2005	2006	2007	Later	Total
		All Existing and Planned Releases (incl contingency) Cumulative Values									
											0
Full	May	2001	2,130	1,840	2,070						6,040
Superseding	Jul	2003		4,037	1,800	2,830	2,333				11,000
Superseding	Jan	2007						9,750	983	267	11,000
		Choose									0
		Choose									0
		Choose									0
		Choose									0
LTD Spent	Dec	2007	2,473	1,564	1,651	1,836	1,780	446			9,750

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

N/A

Financial Assumptions:

Interest = 6%

Project / Station End of Life Assumptions:

2018

Energy Price / Production Assumptions:

N/A

Operating Cost Assumptions:

N/A

Other Assumptions:

N/A

Main Control Room HVAC 16 - 33293

Superseding Business Case NK38-BCS-73920-10002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008	This Release 2009				Later	Total
Project Management (OPG)	1,306	64	30	4					1,404
Engineering & Drafting (OPG)	481	245	137	26					889
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	9,750	983	237	30	-	-	-	-	11,000
2007-2011 Business Plan		1,039	-						1,039
Variance to Business Plan	9,750	(136)	212	30	-	-	-	-	9,856
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	9,750	903	212	30	-	-	-	-	10,895
Total Release (incl contingency)	9,750	983	237	30	-	-	-	-	11,000
Ongoing OM&A [illegible]									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	No

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007

Reviewed By: 24 Apr 2007

Tom Cvitkovic
Project Manager

Date:

Approved By:

Terry Chong
Eng & Mods Manager (Strat IV)

25 Apr 2007

Date

Main Control HVAC 16 - 33293

Superseding Business Case NK30-BCS-73920-10002-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2006	Choose One: Last BCS Jul 2003	Choose One: This BCS Jan 2007	Variance	Comments
Project Management (OPG)	1306	603	1404	801	Low initial estimate, schedule extension
Engineering & Drafting (OPG)	481	773	889	116	Low initial estimate, schedule extension
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	**9750**	**11000**	**11000**	**0**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**9750**	**11000**	**11000**	**0**	
Total Release (excl contingency)	**9750**	**9400**	**10895**	**1495**	
Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
18	05	2007	(PTA) Work Package Assessment Complete
13	08	2007	(SOI) Start of Installation Dampers
14	01	2008	(AFS) AFS Damper Mods Complete
19	02	2008	(DCP) DCP Rev03 - Complete
28	04	2008	(AFS) Final AFS
13	03	2009	(PCM) Project Complete

A Project Execution Plan (PEP) will be approved by Jun 2007

Comments:

Approved PEP (NK38-PEP-73920-10001) will be revised by June 2007.

DND: Chiller Replacement to Reduce CFC Emissions 16 - 33631

Full Release (Phase 1) Business Case Summary D-BCS-73910-10002-R002

Routing	Location	Action	Signature	Date
A. Yun Project Leader, Design Projects 703-3557	BW7-02	Prepare BCS	A. Yun	APR. 26, 2007
M. Guy Project Manager, Design Projects 703-3550	BW7-02	Review BCS	R M Guy	APR 26 2007
J. Tarris Section Manager, Project Mgmt Office 703-3528	BW7-02	Review BCS	J. Tarras	Apr 26/07
T. Chong Manager, Design Projects 703-3520	BW7-02	Review BCS	[signature]	26 Apr 2007
J. Lehman Manager, Performance Engineering 703-7484	D08-ES2	Review BCS	[signature]	01 May 07
D. Williams Manager, Projects Design 703-1963	D08-ES3	Review BCS	[signature]	04 May 2007
A. Kleer Senior Financial Analyst [illegible]2-4110/400-7728	P82-3	Review BCS	M Kleer	04 May 2007
[illegible] Amone Director, Projects & Modifications 701-6063	P72	Review BCS	[signature]	04 May 2007
W. Robbins Senior Vice President, Darlington 703-7499	D08-ES3	Submit BCS	Wayne Robbins	2007 05 07
R. Leavitt Director, Investment Management 702-5086	D08-ES3	Approve BCS	T Leavitt	2007.05.10
D. Power VP, Corporate Investment Planning 400-7172	TCH07-D06	Approve BCS	[signature]	2007-05-18
J. Beech VP, Nuclear Finance 400-7226	TCH09-D06	Approve BCS	[signature]	2007-05-18
T. Mitchell ~~Executive Vice President~~ & CNO 702-5294	P82-6A	Approve BCS	A Mitchell	31-MAY-07
R. Ball Senior Financial Analyst [illegible]2-4084	P82-3B6	Return For Distribution		

DND: Chiller Replacement to Reduce CFC Emissions 16 - 33631

Full Release (Phase 1) Business Case Summary D-BCS-73910-10002-R002

1/ RECOMMENDATION:

Approval of this Phase 1 Full Release is requested, to

- Reduce the total project cost from previously-estimated 23.245M$ to 14.9M$ (Capital).
- Increase the approved amount from 6.369M$ to 10.44M$ for this Phase 1
- Purchase 11 chillers all at once instead of individually, thereby achieving significant price savings
- Install three chillers under this phase and the remaining eight in Phase 2.
- Complete the detailed engineering and procure the materials for the additional scope to improve the chiller system performance

The business objective of this project is:

- To replace the 11 existing chlorofluorocarbon (CFC) based water-cooled chillers at Darlington with units that use an approved refrigerant by January 1, 2015 in order to comply with Environment Canada's 2003 Halocarbon Regulations
- To improve the performance of Darlington chiller systems at low load conditions.

A partial release of $6.4M was approved in May, 2006 to complete the detailed engineering, procure 2 chillers and install the T-pipe tie-ins. The detailed engineering is scheduled to be completed by Q4 2007

During the detailed engineering, it was realized that significant savings in design/engineering costs could be realised and the costly installation strategy was not necessary if the manufacturer were to supply the chillers with the same power voltages and nozzle orientations as the present ones, i.e. custom-make the chillers to fit OPG's specific needs. The preferred manufacturer agreed to this, while also offering a significant discount if all 11 chillers are procured at the same time.

In addition, a close examination was made of certification/registration requirements. It was found that the requirements originally proposed are not necessary and thus additional savings were realized. Specifically

- CNSC Code & Classification and TSSA Registration were exempted per newly issued N-PROC-MP-0040 and 0082
- CRN for individual component within the chiller package is not required since the Darlington chiller system is not a registered system
- PEO stamps on vendor's drawings are not required.

As a result, it is now estimated that the project can be completed for 14.9M$ (Capital). The experience gained during the installation of first three chillers will be used to estimate the remaining work for the Phase 2 Release.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Partial	2,889	3,480						6,369
Requested Now	Full - Phase 1		(2,075)	3,046	1,200	1,200	700		4,071
Future Funding Req'd	Full - Phase 2				1,800	1,660	1,000		4,460
Total Project Costs		2,889	1,405	3,046	3,000	2,860	1,700	-	14,900
Other Costs									-
Ongoing Costs									-
Grand Total		2,889	1,405	3,046	3,000	2,860	1,700	-	14,900
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Sustaining		Capital		(8,778)		N/A		N/A	

Submitted By

Wayne Robbins 2007-05-07

W. Robbins
Senior VP Darlington

Date

Finance Approval:

2007-05-18

J. Booth
VP, Nuclear Finance

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

T. Mitchell 2007-05-31

T. Mitchell
~~Executive Vice President &~~ CNO

Date

2/ BACKGROUND & ISSUES

Regulation Requirement

Halocarbons are chemical substances that include, among other components, halogen (bromine, chlorine and/or fluorine) and carbon. They are used specifically as refrigerants in air-conditioning and refrigeration systems, fire extinguishing agents in fire extinguishing systems and blowing agents in the manufacture of foams and as solvents. Halocarbons pose a double-edged environmental problem. Firstly, most of them contribute to the depletion of the stratospheric ozone layer. Secondly, they are greenhouse gases which contribute to climate change. Hydrocarbons are identified by an alphanumeric code, with R-11 being the most common refrigerant in use.

Environment Canada's 2003 Federal Halocarbon Regulations mandate the phase-out of equipment containing CFCs. The following specific excerpts of the regulations apply:

- "Effective January 1, 2015 no person shall operate or permit the operation of any chiller [containing CFCs]" (Section 20)
- Between January 1, 2005 and December 31, 2009 an overhauled/recharged chiller is allowed to operate for one year from the date of charging. An overhaul does not constitute the replacement of parts in the course of OPG's normal maintenance.
- The one-year grace period for repairs disappears on January 1, 2010.

The Ontario Government is seeking to phase-out CFC refrigerant on January 1, 2012, 3 years earlier than Federal Regulation. This change impacts the TRF chiller which is under Ontario Provincial jurisdiction.

In addition, the poor performance of the existing 3-way control valve is identified as impacting the chiller operating at the low load condition. Darlington requested to replace the 3-way valve and its controller in order to improve the performance of chiller system.

Project Scope

Darlington has total twelve (12) chillers inside operating island. One of TRF chillers was replaced with a chiller using R-134a as refrigerant in 2002 through Project # 31531. This project will replace Darlington's eleven (11) R-11 refrigerant water-cooled chillers with R-134a refrigerant water-cooled chillers:

- 2 chillers (2x100% configuration) in Central Service Area (CSA) provide cooling to CSA and Main Control Room (MCR). CSA chiller is in-service year-around and has no off-season.
- 8 chillers (2x100% configuration) in Reactor Auxiliary Building (RAB) provide cooling to RAB and the instruments for shutdown system. RAB chiller is off-service from November to April.
- 1 chiller (2x100% configuration) in Tritium Removal Facility (TRF) provides cooling to Heavy Water Management Building (HWMB). TRF chiller is off-service from November to April.
- Eleven (11) 3-way control valves and controllers for each of new chillers.

A revised Project Execution Plan is projected to be approved in Aug. 2007.

The chiller installation includes the removal of the existing chillers, at a total value of $330K. There is no significant salvage value to be realized from the existing/old chillers due to the age of the equipment and the phase-out of R-11 refrigerant

Technical/Design Requirements

The eleven chillers and other required materials were originally estimated to cost [redacted] however the lowest acceptable bid came in at [redacted] As a result of challenging the technical/design requirements, the following changes have significantly reduced the cost of 11 chillers down to [redacted]

- Canadian Registration Number (CRN) for each individual Pressure Boundary (PB) component in the chiller package is not required per CSA B51 (PB Code) since Darlington chiller system is not a registered system. However, the vendor shall supply Darlington the chiller with one CRN per CSA B52. (Refrigeration Code)
- The requirement for vendor's drawings to be PEO stamped was eliminated from the Technical Specifications as per N-LIST-01300-10000
- Due to the changes above, OPG is able to look for a proposal directly from the chiller manufacturer, instead of seeking the proposal through a commercial grade dedicator.

Optimized Installation Strategy

We optimized the new installation strategy as per the following changes, resulting in a reduction in the estimated installation cost from [redacted] to [redacted]

- Based on a Constructability Operability Maintainability and Safety (COMS) screening conducted at the scoping phase in 2004, we had planned a costly strategy to install T-pipe tie-ins and "3rd chiller" (to provide backup during the installation) for the replacement of the 2 CSA chillers. Now, based on keeping the chiller physical configuration the same, thereby reducing installation duration and risks, we are able to replace the 2 CSA chillers without having to use a backup. The stakeholders agreed to proceed with this new installation strategy by re-assessing the COMS requirements.
- We requested the vendor to supply the chillers with the same power voltages and similar nozzle orientations, which will minimize the field work.

As a result of this installation strategy change, we are able to lower the estimated engineering cost from [redacted] to [redacted] and project management cost from \$1.4M to \$1.1M respectively due to:

- The detailed design schedule (design agency) being shortened by 4 months (Fixed price)
- The work load of OPG project team being significantly reduced.

Installation Schedule

We will use the chiller off-season, November to April, to replace RAB chillers. Two RAB chillers were selected as part of the scope of Phase I to gain installation/commissioning experience and confirm the installation cost. In addition, the TRF chiller will be replaced in Phase I to ensure that Darlington will comply with Ontario CFC regulation. The following is the planned chiller replacement schedule:

2008	Q1 2009	Q1 2010	Q1 2011
2 RAB chillers (Q1) 1 TRF chiller (Q4)	1 CSA chiller and 2 RAB chillers	1 CSA chiller and 2 RAB chillers	2 RAB chillers

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Choose One	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue							
Project Cost		(11,603)		(13,066)			
NPV (after tax)		(8,778)		(8,950)			
Impact on Economic Value (IEV)		(8,778)		(8,950)			
IRR%		N/A					
Discounted Payback (Yrs)		N/A					

Stop the Project - Not Recommended

We do not recommend stopping this project as OPG must demonstrate to the public that the company is environmentally responsible and complies with all Federal and Provincial Environmental Regulations.

To do nothing will force OPG to replace the existing R-11 chillers when they are broken down. As well OPG would face the environmental penalty after the regulation effective January 1, 2015 and would be forced to replace those R-11 chillers any way at much higher cost.

Alternative 1 - Replace eleven R-11 chillers and eleven 3-way control valves - Recommended

We recommend this alternative as it allows us to procure all 11 chillers and start replacing the existing R-11 chillers in order to comply with the halocarbon regulatory deadline of January 1, 2015. The strategy is to install three chillers, then learn from this release and obtain a Phase 2 release to install the remaining eight chillers. This alternative also makes an emergency replacement possible if any of the existing R-11 chillers fail prematurely since all 11 new chillers will be stored in OPG's warehouse.

Alternative 2 - Delay Project - Not Recommended

We do not recommend delaying this project. Although it's possible to delay the chiller replacement once a chiller has failed, the delay will be for a maximum of 2 years. The consequence of this alternative will be that:

- There will be no one-year grace period (refer to Glossary) after January 1, 2010. Any failed chiller must be replaced instead of having it overhauled or recharged.
- A temporary chiller is required since the lead time is about one year to deliver a chiller. It will cost more to order one chiller and the additional costs in engineering and temporary tie-in for a temporary chiller.
- We are not able to conduct an emergency replacement of a chiller if an existing chiller needs to be overhauled/ recharged since there are no new chillers available. In this case, we have to install a temporary chiller (an off-the-shelf chiller) to meet the need of the emergency before the Darlington specified chiller is delivered and installed.

Alternative 3 – Do Less - Not Recommended

We do not recommend doing less since all eleven (11) R-11 chillers must be replaced in order to comply with Federal and Provincial Environmental Regulations

Alternative 4 – Do More - Not Recommended

We do not recommend doing more as the scope of this release aligns with the project objective addressed in Project Charter

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The major project deliverables for this project are as follows:

This Release

- Procurement of all 11 chillers and 11 3-way control valves with controllers.
- Complete the detailed engineering for replacing of 3-way control valve.
- Revision of Project Execution Plan NK38-PEP-73910-10001
- Installation/commissioning of 2 RAB chillers and 1 TRF chiller
- Declaration of 2 RAB chillers and 1 TRF chiller in service
- Full Release BCS Phase 2.

Release Phase 2

- Revision of Project Execution Plan NK38-PEP-73230-10001
- Installation/commissioning 11 3-way control valves
- Installation/commissioning of the remaining 2 CSA chillers and 6 RAB chillers.
- Declaration of the remaining 2 CSA chillers and 6 RAB chillers Available for Service
- Declaration of 11 3-way control valves Available for Service
- Post Implementation activities
- Project close-out

5/ QUALITATIVE FACTORS

- The addition of refrigerant leak detection and an alarm system will provide an automated early warning system. These additions have a positive benefit to worker and environment health and safety and also on equipment health monitoring
- Improvement of equipment reliability due to new technology with commensurate reduction in ongoing maintenance and spare parts

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Since the detailed engineering has not been completed to date, the detailed installation scope has not been finalized.	The cost estimate in Project Cost Summary needs to be adjusted.	Medium	1) The cost will be adjusted at Phase 2 BCS as per actual Phase I installation cost. 2) [redacted] general contingency is available.	Low
The vendor drawings are not available.	1) The design agency may claim delay charges due to a lack of vendor's information. 2) The milestone of issuing DCP packages may be missed.	Medium	1) Actively support Supply Chain to get the the chiller PO issued ASAP. 2) Intend to introduce incentive or penalty into the PO to encourage the vendor submit the drawing as early as possible. 3) Reserve [redacted] specific contingency for delay charges.	Low
Scope				
The poor performance of the existing 3-way control valve/controller has been identified as a contributing factor to poor chiller performance at low load, however, replacement alone may not be sufficient to allow reliable operation at low load.	Additional modifications may be required impacting both cost and schedule.	Medium	1) Detailed investigation into the low load performance issues will be conducted. The most cost effective solution will be adapted. 2) Reserve [redacted] specific contingency for the additional engineering.	Medium
See Cost and Technical				
Schedule				
Very tight installation window.	The installation will be delayed one year if the off-season is missed.	Low	Expedite completion of RAB chiller DCP.	Low
Long lead time required for chiller delivery, which impacts	The off-season will be missed if the chillers are not delivered.	Low	Expedite delivery of 2 RAB chillers to meet installation schedule.	Low

on first installation.

The new TRF chiller (RFU1 replaced in 2002) currently has difficulty running at low load condition.	The chiller to be replaced (RFU2) may not be allowed to shut down for replacement as per the scheduled period, Q4 2008.	Medium	1) Test run RFU1 in Q4 2007 to verify the low load ability 2) If RFU1 can't meet the low load requirement, the replacement will re-schedule during next TRF outage, Q1 2009.	Low
Resources				
Availability of the installation team and commissioning team	The installation/commissioning will not happen if resources are not available.	Low	1) Work with Contract Management Office to select an installation team in order to commit to the installation labour. 2) Schedule the commissioning tasks in IPG to reserve the Mechanical Maintainer resource. (Commissioning team)	Low
Technical				
Low Load Operation Project team has identified that the capacity of the existing chillers is about 40% higher than that required during normal operation. However, the stakeholders would like to keep capacity of the new chillers the same as the existing one in case of any emergency event.	When the chiller is operated at very low load (<10%), some components, such as 3-way control valves, controllers etc, in the chiller system may be operated beyond the design margin leading to chiller trips.	Medium	See scope risk	Low
Chiller Performance	The new chiller may not achieve the capacity specified.	Low	1) Project team will witness the tests to ensure that the new chillers achieve the capacity 0% ~ 100% (RAB & TRF chillers) and 10% ~ 100% (CSA chiller) specified by the manufacturer. 2) The manufacturer will provide a performance test report for each individual chiller.	Low
Operator and Maintainer training	The commissioning may be delayed if Operator and Maintainer are not familiar with the new chillers	Medium	1) Project Team has reserved 40 hours of basic training, provided by the manufacturer, in order for the Operators to initially startup a	Low

			chiller and the Maintainers to conduct basic maintenance before the first chiller is commissioned. Additional training will be provided as required. 2) The manufacturer will provide a service engineer to supervise the initial settings and commissioning for each chiller.	
Regulatory				
CRN is required as per refrigeration code CSA B52. (Refrigerant loop)	The chiller cannot be operated without a valid CRN.	Low	1) Vendor is required to supply the chiller with a valid CRN. 2) The preferred vendor [redacted] has the experience to apply CRN for its customers.	Low
Environmental				
Refrigerant leakage	The chemical impacts the environment.	Low	A refrigerant leakage detection and alarm system is provided for each chiller.	Low
Health & Safety				
Workplace injury or serious MRPH event.	The event may impact project schedule and costs.	Low	Work to be performed per existing OPG safety rules, procedures and OH&SA regulations. Any non-standard conditions will be identified via workplans and pre-job briefings.	Low
Large amount refrigerant leakage that may pose an increased risk to station staff.	Potentially create a chemical hazard to the staff who are working in the mechanical room.	Low	The refrigerant leakage detection and alarm system is interlocked with the mechanical room ventilation fan system. The ventilation fan system will automatically activate to reduce the refrigerant concentration when the refrigerant leakage reaches the set point.	Low
Investment				
No risk is identified.				

7) POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	May 2011	Dec 2011	Manager Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1	Environment Canada's 2003 Halocarbon Regulations	Will not be in compliance with the regulations after 2014.	Comply with the regulations	The new chillers with approved refrigerant in service	All AFS signatories sign-off "Declaration of Available for Service" N-FORM-10091
2					
3					
4					
5					

Appendix "A" Glossary (acronyms, codes, technical terms)

- CFC - Chlorofluorocarbon
- CRN - Canadian Registration Number
- PEO - Professional Engineer of Ontario
- CSA - Canadian Standard Association
- PB - Pressure Boundary
- CSA - Central Service Area
- RAB - Reactor Auxiliary Building
- TRF - Tritium Removal Facility
- COMS - Constructability Operability Maintainability and Safety
- PB code (CSA B51) – Governing requirement for Pressure Boundary system
- Refrigeration Code (CSA B52) – Governing requirement for refrigeration system
- Evaporator – Heat exchanger, in which refrigerant cools down chilled water
- Condenser – Heat exchanger, in which refrigerant is cooled by water or air
- Water-cooled chiller – Refrigerant is cooled by water
- Refrigerant loop – A closed refrigerant loop inside chiller, including compressor, refrigerant sides of evaporator and condenser, etc.
- Chiller Package –Chiller mechanical package, including refrigerant loop, evaporator and of condenser, etc.
- R-11 – CFC based refrigerant
- R-134a – Approved non-ozone depleting refrigerant without phase-out time
- Federal Halocarbon Regulation – Phase-out CFC based refrigerant equipment on January 1, 2015.
- One-year grace period – Overhauled/recharged chiller can only be allowed to operate for one year from date of charging effective from January 1, 2005 to December 31, 2009.
- T-pipe tie-in – A new system will tie-in to the existing system through a T-pipe.
- "3rd chiller" configuration –Due to project scoping phase and conservative approach, an installation strategy was proposed to
  - Install T-pipe tie-ins first
  - Install a new chiller (3rd chiller) at new location with new piping system, new power/instrument cables, new monorail, new plinth etc before replacing the 2 existing CSA chillers.
  - Replace one of the existing CSA chillers with a new one.
  - Dismantle another existing CSA chiller and associated piping, cabling etc.

Appendix "B" **Project Funding History**

$ 000's			Previous Releases (incl contingency) Cumulative Values								
Release Type	Month	Year	2004	2005	2006	2007	2008	2009	2010	Later	Total
Developmental	April	2004	520								520
Interim	Feb	2005		620							620
Interim	Jan.	2006			300						300
Partial	May	2006	500	576	3,367	1,926					6,369
[illegible]											0
[illegible]											0
[illegible]											0
[illegible]											0

LTD Spent	Dec	2006	501	576	1,812			.			2,889

Comments:

The development funding was approved for Project # 16-38433. Project number changed because the funding changed from OM&A to Capital.

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:

- The additional scope is added to this project as per request of project sponsor.
- The detailed engineering for the chiller replacement packages has been completed at about 80% and the cost for Design Agency is fixed.
- The additional scope will be initiated from the problem identification process.
- The chillers proposed by the manufacturer meet the technical requirements.
- OPG has received the quotation for the chillers.
- Project has a budgetary quotation for the installation cost. The installation cost will be adjusted at Full BCS Phase II as per the actual installation cost.

Financial Assumptions:

- NPV discount rate = 7%

Project / Station End of Life Assumptions:

- Station end of life at 2018

Energy Price / Production Assumptions

N/A

Operating Cost Assumptions

- The new chillers have the same operability as the existing ones. Operating costs for the new chillers will be the same as the existing ones or slightly lower.

Other Assumptions:

- For Alternative 2, a 2-year delay: it is assumed that a failure would occur, necessitating purchase and installation of a temporary chiller at a cost of [redacted]

DND: Chiller Replacement to Reduce CFC Emissions 16 - 33631

Full Release (Phase 1) Business Case Summary D-BCS-73910-10002-R002

Attachment "A"

Project Cost Summary

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008	Future Release 2009	Future Release 2010	Future Release 2011		Later	Total
Project Management (OPG)	450	153	157	120	120	110			1,110
Engineering & Drafting (OPG)	487	176	80	65	65	70			943
Material	[redacted]								
Installation - PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
Project Costs (incl contingency)	2,889	1,405	3,046	3,000	2,860	1,700	-	-	14,900
2007-2011 Business Plan		583	4,500	4,000	3,850	4,019			16,952
Variance to Business Plan	2,889	522	(1,904)	(1,400)	(1,290)	(2,469)	-	-	(3,652)
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	2,889	1,105	2,596	2,600	2,560	1,550	-	-	13,300
Total Release (incl contingency)	2,889	1,405	3,046	3,000	2,860	1,700	-	-	14,900
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)			90	90	90	60			330

Basis of Estimate

Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007

Reviewed By:

M. Guy
Project Manager

APR 26 2007
Date:

Approved By:

T. Chong
Eng & Mods Manager (Strat IV)

26 Apr 2007
Date:

DND: Chiller Replacement to Reduce CFC Emissions 16 - 33631

Full Release (Phase 1) Business Case Summary D-BCS-73910-10002-R002

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2006	Choose One: Last BCS May 2006	Choose One: This BCS Apr 2007	Variance	Comments
Project Management (OPG)	450	1,395	1,110	-285	Less work load due to the change of installation strategy
Engineering & Drafting (OPG)	487	1,794	1,143	-651	Less work load due to the change of installation strategy
Material	[redacted]				
Installation - PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	2,889	23,245	14,900	-8,345	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	2,889	23,245	14,900	-8,345	
Total Release (excl contingency)	2,889	19,601	13,300	-6,301	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)		0	330	330	Removal costs: $30K/chiller

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
29	06	2007	LLA - Long Lead Time Material Contracts Awarded
15	10	2007	DCP - Issue DCP package for RAB chillers, detailed engineering completed.
07	11	2007	DCP - Issue DCP package for TRF chillers, detailed engineering completed.
07	12	2007	DCP - Issue DCP package for CSA chiller, detailed engineering completed.
30	11	2007	ICA - Award Installation labour (2 RAB & 1 TRF) contract
14	12	2007	PTA - Ready for installation, work package assessed and ITP issued - U1-RFU1
11	01	2008	PTA - Ready for installation, work package assessed and ITP issued - U2-RFU1
04	02	2008	SOI - Start of Installation of U1-RFU1 chiller
10	03	2008	SOI - Start of Installation of U2-RFU1 chiller
30	03	2008	DES -- Preliminary Engineering for 3-way valve completed
20	06	2008	AFS - Declaration AFS for U1-RFU1 chiller
20	06	2008	AFS - Declaration AFS for U2-RFU1 chiller
31	10	2008	FR2 - Full Release BCS Phase II Approved
03	11	2008	SOI - Start installation of TRF chiller
23	12	2008	DCP -- Detailed enginnering for 3-way valve completed.
26	06	2009	AFS - Declaration AFS for TRF chiller

A Project Execution Plan (PEP) will be approved by Aug 2007

Comments:

FH Computer Replacement 16 - 33815

Full Release Business Case Summary D-BCS-69740-10002-R000

Routing	Location	Action	Signature	Date
S. May TE/O, DCCs	DCDFB	Prepare BCS	Stephen May	8 June 2007
S. Ilott Section Manager, FH Technical	DOSB-2	Review BCS	[illegible]	11 Jun 07
E. Hung Section Manager, DCCs	DESB-2	Review BCS	Eric Hung	June 12, 07
Wm. Owens Manager, Darlington Fuel Handling	DOSB-2	Review BCS	[illegible]	11 June 07
R. Hohendorf Manager, Computers and Control Design	P82-5	Review BCS	[illegible]	June 13, 2007
D. Zerkee Manager, Investment Management	P83-3	Review BCS	[illegible]	13 Jun 07
R. Leavitt Director, Nuclear Investment	P82-3	Review BCS	R Leavitt	June 15, 2007
Dermarkar Director Engineering Services	P82-6	Review BCS	[illegible]	14 Jun 2007
B. Duncan Director, DNG Operations & Maintenance	DOSB-2	Review BCS	[illegible]	[illegible]
J. Beech Vice President, Nuclear Finance	P82-3	Review BCS	[illegible]	
W. Robbins Senior Vice President, Darlington	DESB-3	Review BCS	Wayne Robbins	2007-06-27
D. Power Vice President, Corporate Investment Planning	TCH-7	Review BCS	D Power	Aug 1/07
T. Mitchell Chief Nuclear Officer	P82-6	Approve BCS	T Mitchell	7 Aug 2007
R. Ball …ior Financial Analyst …4084	P82-3B6	Return For Distribution		

FH Computer Replacement 16 - 33815

Full Release Business Case Summary D-BCS-69740-10002-R000

1/ RECOMMENDATION:

We recommend the approval of a release of $12,470K (including contingency) to perform detailed engineering and installation of replacement equipment for Fuel Handling (FH) Control Computers and their peripheral devices. This project is an essential part of the Life Cycle Management Plan. The Business Objective of this release is to ensure that the Darlington FH computer systems operate reliably by relieving them of urgent age-related reliability problems. This release is needed in order to protect station generating capacity from an inability to fuel the 4 Darlington Nuclear Generating Station (DNGS) reactors due to failures in FH Control Computer system.

Computer internals and peripheral equipment replacements must be provided quickly to prevent loss of reactor re-fuelling capacity. Control console teleprinters are failing and must be replaced within the next 24 months. The stock of spares is expected to be exhausted by 2009.

This release will provide for the design of replacement FH CPUs and their offline testing facilities. An FH system simulation testing facility will be created to prove the replacement computers and their adjusted FH Control Computer software prior to their subsequent installations. A facility that will be a source of system control components that are known to be good will be set up to support regular effective maintenance subsequent to the computer replacements.

This release will provide for FH software updates to address legacy Human Factors Engineering issues, and provide necessary data access and display for today's FH operating environment. The FH operators' console will be modified to comply with Human Factors Engineering requirements that will support safe and reliable FH System operation.

This release will provide for the design of replacements for the control console teleprinters, operators' keyboards, main disk drives and interface boards, video display generators, main FH Control Computer internal interconnection busses, changes to the Human-System Interface, and computer surveillance and maintenance terminals. The paper plant will also be brought up to date.

The installation of this equipment will take place starting in 2008 through 2012.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Developmental	1,422							1,422
Requested Now	Partial	(643)	1,450	3,593	2,339	1,919	1,865	525	11,048
Future Funding Req'd	Full					-	-		-
Total Project Costs		779	1,450	3,593	2,339	1,919	1,865	525	12,470
Other Costs									-
Ongoing Costs									-
Grand Total		779	1,450	3,593	2,339	1,919	1,865	525	12,470
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Sustaining		Capital		5,051,449		335.1%		3.3	

Submitted By:

2007-06-27

W. Robbins
Site VP, Darlington Nuclear

Date:

Finance Approval:

D. Power
~~Director, Investment and Business Planning~~
VICE PRESIDENT
Corporate Investment Planning

Aug 1/07
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

T. Mitchell
Chief Nuclear Officer

7 Aug 2007
Date:

2/ BACKGROUND & ISSUES

This project received its first funding in September 2005. The project has carried out developmental engineering in order to determine the best alternatives for resolving the age-related problems of the FH control computer system. The campaign also examined the candidate solutions for their value in view of a possible a life-extension of the Darlington plant.

As well, the main Fuel Handling (FH) video interface monitor screens in the Main Control Room were successfully replaced during this first part of the project.

This project supports initiative number 244 in the Darlington "Plant Reliability List". The Fuel Handling (FH) control computer systems are not expected to survive until the station's pressure tube end of life without the proposed device replacements. Weaknesses affect its central processing units and supporting subsystems and interfaces, including the Human-System Interface.

Reactor fuelling capacity (thus generating capacity) cannot be maintained in the long term unless action is taken to replace equipment that is now failing or about to fail. The CPUs will be out of spares by 2011. The console teleprinters must be replaced sooner, within the next 2 years.

FH Control Computer System Description

The Fuel Handling Control Computers direct the automated reactor fuelling process at the Darlington Nuclear Generating Station. Three pairs of PDP-11 computers control the trolleys, bridges and Fuelling Machine heads. Those computers are located in the Main Control Room area. An additional 4 computers control the new fuel loading into the mobile Fuelling Machine head and used fuel discharge processes in the Fuelling Facility Auxiliary Area buildings. Another PDP-11 is used for Fuelling Machine head setup and maintenance in the plant's Central Service Area.

All of these computers must be functioning reliably in order to maintain automated fuelling capability. Automatic fuelling capability is required to stock the reactors with fuel that will keep reactor power levels in a range that will ensure economical nuclear fuel burn up and prevent unit de-rating or shut down.

Two trolley fuelling systems must be available in order to maintain adequate fuelling capacity. The FH systems equipment thus have marginal redundancy. The FH systems must have high reliability from the FH control computers as it cannot afford to have reduced capacity for any extended period.

Problem Areas

Maintenance of the FH control computer systems is becoming increasingly difficult. The control computer equipment in the FH system is nearly 30 years old. A trend of increasing obsolescence of control equipment components was recognized in 2002. That trend that has continued and many critical parts can no longer be obtained, and no support from the original equipment manufacturers is available for the computers.

The most critical age-related problems in the Fuel Handling Control Computer systems are in the

- Operator's main console,
- Main computer console tele-printers,
- Disk drive sub-systems,
- Custom operator keyboards,
- Video Display Generators,
- Computer backplanes,
- Human-System Interfaces,
- Central Processors and power supplies, and
- Inadequate Component and Software Test Facilities.

Operator's Main Console
The existing Fuel Handling main panel was designed prior to now-compulsory Human Factors Engineering (HFE) reviews. The main panel layout exhibits a number of flaws because of this. One of the most serious problems is that operator must have his/her back to the main panel displays in order to enter data in another computer during times when high panel vigilance is required. Serious HFE problems were formally recorded in "Human Factors Assessment of the Control Centre Arrangement" [R-2] in 1997. This project addresses those as well as subsequently identified problems such as poor information grouping in displays, line-of-sight to outer panels, and inadequate indication of used fuel transfer status.

Main panel switches and indicators are labeled inconsistently among panels and their associated operating and design documentation. These problems are described more fully in "Fuel Handling Human Factors Issues" [R-1]. An attempt was made in 2005 by the Main Control Room Furniture project to resolve panel peripheral visibility and operator seating orientation. The work was unsuccessful in resolving these issues since the engineering resources needed to relocate main control interfaces to a new desk were not within the scope of that project.

Main Computer Console Tele-Printers
The tele-printers are old-style LA120 computer terminals that are used for direct communication with the FH Control Computers. They produce a printed record of all the FH machine control operations, errors and events. They are also used for computer start up, shut down, maintenance operations and emergency system control.

The LA120 tele-printers suffer from failing key-switches, and mechanical failures of the feed mechanisms, carriage drive and print heads. There are no more print heads available. The only source of the spare parts is from previously failed LA120's. Main circuit board electronic components are becoming increasingly unavailable as well.

Disk Drives and Sub-System Controllers
Non-repairable and Insufficient Spares
The disk drive controller used on FH computers is obsolete, unsupported by any manufacturer, and not repairable. When the boards were purchased, a less than optimal number of spares were obtained. The controllers use a protocol that will soon be obsolete. There appear to be 2 options to prevent this weakness from shortening the computer's' life expectancy. The disk controllers could be replaced so that they work with an easily replaceable type of disk drive. Alternatively, long-life drives that are compatible with the existing controllers could be put in place.

Custom Operator Keyboards
The automatic input and semi-automatic control keyboards are subject to failures related to key-switches, memory chip failures and various electronic component failures. The power supplies of the semi-automatic keyboard are out of spares. The power supplies are increasingly difficult to repair due to their physical design and difficulties with obtaining replacement electronic components. The last of the failed keyboards are being cannibalized for replacement keys.

Display Generators
Each of the 6 Main Control Room FH computers is connected to a Ramtek model RM9400 video Display Generator (DG). The DG is required all the time when a fuel handling system is transferring nuclear fuel. If a DG becomes unavailable, an entire fuelling system is unavailable for service. Interruptions in operation of the video generator leave the operator without automatic fuelling control and without access to the system status data provided via the FH computers. Fuelling runs have to be suspended until a DG repair can be performed.

Instances of degraded performance of these units have coincided with slow operation of the control computers, resulting in stalls during the high-risk transfer of irradiated fuel from the F/M heads.

Computer Backplanes
The FH computer boards are plugged into a common back-plane via board-edge connector sockets. This

backplane is prone to non-repairable failures with age. Each back-plane contains from 54 to 264 sockets. Each socket has dozens of individual connections that are made by an unsoldered compression wire wrap using very fine gauge wire. When one of these connections fail, it is extremely difficult to localize. This is made more difficult on FH computers, since they lack a connection for a logic analyzer like the one added to the DCC computers by OPG.

Human-System Interface

The FH Control Computer software contains numerous long-standing deficiencies in video display data presentation. For instance, there are identical displays for similar equipment that is located in different buildings at the station. The building is selected when the display is active. If the display is exited to check on other status, the selection of equipment will change and the drive the equipment in the wrong building. These and many other problems were important enough that work was started to correct a number of these problems in 1994. That work was inadvertently abandoned due to changes related to funding and other re-organization issues when Ontario Hydro changed to OPG. The software shipment that was started needs to be finished. As well important problems that were identified in the Human Factor Engineering survey of the FH control system need to be resolved.

Central Processors (CPUs)

The FH Control Computers use model QED95 Central Processing Units. The QED95 CPUs were used to replace the original model PDP-11 CPUs when a significant processing performance was needed to reach the commissioning target for system response. The QED95s perform well but make use of a memory storage technology that is has a wear-out period that is entered about 10 years from when they are loaded with their program. The memories can't be re-written. As well, the board construction prevents replacement of those electronic components.

The number of spares CPUs that were originally purchased assumed a lower failure rate and greater ability to repair them than was seen after they were placed in service. There have been ongoing failures in the CPUs of an undetermined nature. This situation is complicated by having too few spares to get to the station end-of-life. We expect that the stock of spare QED95 CPU's will be exhausted by 2012 based on the observed failure rates.

CPU Power supplies

These power supplies are not expected to last for the life of the station and are at best only marginally adequate for their present use.

There have been ongoing refurbishments of the power supplies. The power supply reliability can't be ensured since many electronic components required by this refurbishment campaign are expected to become completely unavailable in the next few years. Some of these components are those most susceptible to aging, and thus needing replacement (for example, electrolytic capacitors). These parts have limited shelf lives as well and so a strategy of increasing inventory to maintain parts availability wouldn't help since the parts could fail in storage before they were needed.

The present power supplies were designed for the original PDP-11 CPU, not the present QED95 CPU. CPU lock-up during brown-outs or computer re-starts can happen, as seen during the Bulk Electrical System Failure of the Northeast grid in 2003. An uninterruptible power source is required instead of the existing switch-style supplies in order to prevent CPU lock-ups.

FH System Simulator

The problems that need to be resolved by a computer simulation of the FH system are:

- Insufficient time to fully commission the FH system control on-line
- No test facilities for proving protective logic in OpData (FH machine control programs)
- No test bed for representative integration testing of FH application software changes

Allows Off-line Commissioning of CPU Replacement

The simulation of the Fuel Handing system equipment will be developed to support the testing and commissioning of the CPU replacements in an off-line environment. This will make a retrofit of all 3 FH trolley control systems possible, while maintaining sufficient on-line fuelling capacity to support operation of the 4 Darlington reactors. For DCC computer systems, commissioning can be done during outages. This possibility does not exist for Fuel Handling systems, since they continue to operate through Unit outages. Unit outages present additional demands to FH, since the fuelling equipment redundancy is reduced when one system is dedicated full time to support reactor inspection equipment.

Although the upcoming Vacuum Building Outage (VBO) presents a time when reactor fuelling is not required, the constraints on the FH system operation make it an unsuitable to commission the processors and software. The time required to perform the commissioning work will exceed the length of the upcoming VBO. The commissioning testing will require the trolleys to traverse full length of the fuelling duct. As well, ports that cross containment boundaries would need to be opened, which is inappropriate activity for this kind of outage.

Provides a Needed Software Test Bed
The Fuel Handling system simulation will be used to verify changes to the complex fuel handling software. This will help ensure that software changes do not adversely affect the operation of the Fuel Handling Systems. A realistic off-line testing facility has not been available to verify fuel-handling software. Most of the control programs were developed during plant commissioning before reactor fuelling began. This method is obviously no longer available.

Hot Spares System
A standalone computer system is required to pretest and provide a stock of ready hot-swappable computer and control components for the fuel handling systems. This facility is available for computer systems of similar complexity, such as the common process and reactor controller DCCs. The absence of the Hot Spares system has resulted in significant delays in returning Fuel Handling computer and peripheral equipment to service.

This facility for FH Control Computers existed at one time. However the system was disassembled and removed by the plant computer maintenance group in 2004 so that a second DCC maintenance computer could be installed in its place. The FH Hot Spares system has not been reinstated since that happened. Some components for that system are missing due to their consumption as spare components in the running systems and will need replacement.

Surveillance and Monitoring Terminals
The Field Monitor and External Protective Operator Display computers are used to perform monitoring of system conditions and updates to programs in the Auxiliary Control Equipment Computers. These IBM-PC compatibles are obsolete as is their operating software. The spares for both of these computer systems are exhausted and they can't be repaired.

Related Projects

Lessons learned from projects 40505 (FH Typer), 33509 (Obsolete Computer Components) and 33977 (DCC Replacement) will be used by this project. Project 40505 replaced a tele-printer on the Pickering FH control interface that was similar to the Darlington FH console tele-printer. Project 33509 has provided replacements for certain critical DCC subsystems that use the PDP-11 computer. Project 33977 has started the design and manufacture of the new CPU that will be used to replace the PDP-11 CPUs in various DCC Computer systems. This computer CPU will also be used to replace the FH Control Computer's QED95 CPU.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended)		Alt 2 Delay	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost				
Revenue	(20,071,403)	(1,879,309)	(1,879,309)	(6,219,845)	(3,854,015)	(1,564,501)	
OM&A	(1,041)	-	-	-	-	-	
Capital	-	(10,337)	(9,558)	(17,033)	(24,820)	(27,870)	
NPV (after tax)	(5,883,511)	(832,841)	(832,062)	(2,665,336)	(1,697,000)	(761,474)	
Impact on Economic Value (IEV)	N/A	5,050,670	5,051,449	3,218,175	4,186,511	5,122,037	
IRR%	N/A	237.0%	335.1%	41.3%	138.8%	237.0%	
Discounted Payback (Yrs)	N/A	3.4	3.34	10.1	3.4	3.4	

Stop the Project - Not Recommended

This involves rejecting the recommendation and not providing the requested scope. The impact would be a loss of automated reactor fuelling capacity by 2011. Experience with the Darlington Fuel Handling (FH) control system in 2006 supports the assumptions of failure rates stated in the first BCS for this project. Substantial parts of the FH control computer system must be replaced before 2010 to support continued safe fuelling of Darlington's reactors. The FH System weaknesses with their probability of contributing to unit de-rating and shutdown are:

1. Console teleprinters — P = 1 in 2010
2. Disk drive sub-system — P = 1 in 2010
3. Display generators — P = 1 in 2011
4. Operator keyboards — P = 1 in 2012
5. Central Processor (CPU) — P = 1 in 2013
6. Computer backplanes — P = 1 in 2014
7. Operator's console — P = 0.8 by 2020
8. Human-system interface — P = 0.7 by 2020
9. Test Facility — P = 0.7 by 2020

Attachment D shows graphs of reactor fuelling loss probability in both cases of stopping the project and proceeding with alternative #1.The failure of a Fuel Handling system to run is expected to reduce the number of reactors that can be fuelled from 4 to 2. Due to redundancy requirements, mechanical failures due to aging and so forth, 3 units are not supportable with 2 fuelling systems. The second failure will reduce the serviced reactors to 1. A planned station out of service date of July 2050 is assumed for the cost of lost generation.

Alternative 1 - Replace Main CPUS and Peripherals by Emulators - Recommended

The computer's central processor (CPU) would be replaced by a processing unit which is based on a hardware emulation of the originally installed PDP-11/70 computer. It would execute all the software now used to fuel the reactors.

Largest Savings in Software

This alternative allows the automated fuelling system to continue operation using the existing custom FH application software. This ability is important, since the existing Fuel Handling software was written in a language that will not permit it to run on any other family of computers. The system specific language was used in order to speed the operation of the computer programs and to support the large number of complex functions operating on the same computer.

The retention of the same software represents an estimated savings of about 6 million dollars, in addition to avoiding the operational and other risks inherent in developing new software code.

[illegible]s alternative will result in minimal impact to existing software programs and guarantees greater compatibility [illegible]n the existing FH systems than a software emulation approach. This alternative has already proven to be cost effective in an installation of an earlier vintage of hardware emulator, in the Darlington FH systems.

Available Technology

The CPU emulator, the QED970, is based on an enhanced design of an existing product, the QED95. The same company that is providing DCC life extension support for the CANDU 600 control computers will be used to acquire the QED970 emulators.

Renovate the Peripheral Equipment

The use of the QED970 CPU will provide a platform for the upgrading or replacement of the video display generators, consoles, control keyboards and printing terminals, all of which have exhibited significant design and/or maintainability issues

Alternative 2 - Delay Project - Not Recommended

Past delays to the start of this project have removed all substantial float time between computer system replacement component design, and installation and the ability to fuel the reactors without substantial disruption. Experience with the Darlington Fuel Handling control system in 2006 supports the assumptions of failure rates stated in the first Business Case Summary for this project. The successful replacement of the main control panel video screens barely kept ahead of the obsolete video unit failures. At one point, a Fuel Handling equipment delay caused rescheduling of installations. This would have resulted in the loss of 1 trolley fuelling system during the fall outage. This was averted by exceptional efforts by FH Maintenance, who was installing the new monitors, by reallocating work. This near miss underscores the need to continue without delay.

Delaying the project would result in a dramatic increase in cost to extend the FH control computer life due to a missed opportunity to buy from what is expected to be the last production run of the QED970s in 2009. In the best case, there would be cost increases to provide another production run. The cost of a subsequent run would likely be higher since the market for these devices is very small, and the customers will be those with mission critical systems whose replacement cost would justify a substantial outlay for hardware. If components on these boards become obsolete before a production run could be arranged, re-engineering of the boards may be required at extra cost.

There is a risk that the QED970 design staff would not be available to do this re-engineering. In that case a separate engineering campaign would be required in order to develop another emulator for FH. Investigations by the DCC replacement project placed the cost of that work tentatively at 10 million dollars.

Alternative 3 – Replace Main CPUS and Peripherals with State-of-Art Equipment - Not Recommended

A full replacement of the PDP style control computers with new technology is not recommended for this phase of the Fuel Handling computer aging management strategy.

This would be an opportunity to have the software prepared to modern standards, which could increase the reliability, robustness and functionality of the controller's software. At that time, the redesigned software would be more easily portable, thereby reducing future costs of hardware replacement.

Would Need More Time Than Available

Although this alternative may be the best option for long term supportability, there is not enough time or internal resources to execute this alternative before the existing computer equipment fails irreparably. Replacement of the existing CPUs must be done before 2011, given the current number of spare units and failure rates. Other peripheral devices must be replaced sooner. A re-writing of the controller software, testing it with a system simulator with adequate category 3 quality assurance standards and its installation is expected to take a minimum of 4 years. The consequences of lost fuelling capability and subsequent generation loss resulting from project delays when changing to this type of control system is too great to start down this path at this time.

Best Cost Recovery Only when Entire Trolley Control Replaced

The feasibility of replacing the FH control system auxiliary (FFAA) controllers was examined in the preliminary engineering phase. The intention was to only replace the FFAA main controllers. We determined that commercially available equipment would be suitable for the control application. However another custom device would be required to allow compatible communication with the main controller. This device would not be required after the main controllers were replaced by a modern style controller. As a result, the significant investment in the custom communication adapter device would be lost. It would be better to carry out a replacement of both main and auxiliary controllers together to make best use of modern technology. As well this should be done when there is not as much concurrent work in this project. The concurrent work is needed to replace equipment before system operability is lost. Full focus should be applied to a controller "re-hosting" to new technology in order to transfer the knowledge to OPG from any outside design agencies that might be involved.

Alternative 4 – Two-Stage Repalcement of Main CPUS and Peripherals - Not Recommended

A Two-Stage Replacement of Main CPUS and peripherals is not recommended for this phase of the Fuel Handling computer aging management strategy.

In comparison with alternative 1, this alternative would entail a slightly reduced scope of changes to the FH software and teleprinters. However the CPUs would still be replaced. Subsequently, the replacement CPU equipment would be replaced with state of the art computers, or Programmable Automation Controllers (PAC).

This could increase the reliability, robustness and functionality of the controller's software. This would increase the ease of maintenance for the hardware and software if the life of the DNGS plant is extended. In comparison with alternative 3, this avoids the generation losses that would likely occur due to the time needed to re-design the control software and install a new technology system. The new CPUs that are displaced by the new PACs could be returned for stores, ensuring that the DCCs, that also use the new CPUs, would have plentiful spare parts.

Would Need Retention of Rare Knowledge
Although this alternative may be a very good option for long term supportability, and power generation support, there is no way to be certain that people skilled in Fuel Handling controls and PDP-11 computers will be available for the extended duration of the project. A re-writing of the controller software, testing it with a system simulator with adequate category 3 quality assurance standards and its installation is expected to take a minimum of 4 years longer than the Alternative 1 replacement. Due to full use of those resources in the first part of the project it would not be possible to re-use those for parallel software design, transfer the skills and knowledge to others nor effectively coordinate additional work by external design agencies.

The consequences of the failure to complete the project could be a loss of several million dollars of investment capital.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The modifications required by this project can be classified as directly age related or design related. The age related changes are needed to prevent loss of system function as parts degrade and become non-repairable. These changes affect the Main Control Computer, Display Generator and Tele-printers.

The design related changes address simple and time-compounded design misconceptions. These changes fix long standing problems and thus provide a sound base upon which future modifications can be made. These changes improve the Fuel Handling Human-System Interface. The Fuel Handling (FH) operators will experience improvements in reliability and function of the main control keyboards, FH controller software, the Main Control Room FH Panels, and the Operator's desk, as well as improved access to control computer data.

The modifications are outlined in more detail in the following paragraphs.

Aging Related Improvements

Main Control Computer

The Main Control Computers' central processors will be replaced in the CSA and FFAA control computers by new software compatible QED970 units.

Prior to the installation of these new units, which have a long lead time, a number of obsolete components will be removed from the FH control computers to increase system reliability. These components are potential sources of system malfunction since they are no longer required but affect the computer main bus. These components include RL02 disk drives and interfaces, video printer switches, and some high and low speed network communication adapters.

Maintenance documentation will be brought up to date with the existing configuration and kept current as changes are made.

The main disk drives and controllers will be replaced by new interfaces to the main bus and long-life sold state drive units.

The existing computer software/hardware test facility will be upgraded in order to fully test the new central processors, computer configuration and attendant software changes. It will be equipped with a computerized simulation of the FH field equipment so that performance of the new computer components can be realistically gauged and verified for used in the plant.

The original hardware maintenance facility will be re-established. Also, in support of maintenance, the life of key maintenance and supervisory computer tools will be extended. These include the External Protective Operator Display, Protective Ladder Software Test Tool and Field Monitor computers, which will be upgraded to use commercially available components and software.

When the main Central processors are replaced, the main computer cabinets will be optimized. The main power supplies will be replaced with more efficient and reliable units at that time. The main backplane segments that hold the processors and adapter boards will be replaced as well.

Display Generator Replacement

The Ramtek Model RM9400 video display generator will be replaced by a computerized device that will produce displays based on the instructions sent by the control computers. This will greatly reduce the amount of change to the control computer software.

Tele-Printers Replacement

The Model LA120 tele-printers will be replaced by IBM PC-compatible computers. They will allow operators to access the control computers in the same way as they do now. The new equipment will provide fast access to a larger amount of each system's operating history in order to support returning systems to service more quickly.

Field Monitor and EPOD Replacement
The surveillance and maintenance computers will be re-hosted in new computer hardware. The software will be updated as necessary to ensure easy maintenance.

Design-related Improvements

Automatic and Semi-Automatic Control Keyboards
The keyboards will be replaced by commercially available keyboards. Keystroke signals will be mapped by a small computer that will communicate with the main FH control computers.
FH Controller Software
The software in the main control room FH computers will be modified to correct problems related to information display. The software corrections will span approximately 4 shipments in order to shorten commissioning time and reduce the risk of unexpected interaction between concurrent modifications.
Main Control Room FH Panels
Switches and Indicators labels will be changed to eliminate confusion about the purpose of switch or state of the devices. The Labeling will be made consistent between panels and documentation.
Un-used switches and indicators will be removed from the panels. The FFAA computer re-start switch will be replaced to prevent accidental operation. The Irradiated Fuel related indicators will be upgraded to ensure that they provide information in appropriate to their function during the fuelling process.
Operator's Desk
The Video Display terminal count and position will be optimized when a new desk is put in place. The desk will place the operator so their line of sight will be towards the panel during reactor fuelling.
Improved Access to Computer Data
The tele-printers will be connected to a network so computer log and IO data is easily accessible to FH operators and technical support staff. Predefine monitoring screens will permit timely monitoring of Fuel Handling in a post transient situation. Electronic files retrieval will be simplified to eliminate computer history data loss.

5/ QUALITATIVE FACTORS

Completion of this project will result in more reliable Fuel Handling System Performance. Some key benefits are:

- Maintenance effort will be reduced
- Spare parts supply will be made adequate
- System health reports concerns will be addressed
- Forced loss rate escalation due to failures of current equipment will be avoided
- Dependence on a single supplier for support of the Fuel Handling Systems will be eliminated
- Obsolescence of peripheral equipment (e.g. LA120 terminals, Display Generators, disk drives, keyboards) will be addressed
- Operator issues associated with Input Devices will be addressed
- Risks associated with software changes will be mitigated by providing a FH Simulation facility.
- On-line fuelling of Darlington reactors can be maintained by the new FH Simulation facility which will avoid taking FH systems out of service for extended periods in order to commission new software and hardware.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Design Agency costs may be higher when contract negotiations proceed	Higher costs of external support providers who do not fully understand the work scope.	**Medium**	Provide tightly defined scope to supply chain for inclusion with requests for Proposals, thus reducing liklihood of bidders underestimating effort required. Use contingency funding.	**Low**
Scope				
The Customer (FH Operations) changes expectations of the project's deliverables.	Reluctance by Operations to sign-off on AFS for equipment	**Medium**	Have FH manager sign-off on Project Plan so there is a clear understanding of the deliverables and schedule	**Low**
Schedule				
Changes to supply chain policy or staffing results in extended delays to arrangement of contracts for design and supply	Loss of coordination of project segments increases interest costs and may delay overall time to project close-out	**Medium**	Obtain Sevice level agreement signed with Supply Chain	**Low**
Delays due to failure of other FH equipment	Failure of mechanical components of FH system delays equipment installations since the focus of FH Maintenance will be shifted to re-stablishing fuelling capacity rather than installing new equipment.	**High**	Obtain agreement from FH Maintenance section manager to work with the project to blend FH work with project installations following return to service of failed equipment. This will minimize work-bumping	**Low**
Delays due to reactor closure plug replacement	The FH control systems will have less idle time in which to install replacement equipment if the all the reactor closure plugs need to be replaced (now being proposed)	**High**	Perform as much commisssioning work as possible for the replacement equipment in simulated environments. This will reduce the length of the installation and commisioning time needed in the Main Control Room.	**Low**

Resources				
Loss of internal resources with knowledge of fuel handling software	Possible schedule delays in implementation of Hot Spares system, controller display problem fixes, and FH FFAA system simulator	**Medium**	Coach and provide mentoring to other members of the DCC group so redundancy exists, shortening time to recover schedule if key member leaves	**Low**
External design agency becomes unavailable to the project due to their commitments to other customers during the design part fo the project	Possible schedule delays in implementation of Hot Spares system, controller display problem fixes, and FH CSA system simulator	**Medium**	Diversify allocation of design contracts to decrease effects	**Low**
Potential suppliers fail to bid for parts of the project	Nuclear station refurbishment and promises of new-build are increasing demand for traditional supplier's services. New-build contracts may be considered more lucrative and result in suppliers focusing on nuclear new-build instead.	**Medium**	The external work for this project can be arranged in 2007 rather than waiting to initiate contracts later. Nuclear new-build request for proposals are not likely going to be issued until after 2008.	**Low**
Technical				
Loss of primary design resource for CPU replacement (QED, Inc)	Restart of CPU hardware design process adding extra cost and delay to schedule and possible derating	**Medium**	Secondary agency (MAPPS) is providing design oversight and can carry on the design process if primary designer is lost	**Low**
Regulatory				
Change in regulator's policy may require more time consuming administrive overhead in order to put the new CPUs in service	Delay to the implementation of the processors results in delay in CPU installation schedule. Non-recoverable failure of old CPUs results in decrease fuelling capacity and unit derating	**Low**	Formal communication to Darlington Licensing Section to inform them of this risk, asking that this project be informed immediately of a change in regulator policy in this area, so we have more time to comply	**Low**
Environmental				
No risks identified.				
Health & Safety				
No risks identified.				

Investment				
No risks identified				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Feb 2012	Jul 2013	Manager, Fuel Handling

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Central processing units function reliably	Functional failure rate of 2003	No failures in 12 months folowing installation of new CPUs	Functional failure count per SCI 69740 health report	Fuel Handling Technical, System Engineer for 69740
2.	The deficits indentified in the 2005 Human Factors analysis have been resolved.	NK38-REP-63500-10002	The elements from the report that were scoped for this project are resolved	Post implementation comparison against baseline.	OPG Human Factors Engineering group
3.	All peripherals operate reliably.	Passport work order data	Less than 2 failures per device type per year following installation of devices	Functional failure count per SCI 69740 health report	Fuel Handling Technical, System Engineer for 69740
4.	Adequate maintenance strategy is active	Maintenance department is struggling to keep equipment in service	A sufficient quantity of serviceable spares are available	Less than 4 trolley system-days per year are lost due to delays in obtaining replacement equipment	Fuel Handling Technical, System Engineer for 69740
5.	Commissioning time does not impede the ability to maintain adequate zone levels in the 4 Darlington reactors	No trolleys are unavailable due to FH control computer malfunctions during commissioning	No units shut down or de-rated due to the effects of commissioning this project's elements	Darlington outage report and Darlington SCR database	Fuel Handling Technical, System Engineer for 69740

Appendix "A" Glossary (acronyms, codes, technical terms)

CPU Central processing unit, the heart of the FH controller. It executes program instructions to control the input – output equipment and so the field devices of the FH system.

CSA Central Service Area of the Darlington Plant. This is the location for the main trolley and FM head control computers.

DCC The Digital Control Computers that control the reactors. Also used to refer to the Darlington computer design group.

FFAA Fuelling Facility Auxiliary Area. This abbreviation is used to refer to the equipment contained in either of the 2 buildings used to load, discharge and store nuclear fuel. The buildings are adjacent to the extreme east and west ends of the 4 reactor buildings.

LA120 The model number of the printing terminal used as the primary interface with the FH control computers. It works similarly to a "dumb" terminal, but communicates by printing on tractor feed paper instead of by graphic display on a video monitor.

PDP-11 The "Programmed Data Processor", originally produced by the Digital Equipment Corporation of Maynard Mass., USA in 1978. The DN FH computers were originally model PDP-11/70, the 21 bit addressing version.

RM9400 This is a model of video display generator that is used to receive computer instructions from a PDP-11 computer and turn them into video signals. The signals are sent to special monitors when the images are viewed.

QED95 This is a "work-alike" computer processing unit for the PDP-11/70. It was built in 1993 to support life extension of systems that used PDP-11/70 computers that had a large investment in software. This allows the existing computer systems to run using the same software. These are used in the FH computers.

QED970 This is a more modern "work-alike" computer processing unit for the PDP-11/70. It is being designed to replace the QED95. The new design addresses the maintenance issues with the old QED's so that they will last at least to the DN station's end of life.

References

1 NK38-REP-63500-10002 R00, "Fuel Handling Human Factors Issues", OPGI, 2005

2 NK38-REP-66000-001 R00, "Human Factors Assessment of the Control Centre Arrangement", Greenley & Associates, 1997

Appendix "B" Project Funding History

Choose		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2005	2006	2007	2008	2009	2010	2011	Later	Total
Developmental	Sep	2,005	1,422								1,422
Full	May	2,007			11048						11,048
											0
											0
											0
											0
											0
											0
LTD Spent	Dec	2006		779							779

Comments:

The project is included in the 2006-2010 Business Plan at a value of $6.9 Million. A variance to the 2006-2010 Business Plan of $3527K will be addressed via inclusion in the 2008 Business Plan. A Project Execution Plan (PEP) is scheduled for completion by Q3 2007.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
The device that will be used to replace the CPU will be the same one used for the Darlington DCC computer replacement. The development of the device will be successful and meet the schedule included in the contract with the vendor of the device.

Financial Assumptions:
Not applicable.

Project / Station End of Life Assumptions:
The Station End of Life is assumed to be extended by a refurbishment with a new end of life of April 1, 2050.

Energy Price / Production Assumptions:
$49.50 per Megawatt-hour. Nominal 900 MWe net output, 97% capacity.

Operating Cost Assumptions:
Darlington Station operating funds will be used to pay for spare computer component that are purchased by this project and are consumed during the station's life after the closure of this project.

No Additional staff will be required to run the new equipment. Training costs will be small since the new equipment will be very similar in operation to the equipment that is replaced.

Other Assumptions:
Contracts with external suppliers and design agencies can be arranged within 130 days or less.
OPG supply chain will support expeditious contract arrangements with appropriate external resources.

The project will be free to identify capable and appropriate qualified suppliers and design agents as required, subject to technical governance. OPG policy interpretations will not artificially constrain the selection of external resources in order to shorten the Approved Suppliers List.

FH Computer Replacement 16 - 33815

Full Release (Phase 1) Business Case Summary D-BCS-69740-10002-R000

Attachment "A"

Project Cost Summary

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011	This Release 2012	Later	Total
Project Management (OPG)	153	164	162	179	172	147	148		1,125
Engineering & Drafting (OPG)	299	406	482	437	381	145	148		2,298
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	779	1,450	3,593	2,339	[redacted]		525	-	12,470
2006-2010 Business Plan	872	1,450	2,544	900	1,129	-			6,895
Variance to Business Plan	(93)	(51)	348	983	416	1,501	423	-	3,527
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	779	1,399	2,892	1,883	1,545	1,501	423	-	10,422
Total Release (incl contingency)	779	1,450	3,593	2,339	1,919	1,865	525	-	12,470
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to ~ 15%		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process.
A PCRAF will be approved by Jul 2007.

Reviewed By:

[signature] June 12, 07

L. Hung
Project Manager
Date:

Approved By:

[signature] June 13, 2007

R. Hohendorf
Eng & Mods Manager (Strat IV)
Date:

FH Computer Replacement 16 - 33815

Full Release (Phase 1) Business Case Summary D-BCS-99740-00002-R000

Attachment "B"

Project Variance Analysis

Choose One	LTD Dec 2006	Choose One: Last BCS Sep 2005	Choose One: This BCS Apr 2007	Variance	Comments
Project Management (OPG)	153	483	1127	644	Close integration of multiple work segments requires more oversight
Engineering & Drafting (OPG)	299	310	2296	1986	It is more efficient to have OPG staff perform work that requires a lot on site specific information
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	779	8756	12470	3714	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	779	8756	12470	3714	
Total Release (excl contingency)	779	6895	10422	3527	
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

In order to perform the installations of replacement equipment in the manner required to prevent critical system failure, more project oversight is required. However, this is expected to provide more rapid recovery of investment, thus offsetting the higher project management costs.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
9	JUL	2007	Video Monitor Replacement Close-out Complete
03	DEC	2008	Obsolete Equipment Removal AFS
17	DEC	2008	Main Console AFS
20	MAY	2008	Protective Display Terminal Replacement
13	NOV	2009	FH System Simulator in service
26	FEB	2010	Control Keyboard Replacement AFS
30	AUG	2010	Teleprinter Replacement AFS
22	SEP	2010	Field Monitor Replacement In Service
01	APR	2011	Computer Backplanes AFS
22	APR	2011	CPU Replacement AFS
24	NOV	2011	Display Generator AFS
28	FEB	2012	Human System Interface Software AFS
09	NOV	2012	Final Project Close-out

A Project Execution Plan (PEP) will be approved by Jun 2007

Comments:

Attachment D

Figure 1 below shows the probability of non-repairable Fuel Handling Computer System based on not proceeding with this project. There are several components that could influence this eventuality. Each is shown on a separate line. The graph in Figure 2 shows the same risk factors with probabilities of failure influenced by the actions of proceeding with alternative 1 of this project.

Figure 1 – "Stop the Project"

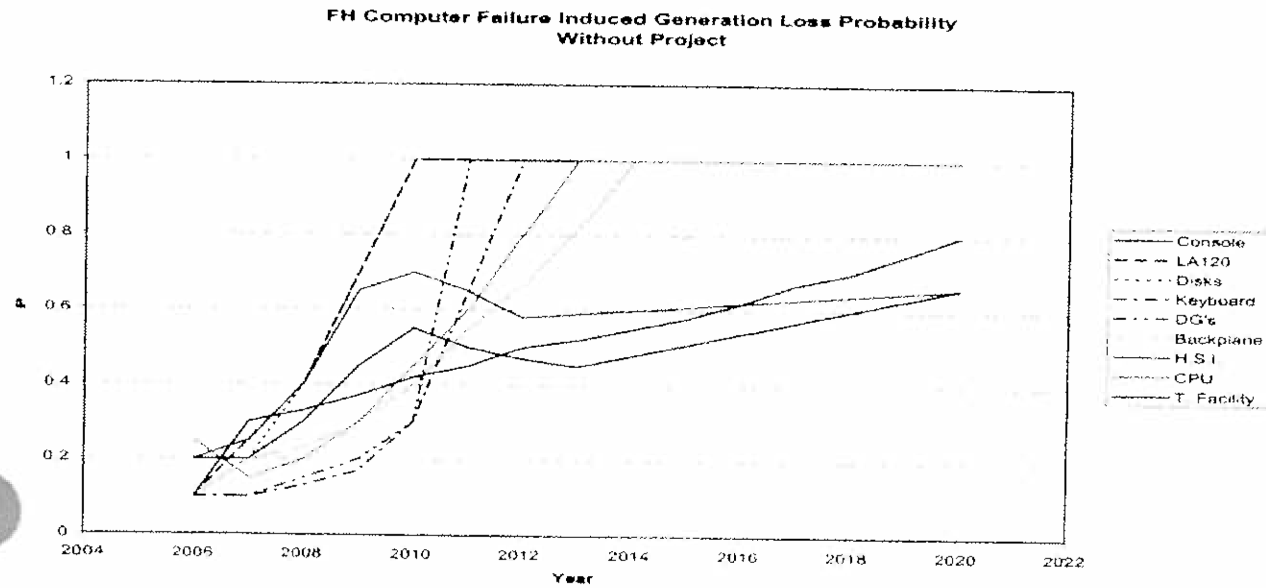
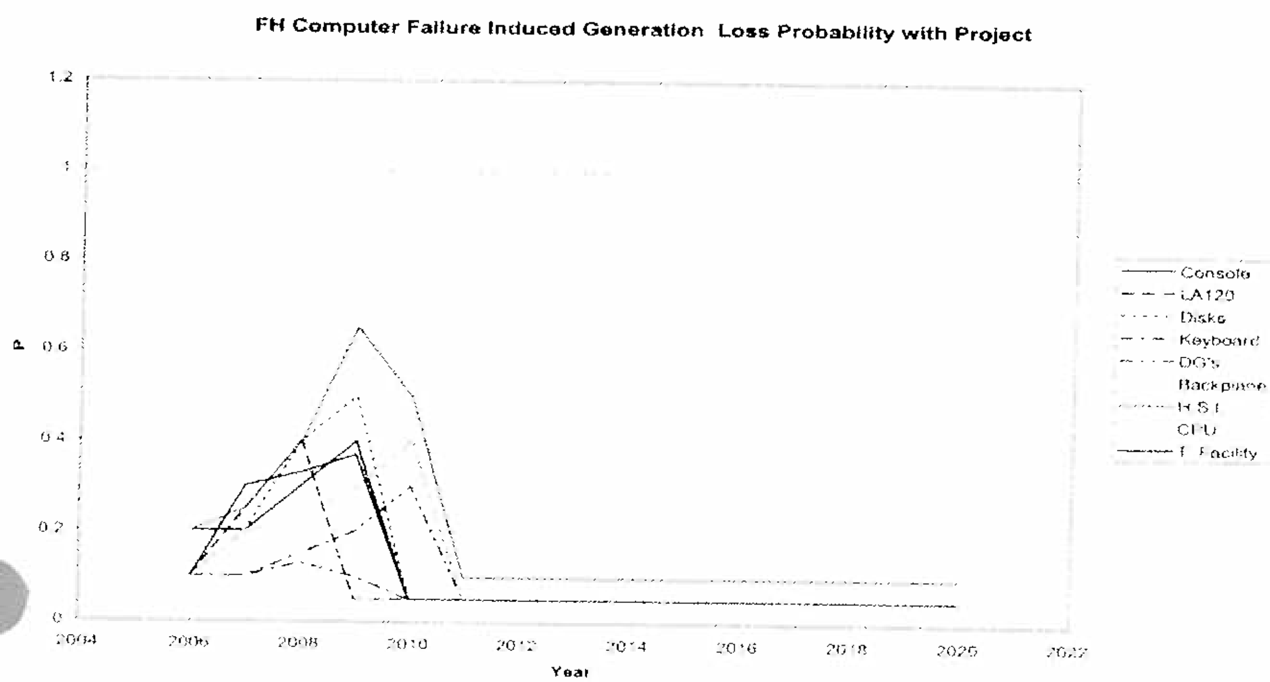


Figure 2 – "Alternative 1"



ONTARIOPOWER GENERATION

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ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

Darlington DCC Replacement 16 - 33977

Full Release (Phase 1) Business Case Summary D-BCS-33977-10001-R001

Routing	Location	Action	Signature	Date
Eric Hung, Section Manager Darlington DCCs 703, 1293	D08-ESB2	Prepare BCS	M Stutes Eric Hung	16 May 06
Richard Hohendorf Manager, Computers and Control Design 702, 5077	P82-5f-6	Review BCS		May 17/2006
Ron Ball Senior Financial Analyst 702, 4084	P82-3b-6	Review BCS		23 May 06
~~Gord Brown~~ D. Zerkee Controller, Engineering & Mods 702, 5059	P82-F3-A6	Review BCS	Per D.Z.	23 May 06
Fred Dermarkar Director, Engineering Services 401, 8243	P82-6-C	Review BCS		30 May 2006
JP Froats VP Engineering & Mods 5044	P82-6-E	Review BCS		12 JUNE 06
Smith SVP Darlington	D08	Review BCS	See attached	
PR Charlebois EVP and Chief Nuclear Officer 702, 5294	P82-6-A	Review BCS		July 2006
D. Power Director Investment & Business Planning 400-7172	H7 D06	Approve BCS		Aug 1/06 Aug 1/06
J. Hankinson President & CEO	H19 A24	Approve BCS		Aug 22/06
R. Ball Senior Financial Analyst 8241	P72-2	Return For Distribution		

ONTARIOPOWER GENERATION	OPG Confidential	Page: 1 of 14
	ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

Darlington DCC Replacement 16 - 33977

Full Release (Phase 1) Business Case Summary D-BCS-33977-10001-R001

Routing	Location	Action	Signature	Date
Eric Hung, Section Manager Darlington DCCs 703, 1293	D08-ESB2	Prepare BCS	Eric Hung	16 May 06
Richard Hohendorf Manager, Computers and Control Design 702, 5077	P82-5f-6	Review BCS		May 17/2006
Ron Ball Senior Financial Analyst 702, 4084	P82-3b-6	Review BCS		29 May 06
~~Gord Brown~~ D. Zerkee Controller, Engineering & Mods 702, 5059	P82-F3-A6	Review BCS	for D.Z.	23 May 06
Fred Dermarkar Director, Engineering Services 401, 8243	P82-6-C	Review BCS		30 May 2006
JP Froats VP Engineering & Mods 702, 5044	P82-6-E	Review BCS		12 June 06
G. Smith SVP Darlington	D08	Review BCS		20 June 2006
PR Charlebois EVP and Chief Nuclear Officer 702, 5294	P82-6-A	Review BCS		
D. Power Director Investment & Business Planning 400-7172	H7 D06	Approve BCS		
J. Hankinson President & CEO	H19 A24	Approve BCS		
R. Ball Senior Financial Analyst 701-8241	P72-2	Return For Distribution		

Darlington DCC Replacement 16 - 33977

Full Release (Phase 1) Business Case Summary D-BCS-69100-10001-R001

1/ RECOMMENDATION:

We recommend an additional release of $16.0M ($22.1M total including contingency) for the Darlington Digital Control Computer (DCC) Replacement Project.

The business objective of this project is to avoid a shutdown of a unit due to the unavailability of the CPUs in a dual DCC configuration due to either a component failure or a lack of available spares. A shutdown of this nature would be lengthy as a replacement DCC would have to be engineered and installed. This objective is consistent with the Darlington DCC Life Cycle Strategy as defined in NK38-REP-69000-10001.

The existing DCC hardware is obsolete and will not operate for very much longer with the required system availability. An associated project (Replacement of Obsolete Computer Components 33509) has been successful in replacing some of the subsystems (memory, power supplies, mag tape units etc) whose reliability or maintainability was threatening the overall DCC performance. However the limit of useful subsystem replacement has been reached and it is necessary to replace the core of the DCC system.

A partial release of $6.1M was approved in Sep 2003 to replace the Sequence of Events (SEM) and Common Processes (CP) computer, and perform initial preliminary engineering for the replacement of the Darlington DCC's. At the time, it was assumed that we could use "off the shelf" PDP-11/70 emulators for all 3 applications. However, after spending $1.2M of the current release, to complete the preliminary engineering (including the "design challenge" process) we have identified serious design issues that prevent the use of "off the shelf" technology in a nuclear control application.

We are now recommending the re-design of an existing PDP emulator from Quickware, with QA oversight from an independent and external source. Although the need to redesign (with oversight) has driven the estimated cost of the project from $14.8M to $22.1M, a rigorous RFP process has determined this to be the most viable and cost effective solution for all 3 applications. Moving to a full release at this time will allow us to keep costs down and ensure compatibility amongst the 3 systems. (See Attachment B for details).

This project is listed in the 2006-2010 Business Plan at $82.2M; with $15.5M allocated for this work and $66.7M targeted for DCC replacement under a Life Extension program beyond 2010. This funding request is intended to sustain the operation of the control computers until retubing takes place. Only minimal functional improvements will be made. This request is consistent with the 2006 Budget; however, changes in the estimate for the 2007 to 2011 timeframe will need to be addressed in the next Business Plan. A Project Execution Plan (PEP) will be approved by ~~10 May 2006.~~ 2 Jun 2006

$000's Capital		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Full (Phase 1)	6,050	5,261	Mar-06	Spent Life to Date:	1,231
Requested Now:	Full	16,008	13,921	2006-2010	Appr'd Business Plan (Tot Proj):	15,521
Cumulative Release:	Total to Date	22,058	19,182	2006-2010	Business Plan Variance:	3,661
Total Project Estimate:	+30% to -15%	22,058	19,182	2006	Budget (Current Year)	2,727
Current Year Estimate:	2006	3,134	2,726	2006	Budget Variance (Current Yr)	(1)
Type of Investment:	Sustaining	N/A	N/A	Cumulative Release Remaining:		17,951
NPV:			N/A	Contingency on Remaining Release:		2,876
IRR:			N/A	Contingency % on Remaining Release:		16.0%

Submitted By:

P R Charlebois
EVP and Chief Nuclear Officer Date:

Finance Approval:

D. Power
Director Investment & Business Planning Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson
President & CEO Date:

2/ BACKGROUND & ISSUES

Darlington DCCs

Project 33977 addresses several issues, which present risk to the continuing performance and operation of the Darlington Digital Control Computer (DCC) systems:

- Hardware obsolescence. The current computers are of obsolete 1970s technology (DEC PDP11 minicomputers).
- Diminishing support from the Industry. There is no OEM support and, unlike other CANDU stations, the hardware and software used at Darlington are unique. The few manufacturers of PDP emulators are ceasing production, and PDP expertise is disappearing quickly.
- The availability of spare parts in the marketplace has dwindled to a very small number of suppliers, and the quality and history of available spares is questionable.
- Certain key components, such as computer backplanes, are prone to wear out as a result of troubleshooting activities. This situation will deteriorate with time. The backplanes are cannot be reproduced.
- Pending shortage of in-house engineering resources. Large numbers of the original design team are eligible for retirement.
- The skill set required to repair the PDP equipment is disappearing, and the skills are not taught in trade schools.

The business case for the initial release for project 33977, approved in 2003, requested funding in the amount of $6.05M, including contingencies, and provided for the replacement of the five Sequence of Events (SEM) Computers and the Common Processes Computer (CP). The business case indicated that approval of a further amount, then estimated at $8.7M, would be requested later (in approximately 3 years) when a path forward was confirmed. This further funding would be required to complete the replacement of the Unit Computer DCCs and the Ramtek Display systems.

A highly skilled team, following a rigorous Software Quality Assurance (SQA) program, undertook the original design of the Darlington control software. This represents an enormous investment, both financially, and in expended time. Any attempt to recreate the software using modern Operating Systems and computer platforms would be extremely expensive and time consuming. Thus, at present, only solutions to the DCC maintenance and support issues that enable the investment in the control software to be retained are being considered.

At Darlington NGS, computers are used in Sequence of Event Monitoring Systems, the Common Processes monitoring System, the Unit DCCs and the Fuel Handling systems. All these systems use models from the Digital Equipment Corporation (DEC) family of PDP11 processors. Although this family was popular at the time of the Darlington engineering design, in the early 1980s, it is believed that Darlington represents the only instance in which this type of computer is used in a nuclear control application.

The provision of replacements for the Digital Equipment Corporation (DEC) line of processors is a specialty and declining field. Basically there are two types of replacement products:

- Hardware emulators, in which the instruction set of the original PDP11 is emulated in the replacement computer, using modern custom-designed hardware to replace the functions of the DEC equipment.
- Software Emulators, usually based on a PC platform, using a commercial, or custom operating system. The original DEC computer language is emulated by the PC, using the software resident in the "host computer".

Hardware emulators are relatively complex to design, and require considerable engineering knowledge and understanding of the operation of the original DEC computer hardware, and peripherals. While using modern technology, they do, however, provide for an almost exact emulation of the performance of the original DEC computer. As such, this would allow the transfer of the existing DCC control software to the emulator, with minimal issues with respect to instruction timing, while maintaining compatibility with the existing peripherals.

An RFP process was Initiated, which identified Quickware as the most viable and cost effective provider of a hardware-based PDP Emulator, suitable for use in the Darlington DCCs. (Quickware has already provided an earlier model of hardware emulator used in the Fuel Handling systems at Darlington.) Subsequently an OPG internal design challenge process was initiated, which resulted in the development of a detailed design specification for the hardware emulator. The recommended approach will involve re-design of the original Quickware product to meet the additional requirements for operation in the Darlington DCCs.

At the time of the initial release of funds it was assumed that an "off the shelf" product would be able to replace the original DEC computers. However the detailed engineering performed under the initial release of funds identified serious design issues in the available off the shelf emulator products that would prevent their use in a nuclear application. The re-design of the Quickware project, under the oversight of a rigorous QA program, has been identified as the most cost effective and risk free approach. The cost estimate refinement resulting from the preliminary engineering activity, plus the identified increased engineering work due to the unavailability of a suitable existing product has resulted in an increase in estimated project costs from $12.9M to $19.2M.

Ramtek Display Systems

Under the initial release for project 33977, an experienced software consulting company determined that replacement of the existing aging display generators by modern compatible is feasible. The analysis also identified that the phased implementation of a replacement display system on the DCCs at power would be complex, and would best be carried out in conjunction with a future unit outage. It is therefore recommended that the Ramtek replacement should be first implemented in the SEM and CP systems.

Required Annunciation Improvements

Operational Experience Review of CANDU stations including Darlington Nuclear Generating Station, has demonstrated that original control room annunciation design does not fully support current operational goals and user needs in the main control room across all plant states. Improvements to the Darlington MCR Annunciation System (SCI 60312) are needed to improve alarm conditioning to inhibit nuisance alarms, which occur during reactor start-up/shutdown and during, upsets.

Specific assessments of the Darlington Loss of Bulk Electrical System (LOBES) upset and outage related Operational tasks (i.e. Shutdown and startup, equipment out-of-service declaration) were conducted to characterize the annunciation system deficiencies and user needs. The Annunciation Improvements segment of Project #33977 will focus on the elimination of the identified conditioning and suppression deficiencies. Further, the Darlington Authorized Training Section has identified Turbine Trip as another upset that has excessive Operator workload demands due to Annunciation deficiencies analogous to the LOBES event. These nuisance alarms will also be addressed.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Stop the Project (Not Recommended)

Stopping the project is not a viable option. The life limiting components at this point are the availability of the CPU backplane and the floating-point processor. Currently, the entire supply of healthy spares has been used. This is especially true for the CPU backplane. It is "wire wrapped" and the board contacts are made mechanically. The probability of these components breaking down will increase with time, in proportion to the number of card re-insertions, typically made during "troubleshooting". Another important factor is that, most likely, the members of the original DNGS design team, as well as the currently available hardware vendor will become un-available in the next 3-5 year timeframe, since the market demand is small and the existing experts in the technology are aging. "Stopping the project" now will cost the corporation considerably more in the future, as the result of eliminating the most economical and risk-free option.

Unavailability of the CPUs in a dual DCC configuration, due to either component failure, or lack of available spares, would cause a complete shutdown of that unit, with associated loss of production. The shutdown would be lengthy, until a replacement DCC could be engineered and installed.

Alternative 1 – Replace the PSP11 Computers in the DCCs by a Hardware Emulator (Recommended)

The preliminary engineering work, performed under the initial release of funds for this project, has identified a suitable hardware-based emulator, for use in the Sequence of Events (SEM) systems, the Common Processes (CP) system, and the DCCs. The proposed product is from the same company (Quickware) that supplied the emulators currently in use in the Fuel Handling Systems at Darlington NGS. Re-design of the product is required, and this work, by the vendor, should proceed, with QA oversight provided by another company (L-3 MAPPS) to minimize long-term support risks.

- Hardware emulation is accepted by the CNSC as a "low risk" replacement technique, thus no regulatory approval is likely to be required.
- L-3 MAPPS, who have submitted a joint proposal with Quickware, have a history of providing equipment and support to OPG (as CAE).
- L-3 MAPPS is developing nuclear support as a long-term corporate goal, and have received a long-term contract for the supply of a Varian Computer emulator, and associated long-term support, from the COG organization.
- L-3 MAPPS has the capability to continue the design effort associated with the PDP11 emulator design, testing and production, should unforeseen issues affect the capabilities of the Quickware organization.
- The QED 95, developed by Quickware, is currently in use on the Fuel Handling Systems at Darlington. (Note: this product can no longer be manufactured, due to obsolescence of certain parts, and also has limitations that would prevent its use in the Darlington DCCs).
- The Quickware organization has the capability to adapt the design of the redesigned emulator to address OPG technical concerns with respect to failure modes, error checking and detection, and packaging. The design can also utilize successful OPG initiatives, completed under project 33509, to resolve obsolete DCC equipment issues (e.g. power supply replacements).

A hardware-based emulation solution has a lower risk of issues developing with respect to compatibility with existing control software, than with a software emulator. This is consistent with the approach successfully used to replace the DCCs at Pickering A.

Alternative 2 - Delay the Recommendation (Not Recommended)

Action on this issue has already been delayed to the point where the availability of the most economical and least risky alternative could disappear. Further delay would lead to a level of DCC performance risk that is unacceptable to the overall objectives of OPG. In addition, experienced Darlington staff members who are critical for the success of the project will be lost due to retirement in the next few years. As well, the number of potential suppliers will also diminish as the demand for PDP11/70 compatible products declines. The cost of doing the project (if at all possible) will be substantially higher.

Alternative 3 - Do Less (Not Recommended)

The do less option involves the "piecemeal" replacement of equipment in the Darlington DCCs in order to resolve specific problems as they evolve. Project 33509, Obsolete Equipment Replacement, has already taken this approach, and has resulted in providing solutions to maintenance, and longer-term support issues associated with the memory, Moving Head Disk (MHD) Mag Tape unit (MT) and Power Supplies. Project 33509 has taken this "do less" approach to its limit of effectiveness, and now the maintenance and long-term support issues associated with the CPUs themselves and the Display systems must be addressed.

Alternative 4 - Do More (Not Recommended)

Complete DCC Replacement by Modern Digital Control System (Not Recommended)

An alternative approach to the use of PDP emulators as replacements for the CPUs in the Darlington DCCs would be to replace the complete DCC via a modern digital control system. This would offer newer technology and better support from the industry.
However, in this approach, there are a number of significant implications:

- The DCC control software would have to be re-written, which would require a large software team, working within a rigorous QA program. This is not be required if the existing CPUs are replaced by emulators. Additionally there may be process complications in faithfully transferring the control implementation from the existing control system
- There may be high risk in obtaining CNSC licensing approval (completely new control software).
- Significant, and very costly, re-arrangement of the field wiring would be required in a complete DCC replacement.
- Unlike alternative 1, the complete replacement of the DCC by a modern digital control system cannot be performed in a staged manner, and thus an extensive outage would be required, such as that available in retubing. Planned outages of sufficient duration are not planned within the period during which DCC replacement must occur.
- This approach would be resource intensive, and would require lead times considerably longer than those for alternative 6. Thus the risks of outages due to DCC failure would increase significantly beyond 2010, if this approach were to be taken.

These disadvantages outweigh the benefits and the cost of this alternative (even if outages of sufficient duration were available) would be several times greater than of the recommended alternative, should we decide to extend the life of the station by way of a re-tubing initiative.

A complete DCC replacement by this approach is included in the long-term business planning for Darlington, with a conceptual cost of $60M. This approach would only be re-examined if a decision to extend the life of the station by retubing were made.

Alternative 5 – Other - Replace the PDP 11 Computers in the DCCs by a Software Emulator (Not Recommended)

This alternative offers comparable overall cost to the recommended alternative (hardware emulator) based on current estimates. However, even though the costs are comparable, this alternative has considerably greater technical and regulatory risks.

The system architecture would be much more complex than the current DCC implementation. It would involve three interacting systems (SimH, Operating System, and a new hardware platform). Ensuring that the fault tolerance and fault detection of a software-based emulator is equal to or better than the existing PDP 11/70, would be difficult. The nuclear regulator will likely have significant concerns since the use of a software-based emulator in a nuclear plant is "uncharted territory" and only hardware-based emulators have ever been used for DCC replacement on a nuclear unit.

- The various failure detection and handling schemes inherent in the current, PDP11 based design, would need to be re-assessed.
- Several new failure modes will be introduced by the introduction of a software emulation product, and will require significant assessment (e.g. issues with the newly introduced operating system, instruction timing incompatibilities etc.).
- The interface with the DEC Unibus is a weak point in most software emulators, and will require significant engineering and development to ensure a secure design is in place.
- There are uncertainties with respect to the discovery of new significant technical issues, as the design develops. This in turn would result in greater uncertainty and risk with respect to cost and schedule.

A detailed study was undertaken to compare the hardware and software emulation alternatives. Report NK38-REP-69100-10004, dated 10 February 2006, was produced, and concluded that the hardware emulator is the best approach based on DCC unavailability risk.

Alternative 6 – Other – Replace the Darlington DCCs using the Varian DCC emulator being produced for Pickering B and other CANDU stations as part of a COG joint project. (Not Recommended)

The Varian emulator cannot run the Darlington DCC software. Redesigning the Darlington DCC software to run on the Varian Emulator is probably infeasible, would cost several times more than the recommended alternative, and would incur substantially greater regulatory and technical risk.

Alternative 7 – Other -

4/ THE PROPOSAL

This project will replace the PDP11 computer based control systems and the display system with emulator based systems that will:

- Ensure the reliability (99.9%) of the DCC, Common Process Computer (CP) and Sequence of Events Monitoring (SEM) Computers for the current life of the station;
- Provide needed annunciation improvements;
- Prevent obsolescence and avoid shortage of spare parts;
- Provide an upgrade path for future plant life extension (beyond 20 years), if necessary.

The recommended approach is:

- Obtain a replacement as soon as possible.

  In terms of having a replacement as soon as possible with least risk, the hardware-based emulation option (Quickware/L-3 MAPPS) is the best choice. The software-based emulation approach (SimH) requires a much greater internal engineering effort as well as larger schedule and regulator risk. Hence the following is recommended:

- Keep the DCC healthy (complete the planned improvements per Project 33509). The fewer number of stalls, the fewer number of times the DCC needs to be disturbed. This will reduce the possibility of accidental damage to DCCs (especially the backplanes whose connections are made mechanically);
- Continue searching for "used" spare parts qualified for use.
- Implement the replacement as soon as possible:
  - Complete negotiations with L-3 MAPPS/Quickware to clarify and resolve the remaining price structure, and terms and conditions issues.
  - Award the contract to L-3 MAPPS for development of a PDP11 based emulator, based on enhancement of the Quickware design;
  - Complete discussions with L-3 MAPPS with respect to detailed work plans and schedules, to ensure the proposed project is adequately resourced to meet the required schedule.

Proceed with the design and procurement of an emulator for the Ramtek display systems.

Proceed with the design and implementation of Annunciation Improvements, to address nuisance alarms received during turbine trip events and during planned outages.

Milestones Finish Date (D/M/Y)	Description
2-Jun-06	Revise PEP and obtain approval
26-May-06	Award of contract for hardware emulator
15-Oct-07	Re-design of hardware emulator complete
21-Jan-08	Prototype hardware emulator available
24-Nov-08	Functional testing of emulator complete
30-Jun-09	Emulators installed in SEM systems
31-Dec-09	Emulator installed in CP
30-Jun-11	Emulator installed in DCCs
31-Dec-09	Ramtek replacement design complete
30-Jun-11	Ramtek replacement installation in DCCs
31-Dec-08	Annunciation improvement software programming complete
31-Dec-10	Annunciation improvements installed

5/ QUALITATIVE FACTORS

Completion of this project will result in more reliable DCC performance. This will result in:

- The reduction of maintenance effort.
- The elimination of spare parts shortages.
- In conjunction with project 33509, the return the health status of the DCC and CP computers to green (from yellow) and maintain them at that level.
- The improvement of the Annunciation Alarm Conditioning, eliminating the operator work-around caused by nuisance annunciation messages.
- The introduction of newer technology, which will be easier to support and maintain by less experienced staff, greatly reducing the requirement for legacy knowledge.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Unforeseen problems in redesign of hardware emulator	Development costs could increase	Medium	Use fixed price contracts wherever possible. Note:The Design Challenge has already been completed and the project scope is well defined.	Low
Unforeseen problems in design of Ramtek replacement. Note: Little preliminary engineering has been performed in this area, therefore the risk remains.	Development costs could increase	High	Develop synergy with Fuel Handling project, which also requires a solution to the Ramtek replacement issue.I	Medium
Increased project scope due to undiscovered problems occuring.	Potential increase in cost, and schedule delays. Project Charter and contracts must be re-done.	Low	Detailed design specification confirmed and agreed upon before re-design of emulator.	Low
Problems occuring in re-design phase of emulator.	SEM in-service delayed. DCCs in-service possibly delayed	Medium	Negotiate contract with service providers to ensure that payment schedule encourages timely acheivement of milestones. SimH retained as back-up plan.	Low
Unforeseen problems revealed in testing of redesigned emulator.	SEM in service delayed. DCC's possibly delayed.		QA Service provider can apply additional technical resourses.	Low
Loss of key staff members in design team for emulator.	Project would be delayed, but with limited cost implications. (Fixed price contracts in place with service providers).	Medium	Knowledge will be transfered to the QA service provider in the initial engineering phase. The QA service provider could then continue to manage the remaining work.	Low
Loss of experienced staff in the DCC section, due to retirement.	Project would be delayed.	Medium	Several junior engineers will be exposed to new technology on this project.	Low
Lack of HFE resources, and DCC	Schedule delayed.	Medium	Identify risk early in project. Bring in external resources	Low

resources familiar with annunciation.			if necessary.	
The company proposed for the emulator re-design work is small, with the core expertise currently residing with a single person.	Loss of a key resource could lead to a return to the preliminary design stage.	**Medium**	A second agency, L-3 MAPPS, has been commissioned to work with the emulator designer to ensure that the key design elements are captured in the event of loss of this resource.	**Low**
Emulator could include a component with a short life span that cannot be replaced.	Emulators would have to be replaced before their projected life.	**Medium**	The design challenge processs specified that only components with a reliable life span shall be used in the redesigned emulator.	**Low**
				N/A
Any software or firmware used in the emulator will have to be qualifiable to software category two.	CNSC approval process could cause delays.	**Medium**	A hardware-based emulator will be pursued to minimise software changes. This approach is easier to validate and confirm.	**Low**
No risks identified.				
No risks identified.				
The replacement does not meet the business objectives	The detailed design work must be repeated. Increased failure rate for DCC's would be likely while the re-design is performed, with possible associated production loss.	**Medium**	L-3 MAPPS commissioned to oversee the emulator re-design work, and monitor progress and achievement of intermediate design milestones.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2010	Jun 2011	E Hung Section Manager Darlington DCCs

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	DCC Emulator Passes Acceptance Test.	Existing PDP11 performance.	Funtionality demonstrated by system tests.	Suite of tests based on performance of original system.	QA oversight provider, in conjunction with Darlington DCCs staff.
2.	Emulator Functions in SEM systems, CP and DCCs.	Existing PDP11 Operation	SEM, CP and DCC S/W and H/W Check programs function normally in an extended test. Same or better operation using system utilities to measure system loading and performance.	Monitor for system stalls, and errors detected.	Darlington DCCs staff.
3.	Number of System Stalls reduced.	System Health is "White".	System Health returns to "Green".	System health reports..	System engineer.
4.	System spares situation returns to "Healthy" state.	Some parts in short supply.	Sufficient Spares to reach End of Life.	Inventory of Spares is acceptible.	Darlington DCCs/ Control Maintenance
5.	Frequency of nuisance alarms during startup and shutdown.	Established by historical data	Significant reduction in number of nuisance alarms.	Ops acceptance of reduction in alarms.	MCR system engineer

![ONTARIO POWER GENERATION]

OPG Confidential	Page: 13 of 14
ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

Darlington DCC Replacement 16 - 33977

Partial Release Business Case Summary D-BCS-33977-10001-R001

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Years 2005	2006	2007	2008	2009	2010	2011	2012	Total
Project Management (OPG)	238	189	189	189	189	108	81		1,183
Engineering & Drafting (OPG)	282	678	1,370	1,183	705	303	118		4,639
Material	[redacted]								
Installation – PWU, BTU									
Contract – Project Mgmt									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Sub Total (excl Contingency)									
Contingency									
Grand Total	1,243	2,138	5,580	4,133	4,281	3,214	492	-	22,056
2006-2010 Business Plan	1,175	2,727	2,800	2,631	3,415	2,973		-	15,521
Variance to Business Plan (excl Contingency)	(94)	(1)	2,235	963	308			-	3,861

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 15%**

Reviewed By:

E Hung
Project Manager
May [illegible] 06
Date:

Approved By:

R Hohendorf
Eng & Mods Manager (Strat IV)
May 17, 2006
Date:

Darlington DCC Replacement 16 - 33977

Partial Release Business Case Summary D-BCS-33977-10001-R001

ATTACHMENT "B" **TOTAL PROJECT COST VARIANCE TABLE**

$000's Choose One	Last Release day/mth/yr	This Release day/mth/yr	Variance	Explanation
Project Management (OPG)	1,038	1,183	145	Longer project duration
Engineering & Drafting (OPG)	3,637	4,639	1,002	Additional verification required for new product
Installation – (OPG)	257	260	3	
Material	[redacted]			
Contract – Project Mgmt	[redacted]			
Contract - Design	[redacted]			
Contract - Installation	[redacted]			
Contract - Other	[redacted]			
	[redacted]			
	[redacted]			
	[redacted]			
	[redacted]			
	[redacted]			
	[redacted]			
Interest (Capital Project Only)	[redacted]			
Sub Total (excl Contingency)	12,886	19,182	6,296	
Contingency	1,933	2,876	943	
Grand Total	14,819	22,058	7,239	

DND Feeder Replacement ALARA/Optimization 16 - 34008

Full Release Business Case Summary D-BCS-33160-10005-R001

Routing	Location	Action	Signature	Date
M. Christiaans Senior Technical Engineer Ext. 1089	D08-ES2	Prepare BCS	M. E. Christiaans	Nov 14/2006
D. McKenzie Section Manager - Feeders & Reactor Maintenance Engineering Support Ext. 1624	D08-ES2	Review BCS		Nov 16/2006
I. Khan Manager - Feeders & Reactor Maintenance Ext. 1478	D08-ES3	Review BCS		NOV 16/2006
A. Brooks Senior Financial Analyst Ext. 1504	D08-ES3	Review BCS	A Brooks	Nov 21/06
J. McIntee Controller, Darlington Ext. 1324	D08-ES3	Approve BCS		Nov 29/06
Seedhouse ctor Station Engineering 7584 for	D08-ES3	Review BCS		30 Nov 2006
Gregory O. D. Smith Senior VP Darlington Ext. 7488	D08-ES3	Submit BCS		Dec 1/2006
R. Leavitt Director Investment Management - Nuclear	P823-315	Approve BCS		Dec 12, 2006
J. Beech Vice President Nuclear Finance	TCH09F26	Approve BCS		Dec 14, 2006
D. Power ~~Director~~ VICE PRESIDENT, Corp. Inv. ~~Investment and Business~~ Planning	TCH07D06 REC'D Jan. 3/07	Approve BCS		Jan 8/07
~~Pierre R. Charlebois~~ T. Mitchell [redacted] Chief Nuclear Officer Ext. 5294	P826A-1	Approve BCS		11 JAN 07
ooks Financial Analyst xt. 1504	D08ES3	Return For Distribution		

DND Feeder Replacement ALARA/Optimization 16 - 34008

Full Release Business Case Summary D-BCS-33160-10005-R001

1/ RECOMMENDATION:

Approval is requested for $11,700K (including contingency) full release capital funding to provide tooling and capability in order to optimize feeder replacement durations and reduce radiation dose associated with feeder replacements. The work is planned to meet the D611, D721, D811 and D1111 outage schedules and subsequent outages for feeder replacements as per the business plan. The tooling and capability developed under this project will also improve efficiency of the fuel channel reconfiguration and single fuel channel replacement executions.

Based on the economic analysis performed to determine impacts of the new tools on feeder replacement windows the NPV of the project is +$56.8M compared with the base case (feeders replaced in series with 2 ice plugs per feeder for fuel channel isolation) for the assessment period of 2006 to 2011 (Attachment-B). If we expand the assessment period to 2014 the NPV of the project becomes +$97.8M (See the modelling assumptions in Section 4). The radiation dose savings due to improved tooling and methods are expected to be equivalent to $3.7M.

The tooling and capability developed under this project is justified on its own merit. However, the NPV described above is based on an assumption that the 2nd set of advance feeder cut and weld tooling will be available by spring 2008.

However, if OPG decides to not pursue 2nd set of tooling and/or is deferred then NPV of the project will decrease to $35.4M for the assessment period of 2006 to 20011 and $57M for the assessment period of 2006 to 2014.

Note: 2nd set of advance cut & weld tooling is being purchased under a separate project by Science & Technology Div.

The recommended work under this project will provide Darlington the following capability:

- Isolate more than 8 fuel channels (FC) on each reactor face, without having to bring the fuelling machine (FM) back to the reactor face. This capability is required by Spring 2008 outage (D811).
- Optimize feeder replacement durations by allowing parallel work and reduce dose associated with feeder replacements from 8 REM/feeder to 3 REM/feeder.
- Meet the 2007 - 2011 Business Plan and Generation Plan projections for feeder replacements.
- Execute a proactive feeder replacement schedule in order to ensure that the feeder replacement issue is managed to avoid the risk of forced outages or forced outage extensions.

Reduction in the radiation dose exposure due to this project is expected to be as follows:

- Provision of maintenance platform wing extensions will mitigate the requirement to erect and disassemble scaffolding in the reactor vault, for each bridge movement, associated with accessing peripheral feeders for replacement. In D611, 3 of the 5 planned replacements are peripheral feeders.
- Availability of channel isolation plugs (CIP) for feeder replacement campaigns will mitigate the dose associated with ice plugging. 50% reduced ice plugging dose is expected for each feeder as only one ice plug will have to formed per feeder instead of two.
- Improved ice plug freeze jackets will support freeze jacket installation from beyond arms reach resulting in reduced operator dose uptakes from feeder cabinet work.
- A trolley mounted storage magazine will mitigate the need to manhandle shield plugs for campaigns greater

than 8 feeders per reactor face when CIP's are used. The channel isolation plugs replace the shield plugs in the end fitting supporting ice plug formation. Shield plugs have dose rates as high as 20 to 30 REM/hr contact.

- Reduced radiation fields associated with mini platform shielding improvements are expected to result in a reduction of approximately 2 REM per inspection campaign where these canopies are used.

Summary of work required to be completed under this project to meet the business plan objectives, mitigate future risks, and to support future improvements such as reduction in overall outage duration is indicated below. Details are given in Section 4.

- Qualify the Single Fuel Channel Replacement (SFCR) Platform as an Elevating Working Platform (EWP).
- Modify the SFCR Platform to add Wing Extensions to access reactor face areas, not reachable from the existing platform.
- Commission the existing 7 Channel Isolation Plug (CIP) and perform Available for Service (AFS). The existing CIP's were designed and developed under the feeder integrity project (FIP).
- Procure additional 15 CIP's to allow fuel channel isolations for the larger feeder replacement campaigns. Modify inlet CIP design to correct existing design deficiency.
- Modify the mini-platform shielding canopy roof, to minimize radiation dose uptake from the feeder cabinet.
- Modify the SFCR Shielding Canopy to increase access to the feeders at the reactor face.
- Design a modified closure plug as Channel Drain Tool (CDT) to allow fuel channel isolation with the reactor bridge at variable locations. This provides greater flexibility in fuel channel isolation.
- Develop and provide a fuelling machine (FM) trolley mounted storage magazine to store CIP's, shield plug, and closure plugs to improve the fuel channel isolation process. The magazine will allow storage of up to 20 items such as shield plugs, closure plugs, CIPs or modified closure plugs or any combination of those. Install a Fuelling Machine Trolley Control System modification to integrate Storage Magazine Controls.
- Upgrade the Fuel Handling Software to track more than 5 Channel Isolation Plugs and to interface with the Storage Magazine Control System.
- Design and fabricate new freezing jackets to allow formation/maintenance of more than 2 ice plugs.

(details on Attach A)						
Released to Date:		650	[redacted]		Spent Life to Date:	[redacted]
Capital Requested :	Full	10,150	[redacted]	2006-2010	Appr'd Business Plan (Tot Proj):	[redacted]
Cumulative Release:	Total to Date	650	[redacted]	2006-2010	Business Plan Variance:	[redacted]
Total Project Estimate:	+30% to -15%	11,700	[redacted]	2006	Budget (Current Year)	[redacted]
Current Year Estimate:	2006	1,430	[redacted]	2006	Budget Variance (Current Yr)	[redacted]
Type of Investment	Sustaining	N/A	[redacted]		Cumulative Release Remaining:	[redacted]
NPV:		N/A	[redacted]		Contingency on Remaining Release:	[redacted]
IRR:		N/A	[redacted]		Contingency % on Remaining Release:	[redacted]

A PCRAF will be issued to adjust budget variance for 2006 and transfer funding to 2007 and 2008.

Reviewed By:

Nov 16 2006

I. Khan
Manager, Feeders & Reactor Maintenance
Darlington Operations & Maintenance
Date:

Finance Approval:

Nov 29/06

~~J. McIntee~~
Controller, Darlington
Date:

Dec 18, 2006

Reviewed By:

30 Nov 2006

S. Seedhouse for
Director, Station Engineering
Darlington
Date:

Submitted By:

Dec 4/2006

Gregory O. D. Smith
Senior Vice President Darlington
Darlington
Date:

Line Approval (Per OAR Element 1.1 Project In Budget):

~~P. R. Charlebois~~ T. N. Mitchell
Chief Nuclear Officer
Ontario Power Generation

2/ BACKGROUND & ISSUES

The feeders interface with the Reactor Primary Heat Transport (PHT) Inlet and Outlet Headers and the Reactor fuel channels. Hence, feeders are critical to the reactor operation. The requirement for feeder replacements in Darlington Units is as a result of higher than expected wall thinning due to Flow Accelerated Corrosion (FAC), identified during periodic inspections performed under the PHT Feeder Piping Aging Management Strategy and Plan and the CSA N285.4 Standard.

The actual feeder replacements are being performed under OM&A project 38460 in 2006 and under Outage OM&A 30461 from 2007 onwards. This project 34008 is intended to provide the required capability to perform those replacements efficiently and effectively. The current Business Plan and Generation Plan shows a total of 66 feeder replacements required in Darlington Units during 2006 to 2011 window. Reasons for this proposed work are:

- As Darlington Units age, the number of required feeder replacements increases. Hence the requirement to have a proactive approach to eliminate prohibitive number of feeder replacements in the later years. Feeder replacements have been advanced to be proactive on the feeder replacement schedule.
- The Business Plan was aligned with the optimal replacement schedule in order to ensure that the feeder replacement issue is managed to avoid risk of forced outages or forced outage extensions.

The current project estimate of $9M differs significantly from the original estimate of $4.5M. Initial estimates were made at a time when the project scope was unclear and the level of collaboration with Bruce power was anticipated to be of much greater significance. During the development phase, the project deliverables have been defined based on business plan commitments. Both the GE and IMS have provided estimated costs associated with the defined deliverables. It has been determined that collaboration with Bruce Power can not be realized for the tools and capability developed under this project.

Other considerations are:

1. Feeder replacement is a critical path activity during outages when the required window is greater is 10 days. Any opportunity to minimize feeder replacement windows is an economic benefit to the Corporation and provides greater fleet outage flexibility.
2. Darlington does not have capability to perform feeder replacements in parallel and our current fuel channel isolation tools have limitations. These tools do not allow parallel fuel channel isolations.
3. Feeder replacement is a dose intensive operation. There is a need to minimize dose uptake as per the ALARA principles.
4. Critical path analysis to identify outage windows in the Generation Plan were based on certain assumptions or optimization strategies. They are:
   a) Capability to do feeder replacements in parallel on both reactor faces by 2008. For this, we also need to obtain an additional set of advanced cut and weld tooling. This is being addressed by Science & Technology Division under a separate project.
   b) Greater flexibility in channel isolation. For this, we need to purchase a new and improved Channel Drain Tool package.
   c) Develop capability to isolate more than 8 fuel channels on each reactor face, without having to bring the fueling machine back to the reactor face.
   d) Fuel Handling Software upgrade to track installation of Channel Isolation Plugs (CIP) in more than 5 fuel channels.
   e) Develop capability to form/maintain ice plugs in parallel on more than 2 feeders (ideally up to 4).

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Do Nothing - Base Case (Not Recommended)

The status quo (base case of feeders replaced in series with two ice plugs to isolate fuel channels) alternative is not recommended for the following reasons.

1. There will be a greater amount of dose expenditure for feeder replacements and we will not be following the ALARA principles.
2. This will cause extension of the outage durations ranging from one day to 28 days. Outage push is illustrated in Attachment-B.
3. Darlington will not meet the 2007 - 2011 Business Plan commitments. The Business Plan assumes capability to replace feeders in parallel will be in place by D811.

Alternative 1 – Implement full Scope as per Proposal in Section 4 (Recommended)

This is the preferred alternative. The tools and capability will be bought as one package.

1. It will minimize the dose expenditure for Feeder Replacement work and will follow the ALARA principles. The current estimate of approximately 8 REM/feeder will be reduced to 3 REM/feeder once these improved tools are in place.
2. Darlington will be able to execute a proactive feeder replacement schedule in order to ensure that the feeder replacement issue is managed to avoid risk of forced outages or forced outage extensions.
3. Darlington will meet the 2007 - 2011 Business Plan commitments, as capability to replace feeders in parallel on both reactor faces will be in place by D811.
4. It will save significant critical path time for feeder replacements. See attached economic analysis.
5. Based on the economic analysis performed to determine impacts of the new tools on feeder replacement windows the NPV of the project is +$56.8M compared with the base case (feeders replaced in series with 2 ice plugs per feeder for fuel channel isolation) for the assessment period of 2006 to 2011 (Attachment-B). If we expand the assessment period to 2014 the NPV of the project becomes +$97.8M (See the modelling assumptions in Section 4).
6. The radiation dose savings due to improved tooling and methods are expected to be equivalent to $3.7M.
7. The tooling and capability developed under this project is justified on its own merit. However, the NPV described above is based on an assumption that the 2nd set of advance feeder cut and weld tooling will be available by spring 2008.
8. However, if OPG decides to not pursue the 2nd set of tooling and/or is deferred then NPV project will drop to $35.4M for 2006-20011 assessment period and $57M for assessment period of 2006 to 2014.

Alternative 2 – Delay the Recommendation (Not Recommended)

The delay alternative is not recommended for the following reasons.

1. We will not be ready for feeder replacements for the D611 outage.
2. There will be a greater amount of dose expenditure for feeder replacements and we will not be following the ALARA principles.

3. We will not meet the 2007 - 2011 Business Plan commitments. The Business Plan assumes capability to replace feeders in parallel will be in place by D811.
4. This will cause a significant extension to the D811 outage duration. The outage extension will be up to 24 days as illustrated in the Attachment-B.
5. This will not allow feeder inspections to be done in parallel with feeder replacements for minimum of days impact per outage.

4/ THE PROPOSAL

The recommended work includes completing all analysis, documentation, tooling design, fabrication and commissioning, modifications to existing tooling, and training to safely execute the Feeder Replacement ALARA/Outage Optimization project. The project deliverables are as follows.

1. **SFCR Platform qualification as an Elevating Working Platform.**
   This is required for both feeder replacements and fuel channel reconfiguration. Work needs to be done to meet Ontario Health and Safety Act (OHSA) requirements (both legal and safety) and implement restrictions via procedures to use the current maintenance platform and reactor bridge as an elevating working platform (EWP). This is required for the Fall 2006 outage (D611). This task is complete.

2. **SFCR Platform Wing Extensions.**
   Design, build, fabricate and commission wing extensions for East and West Maintenance platforms to access feeder areas, not reachable from the existing maintenance platform. This will eliminate the need to build scaffolds on critical path and save dose and critical path time. Required for feeder replacements in the Fall 2006 outage (D611). This task is complete.

3. **Channel Isolation Plug (CIP) Commissioning and AFS.**
   Commission existing 7 CIP's and implement required updates to Fuel Handling Operating Sequence Code (Op Data) to allow installation and removal of CIP's using fuelling machine (FM). The CIP function is to allow a fuel channel to be isolated for feeder replacement with a single ice plug, rather than using two ice plugs which is the current requirement for channel isolation. The CIP was designed by GE and delivered in 2003 by IMS under the Feeder Integrity Project. It was not commissioned. These are required for feeder replacements in the Fall 2006 outage (D611). This task is complete.

4. **Procure additional 15 CIP's** to allow fuel channel isolations for the larger feeder replacement campaigns such as Spring 2008 and Spring 2011. Modify existing inlet CIP's to correct existing design deficiency. Estimated cost is [redacted]

5. **Mini-Platform Shielding Canopy Modification.**
   This is required to extend the canopy roof to minimize radiation dose uptake from the feeder cabinet. This canopy is used regularly to execute feeder inspections. This is required for Spring 2007 outage (D741). Estimated cost is [redacted] in 2007.

6. **SFCR Shielding Canopy Modification.**
   To increase the size of the access window to the feeders at the reactor face. This is required for feeder replacements and fuel channel reconfiguration. This is required for Spring 2007 outage (D741). Estimated cost is [redacted] in 2007.

7. **Closure Plug Based Channel Drain Tool.**
   Re-design Channel Drain Tool (CDT) package to provide greater flexibility in fuel channel isolation. GE has already developed this tool for Bruce Power. It will require modification to meet Darlington's service conditions and requirements. This is required by Spring 2008 outage D811. Estimated cost is [redacted]

8. **FM Trolley Mounted Storage Magazine.**
   Design and fabricate a fuelling machine (FM) trolley mounted storage magazine to store CIP's, shield plug, and closure plugs to improve the fuel channel isolation process. Install a Fuelling Machine Trolley Control System modification to integrate Storage Magazine Controls. The magazine will allow storage of up to 20 items such as shield plugs, closure plugs, CIPs or modified closure plugs or any combination of those. Storage of these components eliminates the need to manhandle high dose shield plugs for numbers greater than 8 per face or the need to remove and re-install platforms to manage the 8 shield plug limitation. This is required by Spring 2008 outage. Estimated cost is [redacted]

9. **Upgrade the Fuel Handling Software** to provide capability to track Channel Isolation Plugs in the reactor and to interface with the Storage Magazine Control System. This is required by Spring 2008 outage D811. Estimated cost is [redacted]

10. **Design and fabricate Feeder Freezing Jackets** to allow formation of at least four ice plugs in parallel. The current freezing jackets impose limitation of two of ice plugs that can be formed and/or maintained. This prohibits parallel next feeder set up while replacing the current feeder. This is required by Spring 2008 outage. Estimated cost of [redacted] in 2007.

Modeling Assumptions:

Key assumption is that Feeders will always be critical path activity during outages. Current experience suggests that actual allocated outage window is less than that marked for in the Generation Plan and therefore built into the Business Plan. In addition, for future larger campaigns, feeders will have greater potential to secure a complete hold on being the critical path activity. Therefore the benefit will be the incremental days between the base case and the alternative.

Base Case (Do not acquire new capability- Status Quo):

- Dual ice plugs or CIP/Ice plug combination will be required to isolate fuel channels/feeders.
- Feeder replacement duration is 38 hours per feeder (8 hours for set up + 30 hours for cut/weld). Due to limitations in isolation, draining, and fuel channel components tracking and storage capability set up is required for each feeder.
- A three day shuffle of existing CIPs (installed in fuel channels) is required for every five feeders beyond the first five. This is due to the fact that only a limited number of CIPs can be used in the reactor due to handling/tracking limitations of the CIP's in the reactor. The three days is required to pull platforms, bring in the fueling machine and return the platforms.
- All feeder replacements will be conducted in series (including feeder freezing as noted above).
- Restrictions and lack of flexibility due to isolation requirements will force planned parallel feeder inspections to be conducted in series with replacements for D611 (7 days) and D721 (5 days).

Additional Soft Factors (Not included in the economic model):

- FM will remain dedicated to feeder replacements as it will contain the removed highly irradiated shield plugs.
- Serial activities with dual ice plugs will place additional limitations on feeder inspection flexibility, i.e. less opportunity to do parallel work with feeder replacements.

The Base Case applies to D611 and will apply to D721 due to timing of the alternative implementation, therefore incremental feeder replacement impacts will not be looked at until starting in D811 except for the capability to perform feeder inspections in parallel to replacements in D611 and D721.

Alternative (Acquire proposed tooling and capability):

- For greater than 7 feeders total replacements(2) will be conducted in parallel, the equivalent number of feeders determined as per following guideline:
  - Opposite faces (East/West) will be executed 100% in parallel.
  - Same face replacements can be conducted in parallel for 50%(1) of their targeted feeders remaining after completing the shorter opposite face. This assumes both crews operate at the same pace. Note this really only affects D1111 outage for an equivalent of a 2 feeder savings.
- If second set of advance cut and weld tooling is not available all replacements will be conducted in series.
- Feeder replacement duration is 8 hours setup + (30 hrs cut & weld) x (equivalent number of feeder). There is a one time set up for the first feeder as the advancements provided under the alternative allow for preparation of the next feeder while replacing the current feeder. This applies to both parallel and series replacement. This reverts to 0 + 38 hours if not successful in implementing 4 ice plugs in series (post meeting addition).
- The commissioning of existing CIP, wing extensions and qualification of the SFCR platform as EWP allow feeder inspections to be conducted in parallel with replacements for D611 and D721.
- A contingency of [redacted] will be applied to the estimated cash flow.
- The cost of the second set of advance cut and weld tools is 6M$ plus contingency. A relatively small contingency of [redacted] will be assumed for a repeat order of a developed technology, i.e. the total 6.72M$ with contingency and overheads. Assume that [redacted] will not and should not partner and the cost will be shared uniformly between Pickering and Darlington. All cash flow is in 2007.
- The cost of the second set of advance cut and weld tool will be factored into the benefit where the second set is credited in this analysis.
- Dose savings of 5 Rem per feeder at cost of 25 k$ per Rem. The dose benefit will not be added to the bottom line but rather shown as an additional benefit (post meeting addition).
- Dose savings start in 2008.

Notes:

1. Percentage of Feeders targeted which are within three (3) rows apart and greater than four (4) columns apart is 50%.
2. A criterion for parallel vs. series planned replacement is > 7 feeders total, east and west combined.

Additional Soft Factors (not included in the economic model):

- Feeder inspections are more likely to be in parallel with each other (face/face).
- Some potential for greater FM flexibility toward fuelling operating units.

Feeder Replacement Schedule as per current Business Plan

Outage	Year	Feeders	West	East
611	2006	5	4	1
721	2007	5	4	1
811	2008	16	8	8
931	2009	5	3	2
1021	2010	10	5	5
1041	2010	5	3	2
1111	2011	20	8	12
1231	2012	10	4	6
1341	2013	8	4	4
1321	2013	8	4	4
1411	2014	20	10	10

Economic Assumptions:

- Energy costs conservatively applied at 49.5 $/MW.
- Outage overheads (for extensions) of 400 k$/day applied.
- Discount Rate = 7%. (Mid 2006 dollars determined in NPV)
- Escalation not included as this is a very simplified analysis.
- This BCS release covers the necessary work required for the D611, D721, D811, D1111 Outages and beyond.

Milestones Finish Date (D/M/Y)	Description
30-Dec-05	Partial BCS
15-Mar-06	D611 Outage - Design Mod documents issued
30-Apr-06	D611 Outage - Support documents issued
27-Aug-06	D611 Outage – 90% Materials on-site
27-Oct-06	D611 Outage - Tooling and equipment on-site
12-Feb-07	D721 Outage - Design Mod documents issued
12-Apr-07	D721 Outage - Support documents issued
12-Aug-07	D721 Outage - 90% Materials on-site
12-Oct-07	D721 Outage - Tooling and equipment on-site
28-Jul-07	D811 Outage - Design Mod documents issued
28-Sep-07	D811 Outage - Support documents issued
[illegible]-Jan-08	D811 Outage - 90% Materials on-site
[illegible]-Mar-08	D811 Outage - Tooling and equipment on-site
31-Dec-08	Project Closure/Simplified Post Implementation Review

5/ QUALITATIVE FACTORS

1. This preparatory work is required in support of the Feeder Replacement Program to allow us to deal with the results of the inspections performed under the PHT Feeder Piping Aging Management Strategy and Plan and the CSA N285.4 Standard.
2. Feeder Replacement Program is required to operate the component safely and keep them in a safe condition as required by the Nuclear Power Reactor Operating License (NPROL) license condition 5.2.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
-Funding may not be sufficient. - 2006 estimated expenditure may not be possible due to late start of the project.	- Not meeting project objectives and outage milestones. - Cash flow adjustment will be required.	**Medium**	Add a [redacted] contingency to cover this item. Bruce Power has already developed some of the tools. Potential partnering with Bruce Power will reduce project costs. GE/IMS will provide firm estimates.	**Low**
Scope				
Additional tooling/procedures are required to implement the plan.	Higher cost	**Medium**	A [redacted] contingency will cover for additional tooling and procedures.	**Low**
Schedule				
D811 deliverables are on a very tight schedule	May not be able to meet Outage milestones	**Medium**	Provide strong Project oversight and schedule control. Hold regular oversight meetings and communicate any threats and issues ahead of time with Outage.	**Low**
Resources				
2nd set of tooling pursued by Science & Technology Division may not be available for D811.	Training set will have to be upgraded to production set at a cost of [redacted] to allow parallel feeder replacements. The upgraded training set will then be used as a back-up tool set. Potential for one or more tools in upgraded training set to become contaminated if production set tool failure occurs.	**Low**	Work with Science & Technology Division to provide strong oversight to acquire 2nd set of advance feeder cut & weld tooling.	**V. Low**

Technical				
May not be able to bring Nitrogen flow to less than 250Kgs/hour to meet current OP&P limit of 400Kgs/hour for non-isolable air ingress into the vault.	May not be able to form more than 2 ice plugs in parallel. This will require set-up time of 8 hours between each pair of feeders being replaced in parallel. This will impact on project NPV. The NPV will drop from $53M to $46M.	**Medium**	Analyze, prepare technical justification, and pursue increasing the OP&P limit with CNSC or correct interpretation of the limit.	**Low**
Regulatory				
N/A				
Environmental				
N/A				
Health & Safety				
N/A				
Investment				
N/A				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	June 2008	Dec 2008	Feeders & Reactor Maintenance

Comments:

A simplified Post Implementation Review will be done for the project as part of the project closeout. The PIR will evaluate the completion of steps which would lead to success:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	SFCR Platform qualification as an Elevating Working Platform (EWP) completed.	May not be qualified as an EWP.	To be qualified as a EWP.	Standard procedural compliance. OSHA and legal requirement compliance. Report issued.	Feeders & Reactor Maintenance.
2.	SFCR Platform Wing Extensions addition completed.	No access to peripheral feeders.	Provide approved extensions to the existing platform.	Ability to work on peripheral feeders, normally accessible only by scaffolding.	Feeders & Reactor Maintenance.
3.	CIP commissioning and AFS completed.	Isolation capability limited to one feeder at a time.	Isolation capability increased to at least two feeders in parallel.	AFS completed	Fuel Handling
4.	Mini-platform Shielding Canopy modification completed.	Existing shielding canopy provides limited dose reduction for feeder inspection and other reactor face work.	Extension of the shielding canopy provides better protection against radiation dose uptake.	Availability for reactor face work. Dose rate in the canopy reduced.	Feeders & Reactor Maintenance.
5.	SFCR Shielding Canopy modification completed.	Existing canopy provides limited access for feeder replacement work.	Increased access to both reactor faces for feeder replacements and fuel channel reconfiguration.	Availability for feeder replacements and fuel channel reconfiguration work program.	Feeders & Reactor Maintenance.
6	Re-design of CDT package completed.	Existing CDT is large size, it protrudes and can only be installed manually.	Capability to isolate at least 2 Fuel channel/feeder isolation at one time.	Capability to form Ice plugs in parallel Fuel Machine connected to fuel channel	Feeders & Reactor Maintenance.
7	Storage Magazine to be installed on FM Trolley available	No flexibility in channel isolation. Need multiple visits to Fuel Bay.	To store up to 20 Shield Plugs, CIPs, and Closure Plug.	Fuel channel components are managed locally. Visits to fuel bay by FM eliminated.	Fuel Handling

8	Fuel Handling (FH) Software upgrade to track CIP locations in the reactor.	FH Operating Manual and Software cannot support use of multiple CIPs or the Storage Magazine on the FM trolley.	OM updated and Software upgraded.	Allow multiple CIP use and interface with the system control for the Storage Magazine on the FM trolley.	Fuel Handling.
9	Improved design freezing jackets available. Can form or maintain more than 2 ice plugs	The current freezing jackets impose limitation of two of ice plugs that can be formed and/or maintained.	Improved design freezing jackets available that are capable of forming or maintaining more than 2 ice plugs.	Can form or maintain more than 2 ice plugs.	Feeders & Reactor Maintenance.

DND Feeder Replacement ALARA/Optimization Project 16- 34008

Full Release (Phase 1) Business Case Summary D-BCS-33160-10005-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Years 2005	2006	2007	2008	2009	2010	Total	LTD This Mth Dec 2005	LTD %
Project Management (OPG)		50	120	120	120	-	410		
Engineering & Drafting (OPG)			100	100		-	200		
Contract - IMS & [redacted]		1,020	4,130	1960		-	7110		
Contract - Other			50	50		-	100	-	
Contract - [redacted] FH software upgrade		-	400	500	-	-	900		
						-	-	-	
Interest (Capital Project Only)		30	200	50	15	-	295	-	0.0%
Sub-Total (excl Contingency)	-	1,100	5,000	2780	120	-	9,000	-	0.0%
General Contingency (30%)		330	1,500	834	36	-	2,700	N/A	N/A
Total Contingency	-	330	1,500	834	36	-	2,700	N/A	N/A
Grand Total (incl Contingency)	-	1,430	6,500	3,614	156	-	11,700	N/A	N/A
2006-2010 Business Plan		2,500	4,500	1,000	1,000		9,000	N/A	N/A
Var to Bus Plan (excl Contingency)	-	(1,400)	500	1,780	(880)		-	N/A	N/A

Removal Costs included in above	0
Definition Costs included in above	0
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 40%**

Reviewed By: DB McKenzie Nov 16/2006

Douglas McKenzie Date:
Sect. Manager, Feeders & Reactor Maintenance Engineering Support.

Approved By: Nov. 16, 2006

Ijaz Khan Date:
Manager, Feeders & Reactor Maintenance
Darlington Operations & Maintenance

Attachment - B

BCS Economic Analysis Assumptions

All assumptions have been derived from a meeting on 28 September 2006 with site feeder personnel and finance. Attendees were: Ijaz Khan, Doug McKenzie, Ann Brooks, and Bob Grandoni. The assumptions were further refined based on a challenge meeting on 2 November 2006. Attendees were: Ijaz Khan, Stu Seedhouse, Ann Brooks, John McIntee, Ian Mackenzie, Don Powers, Randy Leavitt, and Bob Grandoni.

This economic analysis contains the following elements:

1. Channel Drain Tool (CDT)
2. Fuelling Machine (FM) Trolley Mounted Storage Magazine
3. Channel Isolation Plug (CIP)
4. Fuel Handling (FH) Software Upgrade
5. Freezing Jacket Upgrade

The benefits from above begin in D811. The exception being the commissioning of existing CIPs, Platform extensions and SFCR platform qualification as Elevating Working Platform (EWP) for which benefit materialized for D611 & D721 in way of providing for feeder inspections to be in parallel with replacements. Simplified assumptions will be used to determine the impact and then predict an approximate incremental benefit.

Key assumption is that Feeders will always be critical path. Current experience suggests that actual allocated outage window is less than the marked for in the Gen Plan and therefore built into the Business Plan. In addition, for future, larger campaigns, feeders will have greater potential to secure a complete hold on being critical path. Therefore the benefit will be the incremental days between the base case and the alternative.

Base Case:

- Dual ice plugs or CIP/Ice plug combination will be required to isolate fuel channels/feeders.
- Feeder Replacement duration is 38 hours per feeder (8 hours for set up + 30 hours for cut/weld). Due to limitations in isolation, draining, and fuel channel components tracking/storage capability set up is required for each feeder.
- A 3 day shuffle of existing CIPs is required for every 5 feeders beyond the first 5. This is due to the limited number of CIPs and handling/tracking limitations of the CIP's in the reactor. The 3 days is required to pull platforms, bring in the fueling machine and return the platforms.
- All feeder replacements will be conducted in series (including feeder freezing as noted above).
- Restrictions and lack of flexibility due to isolation requirements will force planned parallel feeder inspections to be conducted in series with replacements for D611 (7 days) and D721 (5 days).

Additional soft factors not included:

- FM will remain dedicated to feeder replacements as it will contain the removed shield plugs.
- Serial activities with dual ice plugs will place additional limitations on feeder inspection flexibility, i.e. less opportunity to do parallel work with replacements.

Alternative:

- For greater than 7 feeders total replacements[2] will be conducted in parallel, the equivalent number of feeders determined as per following guideline:
  - Opposite faces (East/West) will be executed 100% in parallel.
  - Same face replacements can be conducted in parallel for 50%[1] of their targeted feeders remaining

after completing the shorter opposite face. This assumes both crews operate at the same pace. Note this really only affects D1111 outage for an equivalent of a 2 feeder savings.

- If second set of advance cut and weld tooling is not available all replacements will be conducted in series.
- Feeder replacement duration is 8 hours setup + (30 hrs cut & weld) x (equivalent number of feeder). There is a one time set up for the first feeder as the advancements provided under the alternative allow for preparation of the next feeder while replacing the current feeder. This applies to both parallel and series replacement. This reverts to 0 + 38 hours if not successful in implementing 4 ice plugs in series (post meeting addition).
- The commissioning of existing CIP, wing extensions and qualification of the SFCR platform as EWP allow feeder inspections to be conducted in parallel with replacements for D611 and D721.
- A contingency of [redacted] will be applied to the estimated cash flow.
- The cost of the second set of advance cut and weld tools is 6M$ plus contingency. A relatively small contingency of [redacted] will be assumed for a repeat order of a developed technology, i.e. the total 6.72M$ with contingency and overheads. Assume that Bruce Power will not and should not partner and the cost will be shared uniformly between Pickering and Darlington. All cash flow is in 2007.
- The cost of the second set of advance cut and weld tool will be factored into the benefit where the second set is credited in this analysis.
- Dose savings 5 Rem per feeder at 25 k$ per Rem. The dose benefit will not be added to the bottom line but rather shown as an additional benefit (post meeting addition).
- Dose savings start in 2008.

otes:

3. Percentage of Feeders targeted which are within three (3) rows apart and greater than four (4) columns apart is 50%.
4. A criterion for parallel vs. series planned replacement is > 7 feeders total, east and west combined.

Additional Soft Factors (not included in the economic model):

- Feeder inspections are more likely to be in parallel with each other (face/face).
- Some potential for greater FM flexibility toward fuelling operating units.

The Base Case basically applies to D611 and will apply to D721 due to timing of the alternative implementation, therefore incremental feeder replacement impacts will not be looked at until starting in D811 except the capability to perform feeder inspections in parallel to replacements in D611 and D721.

Feeder Replacement Schedule as per Current Business Plan

Outage	Year	Feeders	West	East
611	2006	5	4	1
721	2007	5	4	1
811	2008	16	8	8
931	2009	5	3	2
1021	2010	10	5	5
1041	2010	5	3	2
1111	2011	20	8	12
231	2012	10	4	6
341	2013	8	4	4
1321	2013	8	4	4
1411	2014	20	10	10

Economic Assumptions:

Energy costs conservatively applied at 49.5 $/MW.
Outage overheads (for extensions) of 350 k$/day applied.
Discount Rate = 7%.
Escalation not included as this is a very simplified analysis.
CCA% = 20%

Outage Days Extension For Various Alternatives (Assumes 4 ics plugs):

	2006	2007	2008	2009	2010	2011
Outage	D611	D721	D811	D931	D1021/41	D1111
Do Nothing	7	5	24	1.3	13.6	27.8
Delay 2 year (with 2nd set tool)	7	5	24	1.3	0	0
Do Now (NO 2nd set tooling)	0	0	10	0	6.3	12.5
Do Now (with 2nd set tooling)	0	0	0	0	0	0

Summary of BCS Economic Analysis

NPV & Total Outage Days:

Alternative Benefit Outcomes	To 2011 NPV	To 2011 Outage Days	To 2014 NPV	To 2014 Outage Days	
2nd Tools & 4 Ice-Plugs	$ 56,846	79	$ 97,840	140	*< DN Cost of 2nd Set Tools Included In Benefit*
2nd Tools & 2 Ice-Plugs	$ 49,068	69	$ 85,807	124	*< DN Cost of 2nd Set Tools Included In Benefit*
No 2nd Tools & 4 Ice-Plugs	$ 35,437	50	$ 57,014	82	
No 2nd Tools & 2 Ice-Plugs	$ 21,330	33	$ 33,456	51	

Inferred From Above:

	To 2011	To 2014	
Benefit 2nd Tools & 4 Ice-Plugs	*$ 21,409*	$ 40,828	*< DN Cost of 2nd Set Tools Included In Benefit*
Benefit 2nd Tools & 2 Ice-Plugs	*$ 27,758*	$ 52,352	*< DN Cost of 2nd Set Tools Included In Benefit*

Dose Benefits:

	To 2011	To 2014
Dose Saving (Rem)	330	560
Dose Saving Equivalent NPV (k$)	$ 3,728	$ 6,136

BCS Economic Analysis (2006-2011)

								With 2nd Set Tools			No 2nd Set Tool			Dose Benefits		
Outage (D)	Year	# Feeders	# West	# East	Series vs Parallel in BP	Impact on Inspection (hrs)	Duration Base Case (hrs)	Duration Alternative (hrs)	Benefit hrs	Benefit K$	Duration Alternative No 2nd Set (hrs)	Benefit No 2nd Set (hrs)	Benefit No 2nd Set (k$)	Dose Save (Rem)	Dose Equiv (k$)	Escalation Factor
611	2006	5	4	1	Series	168	196	196	168	$ 10,630	160	168	$ 10,630	0	$ -	1.00
721	2007	5	4	1	Series	120	190	190	120	$ 7,711	190	130	$ 7,711	0	$ -	1.02
811	2008	16	8	8	Parallel	0	824	248	576	$ 38,161	488	336	$ 22,261	80	$ 2,000	1.04
931	2009	5	3	2	Series	0	190	158	32	$ 2,098	156	32	$ 2,098	25	$ 625	1.06
1021	2010	10	5	5	Parallel	0	452	158	294	$ 19,002	308	144	$ 9,307	50	$ 1,250	1.08
1041	2010	5	3	2	Series	0	190	158	32	$ 2,068	158	32	$ 2,068	25	$ 625	1.08
1111	2011	20	8	12	Parallel	0	976	308	668	$ 42,633	608	368	$ 23,486	100	$ 2,500	1.10
1231	2012	10	4	6	Parallel	0	452	158	294	$ 18,812	308	144	$ 9,214	50	$ 1,250	1.13
1341	2013	8	4	4	Parallel	0	376	128	248	$ 16,412	248	128	$ 8,470	40	$ 1,000	1.15
1321	2013	8	4	4	Parallel	0	376	128	248	$ 16,412	248	128	$ 8,470	40	$ 1,000	1.15
1411	2014	20	10	10	Parallel	0	976	308	668	$ 46,700	608	368	$ 25,727	100	$ 2,500	1.17

Cash Flows and NPV:

k$	Total	2006	2007	2008	2009	2010	2011	2012	2013	2014
CDT Cost	[redacted]									
Trolley Cost										
CIP Cost										
Software Cost										
Freeze Jacket										
CIP& Wing Com'n										
Project Total Costs										
Total Cost w/ Contg.					$ -	$ -	$ -	$ -	$ -	$ -
[illegible]d Set Tool DN$										
[illegible]parent Total Cost	-$ 15,060	[illegible]	[illegible]	[illegible]						

* DN Cost of 2nd Set Tools Included In Benefit Where Tool Credited

With 2nd Set Tool

	Total	2006	2007	2008	2009	2010	2011	2012	2013	2014
Savings (k$)	$ 122,303	$ 10,630	$ 7,711	$ 28,491	$ 2,098	$ 21,071	$ 42,633	$ -	$ -	$ -
Benefit (days)	79	7.0	5.0	24.0	1.3	13.6	27.8	0.0	0.0	0.0
NPV =	$ 58,896	To 2011	Successfully implemented 4 Ice Plugs in Parallel							

NO 2nd Set Tool

	Total	2006	2007	2008	2009	2010	2011	2012	2013	2014
Savings (k$)	$ 77,561	$ 10,630	$ 7,711	$ 22,261	$ 2,098	$ 11,374	$ 23,486	$ -	$ -	$ -
Benefit (days)	50	7.0	5.0	14.0	1.3	7.3	15.3	0.0	0.0	0.0
NPV =	$ 35,437	To 2011	Successfully implemented 4 Ice Plugs in Parallel							

Dose Impacts

	Total	2006	2007	2008	2009	2010	2011	2012	2013	2014
Savings (Rem)	280	0.0	0.0	80.0	25.0	75.0	100.0	0.0	0.0	0.0
Savings (k$)	$ 7,000	$ -	$ -	$ 2,000	$ 625	$ 1,875	$ 2,500	$ -	$ -	$ -
NPV =	$ 3,728	To 2011								

Variables

Description	Valve	Name	Notes
Fdr Rep Duration Base Case (hrs)	38	fdrrepbase	
Fdr Rep Duration Alternative (hrs)	30	fdrrepalt	
Setup duration Alternative (hrs)	8	setup	
Shuffle at number of fdrs	5	thresshuf	
Shuffle Duration (hrs)	72	shuffle	=3*24
Threshold for Parallel	7	threspar	
[illegible]utage Overhead per hour (k$)	14.6	outhead	=350/24
[illegible]ost Revenue per hour (k$)	43.0	revlost	=878*49/1000

Analysis Period (0 = to 2011, 1 = to 2014)	0	period

BCS Economic Analysis (2006-2014)

								With 2nd Set Tools			*No 2nd Set Tool*			*Dose Benefits*		
Outage (D)	Year	# Feeders	# West	# East	Series vs Parallel In BP	Impact on Inspection (hrs)	Duration Base Case (hrs)	Duration Alternative (hrs)	Benefit hrs	Benefit K$	Duration Alternative No 2nd Set (hrs)	Benefit No 2nd Set (hrs)	Benefit No 2nd Set (k$)	Dose Save (Rem)	Dose Equiv (k$)	Escalation Factor
611	2006	5	4	1	Series	168	190	190	168	$ 10,630	190	168	$ 10,630	0	$ -	1.00
721	2007	5	4	1	Series	120	190	190	120	$ 7,711	190	120	$ 7,711	0	$ -	1.02
811	2008	16	8	8	Parallel	0	824	248	576	$ 38,161	488	336	$ 22,261	80	$ 2,000	1.04
931	2009	5	3	2	Series	0	190	158	32	$ 2,098	158	32	$ 2,098	25	$ 625	1.06
1021	2010	10	5	5	Parallel	0	452	158	294	$ 19,002	308	144	$ 9,307	50	$ 1,250	1.08
1041	2010	5	3	2	Series	0	190	158	32	$ 2,068	158	32	$ 2,068	25	$ 625	1.08
1111	2011	20	8	12	Parallel	0	976	308	668	$ 42,633	608	368	$ 23,486	100	$ 2,500	1.10
1231	2012	10	4	6	Parallel	0	452	158	294	$ 18,812	308	144	$ 9,214	50	$ 1,250	1.13
1341	2013	8	4	4	Parallel	0	376	128	248	$ 16,412	248	128	$ 8,470	40	$ 1,000	1.15
1321	2013	8	4	4	Parallel	0	376	128	248	$ 16,412	248	128	$ 8,470	40	$ 1,000	1.15
1411	2014	20	10	10	Parallel	0	976	308	668	$ 46,700	608	368	$ 25,727	100	$ 2,500	1.17

Cash Flows and NPV:

K$	Total	2006	2007	2008	2009	2010	2011	2012	2013	2014
CDT Cost	[redacted]									
Trolley Cost										
CIP Cost										
Software Cost										
Freeze Jacket										
CIP& Wing Com'n										
Project Total Costs										
Total Cost w/ Contg.					$ -	$ -	$ -	$ -	$ -	$ -
2nd Set Tool DN$										
Apparent Total Cost	-$ 15,060	[illegible]	[illegible]	[illegible]						

^ DN Cost of 2nd Set Tools Included In Benefit Where Tool Credited

With 2nd Set Tool

	Total									
Savings (k$)	$ 220,638	$ 10,630	$ 7,711	$ 38,161	$ 2,098	$ 21,071	$ 42,633	$ 18,812	$ 32,823	$ 46,700
Benefit (days)	140	7.0	5.0	24.0	1.3	13.6	27.8	12.3	20.7	27.8
NPV =	$ 97,840	To 2014	*Successfully implemented 4 Ice Plugs In Parallel*							

NO 2nd Set Tool

	Total									
Savings (k$)	$ 129,443	$ 10,630	$ 7,711	$ 22,261	$ 2,098	$ 11,376	$ 23,486	$ 9,214	$ 16,941	$ 25,727
Benefit (days)	82	7.0	5.0	14.0	1.3	7.3	15.3	6.0	10.7	15.3
NPV =	$ 57,914	To 2014	*Successfully implemented 4 Ice Plugs In Parallel*							

Dose Impacts

	Total									
Savings (Rem)	510	0.0	0.0	80.0	25.0	75.0	100.0	50.0	80.0	100.0
Savings (k$)	$ 12,750	$ -	$ -	$ 2,000	$ 625	$ 1,875	$ 2,500	$ 1,250	$ 2,000	$ 2,500
NPV =	$ 8,136	To 2014								

NPV

To 2011 - Successfully Implemented 4 Ice Plugs in Parallel

Attachment - C

Description of Impacts of the new tools that will be designed and fabricated under this project:

CDT (Channel Drain Tool)

The existing CDT design limits bridge movement (CDT protrudes). Consequentially, the parallel feeder activities are restricted to within 3 rows and greater than 4 columns apart. The impact of this restriction is that approximately 50% of the planned feeders will have to be replaced in series costing the corporation a significant outage time. This requires additional bridge movements and waiting for one feeder cut and weld activity to complete before the preparation for the next feeder can start. The impact is at least 8 hours per feeder for 50% of feeders to be replaced. The new design CDT (which will be a modified closure plug) will effectively address these restrictions and limitations imposed by the current CDT.

FM Trolley Mounted Storage Magazine for Shield Plugs, Closure Plugs, CIP's

The FM has a capacity to swap one (1) closure plug at a time. As result, a run back to the fuel bay would be required for each channel undergoing feeder replacement for installing the CIP/modified closure plug and then to return the shield/closure plug. The proposed trolley storage magazine allows these items to be managed locally. The impact is 4 hours to run to the fuel bay twice vs. 0.5 hours to drop to the trolley twice per feeder.

CIP (Channel Isolation Plug)

Currently Darlington has 7 CIPS (hold one CIP back as a spare for failure/discovery and credited 6) and will require greater than 20 CIP's in the Business Plan period. The project will commission the existing set of CIP's and procure 15 more. Not having sufficient CIP's will force use of 2 ice-plugs for the additional feeder replacements. This has two impacts;

1) Forces serial activities, and
2) Displaces parallel feeder inspection activities for already serial feeder replacements. The displaced inspections are 7 days critical path for D611 and 5 days critical path for D721.

FM Software

Fuel Handling Operations can manually track using procedural barriers up to 5 CIP's installed in the reactor without causing increased risk to fuel cooling. The current FM software has no capability to track CIP's installed in the fuel channels. Replacement of greater than 5 feeders in one outage will require cycling the FM for a 3 day delay for every 5 feeders.

Feeder Freezing Jackets

The current freezing jackets impose limitation of two ice plugs that can be formed and/or maintained. This prohibits parallel next feeder set up while replacing the current feeder. Therefore, it adds 8 hours of set up to each feeder targeted for replacement. It is therefore imperative to expand this capability to at least 4 ice plugs that can be formed or maintained in parallel.

ONTARIO POWER GENERATION

CFC Chillers Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

Routing	***Location***	***Action***	***Signature***	***Date***
M. Arnone Director, Projects & Modifications 701-6063	P72-1	Review BCS	[signature]	7 Nov 2006
T. Mitchell Site VP, Pickering B 701-3501	P41E3	Submit BCS	[signature]	7 NOV 2006
~~P. Charlebois~~ T. Mitchell ~~EVP and~~ CNO 702-5294	P82-26A	Concurred By	[signature]	21 Dec 06
R. Leavitt Director, Investment Management 702-5085	P82-3	Review BCS	[signature]	Nov. 16, 2006
J. Beech VP, Nuclear Finance 400-7226	TCH 09 F26	Review BCS	[signature]	Jan 3, 2007
D. Power ~~Director of Invest & Bus Planning~~ VP Corp. Investment Plng 400-7172	TCH 07 D06	Approve BCS	[signature]	Jan 7/07
J. Hankinson President and CEO Rec'd Feb 7/07 400-2121	TCH19A24	Approve BCS	[signature]	Feb 8
R. Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

CFC Chillers Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

.Lo / K. Osman Project Engineer, Design Projects 701-5034 / 701-3364	P72-3	Prepare BCS		Oct 3, 2006 Oct. 3, 2006
C. Misketis Project Leader II, Design Projects 701-2512	P72-3	Review BCS		Oct 3 2006
G. Makdessi Project Manager, Design Projects 701-6617	P72-3	Review BCS		3 Oct 2006
D. McAuley Section Manager, PMO 701-4491	P72-3	Review BCS		4 Oct 06
R.Ludlow Manager, Design Projects 701-8055	P72-3	Review BCS		6 Oct 06
R. Bail Senior Financial Advisor 702-4084	P823B-6	Review BCS		20 Oct 06
G. Brown Controller, Engineering & Modifications 702-5039	P823B-6	Review BCS		20 Oct 06
Mark Elliot Director of Station engineering PNGS B 1-2106	P41-E3	Review BCS		24 Oct 06

CFC Chiller Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

1/ RECOMMENDATION:

We recommend a Phase II full release for a total of $22,377 K (including contingency) to complete the following:

- The installation/commissioning of the three Reactor Auxiliary Bay (RAB) Chillers,
- The detailed design and installation/commissioning of the three Service Wing (SW) Chillers
- The installation/commissioning of the Administration Building Extension (ABX) Chiller

The objective of this sustaining project is to replace the seven (7) existing Pickering CFC Chillers in order to:

- comply with the amendments by Environment Canada Federal Halocarbon Regulations-2003.
- remove some of the obstacles for returning the System Health status of each system from red/yellow to white, by addressing increasing maintenance on this aging equipment
- provide contingency planning to meet regulation requirements prohibiting major chiller repairs after January 1, 2005.

Failure to comply with this new regulation would result in significant fines, legal ramifications, and a significant impact to our corporate image.

A Phase I full release of $6.7M was previously approved in January of 2005. After progressing through the Phase I portion of the project, it was realized that the split of Phase I and Phase II work would need to be revised to accommodate a more cost effective installation sequence. Also during this project phase, it became apparent that both Phase I and overall project costs would be significantly higher than originally estimated. The estimated cost of work previously identified as Phase I is now $16.8M versus the previously released $6.7M. The overall project cost estimate is now $22.4M versus the previously estimated $9.4M due to discovery work, improved cost estimates after the completion of more detailed engineering, and receipt of more accurate vendor quotations.

The details of the cost increases and progress to date are outlined in the Background / Issues section of this BCS. SCR No. 2006-18017 has been raised to document the problems with the estimate used for the Phase I BCS.

With most of the engineering complete, RAB platform and chillers in place, RAB installation experience gained, and a third party cost estimate review, we feel confident that this project can be finished on time and within the cost estimate of $22.4 M. The estimate includes a specific contingency of [redacted] and a general contingency of [redacted] for unforeseen issues.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Full - Phase 1	4,006	2,735						6,741
Requested Now	Full - Phase 2	(110)	932	8,843	5,127	844			15,636
Future Funding Req'd									-
Total Project Costs		3,896	3,667	8,843	5,127	844	-	-	22,377
Ongoing Costs									-
Other Costs									-
Grand Total		3,896	3,667	8,843	5,127	844	-	-	22,377

Investment Type	Class	NPV or IEV	IRR	Discounted Payback
Regulatory	Capital	(14,499)	N/A	N/A

Submitted By:

T. Mitchell
Site V.P. Pickering

Date: 7 Nov 2006

Finance Approval:

D. Power
Director of Investment & Business Planning

Date: Jan 11/07

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson
President and CEO

Date: Feb 8 '07

2/ BACKGROUND & ISSUES

Pickering "B" NGS has seven (7) CFC Chillers located in three separate areas that need replacement with non-CFC units (Reference: ECR 734369 and SCR P-2003-03155). This project will ensure that Ontario Power Generation (OPG) PNGS B complies with the Environment Canada amendments to the Federal Halocarbon Regulations 2003, and the potential changes on Provincial Legislation O/Reg 189. This regulation prohibits the re-charge of CFC refrigerant in any chiller unit by January 2015. Although OPG has made a commitment to the Ministry of Environment (MOE) to replace all their CFC chillers by 2012 (N-CORR-00521-00008), management has chosen a more aggressive deadline for completion by 2010.

Furthermore, should a chiller fail requiring the replacement or modification of an internal sealing device, internal mechanical part, or an evaporator or condenser tube, between January 1st, 2005 and December 31, 2009 that unit can be returned to service for up to one year, at which time it must be replaced with a chiller using an approved or non-ozone depleting refrigerant. Should a chiller fail catastrophically after January 1st, 2010, that unit must be replaced or charged with an approved refrigerant (non-ozone depleting) immediately prior to being brought back into service. The existing chillers are not suited to have their refrigerants changed to a non-CFC refrigerant. The only option is to replace the units.

The following activities were completed with Phase I funds:

- Preliminary engineering for the ABX, SW and RAB chillers is complete
- Detailed Engineering is complete for ABX and RAB chillers
- All RAB chillers have been delivered and installed on the newly erected chiller platform but not tied-in to the existing system
- The ABX chiller has been factory tested, accepted, and delivered to OPG
- SW chillers have also been factory tested and accepted and will be delivered in October of this year
- All pumps have been delivered to site
- Detailed engineering for the SW chillers is in progress.

Premature Chiller Failure Contingency Status:

- With the RAB Chillers installed with only the mechanical and electrical tie-ins outstanding, if an RAB Chiller failed and required replacement, the tie-ins could be completed within the 1 year grace period.
- Should the ABX Chiller fail, a TMOD would be prepared to tie in to the Admin Building chilled water system within the one year grace period. This TMOD would mimic a similar one that was successfully used in the past.
- 90% of the SW Chiller design is complete and if a SW Chiller suffered a catastrophic failure, with a change in installation schedule, a SW Chiller could be replaced within the one year grace period.

Extra expenditures that were incurred during Phase I of the project are as follows:

- Increased labor costs and firm quotes from potential vendors for installation were higher than originally estimated.
- Chiller vendor delays in submitting equipment documentation for approval resulting in less efficient use of design engineering hours.
- Poor quality of vendor documentation resulting in extensive document reviews and comments with multiple iterations back and forth prior to obtaining final approval.
- Electrical redesign to accommodate power supply constraints. Design changed from a 600V supply to using a 4kV supply which necessitated the specification and use of step down transformers and current transformers.
- Discovery work for the RAB chiller design due to the realization that a structural column (M139) was discovered to have insufficient capacity to support the weight of the new air-cooled RAB chillers. This column had to be reinforced prior to both completion of the platform and installation of the chillers

The Phase II funds will ensure that the following activities of the project are completed:

- Installation of the mechanical and the electrical components of the RAB chillers; Commissioning and Available for Service Declaration,
- Full installation of the ABX and SW chillers, commissioning and Available for Service Declaration, and
- Close-out activities for the project.

The project schedule has been revised to reflect the current installation strategy and the previously encountered delays. The installation schedule is affected by both operational and weather constraints. For example, all outdoor work cannot be performed during the winter months. The adopted schedule for the recommended alternative takes these constraints into account while minimizing the overall project duration.

The release strategies considered were:

(a) Prepare a superseding Phase I BCS documenting the change in cost of the original Phase I scope of work and request a release for $16.9M. Then follow with a Phase II BCS requesting a release of $22.9M to complete the project.

(b) Superseding Phase 1A BCS requesting a release of $19.8M to complete the revised scope of work included in Phase 1A (Includes the installation of the ABX Chiller, two SW Chillers, and two RAB Chillers). Then follow with a Phase II BCS requesting a release of $22.4M to complete the project.

(c) Proceed directly with a Phase II release of $22.4M based on the new installation strategy, while documenting both the progress and issues associated with the original Phase I release.

Option (a) was not selected as it is a more costly option. Option (c) is preferable to option (b) as the relative increment in the amount released is low, there is adequate information to reasonably estimate the full project cost, and the project schedule now requires a full release in October 2006 to commit to the installation contract.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Do Nothing	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay (2yrs)	Alt 3 Ph. I Install Schedule	Alt 4 Do Less	Alt 5 Do More	Alt 5
Project Cost	N/A	(11,126)	(5,926)	(11,759)	N/A	N/A	N/A	N/A
NPV (after tax)	(14,499)	(15,011)	(10,758)	(13,803)	N/A	N/A	N/A	N/A
Impact on Economic Value	N/A	N/A	(7,934)	N/A	N/A	N/A	N/A	N/A
IRR%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: The figures shown above are for the RAB Chiller portion of the project only. As outlined below, the Service Wing and ABX Chillers must be replaced to meet the 2015 environmental regulation implementation date since they are common to Pickering B and A and will therefore be required to operate after the 2014 Pick B end of life date. The justification for proceeding with the RAB Chiller replacement is based on a financial analysis since it only services Pickering B and could feasibly be delayed until after a decision is made for Pick B plant life extension. The financial justification is made by comparison of the incremental NPV's for the different alternatives strictly for the RAB portion of the project.

Stop the Project - Not Recommended

onsequences of doing nothing are increased chances of encountering chiller failures as they are approximately years beyond their life expectancy and experiencing condenser tube erosion. Details of the probabilities of failures, consequences of failures, and current status of the various chillers are outlined in attachment "E". A summary of the consequences of failure are described below:

Failure of the ABX Chiller: Results in a loss of cooling to the Administration building where Pick A / B support staff, CNSC and TSSA staff are located. The 2014 end of life for Pickering B does not apply in this situation as Pickering A staff are also located in the Admin. Building and the chiller would have to be replaced by 2015.

Failure of two Service Wing Chillers: Results in a loss of cooling to the chemistry lab which provides critical services to both Pick A and B which can affect station operability and guarantees of shutdown during an outage. Again, the 2014 end of life date for Pick B does not apply as this affects Pick A as well and must be replaced by 2015 as required by the environmental regulation.

Failure of two RAB Chillers: Results in a loss of cooling to the Main Control Room and Control Equipment Room where a temperature controlled environment must be maintained at all times. A loss of cooling to these areas could potentially result in a four unit shutdown. These chillers do not affect Pick A and therefore the 2014 end of life date does apply. The probability of a dual unit failure of the RAB Chillers is estimated at 50% between now and 2015. However, based on the NPV calculated for the RAB portion of the project, with a low probability of revenue losses due to a four unit shutdown, it is a more costly option than the recommended option. The NPV for this alternative is **NPV = (14,449)**.

Alternative 1 - Continue project per Phase II schedule - Recommended

The ABX and Service Wing chillers should be continued as per the revised Phase II schedule (see attachment "C") since they service Pick A and will need to be replaced by 2015 as mandated by the environmental gulations. The Pick B end of life 2014 does not apply to these chillers.

For the RAB Chillers, the financial analysis show that this is the most cost effective approach given the risk of a four unit shutdown and the subsequent revenue losses. The **NPV = (10,758)** for this alternative.

Successful completion of this project will fulfill environmental regulations and improve the current red/yellow status of each associated HVAC system health indicator.

Alternative 2 - Delay Project - Not Recommended

The schedule can be delayed by as much as two years, and still meet the MOE commitment to replace all CFC chillers by 2012. This, however, would pose a significant threat to the station as the one year 'grace' period to replace failed CFC chillers, will be eliminated after January 1, 2010.

This option is not recommended for the ABX or Service Wing Chillers because the cost savings due to time value of money is relatively insignificant (approx. $100K) and the project team is already mobilized to continue per the recommended schedule, and resources have already been committed based on this schedule.

The option of delaying by two years is not recommended for the RAB Chillers because the financial analysis shows this to be a more costly option than the recommended alternative. This is primarily due to the increased probability of a two unit RAB chiller failure potentially causing a four unit shutdown resulting in revenue losses, as well as additional de-mobilization / re-mobilization costs. The **NPV = (13,803)** for this alternative.

Alternative 3 – Proceed with installation as per Phase I release schedule - Not Recommended

This alternative is no longer viable because this schedule change only affected the installation of the ABX Chiller and has no impact on the costs of the RAB portion of the project. However, had this schedule been used, additional overall project costs of approximately $800 K would have been incurred.

Alternative 4 – Do Less - Not Recommended

All seven CFC chillers are impacted by the environmental regulations; doing less will lead to non-compliance and un-reliable performance of the system. The technical requirements of the recommended option (Alternate 1) are acceptable. Additionally, the costs of the recommended option have been minimized through on-going review and challenge.

A comparison of this project to the Darlington CFC Chiller Replacement project shows that the two projects are very different, where the Darlington installation is a plug and play approach; Pickering's installation involves the relocation of the RAB and ABX chillers to the outside and the redesign of the Service Wing chillers. In addition, the QA requirements for the new chillers at Pickering were more stringent at the time of purchasing which resulted in more expensive design and equipment costs. Although using air cooled chiller designs for RAB and ABX chillers, increased costs, they benefited the station by reducing the already limited service water supply. The need to evacuate control room staff in the even of a refrigerant leak would also be eliminated by the relocation of the RAB chillers to the roof.

Increased costs due to replacement of the glycol pumps, design of a chiller platform, increased piping and piping design changes, the need for new power supplies, were incurred as a result of relocating the RAB Chillers to the outside. Based on current estimates, the 'per ton' cost of the Darlington CFC Chiller Replacement project comes to approximately $10.4K/ton compared to this project which comes to approximately $20.8K/ton.

Alternative 5 – Do More - Not Recommended

The current scope of the project has effectively addressed the potential modification requirements. Adding scope at this stage would increase costs without making a meaningful contribution to the overall project objectives.

4/ THE PROPOSAL

We recommend the completion of this project by the end of 2009. The key project milestones are shown in the table below:

Completion Date			Description
Day	Mth	Yr	
22	Dec	2006	Complete DCP package for Service Wing chillers
21	Nov	2006	Start installation for all RAB chillers
21	Feb	2007	AFS of RAB chilled-glycol pumps and Relief Valve RV102
23	Feb	2007	Start tie-in installation for 1st RAB chiller (058-73180-RFU4)
01	Nov	2007	Start tie-in installation for 2nd RAB chiller (058-73180-RFU5)
01	Nov	2008	Start tie-in installation for 3rd RAB chiller (058-73180-RFU6
01	Aug	2007	Start Installation and tie-in for ABX chiller
03	Aug	2007	Start Installation and tie-in for 1st SW chiller (018-73430-RFU2521)
01	Feb	2008	Start installation and tie-in for 2nd SW chiller (018-73430-RFU2522)
02	July	2008	Start installation and tie-in for 3rd SW chiller (018-73430-RFU2520)
02	July	2007	AFS 1st RAB chiller
03	July	2008	AFS 2nd RAB chiller
02	July	2009	AFS 3rd RAB chiller
03	July	2008	AFS ABX chiller
14	Dec	2007	AFS 1st SW chiller
19	June	2008	AFS 2nd SW chiller
18	Nov	2008	AFS 3rd SW chiller
24	Dec	2009	Project Completion

5/ QUALITATIVE FACTORS

The following are the non-quantifiable benefits of the project. The major project measurable deliverables are listed in Section 4.

- Improve reliability of the chiller units in each area; hence reduce emergent-based maintenance costs.
- Improve safety by eliminating hazards due to refrigerant leaks in an enclosed space for the Reactor Auxiliary Bay and Administration Building (Air-cooled units are installed outdoors)
- Alleviate strain on Low Pressure Service Water (Safety-Related Support System) by replacing the Reactor Auxiliary Bay and Administration Building chillers with outdoor air-cooled units.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Detailed release estimates for the installation of SW Wing Chillers is unavailable during BCS phase II preparation.	Complete installation costs are not available in the cost esitmate. Therefore, project may over spend estimated budget	**High**	Include [redacted] contingency for the installation of the Service Wing Chillers. Apply only [redacted] contingency on the RAB and ABX chillers. See Attachment "A" for Service Wing contingency. Independent 3rd party review of the cost estimate for the Phase II BCS was conducted by Helyar.	**Low**
Further cost estimation on the total project	Cost push on the $22.4M total	**Medium**	Vendor quotes are now available for all aspects of the project except for the SW chiller installation. 90% of Detailed Engineering is complete for the SW Chillers Design Package. A third party review estimate has been completed and incorporated into this estimate A higher [redacted] contingency was used to reflect the higher uncertainty for the installation of the SW Chillers.	**Low**
Scope				
Discovery and Legacy Work (chiller system is 20 years old - Auxiliary equipment failure)	Increase in costs and impact on schedule	**High**	COMs Meeting and Walkdown were performed to minimize discovery work. Reviewed equipment history and are continuing to perform preventative maintenance on any support systems during modification. Initial documentation check was conducted. Pre-identifying documentation errors. Field Engineering involved early in the design phase. Multiple field walkdowns were done to determine scope of legacy issues. Any increased	**Low**

			design scope would be covered by general contingency funds.	
Schedule				
Premature Chiller failure, schedule may vary due to station priorities (contingency plan - failure equipment trigger 1 year replacement).	Negative impact to Cost, Scope and Schedule.	**High**	RAB: At time of Phase II release, all three existing chillers are functioning. New chiller units are installed at this time. Complete installation (i.e. piping, electrical cable, instrumentation) can be accomplished within 1 year. Risk is Low. ABX: Develop TMOD to tie into the Administration Building chilled water system to Administration Building Extension system. Risk is Low SW: If a SW chiller fails during the life of the project and needs to be replaced, the installation schedule can be re-prioritized to allow for the installation of the replacement SW chiller ahead of other chiller installations. The cost associated with implementing these contingency plans is estimated to be [redacted]	**Low**
Contractor/OPG managed task delays	Schedule delay and negative cost impact	**High**	Review detail installation and commissioning strategies. Ensure Contract Administrator and Monitor scrutinize daily activites of Contractor. Resources to immediately respond when problems are encountered in the field. Order materials proactively; that is, ahead of scheduled activity per 13-week IOP schedule. Extra costs associated with this risk are covered under general contingency.	**Low**
Other modification projects (i.e. Cafeteria Upgrades) occuring in the same location ABX, RAB and SW chillers at	Delay to schedule due to conflicting work activities in the field.	**High**	Communicate with Contract Management office continuously during modification. Coordinate with other project teams to avoid and mitigate any conflicts	**Low**

the same time.			Rescheduled ABX Chiller Installation from November 1, 2006 to August 1, 2007 to accommodate the Cafeteria Upgrades project.	
Resources				
Availability of Qualified OPG station staff during outage and non-outage periods	Fewer resources to complete tasks. Increased risk in schedule delays. Outage organization requires full support from Installation support staff	**Medium**	Early involvement of operation and maintenance support. Ensure compliance of IOP work planning & station support. Defer any non-critical activities to accommodate station resources. Commitment obtained from outage organization to supply limited staff for installation activities during outage periods.	**Low**
BTU staff may not be available to perform RAB chillers RFU5 and RFU6 Tie-in activities; Project may be required to use External Contractor Resources	Increase cost to use external contractor.	**Medium**	Include specific contigency to cover additional costs if BTU staff cannot be commited to this activity. The cost estimate for this is $200K	**Low**
Lack of available qualified contractors to execute the installation	Schedule delays and cost push	**Medium**	The request for proposal to the installation contractors will be issued immediately after the approval of this BCS to meet the schedule. Contractors have already been briefed on the scope and schedule for this work. Standard skilled trades will be used for this installation. Specialized commissioning services will be provided by the Chiller equipment vendor.	**Low**
Technical				
Unforeseen commissioning issues with chiller units	Delay in schedule	**Medium**	Chiller vendor field representatives will be on-site for startup/commissioning. Also, project team will be on standby to resolve any issues	**Low**
Regulatory				
A project delay or cancellation would result in a failure to comply with the new environmental regulation.	The corporation could face significant fines and there could be legal ramifications. This would also have a potentially serious impact on the corporate image.	**Medium**	Securing funding to implement installation and commissioning activities will ensure that OPG remains compliant with the environmental regulation. The management expectation for completion of this project is 5 years ahead of the environmental regulation	**Low**

			implementation date.	
Environmental				
Unforseen chemical handling procedures during this work	Higher Cost. Approximately $50K worth in additional chemical handling charges	**Medium**	Ensure refrigerant and materials (lubrication) brought on site are concurred by Environmental group. Extra costs are included in specific contingency.	**Low**
R-11 (CFC) refrigerant disposal more effort intensive than anticipated	Higher Cost. Approxmately $50K worth in additional chemical handling charges	**Medium**	Early involvement with Disposal companies. Meetings with this vendor show that there is no cost to remove R-11 refrigerant. Potential extra costs are included in specific contingency.	**Low**
Health & Safety				
Workplace injury or serious MRPH event	Negative impact to Schedule due to delay for investigation.	**Medium**	Work plans will be reviewed by conventional safety prior to use. JSA to be prepared for crane/rigging and high hazard work. Lessons learned applied to prevent further incidence. Comprehensive work skill OPEX review.	**Low**
Investment				
New chillers operation, reliability and service-life below expectation	More maintenance and operational related activites	**Medium**	Technology of the new Chillers is standard and is widely used in industry. They are manufactured by Trane, one of the world's leaders in HVAC equipment. Chillers are factory acceptance tested and inspected by OPG Source Inspector prior to delivery.	**Low**
Newly purchased chillers become obsolete through the life of the project.	Unable to purchase spare-parts; no service support from the vendor	**Medium**	Technology of chillers changes slowly compared to the life of the project. Purchase spare-parts as part of the equipment purchase orders.	**Low**
New regulatory requirements which change the acceptable replacement refrigerants	Cost and schedule delay to re-engineer the chillers for a new refrigerant	**Medium**	The selected refrigerants are not only acceptable for use post 2015 but they are also not on the list of refrigerants to be phased out by 2030. Therefore there is a minimum of a 24 year expectancy.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jul 2009	Jul 2010	Director of Station Engineering (Pickering A and B)

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Design meets performance reliability criteria	Chillers meet system requirements using CFC refrigerant.	Replacement chillers to operate within design parameters using non-CFC refrigerant	Commissioning reports will document performance parameters	Projects
2.	Design meets performance reliability criteria	Not Applicable	AFS procedure to be performed and accepted	Final acceptance of AFS during final meeting.	Stakeholders
3.	Removal of ozone depleting substance	Not Applicable	All ozone depleting substances pertaining to this project to be removed	Projects to ensure that all ozone depleting substances are removed from site.	Site Management Board
4.	Improve health status of chillers	System health reports shows RAB and SW chillers are yellow. No status is available for ABX	System health of chillers will be improved to white/green.	Compare system health reports from project initiation to project completion	Performance Engineering
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

RAB – Reactor Auxiliary Bay

ABX – Administration Building Extension

SW – Service Wing

Free Cooling - HVAC systems rely on outside air for cooling (outside air temperature is below 12C); air is directly drawn into the building. Chillers and systems are turned off.

Cooling season – Time when chillers are operating.

Heat Load – "Heat" in the building.

Appendix "C" **Financial Model – Assumptions**

Project Cost Assumptions:

Project Resources (e.g. Projects Design, Drafting office, Maintenance, etc.) provided estimates on monetary resources required to complete their work activities for the duration of 2006 to the end of project. Overtime is anticipated for Projects, Field Engineering and Maintenance resources. Allowances have been incorporated into the project cost.

Installation costs (including materials and installation contractor) for the RAB and ABX chillers are of release quality (+10 to -15%). Installation costs for Service Wing chillers are budgetary (+30 to -15%) since detailed engineering is not complete at the time of BCS issuance.

Project cost estimates have been verified by an independent third party review.

Financial Assumptions:

An interest rate of 6% per annum, labor escalation rate of 3% per annum and an NPV discount rate of 7% are used per corporate standards.

The following assumptions were used to calculate revenue losses due to a forced outage:

- Rates per MW hour:

2007	2008	2009	2010	2011	2012	2013	2014	2015
$55.3	$56.2	$54.1	$51.8	$49.6	$48.4	$49.3	$51.7	$54.2

- Probability of a two unit RAB Chiller failure between now and 2015 is estimated to be 50%. Spread uniformly over 9 years is approximately 5.6% per year
- Output from each unit is 516 MW
- Failure of two RAB chillers would result in a loss of cooling in the Main Control Room / Control Equipment Room servicing all four Pickering B units and would cause a four unit shutdown
- Optimistic duration for an overhaul or replacement is 4 weeks. Therefore the assumed duration of the forced outage is 28 days.

Project / Station End of Life Assumptions:

All Obsolete chillers do not have salvage value; the RAB and ABX chillers are isolated and abandoned in place during construction. Old SW chillers are replaced with new chillers. There is no salvage value assumed for the SW chillers.

Pickering B end of life is 2014. The SW and ABX Chillers also service Pickering A. The RAB Chillers service Pickering B only.

Energy Price / Production Assumptions

N/A in NPV calculations

Operating Cost Assumptions

N/A in NPV calculations

Other Assumptions:

No other assumptions

CFC Chiller Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2005	This Release 2006	This Release 2007	This Release 2008	This Release 2009			Later	Total
Project Management (OPG)	233	213	295	139	108				**988**
Engineering & Drafting (OPG)	1,477	989	860	811	210				**4,347**
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Installation - Support									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	**3,896**	**3,636**	**8,843**	**5,086**	**644**	**-**	**-**	**-**	**22,105**
2006-2010 Business Plan	3,896	2,771	1,190	590	291				**8,738**
Variance to Business Plan	**-**	**601**	**6,271**	**3,498**	**#REF!**	**-**	**-**	**-**	**10,241**
Committed Cost									-
Inventory Write Off Required					[redacted]				
Spare Parts / Inventory		[redacted]							
Total Release (excl contingency)	[redacted]								
Total Release (incl contingency)	**3,896**	**3,667**	**8,843**	**5,127**	**844**	**-**	**-**	**-**	**22,377**

Ongoing OM&A (non-project)	**N/A**								**-**
Removal Costs (incl in above)	**N/A**								**-**

Basis of Estimate					
Design Complete	90 to 100%	Contracts in place	No	Competitive Bid	Yes
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Sponsor Cost Estimate	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in Place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance to the 2006 – 2010 Business Plan will be addressed through the portfolio management process. A PCRAF was approved in Jul 2006.
Note: General contingency for the SW chillers (approx. $1.1M) is included in the value for overall project specific contingency.

Reviewed By: Approved By:

12 Oct, 2006

Name Name
Project Manager Date: Eng & Mods Manager (Strat IV) Date:

CFC Chiller Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

Attachment "B" **Project Variance Analysis**

Capital	LTD Aug 2006	Phase 1 Release Last BCS Dec 2009	This BCS Dec 2009	Variance	Comments
Project Management (OPG)	317	598	988	390	See Note 1 [Estimate]
Engineering & Drafting (OPG)	2232	2330	4347	2017	**See Note 2** [Delay, Discovery, Re-Eng]
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Installation support					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	5686	9401	22105	12704	
Committed Cost				[redacted]	
Inventory Write Off Required			[redacted]		
Spare Parts / Inventory					
Total Release (incl contingency)	5686	9401	22377	12976	
Total Release (excl contingency)	[redacted]				
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Note 1 – Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates.

Note 2 - Increase in Engineering costs are due to: delay in design deliverables - Design Engineering ($640K), discovery work – Design Engineering ($94K), additional project engineering ($350K total; $230K worth in delays and $120K worth in discovery work/scope creep), and adjustments from conceptual estimates to quality-release/budgetary estimates ($933K).

Note 3 – Increase in Materials costs are due to re-engineering, discovery work ($286K) and adjustments from conceptual estimates to quality-release/budgetary estimates ($748K).

Note 4 - Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates.

Note 5 - Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates. This variance includes impact of discovery work to reinforce column M139 and the change from the conceptual RAB platform design.

Note 6 - Original estimate was based on conceptual design and direct-hire labor rates of 2004; this new estimate is based on 100% detailed engineering for the RAB and ABX chillers, and 60% engineering complete for the Service Wing chillers and higher labour rates. In addition, installation hours have increased for this estimate. The variance due to increased labour-rates is $880K. The variance due to increased labor hours is $3261K

Note 7 - Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates.

Note 8 – Increase to Installation Support costs are due to emergence of a new project resource, Contract Management Office ($332K). Their cost is included in this release. In addition, Field Engineering Costs have also increased for this release ($757K).

Note 9 - 15% contingency is applied to the Reactor Auxiliary Bay and Administration Building portions of the project. 30% contingency is applied to the Service Wing portion of the project. Itemized contingencies (as specified in Section 6) are included in the Specific Contingency.

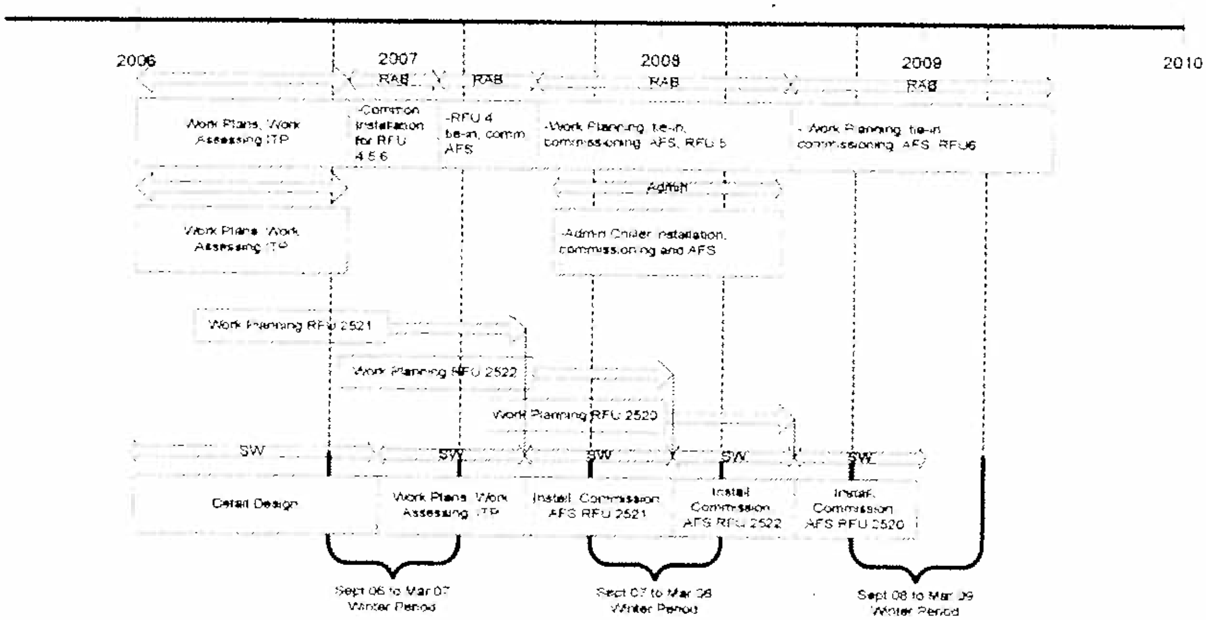
[redacted]

Summary of major issues	Total Cost (K)
Underestimation - Conceptual Estimate to Quality/Budgetary estimate, including interest	[redacted]
Delay in Schedule due to delay in Design deliverables	[redacted]
Discovery Work, Re-engineering	
Labour rates based on 2004 for phase I vs. new rates of 2006 for Phase II	
Inventory write off and spare parts / inventory costs	[redacted]
General Contingency	
Specific Contingency	
Total	

Attachment "C"

Chiller Replacement Schedule
Business Case Summary Phase II Release

Friday, September 15, 2006



**In Service Schedule: ABX - June 2007, SW RFU 2521 - Jan 2008, SW RFU2522 - June 2008, SW RFU 2520-Nov 2008
RAB RFU 4 - June 2007, RAB RFU5 - May 2008, RAB RFU6 - May 2009

Attachment "D"

REIS Declaration Milestones		
AFS Milestone	Declare REIS date	% complete
RAB Structural Steel Platform	30 July 2006	10%
RV102, P1 & P2 Partial AFS	16 March 2007	3%
RAB RFU4 – AFS meeting	01 August 2007	13%
RAB RFU5 – AFS meeting	01 August 2008	13%
RAB RFU6 – AFS meeting	01 August 2009	13%
ABX RFU101 – AFS meeting	01 August 2008	15%
Service Wing RFU2521 – AFS meeting	18 January 2008	11%
Service Wing RFU2522 – AFS meeting	13 July 2008	11%
Service Wing RFU2520 – AFS meeting	19 December 2008	11%
	Total	**100%**

Attachment "E"

	Number of Chillers	Status of Existing Chillers	Status of New Chillers	Probability of failure between now and 2010 (with 1 yr grace period for replacement)	Probability of failure between 2010 and 2015 (no grace period)	Consequence of Failure	Cost Status
RAB Chillers	3 X 50% chillers (i.e. two available during cooling season, 4-6 wks during peak of summer)	- All (3) are operational - All are approx. 5 yrs. beyond life expectancy	Bought and placed on platform, mechanical and electrical tie ins outstanding	1 Unit Failure: High, based on OPEX from SW Chillers and Pick A Chillers (PA Chillers were re-tubed over 10 yrs ago)	1 Unit Failure: Very High, based on OPEX and continued aging	1 Unit Failure: Loss of redundancy	- Approx. cost to complete is $5.9M (excl. contingency) - Approx. sunk cost is $5.2M - NPV reduction with a 5 yr delay is approx. $113 K
				2 Unit Failure: Medium-Low, based on OPEX and the potential for a common mode failure (i.e. tube erosion)	2 Unit Failure: Medium-High, based on OPEX and continued aging	2 Unit Failure: MCR / CER Temperature rise (> approx. 24- 26 deg. C) resulting in a multiple unit forced shutdown (approx. average time at risk for repair is 4 weeks prior to 2010 and longer for replacement if after 2010)	
ABX Chiller	1 X 100% chiller	- Operational - It is approx. 5 yrs beyond life expectancy	Bought and on site, but not yet installed	High, based on OPEX and common mode failure (i.e. tube erosion)	Very High, based on OPEX and continued aging	Loss of cooling to the new Admin Building resulting in discomfort to CNSC, and Pick A / B station support staff, and potential human performance issues There is a TMOD that can be used for to provide temporary partial cooling relief.	Approx. cost to complete is $2.3M (excl. contingency) Approx. sunk cost is $397 K NPV reduction with a 5 yr delay is approx. $44K, the cost of implementing a TMOD in the event of a failure is $300 K

Attachment "E" continued

	Number of Chillers	Status of Existing Chillers	Status of New Chillers	Probability of failure between now and 2010 (with 1 yr grace period for replacement)	Probability of failure between 2010 and 2015 (no grace period)	Consequence of Failure	Cost Status
Service Wing Chillers	3 X 50% chillers (i.e. two available during cooling season, 4-6 wks during peak of summer)	- 1 failed beyond repair, due to condenser tube erosion - Remaining 2 units have 60% tube erosion - All are approx. 5 yrs beyond life expectancy	Bought and on site, but not yet installed	1 Unit Failure: 100% (1 unit has already failed)	1 Unit Failure: 100% (1 unit has already failed)	1 Unit Failure: Loss of redundancy	Approx. cost to complete $4.7M (excl. contingency) Approx. sunk cost is $389 K NPV reduction with a 5 yr delay is approx. $88K
				2 Unit Failure: High, based on OPEX, significant tube erosion, and the fact that one has already failed	2 Unit Failure: Very High, Based on OPEX, continued aging, tube erosion, and the fact that one has already failed	2 Unit Failure: - Loss of cooling to the chemistry lab resulting in inaccurate sampling analysis and the inability to confirm analysis results (when temp increases to beyond 28 deg. C) which are critical to meet operating license requirements, MISA requirements, and station operability requirements. The lab is common to both Pick A and B and is therefore needed to sustain operability of Pickering B to its end of life as well as Pick A thereafter. Some examples include the measurement of Gadolinium levels in the moderator during shutdown every 4 hours per the operating license, which cannot be done off site. Other examples include deuterium levels in cover gas for various systems including the moderator, Heat Transport Storage Tank, Liquid Zone Control System, etc. where if action level 3 limits are reached the station must shutdown unless a downward trend is confirmed. Sampling of boiler ions is another example where if an action level 3 limit is reached, and the chemistry lab cannot produce quality analyses, shutdown would initiate after 4 hours. These cannot be shipped for sampling offsite. (approx. average time at risk for repair is 4 weeks prior to 2010 and longer for replacement if after 2010) - Loss of cooling to maintenance facilities resulting in discomfort and potential human performance issues for Pick A and B maintenance, ops, and stores staff	

ONTARIOPOWER GENERATION

OPG Confidential	Page: 2 of 28
OPG Nuclear BUSINESS CASE SUMMARY	

Auxiliary Power System 13 - 49104

Full Release Business Case Summary P-BCS-50000-00004-R000

Routing	Location	Action	Signature	Date
T. Mitchell Sr Site VP - Pickering B 701-3501	P41 E3	Submit BCS	M Mitchell	14 Nov 05
J. Coleby Sr Site VP - Pickering A 701-3260	P05 A2	Submit BCS	[illegible]	14 Nov 2005
P. Charlebois Chief Nuclear Officer 702-5294	P82 6A	Review BCS	[illegible]	28 Nov 05
D. Power Director Investment & Business Planning 400-7172	H07 D06	Approve BCS		
J. Hankinson President and CEO H19 A2	H19 A2	Approve BCS		

RECEIVED
by P. R. Charlebois
NOV 22 2005
Refer to:

BCS Signature Sheet + Board Approval Memo.
[illegible]

R. Ball Senior Financial Analyst 702-4084	P82-3B8	Return For Distribution		

Auxiliary Power System 13 - 49104

Full Release Business Case Summary P-BCS-50000-00004-R000

Routing	Location	Action	Signature	Date
K.Shore Section Manager, APS Project (Acting) 701-6800	P24 AN	Prepare BCS		2-NOV-05
G.Kotwa Section Manager, PMO 701-3755	P24 B9	Review BCS		Nov 4/05
S. Guthrie Manager, APS Project (Acting) 701-5613	P24 AN	Review BCS Sign Project Cost Summary		NOV 4/05
R. Ball Senior Financial Advisor 702-4084	P82 3B8	Review BCS		
G. Brown Controller Engineering and Mods 702-5059	P82 3A6	Review BCS		4 NOV '05
M.Elliott Di[illegible] Station Engineering, PB 7[illegible]8	P41 E3	Review BCS		05 11 05
M. A[illegible]ona Director, Projects and Modifications 701-6063	P72	Review BCS Sign Project Cost Summary		11 Nov 2005

Auxiliary Power System 13 - 49104

Full Release Business Case Summary P-BCS-50000-00004-R000

1/ RECOMMENDATION:

We recommend the release of an additional $50.2M (total $116.7M, including [redacted] contingency) to complete all activities for the design, build and commissioning of an Auxiliary Power System (APS) Project at Pickering NGS, to be in-service by the 3rd quarter of 2007.

On August 14, 2003 Pickering NGS suffered a site wide loss of Class IV power as a consequence of a Loss of Bulk Electrical System (LOBES) event. As a result, Pickering NGS was unable to operate a High Pressure Emergency Coolant Injection pump for approximately 5 hours, until power was restored from the grid. In addition, all of the operating units tripped and subsequently could not be cooled down without significant economic penalty until power to the station was restored.

The business objective of this project is to restore PNGS within it's licensing basis by enhancing standby power to:

- Be available to start an HPECI pump within 30 minutes of a LOBES event with no surviving units, and,
- Cooldown all 6 reactors to <90C within 24 hours of a LOBES event with no surviving units.

The above are the minimal regulatory requirements of the APS. The business objective will be met by providing a cost effective and reliable combustion turbine power generation facility that will provide back-up power to specific Pickering NGS loads following a LOBES event, should no units survive the transient.

Partial Release for $66.5M has been approved to commit to purchase of the combustion turbine units, and progress engineering on schedule-critical items so as to maintain viability of the September 2007 in-service date. As part of this partial release the station tie-in point has been reviewed and a cost/schedule savings can be ...zed by changing the station tie-in from the middle of the Station Electrical System (SES) bus to the end of the ... bus at U8. Changing the station tie-in point also changes the risks associated with the project. For the most part many of the IPB (inside plant boundary) risks are reduced or eliminated. Obtaining CNCS concurrence for sequencing of load profile may be required (see Section 6/ Risks). Attachment B outlines the savings realized by the station tie-in change.

This project is part of the 2005 - 2009 business plan for $200M. The 2006 Business Plan will be updated to reflect the cost estimates included in this BCS. The Project Execution Plan (PEP) was approved Nov7, 2005.

$ Millions Capital	$M Capital	Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Partial	66.5	[redacted]	Nov-05	Spent Life to Date:	[redacted]
Requested Now:	Full	50.2	[redacted]	2005-2009	Appr'd Business Plan (Tot Proj):	[redacted]
Cumulative Release:	Total to Date	116.7	[redacted]	2005-2009	Business Plan Variance:	[redacted]
Total Project Estimate:	+30% to -15%	116.7	[redacted]	2005	Budget (Current Year)	[redacted]
Current Year Estimate:	2005	16.6	[redacted]	2005	Budget Variance (Current Yr)	[redacted]
Type of Investment:	Regulatory	N/A	N/A		Cumulative Release Remaining:	[redacted]
NPV:			N/A		Contingency on Remaining Release:	[redacted]
IRR:			N/A		Contingency % on Remaining Release:	[redacted]

Submitted By:

N Mitchell 02/10/2005

Tom Mitchell
Senior Site VP, Pickering B — Date:

Submitted By:

Nov 22, 2005

John Coleby
Senior Site VP, Pickering A — Date:

Finance Approval:

...er
...nvestment & Business Planning — Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Jim Hankinson
President and CEO — Date:

EXECUTIVE SUMMARY

1) BACKGROUND

On August 14th, 2003, Pickering NGS experienced a LOBES (Loss Of Bulk Electrical System) event for approximately 5 hours, thus losing grid-supplied power to the station. The three units operating at the time at Pickering NGS-B all shut down as a result of the event. This led to a total loss of Class IV power across the site (Pickering A and B).

Without Class IV power, a number of important systems were unavailable for use. As noted in the previous submissions (June 1, 2004 and September 22, 2005) to the OPG Board of Directors, the High Pressure Emergency Coolant Injection (HPECI) system pumps could not be run and the Pickering B reactor heat transport systems could not be cooled down without substantial economic penalty until power from the grid was restored.

Prior to the LOBES event, two key assumptions in the design basis for the station were;

- there is a 50% probability that an operating unit will keep operating following a load rejection and thus be able to supply station Class IV power, and
- the maximum duration of a LOBES event will be approximately one hour.

During the August 14th 2003 event, these design basis assumptions were not met – which placed continued operation of the station into question.

As noted in the previous submissions to the OPG Board of Directors, extensive communication took place with the CNSC following the LOBES event. The CNSC have accepted the principle of mitigation through the installation of an alternate power supply – with the previously-installed Remote Emergency Power Generator (REPG) as an interim solution to allow continued station operation. Following negotiation with the CNSC, the following are considered to be regulatory requirements for the standby power system at Pickering NGS:

- having an HPECI pump available to start within 30 minutes of a LOBES event.
- Cooling down the reactor heat transport systems of all Pickering NGS units within 24 hours of a LOBES event. This is a derived requirement of adequacy to address the fact that the original design basis assumption of grid power restoration time was not met.
- Starting unavailability/mission time unreliability of 10E-2 (for APS)
- Cost-effective protection from common mode events affecting the electrical grid

Over and above this, it is a CNSC expectation that current OPG efforts to ensure unit survivability will be pursued in parallel – to fully return HPECI to accepted licensing basis.

The proposed Pickering Auxiliary Power System (APS) is the recommended alternative to allow these regulatory requirements to be met, and, at minimal incremental cost, provide additional power to support operationally critical loads.

2) PROJECT DESCRIPTION

The business objective of the project is to permit continued station operation by restoring Pickering NGS to its accepted licensing design basis. The recommended alternative is providing a source of standby power that will satisfy the regulatory requirements identified in section 1, during an event where grid power is unavailable and all units are consequently or coincidentally shutdown.

The recommended solution consists of a twin set of combustion turbines connected to the station's electrical distribution system, which will meet regulatory loads and provide margin to accommodate other needs critical to plant operation during shutdown. Critical plant needs during shutdown, supplied by Class IV power and to now be powered by APS, include: Main Control Room / Control Equipment Room air-conditioning systems (to minimize overheating risk to the unit Digital Control Computers); continued operation of the Chemistry Laboratory (to maintain system chemical control, particularly with respect to impact on reactor safety); and, additional equipment as backup to Class III powered safety systems for defence in depth.

The duplicate combustion turbine units provide the necessary system reliability to ensure that the overall power supply reliability to the HPECI system and reactor cooldown systems will be met. The system will be tied into the electrical grid through the Pickering switchyard to accommodate full power testing and to provide power to the APS system while the combustion turbines are not operating.

As an interim compensatory measure, OPG installed a backup power supply known as the Remote Emergency Power Generator (REPG) (reference previous June 29, 2004 submission to the OPG Board of Directors). This facility was declared in service on September 30, 2004. The REPG will provide power to start an HPECI pump, though not within the specified 30 minute limit. As a result of the tie-in point to the Pickering station, the REPG cannot complete a cool down of the reactors by forced primary heat transport circulation. In addition, being a single source of power, the REPG will not meet the reliability requirements, nor provide independence from common mode failure events such as ice storms since the power is routed to the station via the 230kV grid power lines. Unless another use can be specified and economically justified, the REPG unit will be sold on the open market with an expected return in the order of $5M (highly dependent on market conditions). Cost recovery hasn't been included in this business case.

The cost of the APS solution is $116.7M, including [redacted] for contingency. This request is for an additional $50.2M to the $66.5M released as part of the submission on September 22, 2005. This amount is within the Business Plan estimate ($200M) for this purpose. The cost estimate is based on analysis of the three major components of the project, namely:

- The Power Plant – This is a commercial quality combustion turbine facility located on the Pickering NGS site, but outside of the nuclear Protected Area boundary. The commercial quality (versus nuclear quality) nature of the system, as well as its location outside the Protected Area, will minimize costs.
- Inside Plant Boundary (IPB) – This is the portion of the system that routes power from the Power Plant into the Protected Area boundary and connects to the station electrical distribution system.
- 230kV Connection – This is the portion of the system that connects the Power Plant with the Pickering NGS-B switchyard for full power testing and provision of power to system auxiliaries when the combustion turbines are not operating. It will also be commercial quality and located outside the Protected Area to minimize costs.

The APS will be placed in service by the Fall of 2007. A regulatory commitment is expected to be generated by the CNSC when the project schedule is submitted to them in January 2006.

Subsequent to the partial release BCS and decision to lay-up P2 & P3, the IPB station tie-in was revisited. There are considerable cost/schedule savings (~$24M and 4 weeks) by connecting to P8 station electrical system. This proposal recommends connecting at P8 station electrical system bus.

3) BENEFITS

The primary benefit of this project is to allow continued station operation by restoring Pickering NGS to its accepted licensing design basis – by providing a source of standby power that will meet the regulatory requirements identified, during an event where grid power is unavailable and all units are shutdown. This will satisfy the CNSC requirements of HPECI availability and reactor heat transport system cooldown in the event of a grid loss. In addition, power will be available to other important plant systems normally supplied by Class IV power, and defence in depth will be enhanced by providing backup to Class III powered nuclear safety-related systems.

4) KEY ALTERNATIVES

4.1 Summary of Key Alternatives Reviewed

Alternative (BCS #)	Description	Cost $M	Cost $M (Including Contingency)	Recommendation
0	Upgrade Existing Remote Emergency Power Generator (REPG)	N/A	N/A	**Not Recommended.** • Does not restore Design Basis • Cannot supply all regulatory loads • Does not meet 30 minute start-up • Does not meet 10^{-2} unavailability • Subject to 230kV common mode fault
1A	Install 2x100% CTUs Connected to Unit 8 SES Bus (Regulatory Loads Plus Important Loads)	[redacted]	116.7	**Recommended.** • Meets Design Basis • Additional highly desirable loads • Operational by Fall 2007
1B	Install 2x100% CTUs Connected to Unit 8 SES Bus	[redacted]	112.7	**NOT Recommended.** • Unable to supply highly desirable loads
1C	Install 2x100% CTUs Connected to Centre of SES Bus	[redacted]	147.6	**Not Recommended.** the postulated benefit would be full APS voltage delivery for PA units, including unencumbered PHT pump operation for cooldown. This is approximately $24M more than the recommended alternative due to increased costs associated with work inside the PNGS plant.

4.1 Summary of Key Alternatives Reviewed Continued

Alternative (BCS #)	Description	Cost $M	Cost $M (Including Contingency)	Recommendation
2A	Supplement REPG and Connect to Ring Bus (Regulatory Loads only)	[redacted]	154	**Not Recommended.** • Technical Issue - feeding through the Station Service Transformer will result in unacceptable voltage drop. • Heat Transport Pump modifications required to overcome tripping pumps when started in standard configuration • Loss of generation revenue due to outage extensions to install Heat Transport modifications
2B	REPG Supplemented with Additional Generators and Connected to Secondary Side of Station Service Transformer (Regulatory Loads only)	[redacted]	156.5	**Not Recommended.** • Unable to supply highly desirable loads • Engineering risks with new 3 winding parallel test transformers to overcome voltage drop problem. • Considerable schedule risk

Although not a regulatory requirement, providing power for important Class IV plant systems and backup to important Class III powered systems will provide additional defence in depth for safe operation of the plant during a grid loss event. Elimination of these loads would not reduce the combustion turbine size required, due to the limited number of sizes of combustion turbines available. The cost savings are thus marginal, and not commensurate with the value of providing the service for critical plant needs.

Several alternatives were considered that involve reuse of the existing REPG, but each presented significant schedule and/or technical risks and most could not meet the regulatory requirements.

The APS will be tied into the 230kV grid, which will allow for full power testing and supply to the power plant auxiliaries. This grid tie-in could facilitate future grid emergency power back-up or peak power operation. However, this would require an additional funding release and would require an environmental assessment.

5) KEY BUSINESS RISKS

An extensive risk assessment was documented, and mitigating actions put in place to reduce residual risks to "low". To ensure integrity, challenge meetings were held with key stakeholders (Corporate Finance, Risk Assurance Services, Financial Planning and others), and mitigating plans/contingencies adjusted accordingly.

Since the last submission on September 22, 2005, all Power Plant risks indicated as Medium have now been dispositioned as Low. The sole remaining Medium risk is Regulatory in nature and is:

- Obtaining CNSC concurrence for sequencing of load profile. The HPECI pump will not be started prior to PHT cooldown. The HPECI pump will be on AUTO and declared available for service once power is supplied to the SES bus. Cost for rework if CNSC concurrence is not received is estimated at $24M, plus increased risks associated with the Inside Plant Boundary (IPB) work.

Overall contingency [redacted] or [redacted]f estimate) has been allocated based on approximately 15% of Design Engineering complete and mitigating actions to address cost and schedule risks associated with the challenging project schedule.

The above risk is being closely monitored.

Appendix A   Project Cost Summary

$ Millions Capital	LTD Prior Years 2004	2005	2006	2007	2008	2009	Total	LTD This Mth Oct 2005	LTD %
OPG Resources		1.3	3.0	2.8	0.3		7.5		
Power Plant	[redacted]								
230kV Phase 1	[redacted]								
230kV Phase 2	[redacted]								
Inside Plant Boundary (IPB)	[redacted]								
Misc. - Contract	[redacted]								
Escalation	[redacted]								
Interest (Capital Project Only)	[redacted]								
Sub Total - (excl Contingency)	[redacted]								
OPG Resources	[redacted]								
Power Plant	[redacted]								
230kV Phase 1 (Swyd tie-in)	[redacted]								
230kV Phase 2	[redacted]								
Inside Plant Boundary (IPB)	[redacted]								
Sub Total - Contingency	[redacted]								
Grand Total	**0.0**	**18.6**	**74.8**	**25.0**	**0.3**	**0.0**	**118.7**	**N/A**	**N/A**
2005-2009 Business Plan		45.0	100.0	55.0	0.0		200.0	N/A	N/A
Variance to Business Plan - (excl Contingency)	[redacted]								

Appendix B Key Milestones

Milestones Finish Date (D/M/Y)	Description
20/10/05	Outside – EPC – Agency Approval to issue PO (complete)
25/10/05	Start of Installation (complete)
15/12/05	Full Release Funding of APS Project
21/04/06	P681 230kV Switchyard Available for Service Declaration complete.
30/05/06	Design Complete
15/06/06	All Major Contracts Awarded
19/02/07	All Regulatory Approvals Obtained
13/04/07	Power Plant – Mechanical Completion Finished
16/07/07	Power Plant – Substantial Completion Finished
27/07/07	APS Available for Service
28/09/07	In Service Declaration to CNSC

ONTARIOPOWER GENERATION

BUSINESS CASE SUMMARY

Standby Generator Governor Upgrades Pickering B 13 - 49109 Capital 13 - 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

Routing	Location	Action	Signature	Date
David Calkin, Project Leader, Design Projects 701-3831	P72-3	Prepare BCS		Jan 30 2007
George Makdessi Project Manager, Design Projects 701-6617	P72-3	Review BCS		30 Jan 2007
Joseph Leung Section Manager, Project Design 701-2635	P72-3	Review BCS		Jan 30 2007
Sepehr Ghorashi Section Manager, Process Scheduling 701-4491	P72-3	Review BCS		2007/01/30
Randy Ludlow Manager, Design Projects - Strat IV 701-8055	P72-3	Review BCS		2007/01/31
Alnoor Bhaloo Manager, Perf Engineering - Strat IV 701-3562	P41E3	Review BCS		2007/02/02
Mark Arnone [illegible]ctor, Projects & Mods [illegible]063	P72-1	Review BCS		02 FEB 2007
~~[illegible] Elliott~~ Bob Goodman Director Station Engineering 701-7078	P41-E3	Review BCS		Feb 2 2007
Ron Ball Senior Financial Analyst 702-4084	P82-3	Review BCS		2 Feb 07
[illegible]ll [illegible] Financial Analyst [illegible]084	P82-3B6	Return For Distribution		

Standby Generator Governor Upgrades Pickering B 13 – 49109 Capital 13 – 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

Routing	Location	Action	Signature	Date
R. Leavitt Director Investment Planning	P82-3	Review BCS		Feb 6, 2007
P. Tremblay Senior V. P. Pickering B	P41-E3	Submit BCS		Feb 7/07
J. Beech V.P. Nuclear Finance	H7-E19	Review BCS		Feb 7/07
T. Mitchell Chief Nuclear Officer	P82-6	Review BCS		Feb 8/07
D. Power V. P. Corporate Investment Planning	H7-D06	Approve BCS		Feb 18/07
P. Charlebois Chief Operating Officer	H19-E21	Review BCS		Feb 20/07
J. Hankinson P...ident & C.E.O.	H19-A24	Approve BCS		Mar 5/07
...ll ... Financial Analyst ...4084	P82-3B6	Return For Distribution		

Standby Generator Governor Upgrades Pickering B 13 - 49109 Capital 13 - 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

1/ RECOMMENDATION:

We recommend a Phase 2 release of $8.8M (total project $23.3M) to complete the design, comprehensive installation work packages and installation/commissioning of governors on the remaining four (of six) Pickering B Standby Generators (SG's).

This project is one of five SG Upgrade projects designed to reduce the likelihood of a forced outage due to SG obsolescence and spare parts unavailability that has been negatively impacting reliability. The scope of these projects was based on a Pratt & Whitney (P&W) report IMR # 510 issued in May 1999 which focused on equipment obsolescence issues and the OEM's inability to support critical products. Phase 2 of this project ($8.8M) and the Protective Relay project ($1.8M) are the two outstanding initiatives of the overall program that is estimated to cost $50M. We have a REGM target to complete this work by Dec 31, 2007.

Prior to the start of this initiative, Pickering B SG performance indicated a deteriorating trend. We were not able to consistently meet the design basis SG start reliability. Approximately 70% of the total SG trips identified in the P&W report could have been prevented by the SG Governor upgrade by ensuring consistent SG starting time bench marks within the start permissive logic. Continued degradation has the potential of severe, protracted adverse impact on SG performance and forced unit outages due to unavailability of Standby Class III Power redundancy. Forced shutdowns of operational Nuclear units can occur when SG unavailability is combined with other safety support system degradation, functional failures or operational restrictions (such as Class II UPS and SES).

At this time, two (2) Governors have been installed, placed in service, and a Post Implementation Reviews (PIR) has been completed. We have seen improvements in SG performance, as work has progressed and the SG health system recently changed from RED to WHITE. Project completion is a requirement to maintain system health WHITE assessment. The total project estimate has increased $1.2M to $23.3M, due primarily to Vendor QA issues, material costs, and underestimated design costs. Lessons learned from Phase 1 have been incorporated into the Phase 2 estimate.

The current Integrated Operating Plan (IOP) schedule calls for the completion of four (4) SGs in 2007. However, due to the degree of difficulty in executing four installations in one year, we are recommending the installation of three (3) governors in 2007 and one early in 2008. This will involve an adjustment to the IOP schedule and an extension to the REGM commitment. However, if conditions prove favourable, we will install four (4) units in 2007.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Full - Phase 1	2,672	8,850	2,969	-				14,491
Requested Now	Full - Phase 2	-	(1,186)	6,984	3,042				8,840
Future Funding Req'd	None								-
Total Project Costs		2,672	7,664	9,953	3,042	-	-	-	23,331
Other Costs									-
Ongoing Costs									-
Grand Total		2,672	7,664	9,953	3,042	-	-	-	23,331

Investment Type	Class	Breakeven Level of Risk	IRR	Discounted Payback
Sustaining	Cap & OM&A	5.2% forced outage	N/A	N/A

Submitted By:

Feb 21/07

Pierre Tremblay
Senior Site Vice President, Pickering B
Date:

Approved by:

T.N. Mitchell
Chief Nuclear Officer

Finance Approval:

Feb 18/07

D. Power
V. P. Corporate Investment Planning
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Mar 5/07

Jim Hankinson
President and CEO
Date:

2 BACKGROUND & ISSUES

The Standby Generator Health system was rated as RED as recently as Q1 2006 due to functional failures on aging parts that are obsolete and no longer supported by the OEM. Over the last few years the SGs have experienced a number of functional failures that contributed to forced outages. The functional failures reduce redundancy and potentially could lead to a Pickering B units shutdown. Recent upgrades and maintenance have improved the system health rating from RED (Q1) to YELLOW (Q2/3) to WHITE (Q4). Project completion is required to ensure system reliability and resolve obsolescence of the governor system which is not supported by the OEM.

The SG system is an essential safety related support system which supplies Class III power to the electrical equipment required to ensure a safe shutdown of the reactor; continuous core cooling, and supply to essential loads in the turbine, water and air systems, in the event of loss of Class IV power. There are three SGs that support each pair of Pickering units (i.e. 056-54600-SG1/SG2/SG3 supports Units 5 & 6, and 078-54600-SG1/SG2/SG3 supports Units 7 & 8).

As per Abnormal Incidence Manual (NK30-AIM-058-09013-04.01), following are the impairments for the Standby Generator system:

- Coincidental unavailability of three SGs per pair of units will result in SG system impairment (system does not meet design intent). In this impairment, both Pickering B affected Units need to be shutdown within 24 hours unless approval has been given by the Duty Manager for continued operation beyond 24 hours. The minimum system requirement is to have at least one SG available per pair of units.

- If two of the three SGs are unavailable per pair of units, the system will be considered to have reduced redundancy or margin of safety and required action will be to suspend testing of remaining SGs and repair to be carried out on high priority basis for the affected SG.

- If one of the three SGs is unavailable per pair of units, the system will be considered to have reduced redundancy or margin of safety and required action will be to suspend non-emergency operation of remaining SGs above 3.5MWe in peaking mode and repair to be carried out on high priority basis for the affected SG.

The following projects represent the Pickering B SG Upgrade program:

Pickering B Standby Generator Upgrade Projects				
49033	SES/HPECI Power Supply Upgrade	Capital	12.7	Complete
49088	Standby Generator Upgrade	OM&A	1.0	Near Completion
40412	Standby Generator Upgrade	Capital	11.0	Near Completion
40628	New Protective Relays	Capital	1.8	Developmental Stage
49109 /40528	Standby Generator Governor Upgrade	Capital / OM&A	23.3	2 of 6 complete
Total			49.8	

See Attachment 'D' for summary of Pickering B SG functional failures extracted from the System Health Report.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay 1 yr			
Revenue	(16,265)	(1,857)	(1,857)	(3,778)			
OM&A	(9,847)	(2,466)	(2,007)	(2,316)			
Capital	1,477	(22,872)	(12,995)	(13,385)			
NPV (after tax)	(12,401)	(20,782)	(12,401)	(13,353)			
Impact on Economic Value (IEV)	N/A	(8,381)	-	(952)			
IRR%	N/A	N/A	N/A	N/A			
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A			

Stop the Project - Not Recommended

This is not recommended as we are at risk of an unplanned SG outage or possible forced unit outage due to SG obsolescence and a lack of spare parts. Moreover, the REGM commitment would not be addressed and we would have to write approximately $ 5.4 M of capital charges off to OM&A

Alternative 1 - Proceed with Project - Recommended

Proceed with upgrades to the SG Governor system and related controls as outlined in section 4 below to reduce the increasing likelihood of an unplanned SG outage or forced unit outage. Because we cannot effectively install more than 3 governors this year, we will need to seek an extension to our REGM commitment and complete the final installation early in 2008. Completion of this work and the Protective Relay project will finalize the upgrades to the Pickering B Standby Generators and thereby remove the threat of a forced outage, maintain the Health System at white and satisfy a REGM commitment.

Due to the complexity of such an event (see Background Section), the likelihood of a forced outage due SG failure is not easily estimated. Lacking an accurate way to determine this level of risk, financial justification must be made on an assessment of whether there is a reasonable chance that the breakeven point for the incremental investment will be surpassed. Calculations indicate that the breakeven point is reached when the likelihood of a forced 30 day outage (involving 2 units) is 5.2% and the cost to repair is $300K. Based on past SG performance (see Attachment D), we feel it is reasonable to assume that we would likely surpass this level of risk, should the investment not be made. Moreover, it makes sense to complete the last major initiative of the $50M SG Upgrade program, so that we can realize the overall objective of SG reliability.

Alternative 2 - Delay Project - Not Recommended

This is not recommended as there is an increasing likelihood of an unplanned SG outage / forced unit outage and we would not be addressing the REGM commitment.

Alternative 3 – Install 2 of the remaining 4 - Not Recommended

Modifying only 2 of the remaining 4 Pickering B SG's is not recommended for the following reasons:

a) OPG is locked into an Engineered Material Vendor contract totaling all six SG's (as per previous release),
b) Increased likelihood of error when performing SG maintenance, as there would be two designs.
c) Increased documentation effort as all the operating and maintenance documentation would need to reflect two designs.
d) 68 percent of the project cost is with the first two SG's.

4/ THE PROPOSAL

We recommend continuing with the replacement of the existing SG Governor, sequencing/control relay logic, fuel delivery package and associated I&C monitoring for the remaining four Pickering B SGs.

Scope Breakdown:

Governor fuel delivery system replacement
New PLC based integrated governor and sequencer controls
Replace majority of the relay start/control logic with PLC
Independent over speed protection system (due to adoption of PLC)
Relay logic changes covered by Pratt & Whitney Study Report IMR 510
PLC based speed switches and timers
New Data event logger with expansion capabilities
New Machine monitor (temperature and vibration)

Phase II major project deliverables are as follows:

(a) Update Project Execution Plan
(b) Revise Vendor design packages as required
(c) Complete Design Packages for remaining two SG's (first four SG's completed under Phase I)
(d) Work Plans and Field Engineering Packages for remaining four SG's
(e) Systems and equipment installation and commissioning remaining four SG's
(f) New and/or revised Operating and Maintenance Procedures for remaining SG's.
(g) Project close out – station document updates, PASSPORT updates
(h) Post implementation review, lessons learned

The SG Governor Upgrade Project Execution Plan (PEP) NK30-PEP-54600-00001 defines the project scope to complete the deliverables. Finish dates in future based on current SG outage schedule. Should outages move, dates will vary accordingly.

5/ QUALITATIVE FACTORS

1. Lower system maintenance costs (Governor and logic failures being minimized) with the new Governor and start/control logic.
2. Improved diagnostic capabilities using new data logger and machine monitor, thus reducing forced SG outage troubleshooting times.
3. Elective and Corrective Maintenance backlogs expected to decrease due to replacement of instrumentation and components

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Additional material may be required depending on as found condition of machine when disassembled for the retrofit modification.	Added material costs to replace broken or unusable existing equipment.	**Medium**	Added [redacted] specific contingency for materials	**Low**
Increased OPG installation package preparation and design review costs due to Vendor documentation QA issues.	May not be able to complete installation packages within budget and schedule.	**Medium**	[redacted] Specific Contingency included for increased installation package preparation effort. OPG Supply Chain working with the Vendor to improve documentation QA through OPG corrective action process. Incorporating Lessons Learned.	**Low**
Scope				
May need to account for field discovery during installation phase.	Delay completion of tasks. May not be able to complete scope within allocated budget.	**Medium**	[redacted] Specific Contingency included for Installation to minimize impact. Design phase comprehensive walkdowns complete. Increase scope only with management approval and funding allocation. Incorporating Lessons Learned.	**Low**
Integration complexities with SG Upgrade project and other Maintenance.	Delay completion of tasks. May not be able to complete scope within allocated budget.	**Medium**	Specific Contingency included for Installation (see above) to minimize impact. Integrated work programs of SG Governor & SG Upgrade projects and station maintenance. Multiple station challenge reviews conducted. Incorporating Lessons Learned.	**Low**
Schedule				
REGM commitment for Dec07 at risk (aggressive station SG outage schedule).	Project may not meet current REGM deadline	**High**	REGM commitment date to be reviewed and extended as required.	**Low**
Station driven SG Outage	IOP process not being followed for	**High**	General contingency includes amounts for	**Medium**

schedule and SG outage maintenance window is very aggressive with little contingency. SG outage opportunities may change.	design issuance milestones and installation package preparation. Delay installation and SG return to service. May not be able to complete scope within allocated schedule windows and budget.		minor delays for the remaining 4 SG's. Many challenge reviews conducted to minimize hand-off / turn-over delays. Increased pre-outage preparation planning. Incorporating Lessons Learned. Recommend adding $2.8M to 2008 B.P. budget against final SG installation delays to 2008. To be reviewed during 2008 Business Planning. Risk remains medium.	
Delays caused by maintenance activities (unforeseen work) during SG outages could affect SG outage schedule	Delay installation. May not be able to complete scope within allocated budget.	**Medium**	Project integrated into station SG maintenance program. Added minor contingency to project schedule. Covered by Specific Installation Contingency discussed on previous page.	**Low**
Resources				
Limited engineering resources. Other project priorities.	Delay completion of scope. Impact on design schedule for subsequent SG's.	**Medium**	Use contract resources, if necessary.	**Low**
Limited installation resources (BTU and PWU). Competing with SG Upgrade project and other maintenance programs. Limited Ops resources during commissioning.	Delay installation	**Medium**	Use contract resources, if necessary. General contingency includes overheads to administer contracts. Pre-arranged Ops support including a SPOC prior to outage. Permit walkdown prior to outage.	**Low**
Engineered Material Vendor resources diverted to other contracts. Vendor has access to limited resources and has limited project management skills.	Delays in subsequent design packages for remaining SG's. Delays in testing and material delivery	**High**	OPG added resources to assist Vendor in project co-ordination. Vendor added technical and project management resources. Vendor advancing production schedule for remaining SG's. Supply Chain exploring other contractual remedies.	**Low**
Technical				
Commissioning / testing of complete modification on subsequent SGs. Possible software modifications during commissioning.	Delay return to service due to cumbersone SQA field change process. SG unavailability combined with other safety support system degradations (i.e., UPS, SES) may cause forced unit shutdowns.	**Medium**	Minor schedule and cost contingency added (see specific contingency on previous page). Design verifications, simulations and comprehensive FAT prior to installation. Independent verification of software and hardware design. Software Field Change process developed with Computer Design Group to enable parallel Software	**Low**

			verification with field implimentation. Incorporating Lessons Learned.	
Regulatory				
None.				
Environmental				
Scrapping of old material	Environmental regulatory non-compliance	**Medium**	Material to be sampled and scrapped in accordance with approved procedures.	**Low**
Health & Safety				
None.				
Investment				
Project does not satisfy the Business Objectives	Rework, extra cost	**Low**	The first two governors have been installed and are operating as designed	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	**Jun 2008**	**Dec 2008**	**Director - Station Engineering**

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Available For Service (first 2 SG's)	N/A	AFS and open items acceptance by stakeholders	Attach copy of AFS and open items with A/R's to PIR	System Engineer
2.	SG Machine performance Criteria Met	N/A	Commissioning results acceptance by Design	Signed Commissioning Report scanned in Passport	Project Manager
	Standby Generator (SG) System Health	Red	Removal of SG Governor and associated control systems as contributor to Red system status	Updated SG system health report indicating improved status for affected equipment	System Engineer
4.	REGM 28007285 complete	Dec 2007	SG Governor Project contribution to REGM completion	SMB REGM schedule review Milestone added to SG Outage Plan	Project Manager
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

AFS	Available for Service
BCS	Business Case Summary
B.P.	Business Plan
BTU	Builders Trade Union
COMS	Constructability, Operability, Maintainability, Safety
CUSW	Direct Hire Building Trade Union (Electrical)
CWP's	Comprehensive Work Packages
DCN	Design Change Notice
ECC	Engineering Change Control
EPG	Emergency Power Generator
FAT	Factory Acceptable Test
FE	Field Engineering
FIPR	Field Installation Package Release
FME	Foreign Material Exclusion
HFE	Human Factors Engineering
IOP	Integrated Operating Plan
ITP	Inspection Test Plan
I&C	Instrumentation and Controls
IRR	Internal Rate of Return
NUCORDS	Nuclear Components Reliability Data System
NPV	Net Present Value
OAR	Organizational Authority Register
OLW	Online Wiring
OM&A	Operations, Maintenance and Administrative expense
ONL	Online Wiring
OPEX	Operating Experience
Ops	Operations
O.T.	Overtime
PC1	Worker Protection Permit application Form
PEP	Project Execution Plan
PIR	Post Implementation Review
PFU	Predicted Unavailability Factor
PINO	Performance Improvement Nuclear Oversite
PLC	Programmable Logic Control
PSL	Power Supply List
PWU	Power Workers Union
QA	Quality Assurance
QCIV	Quality Control Inspection Verification
QSITP	Quality Surveillance Inspection Test Plan
REGM	SNSC Management Commitment
SCR	Site Condition Report
SE's	System Engineer
SES	Site Electrical System
SG	Standby Generator
SMB	Site Management Board
SPOC	Single Point of Contact
SQA	Software Qualification Assurance
TSSA	Technical Safety Standards Authority
UPS	Uninterruptible Power Supply

Appendix "B"

Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2002	2003	2004	2005	2006	2007	2008	Later	Total
Developmental	Jul	2,002	300								300
Full (Phase 1)	Apr	2,004	87	0	1,010	7,712					8,809
Superseding	Feb	2,006	87	0	372	2,213	8,850	2,969	0		14,490
Full (Phase 2)	Jan	2,007	87	0	372	2,213	7,664	9,953	3,042		23,331
											0
											0
											0
											0

LTD Spent	Dec	2,006	87		372	2,213	7,664				10,336

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Cost estimates have been verified by 3rd party reviewer, Atlas Helyar. Task Identification Sheets (N-Form-11025) have been validated by all contributing resource groups. Actuals and lessons learned have been incorporated into estimates.

Financial Assumptions:

The breakeven point for this investment is reached when the probability of a 2 unit forced outage of 30 days reaches 5.2% and the cost of repair accumulates to $300K. This is based on the following:

Loss of Revenue during forced unit outages:

(516MW for PB) X (85% Capacity Factor) X (24 Hours) X (30 Days) X (Rate MWH) X (2 Units).

Repair Costs during forced SG outages:

$300K per year + 3% Inflation

Project / Station End of Life Assumptions:

Pickering B End of Life: 2014 Units 5, 6, and 7 2016 Unit 8

Energy Price / Production Assumptions:

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
56.2	58.2	57.0	55.6	54.4	54.2	56.3	60.2	64.4	67.1

Operating Cost Assumptions:
N/A

Other Assumptions:
N/A

Standby Generator Governor Upgrades Pickering B 13 - 49109 Capital 13 - 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

Attachment "A" **Project Cost Summary**

$000's Capital & OM&A	LTD Prior Yr 2006	This Release 2007	This Release 2008					Later	Total
Project Management (OPG)	623	253	260	-					1,136
Engineering & Drafting (OPG)	1,874	1,018	374	-					3,266
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
OMA Project 40528									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	10,336	9,953	3,042	-	-	-	-	-	23,331
2007-2011 Business Plan	10,336	7,083	2,230	-					19,649
Variance to Business Plan	-	2,060	566	-	-	-	-	-	2,626
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	[redacted]								
Total Release (incl contingency)	10,336	9,953	3,042	-	-	-	-	-	23,331

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	100%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Apr 2007.

Reviewed By: 30 Jan 2007

George Makdessi
Project Manager
Date:

Approved By: 31 Jan 2007

Randy Ludlow
Eng & Mods Manager (Strat IV)
Date:

Standby Generator Governor Upgrades Pickering B 13 - 49109 Capital 13 - 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

Attachment "B"

Project Variance Analysis

Capital & OM&A	LTD Dec 2006	Total Project Last BCS Feb 2005	Total Project This BCS Jan 2007	Variance	Comments
Phase 1					
Project Management (OPG)	623	668	623	(45)	As per actuals
Engineering & Drafting (OPG)	1,874	1,518	2,039	521	Vendor software changes QA, Rework, Field Changes
Material	2,370	5,667	6,142	475	Commissioning Supp from Vendor, Increases to Misc Matl
Installation – PWU, BTU	3,534	3,654	3,735	81	As per actuals
Contract - Design	495	322	502	180	As above
Contract - Installation	386	260	392	132	056-SG3 Outage start delays, ES Fox/Crosby Dewar Increased Costs due to design changes.
Contract - Other	340	302	340	38	Training materials and hardware costs
OMA Project 40528	459	459	459	-	Sunk costs of previous OM&A project
Interest (Capital Project Only)	255	258	255	(3)	As per Actuals
Phase 1 (excluding contingency)	10,336	13,108	14,486	1,378	
General Contingency		**242**	-	(242)	Materialized risk as outlined in last BCS brought into budget.
Specific Contingency	-	1,140	-	(1,140)	Materialized risk as outlined in last BCS brought into budget
Phase 1 (incl contingency)	10,336	14,490	14,486	(4)	
Phase 2					
Project Management (OPG)	-	238	513	275	Outage Delays and increased support of Vendor
Engineering & Drafting (OPG)	-	450	1,227	777	Adjustments as per lessons learned and increased review effort of vendor design and field changes
Material	-	186	440	254	Commissioning Support from Vendor, Increased Misc Matl costs (lessons learned)
Installation – PWU, BTU	-	4,650	4,787	137	Adjustments as per lessons learned
Contract - Design	-	49	55	6	Adjustments as per lessons learned
Contract - Installation	-	393	344	(49)	Adjustments as per lessons learned
Contract - Other	-	100	100	-	
OMA Project 40528	-	-	-	-	
Interest (Capital Project Only)	-	174	323	149	Cash Flow adjustments
Phase 2 (excluding contingency)	-	6,240	7,789	1,549	
General Contingency		**1,409**	**86**	(1,323)	Incorporation of lessons learned.
Specific Contingency		-	970	970	Identified risks going forward
Phase 2 (incl contingency)	-	7,649	8,845	1,196	
Total Project (incl contingency)	10,336	22,139	23,331	1,192	
General Contingency		**1,651**	**86**		
Specific Contingency		**1,140**	**970**		
Total Project (excl contingency)	10,336	19,348	22,275	2,927	

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
15	Apr	2007	Revise PEP
09	Feb	2007	5th SG Detailed Design Package 056SG2
07	May	2007	6th SG Detailed Design Package 078SG2
19	Feb	2007	056-SG1 (3rd SG) Installation Start (T-0)
07	May	2007	078-SG1 (4th SG) Installation Start (T-0)
22	Oct	2007	056-SG2 (5th SG) Installation Start (T-0)
15	Feb	2008	078-SG2 (6th SG) Installation Start (T-0)
10	Apr	2007	056-SG1 (3rd SG) AFS
06	Jul	2007	078-SG1 (4th SG) AFS
21	Dec	2007	056-SG2 (5th SG) AFS
7	Apr	2008	078-SG2 (6th SG) AFS
30	Dec	2008	Project Complete

A Project Execution Plan (PEP) will be approved by 2007

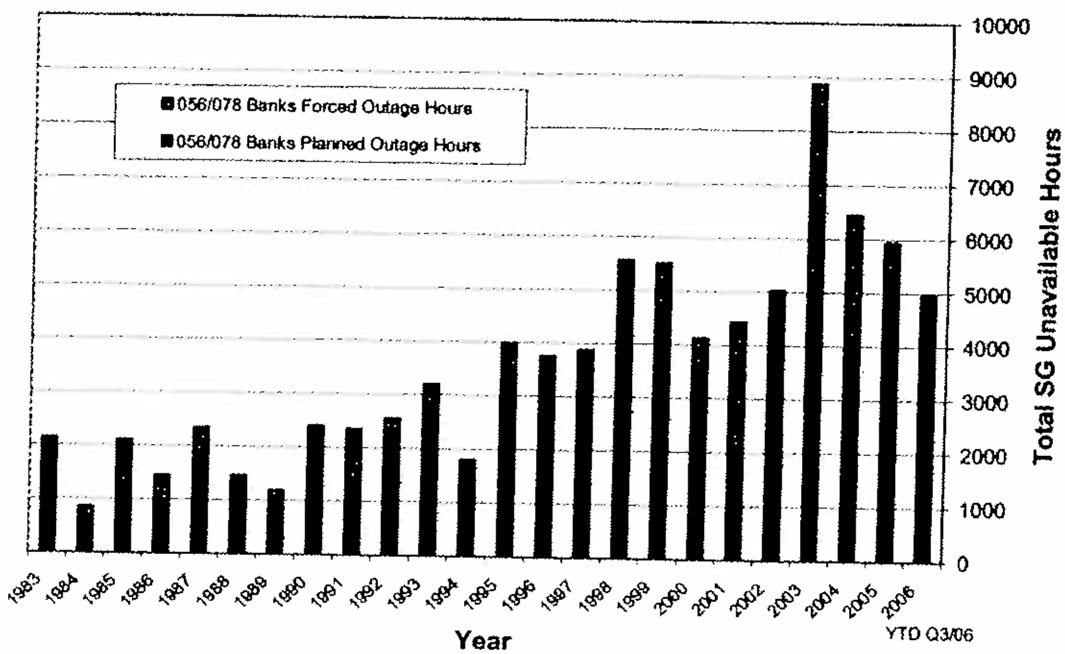
Comments:

Attachment 'D'

Pickering B Standby Generator 2005 & 2006 Failures / SCR Summary

Functional Failures (QTR/2YR)	Common		056 SGs		078 SGs		Overall System Health
	Qtr	2 Yr	Qtr	2 Yr	Qtr	2 Yr	
Q1 2005	0 →	0	0 ↓	9 ↓	2 ↑	17 →	RED
Q3 2005	0 →	0	1 ↓	6 ↓	1 ↓	16 ↓	RED
Q2 2005	0 →	0	2 ↓	6 ↓	2 ↓	16 ↓	RED
Q4 2005	0 →	0	0 ↓	6 →	1 →	16 →	RED
Q1 2006	0 →	0 →	0 ↓	4 ↓	0 →	14 ↓	RED
Q2 and Q3 2006	0 →	0 →	0 ↓	4 ↓	0 →	14 ↓	YELLOW
Q4 2006	0 →	0 →	0 →	1 ↓	0 →	7 ↓	WHITE

Pickering B SG Unavailable Hours per Year (Planned vs Forced/Outage Extension)



Event Date	SCR	Equipment / Event Summary
Jan 04, 2005	P-2005-00131	056-54600-SG3 tripped during start-up of pre-outage test run on "PT Exhaust Temp.
Jan 18, 2005	P-2005-01151	078-54600-SG2 tripped during start-up of routine P-07 test run.
Feb 13, 2005	P-2005-02699	078-54600-SG2 tripped on "DC Lube Oil Pump Failure" during U7 P-05 routine test - defective pressure switch PS12.
Feb 18, 2005	P-2005-03115	056-54600-SG1 incurred a "Fuel Boost Pressure Low" (Test Mode only) start trip during U5 loss of class III bus test. It is a Peaking Mode only trip.
Feb 19, 2005	P-2005-03249	078-54600-SG3 failed to start and was rejected duringU7 P-5 test. Fault was traced back to a faulty T8 timer.
Mar 18, 2005	P-2005-05152	056-54600-SG3 tripped on "PT Exhaust Temp. High" during start-up of U6 UPSB backup test.
May 01, 2005	P-2005-07961	056-54600-SG1 tripped during start-up of P7 routine test run on "PT Lube Oil Sequence Failed". – It is a Peaking Mode only trip. Intermittent equipment failure.
May 22 , 2005	P-2005-09305	078-54600-SG3 tripped during start-up of routine P-07 test run on "Main Lube Pressure Low" - defective T8 timer.
Jun 18, 2005	P-2005-10865	056-54600-SG2 tripped on "PT Lube Oil Sequence Failed" during P7 routine test. It is a Peaking Mode only trip. Defective T11 timer.
Jun 28, 2005	P-2005-11400	078-54600-SG3 tripped during start-up of routine P-07 test run on "Main Lube Pressure Low". – Defective T8 timer.
Jul 05, 2005	P-2005-11683	078-54600-SG2 failed to start.
Jul 06, 2005	P-2005-11734	Temperature Switch Non-Conformance.
Jul 07, 2005	P-2005-11779	Actual Past Unavailability due to SGs Failures
Aug28, 2005	P-2005-14142	056-54600-SG3 Unavailable.
Sep 19, 2005	P-2005-15563	Fuel leak at 056-SG3 fuel oil integrator FZ3399
Nov 22, 2005	P-2005-19625	078-54600-SG3 tripped during start up for routine test.
April 20, 2006	P-2006-06624	078 SG2 trip on startup. 078-SG2 started for supporting Unit 8 BUS transfer operation @ 10:52 on April 20/06. The machine tripped approximately 15 seconds into the start sequence. DC Lube Oil pump did not start as expected. Trip appears to be spurious.
Sept. 30, 2006	P-2006-16975	On 09/30/06 @ 4:00, CI 525 "056-SG1 Process Trouble" annunciated in MCR. Local inspection discovered "FIRE" window lit on. SG was declared unavailable (ref. SCR P-2006-16975 & WR# 520871). Fault was traced back to a defective R1 relay which caused this spurious alarm.
Dec 18, 2006	P-2006-24708	Standby Generation Impairment 078-SG1 tripped on routine test run./ During routine P-007 test run of 078-SG1on Dec 18/06, the machine started up with an initial frequency @ 63 Hz which was above the normal 61.2 Hz.

Review Flight Details

Search Select Review Passengers Purchase Itinerary

Fares shown are the best available uniform rates at this time for the number of tickets requested and the selected travel times and dates. Fares are not guaranteed until you purchase your ticket.

Review your itinerary

Flight	From	To	Date	Depart	Arrive	Stops	Duration	Aircraft	Fare Type	Meal Service*
AC602	Toronto, Pearson Int'l (YYZ)	Halifax, Halifax Int'l (YHZ)	Sun Jun-22	07:00	10:00	0	2hr00	321	Tango	F
AC617	Halifax, Halifax Int'l (YHZ)	Toronto, Pearson Int'l (YYZ)	Thu Jun-26	16:05	17:27	0	2hr22	763	Tango	F

F: Food for purchase onboard

Review final quote details

Fare Summary

Passenger Type	**Adult**
Flight 1 - Departing airfare (Tango)	**129.00**
Flight 2 - Returning airfare (Tango)	**144.00**
Surcharges	96.00
Taxes, Fees and Charges	
Canada Airport Improvement Fee	30.00
Air Travellers Security Charge (ATSC)	9.33
Canada Harmonized Sales Tax	1.30
Canada Goods and Services Tax (GST/HST #10009-2287)	19.92
Total airfare and taxes before options (per passenger)	**429.55**
Number Of Passengers	1
Grand Total - Canadian Dollars	**$429.55**

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Upgrades certificates	Non-eligible	Eligible for upgrade to Executive Class with a Super Elite or Elite Special System Wide Upgrade Certificate (subject to the terms on the certificate).
Advance seat selection	Not included (from $15 CAD per seat)	**Complimentary** (subject to availability)
Flat fee for same-day changes at the airport	$150 CAD (no charge for fare difference)	**Lower change fees!** $50 CAD (no charge for fare difference)

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ONTARIO POWER GENERATION

OPG Confidential	Page: 1 of 14
BUSINESS CASE SUMMARY	

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

Routing	Location	Action	Signature	Date
J. Xiao Section Manager Feeder Cut & Weld Tooling Project	P82-6	Prepare BCS		June 28, 2007
K. Garel Manager Feeder Integrity Projects	P82-6	Review BCS		June 28, 2007
R. Ball Senior Financial Advisor Nuclear Investment Management	P82-3	Review BCS		28 Jun 07
D. Zerkee Manager Nuclear Investment Management	P82-3	Review BCS		28 Jun 07
R. Leavitt Director Investment Management	P82-3	Review BCS		June 29, 2007
P. Spekkens Vice President Science & Technology Development	P82-6	Submit BCS		
T. Mitchell Chief Nuclear Officer	P82-6	Review BCS		29 June 07
P. Charlebois EVP & Chief Operating Officer	H19A21	Review BCS		[illegible]
D. Power V.P. Corporate Investment Planning	H7 D06	Approve BCS		July 12/07
J. Hankinson President & CEO	H19 A24	Approve BCS		July 13/07
R. Ball Senior Financial Analyst 82-4084	P82-3B6	Return For Distribution		

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

J. Xiao Section Manager Feeder Cut & Weld Tooling Project	P82-6	Prepare BCS	[illegible]	June 28, 2007
K. Garel Manager Feeder Integrity Projects	P82-6	Review BCS	[illegible]	June 28, 2007
R. Ball Senior Financial Advisor Nuclear Investment Management	P82-3	Review BCS	[illegible]	28 Jun 07
D. Zerkee Manager Nuclear Investment Management	P82-3	Review BCS	[illegible]	28 Jun 07
R. Leavitt Director Investment Management	P82-3	Review BCS		
P. Spekkens Vice President Science & Technology Development	P82-6	Submit BCS	Paul Spekkens	28 June, '07
T. Mitchell Chief Nuclear Officer	P82-6	Review BCS		
P. Charlebois EVP & Chief Operating Officer	H19A21	Review BCS		
D. Power V.P. Corporate Investment Planning	H7 D06	Approve BCS		
J. Hankinson President & CEO	H19 A24	Approve BCS		
R. Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

1/ RECOMMENDATION:

We recommend approval of a full release of $15.8M to purchase 3 additional and complete sets of Cut and Weld Tools for feeder replacement. Based on lessons learned during the first usage of Cut and Weld equipment in the D611 outage, we recommend supplementing these additional sets with some new minor tools as well as incorporating some design improvements. Ownership and usage of the tools sets will be controlled under the same Cut and Weld agreements we currently have with AECL, B&W, and Bruce Power.

The Business Objective of this project is to generate additional revenue by reducing the length of outages in the 2008 to 2017 time frame by using the recommended new Cut and Weld tooling.

We estimate feeder replacement to be the critical path item for all Pickering A and Darlington outages in the 2008-2017 timeframe. The 3 sets of tools will make the following currently unachievable results possible:

- Conducting feeder replacement execution at 2 reactor faces in parallel when it is required.
- Completing concurrent training or one face execution at another Nuclear station, if it is required
- Reducing feeder replacement time by using the new and improved tools

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

We estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using the new tool sets to reduce feeder replacement times and to mitigate the risk of outage delays due to tooling shortages. The NPV of this $15.8M capital investment is estimated to be $21M with an IRR of 40.5% and a discounted payback of 4.3 years.

A Full Release is required to make commitments to the supplier that will ensure tool availability by D811.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	N/A								-
Requested Now	Full			4,990	9,289	1,484			15,763
Future Funding Req'd									-
Total Project Costs		-	-	4,990	9,289	1,484	-	-	15,763
Other Costs									-
Ongoing Costs									-
Grand Total		-	-	4,990	9,289	1,484	-	-	15,763

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	Capital	21.0	40.5%	4.3

Submitted By:

P. Spekkens
Vice President
Science & Technology Development
Date:

Finance Approval:

July 12/07
D. Power
V.P. Corporate Investment Planning
Date:

July 12/07

Line Approval (Per OAR Element 1.2 Project not in Budget)

July 13/07
J. Hankinson
President & CEO
Date:

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

1/ RECOMMENDATION:

We recommend approval of a full release of $15.8M to purchase 3 additional and complete sets of Cut and Weld Tools for feeder replacement. Based on lessons learned during the first usage of Cut and Weld equipment in the D611 outage, we recommend supplementing these additional sets with some new minor tools as well as incorporating some design improvements. Ownership and usage of the tools sets will be controlled under the same Cut and Weld agreements we currently have with AECL, B&W, and Bruce Power.

The Business Objective of this project is to generate additional revenue by reducing the length of outages in the 2008 to 2017 time frame by using the recommended new Cut and Weld tooling.

We estimate feeder replacement to be the critical path item for all Pickering A and Darlington outages in the 2008-2017 timeframe. The 3 sets of tools will make the following currently unachievable results possible:

- Conducting feeder replacement execution at 2 reactor faces in parallel when it is required.
- Completing concurrent training or one face execution at another Nuclear station, if it is required
- Reducing feeder replacement time by using the new and improved tools

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

We estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using the new tool sets to reduce feeder replacement times and to mitigate the risk of outage delays due to tooling shortages. The NPV of this $15.8M capital investment is estimated to be $21M with an IRR of 40.5% and a discounted payback of 4.3 years.

A Full Release is required to make commitments to the supplier that will ensure tool availability by D8: 1.

[redacted]

Currently Released	N/A								-
Requested Now	Full			4,990	9,289	1,484			15,763
Future Funding Req'd									-
Total Project Costs		-	-	4,990	9,289	1,484	-	-	15,763
Other Costs									-
Ongoing Costs									-
Grand Total		-	-	4,990	9,289	1,484	-	-	15,763

[redacted]

Submitted By:

Paul Speckens June 28, '07

P. Speckens Date:
Vice President
Science & Technology Development

Finance Approval:

D. Power Date:
V.P. Corporate Investment Planning

Line Approval (Per OAR Element 1.2 Project not in Budget):

J. Hankinson Date:
President & CEO

2/ BACKGROUND & ISSUES

The integrity of CANDU primary heat transport piping, which connects the header to the nuclear reactor's fuel channels, referred to as "feeder tubes", has become an issue as a result of two degradation mechanisms; thinning caused by flow accelerated corrosion, and feeder pipe wall cracking, which is believed to be caused by stress related corrosion or low temperature pipe elongation creep. OPG addressed these feeder degradation issues via the Feeder Integrity Project (FIP), which included a number of sub-projects. To address station concerns on feeder thinning, the FIP Cut and Weld sub-project, partnering with a similar team at Bruce Power, managed the development and acquisition of a set of advanced tooling to repair thinned sections of feeder tubing positioned beyond arms reach.

The Advanced Cut and Weld tooling for feeder replacement developed under the original scope (Project #10-33993) has been successfully used during the D611 Outage. Three sets of tooling were obtained, one for face use, one for back-up and a third for training. Following the first use of this one of a kind tooling in the D611 Outage, OPEX identified areas for performance improvements. Additional funding was subsequently released under Project #10-62562 to cover the improvements considered essential for P711 and D721 Outages. However, the existing tooling continues to be limited to feeder replacement at 1 face, 1 station due to the number of tool sets.

Since there has been only one feeder replacement outage, the reliability of the tooling has not been seriously tested, although there have been difficulties in getting some tools out of the station due to contamination. It is highly likely that there'll be attrition loss or contamination of tools as more feeder replacement campaigns are executed. In addition, Darlington has indicated the needs to execute feeder replacement concurrently on the two reactor faces starting in the D811 outage and then on a regular basis until 2017. Pickering A is expected to have the same requirement starting in the P911 outage. Analysis indicates this requirement will add 36 days to Darlington outages and 16 days to PNGS-A outages in the period from 2008 to 2017.

Furthermore, outage delays are possible, if there is a shortage of tools due to an overlap in feeder replacement campaigns for OPG and Bruce Power stations. Outage organizations are trying to maintain a 2-week gap between the outages of different stations (PA, PB and DA); however, there is a reasonable probability that this scheduling will not be maintained. An additional 3 sets of tooling will mitigate the risk of an outage delay due tool shortages.

We estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using the new tool sets to reduce feeder replacement times and to mitigate the risk of outage delays due to tooling shortages.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions	No Project	Alt 1 (Recommended) Full Cost 3 Tools in '08 Bruce 0% No-ROW	Alt 1 (Recommended) Incr Cost 3 Tools in '08 Bruce 0% No-ROW	Alt 3 Training Set '08 3 Tools in '09 Bruce 40% A-ROW incl	Alt 4 3 Tools in '08 Bruce 40% A-ROW Included	Alt 5 1 Tool in '08 Bruce 0% No A-ROW
Revenue	(69.6)			(5.0)		(25.0)
OM&A						
Capital		(15.8)	(15.8)	(14.4)	(12.8)	(10.0)
NPV (after tax)	(32.0)	(11.0)	(11.0)	(12.9)	(9.0)	(18.6)
Impact on Economic Value (IEV)	N/A	21.0	21 0	19.1	23.1	13.4
IRR%	N/A	40.5%	40.5%	N/A	N/A	N/A
Discounted Payback (Yrs)	N/A	4.3	4.3	N/A	N/A	N/A

Status Quo - Not Recommended

We do not recommend this alternative because there is a more economic way to complete feeder replacements by using additional and enhanced Cut and Weld tooling collectively purchased and controlled under the same Cut and Weld agreements we currently have with AECL, B&W, and Bruce Power.

Alternative 1 - Purchase 3 Sets of Tools with NO A-ROW & NO Bruce Participation - Recommended

We recommend this alternative because we estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using 3 additional and enhanced tool sets to provide tooling capability for concurrent feeder replacement campaigns, and to mitigate the risk of outage delays due to tooling shortages. The NPV of this $15.8M capital investment is estimated to be $21M with an IRR of 40.5% and a discounted payback of 4.3 years.

Alternative 2 - Delay Project - Not Recommended

We do not recommend delaying the recommendation because the opportunity to generate more revenue is greater than the savings that can be derived from a delay.

Alternative 3 – Upgrade Training Set for D811, 3 Sets with A-ROW / Bruce for '09 - Not Recommended

We do not recommend this alternative because the extra cost of the tools ($1.6M) when compared the similar alternative (Alt 4) and the lost opportunity to generate more revenue ($5.0M) make this alternative financially less acceptable ($1.8M) than the recommendation.

Alternative 4 – 3 Sets of Tools with A-ROW & Bruce Participation - Not Recommended

We do not recommend at this time as the Bruce Power participation has not been confirmed. If Bruce Power is confirmed at a later date, this alternative will be considered and there'll be an approx. $3M saving to OPG. The trade off is that Bruce Power will share the tools with OPG, but this was the agreement on the original sets of tools. Exclusive ownership of the additional tools by OPG makes the existing tools more readily available to Bruce Power, resulting in effective sharing of all the tools.

Alternative 5 – Purchase 1 Set of Tools with A-ROW & Bruce Participation - Not Recommended

We do not recommend this alternative because the lost opportunity to generate additional revenue ($25M) by using the new tool sets to mitigate the risk outage delays make it financially less acceptable ($7.6M NPV) than the Recommendation.

4/ THE PROPOSAL

External contractors AECL and B&W will be utilized, in keeping with AGREEMENT No. OPG/BP-01, July 15, 2004. Additional external welding equipment expertise will be utilized to ensure tooling improvements are warranted and proposals are sound. Base organizations will provide 1 FTE plus 1 augmented FTE's to support the assessment, specification, development and purchase of the new tool sets.

The scope of the Improved Cut and Weld Tooling project is as follows:

a. **Assess Needs and Improvement Opportunities.** Obtain information from each station to determine the requirements for concurrent 2 face campaigns and risks of overlapping outages. Review OPEX and lessons learned on use of the tooling in Fall 2006 outage at Darlington (D611) and develop recommendations for improvements.

b. **Purchase the additional Tooling.** Complete the required documentation for specification and purchase of the required tooling.

c. **Monitor the development and supply of tooling.** Provide oversight to ensure tooling development meets the improvement and delivery schedule requirements.

5/ QUALITATIVE FACTORS

An increase in tooling efficiency will reduce worker dose uptake and lower risk of injury.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Price increase from vendor budgetary quote to firm quote	Cost overrun	Medium	Obtain updated budgetary quote. [redacted] contingency in place.	Low
Bruce Power does not participate	Cost overrun	Medium	Early identification of Bruce Power interest through negotiations. They have expressed interest in the option recommended in this BCS and a letter of intent is expected soon.	Low
Scope				
Discovery issues require additional scope	Cost overrun and schedule delay	Medium	Increased scope to be addressed using Change Management Process (CPM), PM principles, and/or a superseding BCS	Low
Schedule				
Delayed award of contract affects training and tooling delivery for D811 Outage	Outage critical path extension.	High	Increased effort on the BCS process and contract negotiations.	Medium
Resources				
Lack of experienced engineering support resources for this project	Schedule delay	Medium	Plan to use qualified contractor resources. High level of management oversight to track contractor performance.	Low
Technical				
Technical issues results in less than satisfactory tooling improvements or new tools	Not all the benefits can be realized	Medium	Mock-up testing/training to prove tooling effectiveness. High level of management oversight to track contractor performance	Low

Regulatory				
Environmental				
Health & Safety				
Investment				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2009	Dec 2009	Manager, Feeder Integrity Projects

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Feeder replacement execution on 2 reactor faces in parallel	Work in series between reactor faces.	Work concurrently on 2 reactor faces if required. No project execution delays due to tooling shortage.	OPEX from post outage lessons learned.	Manager, Feeder Integrity Projects
2.	Availability of additional feeder Cut & Weld Tooling for training or execution at another station	Not available	No delays in training or feeder replacement (one face) due to tooling at another station.	OPEX from outages where feeder repacement overlaps at two nuclear stations.	Manager, Feeder Integrity Projects
3.					
4.					
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

technical terms explanation embedded in the BCS

Appendix "B" **Project Funding History**

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Full	Jun	2,007	4,990	9,289	1,484						15,763
											0
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Tool Cost based on Budgetary Quote from AECL and B&W.

Financial Assumptions:

7% WACC

Project / Station End of Life Assumptions:

DNGS 2017
PNGS-A 2023
PNGS-B 2014

Energy Price / Production Assumptions:

49.50 MWH plus 2% starting in 2009

Operating Cost Assumptions:

Estimated number of outage extension days potentially saved when work on 2 reactor faces in parallel is:

# days	2008	2009	2010	2011	2014	2015	2017
PNGSA		2.5	8.3	5.4			
DNGS	5	3.3		6.3	9.4	5	7.2

Other Assumptions:

We are estimating that there is a 10% probability of a $25M outage extension per year due to a tool shortage from conflicting outages among Pick A, B, Darlington and Bruce Power stations in the years 2008 -2017

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

Attachment "A"

Project Cost Summary

$000's Capital	LTD Prior Yr 2007	This Release 2007	Future Release 2008	2009	2010	2011	2012	Later	Total
Project Management (OPG)		10	180	90					280
Engineering & Drafting (OPG)		20	270	140					430
Material	[redacted]								
Installation – PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
	[redacted]								
	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency									-
Project Costs (incl contingency)	-	4,990	9,289	1,484	-	-	-	-	15,764
2007-2011 Business Plan									-
Variance to Business Plan	-	4,530	8,469	1,404	-	-	-	-	14,404
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
~~Total Release (excl contingency)~~	[redacted]								
Total Release (incl contingency)	-	[illegible]	[illegible]	[illegible]	-	-	-	-	15,764
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	N/A		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects	Yes	Contracts in place	No	Competitive Bid	No

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF is not required

Reviewed By:

J. Xiao
Project Manager

Date: June 27, 2007

Approved By:

K. Garel
Eng & Mods Manager (Strat IV)

Date: June 27, 2007

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-00000-R000

Attachment "B"

Project Variance Analysis

	LTD	Choose One		Variance	Comments
		Last BCS	This BCS		
	N/A	N/A	N/A		
	N/A	N/A	N/A		
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
29	May	2006	Project Charter (PCH) issued for use – Complete
08	Jul	2007	Full release Business Case Summary (BCS) issued
15	Jul	2007	Tooling Purchase Contract Awarded
15	Jan	2008	D811 Priority Tooling Mock-up Testing Complete
15	Feb	2008	D811 Tools & Equipment On-site
01	Oct	2008	Main Tooling Mock-up Testing Complete
15	Dec	2008	Main Tooling Package complete
15	Jun	2009	Project Close-out complete

A Project Execution Plan (PEP) is not required

Comments:

Primary scope (development and supply of tooling) of the project will be performed by the contractors which will be retained through the contracting process. Only resources required from OPG will be project management which is well defined. A PEP is not required.

ONTARIOPOWER GENERATION

OPG Confidential	Page: 1 of 14
BUSINESS CASE SUMMARY	

Phase II Fire Protection Project 16 - 79016

Superseding Business Case D-BCS-78000-10003-R000

Routing	Location	Action	Signature	Date
S. Bagshaw Project Leader, Design Projects 703-3554	BW702	Prepare BCS		04-JUL-07
T. Cvitkovic Project Manager, Design Projects 703-3571	BW702	Review BCS		4 July 2007
J. Taras Section Manager, PMO 703-3528	BW702	Review BCS	J. Taras	9 July 2007
T. Chong Manager, Design Projects 703-3520	BW702	Review BCS		12 July 2007
J. Shemilt Manager, Projects Design, Darlington 703-1963	D08-ES3	Review BCS	J Shemilt	2007/7/13
J. Lehman Manager, Performance Eng., Darlington 703-7325	D08-ES2	Review BCS	J Lehman	18/07/07
A. Kleer [illegible] Financial Analyst, Nuclear Finance [illegible]0-7720	P82-3A5	Review BCS	A Kleer	25 Jul 07
M. Arnone Director, Projects & Modifications 701-6063	P72-2	Review BCS		26 July 2007
R. Leavitt Director, Investment Management Nuclear 702-5085	P823-315	Review BCS	R Leavitt	Aug 1, 2007
S. Seedhouse Director, Station Engineering, Darlington 703-7584	D08-ESS3P	Review BCS	for J. Lehman	Aug 9/07
W. Robbins Senior Vice President, Darlington Nuclear 703-7499	D08-ES3	Submit BCS	Wayne Robbins	2007-08-15
D. Power Vice President, Corp Investment Planning 400-7172	H07-D06	Review BCS		Aug 25/07
J. Beech Vice President, Nuclear Finance 400-7226	H07-E19	Approve BCS		Sept 27/07
T. Mitchell Chief Nuclear Officer 702-5294	P82-6A1	Approve BCS		10/10/07
[illegible] Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Darlington Phase II Fire Protection Project 16 - 79016

Superseding Business Case D-BCS-78000-10003-R000

1/ RECOMMENDATION:

$ 19.058 Million, including all Capital costs. $ 185k will be written off to OM&A as discussed below.

Approval is requested for this Superseding release for ~~18.873M$~~ Capital, to:

- Remove Turbine-Generator Dyking from scope as it has been deemed unnecessary by engineering review, and which would drive costs further beyond the previously released amount for this project,
- Write-off the costs incurred against the scope of work for removal ($185K), and
- Approval for an over-variance to release of $127K (including contingency), to complete close-out of this Capital project,

Relevant:

The business objectives of the Darlington Phase II Fire Protection Project were as follows:

1. Install Turbine-Generator Fire Suppression Upgrades (REGC).
2. Install Fire Detection Upgrades in the Main Control Room & associated areas (REGC).
3. Construct an Emergency Response Team (ERT) Facility (CNO Commitment).
4. Install Containment Dyking around each Turbine-Generator set.

The project is now 98% complete. The REGC and CNO commitments were met in 2002. All work on the Detection Upgrades and the ERT Facility is complete, including ECC closeout. With T-G Dyking removed from scope, the outstanding work for this project includes:

- Available For Service (AFS) activities and ECC closeout for the Suppression Upgrades,
- Project Closeout activities, including Post-Implementation Review.

Recommended for scope removal is the Turbine-Generator Oil Containment Dyking modification. An engineering assessment concluded that the intent of containment dykes (to prevent the spread of burning lube oil) is already met. Removal of this work from scope will mitigate the need for an additional $500K funding. To date, $185K has been spent in the design phase for this modification and this money should be written off to OM&A.

The cost over-variance for this project is attributed to the following:

- Discovery work & additional scope for the fire suppression upgrades: install new pressure relief devices and reroute piping due to equipment interferences.
- Rework to change the ERT Facility modification from a Commercial Mod (CMOD) to a combination Permanent Mod (PMOD) and Facility Mod (FMOD).

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Superseding	18,412	306	28					18,746
Requested Now	Superseding			258	54				312
Future Funding Req'd									-
Total Project Costs		18,412	306	286	54	-	-	-	19,058
Other Costs	Write Off			(185)					(185)
Ongoing Costs									-
Grand Total		18,412	306	101	54	-	-	-	18,873
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Regulatory		Capital		N/A		N/A		N/A	

Submitted By:

Wayne Robbins 2007-08-15
Name: W. Robbins Date:
Title: Senior Vice President - Darlington Nuclear

Finance Approval:

Sept 27/07
Name: J. Beech Date:
Title: Vice President - Nuclear Finance

Line Approval (Per OAR Element 1.4 Variance):

10/10/2007
Name: T. Mitchell Date:
Title: Chief Nuclear Officer

BACKGROUND & ISSUES

The Superseding Business Case Summary for this project, D-BCS-78000-10002 R000, was approved on September 12, 2002 for $18.7M, including contingency. The project scope is as follows:

1) Install a Turbine-Generator Fire Suppression System. This was a CNSC Regulatory Commitment, AR #28023793.
2) Install a containment barrier around each Turbine-Generator set to control the flow of potentially burning lube oil and fire water. This modification is per a requirement in OPG Standard N-STM-78200-10000-R01, Fire Protection for Turbine Generator Areas
3) Install Fire Detection upgrades in the MCR, CER & associated areas. This was a CNSC Regulatory Commitment, AR #28023789.
4) Construct an Emergency Response Team (ERT) Facility. This was a CNO commitment.

Current Status:

- The REGC and CNO commitments were met in 2002.
- All Fire Detection Upgrades (item 3 above) are complete. The modification has been closed and there are no open items.
- The ERT Facility (item 4 above) is complete. The modification has been closed and there are no open items.
- The T-G Fire Suppression System installation (item 1 above), to meet the REGC is complete and Final AFS was obtained. However, during the Post-AFS period, the following issues were identified:
  1) Lack of required pressure relief capability in the suppression system (SCR D-2004-08302)
  2) Piping interference with adjacent equipment, preventing maintenance activities from being performed (SCR D-2004-05603)

  As a result, the Final AFS was changed to a Partial AFS, to allow for resolution of these issues. This did not affect meeting the REGC. The field work to resolve these issues is complete, and Final AFS is pending.
- The need for T-G Dyking (item 2 above) has been challenged. An engineering assessment has been performed (see NK38-REP-78000-10004), concluding that the intent of containment dykes, to control the spread of burning lube oil and fire water, is already met via the physical layout of the station, and fire suppression capability in place. Removal of this work from scope will mitigate the need for an additional $500K funding.

Over-Variance Contributors:

- ERT Facility

  The ERT Facility was originally constructed as a commercial modification (CMOD). However, this was not accepted at the time of turn over (reference SCR-D-2003-02188). To obtain final acceptance, the CMOD was converted to a combination of facility modification (FMOD) and permanent modification (PMOD) (reference NK38-REP-28600-10002). The re-engineering to do this conversion, the cost for building maintenance until Final AFS, and the resulting impact on the project schedule, contributed to the over-variance for this project. Final AFS has been obtained and all work with the ERT Facility has been completed. There are no open items & it has been closed out.
- T-G Suppression Pressure Relief & Piping Interference Issues

  Resolution of the two T-G Suppression issues required DCP revision, re-design, additional field work, troubleshooting, AFS activities, and an overall extension to the project schedule.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3 Do Less	Alt 4 Do More	Alt 5 N/A
Revenue	-	-	-	-	-	-	
OM&A	-	-	-	-	-	-	
Capital	19,538	19,038	(500)		N/A	N/A	
NPV (after tax)							
Impact on Economic Value (IEV)	N/A						
IRR%	N/A						
Discounted Payback (Yrs)	N/A						

Status Quo - Not Recommended

The status quo for this project would include installation of T-G Dyking and would cost approximately $500K in addition to the current over-variance requested. A recent engineering review demonstrated that the intent of T-G Dyking is already met through existing suppression & the physical layout of the station. This is a Non-Value-Enhancing project, and significant effort has been put forth to reduce scope where possible. The Regulatory and Management commitments have been met. This option is not recommended.

Alternative 1 - Complete AFS and Close-Out - Recommended

The project is now 98% complete. It is recommended that T-G Dyking be removed from scope, and proceed with AFS & closeout activities for the remainder of the project. This requires an over-variance to release approval of $127K (less than 1% increase on the current release of $18.746M). To date, $185K has been spent in the design phase for T-G Dyking and this money should be written off to OM&A.

Alternative 2 - Delay Project - Not Recommended

Delaying is not recommended as this project is in the Closeout Phase and closeout activities must continue per ECC governance. Delaying the installation of T-G Dykes only is also not recommended as it is a non-value-enhancing modification that has been deemed redundant through engineering review.

Alternative 3 – Do Less - Not Recommended

With T-G Dyking removed from scope, there are no further opportunities to do less as the remaining scope is either in closeout phase, or already closed out.

Alternative 4 – Do More - Not Recommended

This is a Non-Value-Enhancing project, and significant effort has been put forth to reduce scope where possible. The Regulatory and Management commitments have been met.

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

1) Remove T-G Dyking from the scope of this project
2) Write-off $185K to OM&A; the costs incurred to date for the T-G Dyke design
3) Approve $127K over-variance to release for the completion of this project. Specifically:
   - AFS activities for T-G Sprinkler mods
   - Closeout activities for T-G Sprinkler mods
   - Project Closeout activities

5/ QUALITATIVE FACTORS

The drivers for these modifications were Regulatory & CNO Commitments aimed at improving the level of personnel and asset protection from fire. At the current stage for this project, Closeout, the qualitative factor for continuing is compliance with ECC governance.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Risk of cost increase is low as the project is in Final AFS & Closeout. Cost to complete is well defined.	N/A	**Low**	N/A	**Low**
Scope				
Risk of new scope being added to the project is low as the project is in Final AFS & Closeout. All additional scope items were identified at previous AFS..	N/A	**Low**	N/A	**Low**
T-G Dyking not removed from scope.	Project will incur approximate additional $500K in cost and schedule extension	**Medium**	Engineering evaluation performed to show T-G Dyking not required. Approval of this BCS will reduce the risk to low.	**Low**
Station does not accept state of passing RVs in field	Maintenance work required to fix or replace RVs prior to AFS.	**Medium**	Independent Third Party Review obtained states passing RV is code compliant. Field walkdowns with station representatives to obtain acceptance.	**Low**
Schedule				
Maintenance work required to fix or replace RV's prior to AFS.	Missed AFS milestone	**Medium**	Independent Third Party Review obtained states passing RV is code compliant. Field walkdowns with station representatives to obtain acceptance.	**Low**
Resources				
Insufficient Design resources to complete closeout.	Missed Closeout milestone and ECC Action Tracking Assignments	**Medium**	Commitments have been obtained from Design and Drawing Office to complete outstanding work	**Low**

Technical				
N/A - all technical issues identified at previous AFS				
Regulatory				
N/A all Regulatory commitments have been met				
Environmental				
N/A as this remaining work has no environmental risk.				
Health & Safety				
N/A as there is no remaining field work.				
Investment				
N/A as there is no remaining field work.				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Aug 2007	Mar 2008	Manager, Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Project Objectives have been met			Review of Charter, PEP, BCS's	Manager, Performance Engineering
2.					
3.					
4.					
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

AFS – Available For Service
CER – Control Equipment Room
CNO – Chief Nuclear Officer
ECC – Engineering Change Control
ERT – Emergency Response Team
MCR - Main Control Room
REGC – Regulatory Commitment
SCR – Station Condition Record
T-G – Turbine-Generator

Appendix "B" **Project Funding History**

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
Full	Aug	2002	18,718	28							18,746
Superseding	Jun	2007	18,718	101	54						18,873
											0
											0
											0
											0
											0
											0
LTD Spent	May	2007	18,737								18,737

Comments:

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:

- T-G Dyking will be removed from the scope of this project

Financial Assumptions:

N/A

Project / Station End of Life Assumptions:

N/A

Energy Price / Production Assumptions:

N/A

Operating Cost Assumptions:

N/A

Other Assumptions:

Phase II Fire Protection Project 16 - 79016

Superseding Business Case D-BCS-78000-10003-R000

Attachment "A" **Project Cost Summary**

Choose One Choose One	LTD Prior Yr 2006	This Release 2007	This Release 2008	This Release 2009				Later	Total
Project Management (OPG)	2,347	148	42	-					2,537
Engineering & Drafting (OPG)	1,309	48	5	-					1,362
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	18,718	286	54	-	-	-	-	-	19,058
2007-2011 Business Plan	18,718	33	-	-					18,751
Variance to Business Plan	-	216	47	-	-	-	-	-	263
Committed Cost		-	-	-					-
Inventory Write Off Required		(185)	-	-					(185)
Spare Parts / Inventory		-	-	-					-
Total Release (excl contingency)	18,718	64	47	-	-	-	-	-	18,829
Total Release (incl contingency)	18,718	101	54	-	-	-	-	-	18,873
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	100%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	N/A	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process.
A PCRAF will be approved by Jul 2007.

Reviewed By: 4 July 2007
Tom Ovitkovic
Project Manager
Date:

Approved By: 12 July 2007
Terry Chong
Eng & Mods Manager (Strat IV)
Date:

Project Name 16 - 79016

Superseding Business Case D-BCS-78000-10003-R000

Attachment "B"

Project Variance Analysis

Capital	LTD May 2007	Full Release Last BCS Sep ~~Choose~~	Full Release This BCS Jun 2007	Variance	Comments
Project Management (OPG)	2,350	1559	2537	978	
Engineering & Drafting (OPG)	1309	1855	1362	-493	
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (Incl contingency)	**18737**	**18747**	**19058**	**311**	
[illegible]mitted Cost			0	0	
[illegible]tory Write Off Required			-185	-185	Write-Off T/G Dyking Design
Spare Parts / Inventory			0	0	
Total Release (incl contingency)	**18737**	**18747**	**18873**	**126**	
Total Release (excl contingency)	**18737**	**17778**	**18829**	**1051**	
Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
10	Aug	2007	RV Installation AFS
10	Jul	2008	Project Closeout

A Project Execution Plan (PEP) was approved in MAY 1999 ß 07-04-07

Comments:

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

Routing	Location	Action	Signature	Date
Joseph Ramani Project Engineer Design Projects 701-8205	P72-3	Prepare BCS	Joseph Ramani	2007-03-26
Aman Shah CSA Design Projects 701-3889	P72-3	Prepare BCS		2007-03-26
Jeff Phillips Project Leader II Design Projects 701-3567	P72-3	Review BCS		2007-03-27
Vince Tzambazis Section Manager Design Projects 701-2520	P72-3	Review BCS		2007-03-28
Sepehr Ghorashi Section Manager (Acting) PMO 701-3062	P72-3	Review BCS		2007-03-29
Randy Ludlow Manager Design Projects 701-8055	P72-3	Review BCS		2007.3.29
Elio Fracalanza anager Chemistry 1-2126	P05 A2	Review BCS		April 4/07
noor Bhaloo Manager Performance Engineering 701-3562	P41-E3	Review BCS		Apr 13/07
Bob Goodman Director Station Engineering 701-7078	P41-E3	Review BCS		April 13 07
Mark Arnone Director Projects & Modifications 701-6063	P72-1	Review BCS		16 APRIL 2007
R. Ball Senior Financial Analyst 702-4084	P82-3	Review BCS		17 Ap 07
			RECEIVED	
Ball nior Financial Analyst 2-4084	P82-3B6	Return For Distribution		

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

Routing	Location	Action	Signature	Date
R. Leavitt Director Investment Management 701-7078	P82-3	Review BCS	R Leavitt	April 19 2007
P. Tremblay S.V.P. Pickering B 701-3501	P41-E3	Submit BCS	P Tremblay	April 20/07
J. Beech V.P. Nuclear Finance 400-7026	H7-E19	Review BCS	[illegible]	[illegible]
T. Mitchell Chief Nuclear Officer 702-5294	P82-6	Review BCS	T Mitchell	24 APR 07
D. Power V.P. Corporate Investment Planning 400-7172	H7-D06	Approve BCS	D Power	May 7/07
P. Charlebois Chief Operating Officer 400-8470	H19-E21	Review BCS	[illegible]	[illegible]
J. Hankinson President & C.E.O. 00-2121	H19-A24	Approve BCS	J Hankinson	21/5
R. Ball enior Financial Analyst 2-4084	P82-3B6	Return For Distribution		

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

1/ RECOMMENDATION:

We recommend a superseding release to reduce the scope for this wide ranging project (8 modifications). However, we are recommending no change in the currently approved release of $18.4M, as the scope reduction is offset by the issues summarized below.

The business objective of this old IIP project is to standardize and improve station Chemistry Control in order to enhance performance and increase the life of critical station equipment including pressure tubes, feeder tubes, boiler tubes, heavy water upgrader, moderator equipment and stator windings. Completion of this project is important to address several performance, safety, environmental, and reliability issues with modifications that will reduce work and lower costs. (See Alternative Section for details).

In August 2004, the Board of Directors approved a total project cost of $16.8M to complete seven (7) modifications designed to meet the Business Objectives of the project. Later in April 2005, funding was adjusted to $18.4M to accommodate an eight modification, a CEM Environmental Software Module. In December 2006, the D_20 Upgrader Feed Purification Modification was cancelled, triggering a $1.0M write off of sunk costs to OM&A. At this time, four modifications are complete, Life to Date expenditures are $15.0M (after write off), and $3.4M is required to complete the project (see background for details).

The Variance details are as follows:

1 Rework is required to fix problems encountered during the commissioning of two modifications — +$1.9M
- Plugged strainers on the Boiler Water & Steam Sampling modification ($1.0M)
- Flow control problems on the Hydrogen Addition system ($0.9M)

2 Several issues were encountered during installation — +$1.5M
- Discovery issues with degrading interfacing equipment
- Delays and mitigating activities resulting from late delivery of materials
- Additional shift coverage and overtime resulting from shortened outage schedules
- Increased Field Engineering due to changes in work processes such as Pressure Boundary

3 The D_20 Upgrader Feed Purification Modification was removed from the project scope because the installation could not be justified unless Pickering B's life is extended. Sunk costs totaling $1.0M were written off to OM&A (Dec 06). Approved funding needs to be reduced by $2.0M to reflect the new scope. — -$2.0M

4 The risk associated with completing this project has dropped considerably as all but one of the modifications is fully installed or designed. The contingency has been reduced to reflect the remaining risk. — -$1.4M

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2008	2009	2010	Later	Total
Currently Released	Superseding	16,726	1,684						
Requested Now	Superseding	(1,907)	398	1,510					18,410
Future Funding Req'd	None								0
Total Project Costs		**14,819**	**2,082**	**1,510**	-	-	-	-	-
Other Costs									18,410
Grand Total		**14,819**	**2,082**	**1,510**	-	-	-	-	-
									18,410

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	Capital	(2,274)	N/A	N/A

Submitted By:

T. Mitchell
Chief Nuclear Officer
Date: 26 APR 07

Reviewed by:

P. Charlebois
EVP & Chief Operating Officer
Date: May 22/07

Finance Approval:

D. Power
V. P. Investment & ~~Business~~ Planning
CORPORATE
Date: May 7/07

Line Approval (Per OAR Element 1.4 Variance):

J. Hankinson
President & C.E.O.
Date: 2/15

ONTARIO POWER GENERATION

BACKGROUND & ISSUES

Plant chemistry control is an essential element in the production of nuclear power. An effective Chemistry Program is required to achieve excellence in the Nuclear Power Industry. This project is a one time incremental effort designed to standardize and improve station chemistry control.

The Independent Integrated Performance Assessment (IIPA) identified that the general lack of chemistry standards at Ontario Power Generation Nuclear plants was a direct contributor to poor plant chemistry control, which in turn contributed to poor operational performance as well as equipment degradation. The IIPA found examples of specifications not being adequately addressed in the station chemistry control manuals, specification being chronically exceeded and chemistry excursions not reported. The chemical specifications had been written with the objective of minimizing the degradation of materials to prevent the premature end of the plant or its specific components. The general lack of the application of chemistry standards at OPG facilities was a direct contributor to poor plant chemistry control, which in turn contributed to poor operational performance.

The objective of this project is to implement the capital modifications necessary for compliance with the standardized chemistry program. Under this project we planned to implement the following seven modifications and develop CEM Environmental Software. The D_2O Upgrader Feed Purification modification was subsequently removed from the scope of the project since the business drivers do not justify proceeding with this modification at this time.

	Modification	Previous Release			This Request					Funding Required	Status
		Est Cost	Contingency	Total	LTD Costs (End Jan. 07)	Write Off (Dec 06)	Cost to Complete: Installation & Rework	Cost to Complete: Contingency	Total		
1	D20 Upgrader Feed Purification	2,034	931	2,965	1,000	(1,000)	-		-	(2,965)	cancelled
2	He Cover Gas Sampling	2,535	313	2,848	3,609		795	179	4,583	1,735	3 units complete
3	Boiler Water & Steam Sampling	4,485	358	4,843	5,102		989	147	6,238	1,395	rework
4	HTS Hydrogen Control	1,879	503	2,382	1,423		879	264	2,566	184	rework
5	Isolation Valve to HTS IX Column	1,503	163	1,666	868				868	(798)	complete
6	Feedtrain Shutdown Chemistry	583		583	604				604	21	complete
7	ICP Spectrometer	255		255	283				283	28	complete
8	CEM Environmental Software	1,638		1,638	1,638				1,638	-	complete
	Sub Total	**14,912**	**2,268**	**17,180**	**14,527**	**(1,000)**	**2,663**	**590**	**16,780**	**(400)**	
	Interest	1,230		1,230	1,441		189		1,630	400	
	Grand Total	**16,142**	**2,268**	**18,410**	**15,968**	**(1,000)**	**2,852**	**590**	**18,410**	**-**	

5) ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay 1 year			
Revenue	0	0	0	0			
OM&A	(769)	(1,000)	0	0			
Capital	600	(18,410)	(3,447)	(4,114)			
NPV (after tax)	(349)	(15,525)	(2,623)	(2,941)			
Impact on Economic Value (IEV)	N/A	(15,176)	(2,274)	(2,592)			
IRR%	N/A	N/A	N/A	N/A			
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A			

Stop the Project - Not Recommended

We do not recommend stopping this project because:

- The business objective of the project will not be met
- Several safety and environmental issues will not be addressed
- Cost saving opportunities will be lost
- The units will be configured differently
- The Boiler Steam and Water Sampling system cannot be fully placed in service as rework is required
- The HTS Hydrogen Control System is not fully meeting its design requirements
- Capital write offs to OM&A would be approximately $0.6M

Alternative 1 - Complete all Mods (except D20 Upgrader Feed Purification) - Recommended

We recommend completion of the following modifications at a remaining cost of $3.4M (including contingency) to complete the project:

- He Cover Gas Sampling System
- Boiler Steam & Water Sampling System
- HTS Hydrogen Control System

He Cover Gas Sampling System – Unit 5

Completion of Unit 5 will:

- improve reliability of moderator cover gas sampling and reduce the potential of an undetected explosive mixture
- add capability of on-line PHT cover gas sampling and reduce the potential of an undetected explosive mixture
- reduce risk of outage extension due to GC unavailability during unit start-up
- reduce control maintenance resources required to maintain the gas chromatograph
- complete the modification on the fourth and final Pick-B unit and provide constant configuration among the units

Boiler Steam & Water Sampling System (All Units)

Completion of the rework required to resolve the plugging of newly installed strainers will enable heat exchangers to be placed in service and provide constant sample temperature. This will:

- improve accuracy of results which allows optimization of chemical addition rates in order to prolong the life of the feedwater equipment and boiler tubes; and also to prevent unnecessary discharges of excessive chemicals to the environment
- improve accuracy of Chemistry WANO Index
- eliminate Chem Tech resources to recalibrate for temperature changes (up to 6 hr per shift during fluctuating temperatures)
- eliminate action levels based on inaccurate results (example: erroneous high oxygen level could lead to isolation of condenser water boxes and associated unit derating)

HTS Hydrogen Control System (All Units)

Completion of the rework on all units to correct flow control at low rates will:

- minimize excursions of high dissolved H_2 in the PHT system resulting in a potentially explosive mixture and increased rates of hydrogen absorption and hydrogen embrittlement.
- minimize excursions of low dissolved H_2 in the PHT system resulting in increased corrosion rates and potential shutdown limits.
- minimize Chemical Technician resources to take additional samples (1 hour/shift)
- minimize dose as the current sample point is in the RB
- enable injection via dual headers per design
- minimize potential to delay Unit start-up if the system is out of specification
- minimize Operator resources to purge excess hydrogen from the PHT
- optimize consumption of Hydrogen and Helium gases
- eliminate cost of maintaining metering valves ($60k every five years)

Alternative 2 - Delay Project - Not Recommended

We do not recommend delaying the project because it will increase the cost and delay the benefits. The project team is in place, the preferred contractor has been engaged and the work is scheduled in upcoming outages. This project has already been postponed several times and the work to complete ($3.4M) is for the most part, rework required to commission modifications.

Alternative 3 – Complete Original Project Scope - Not Recommended

We do not recommend completing the original project scope. The installation of the D_20 Upgrader Feed Purification system cannot be justified unless the life of Pickering 'B' is extended. It has been removed from the project scope with confirmation from the Project Sponsor). This modification can be re-evaluated as part of a life extension initiative. Sunk costs of $1.0M were written off to OM&A in 2006.

D_20 Upgrader Feed Purification (written off in 2006)

The business driver for this modification was to reduce the rate of deterioration of the upgrader packing by installing the UV oxidation unit currently owned by OPG (purchased outside this project). Reducing the rate of deterioration may have:

- reduced the number of drums stored on site which reduces the risk of drum leaks, environmental spills, and dose to workers
- prevented the cost associated with external assistance in processing drums of water contaminated with organics
- reduced the loss of upgrader capacity as a result of plugging (1 month outage per 7 years for each of 2

upgraders)

- prevented the cost associated with cleaning the upgrader packing in each of the two upgraders
- reduced the cost associated with charcoal consumption and disposal currently required to removed organics from upgrader feed
- allowed the upgrader feed specification (Total Organic Carbon less than 1 ppm) to be met which is one of the outstanding requirements to improve the upgrader System Health Window from Yellow to White

A decision to write off the sunk costs of $1.0M was made in 2006 because at the current rate of deterioration, the upgrading capacity will remain above station needs until well past the current life of Pickering B. Alternate solutions are being investigated to reduce drum inventory. The cost of upgrader distributor cleaning and charcoal consumption are estimated at less than the cost of the modification

Alternative 4 – **- Not Recommended**

Alternative 5 – **- Not Recommended**

'/ THE PROPOSAL

We recommend completion of the following modifications with the following targets:

- He Cover Gas Sampling System December 2007
- Boiler Steam & Water Sampling System December 2008
- HTS Hydrogen Control System December 2008

5/ QUALITATIVE FACTORS

None other than what is stated in the Alternative section.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
There is risk of discovery issues on the Duplex Strainer modification. Installation and commissioning procedures have not yet been prepared. Modification has not yet been installed on any unit.	cost over run	Medium	A specific contingency of [redacted] has been applied to Duplex Strainer modification.	Low
There is risk of discovery issues on the Mass Flow Controller modification. The design is not complete.	cost over run	Medium	Design estimates (TIS Sheets) have been obtained from Projects Design. Design costs and progress reviews will be performed on a weekly basis to monitor actual costs versus estimate. A specific contingency of [redacted] has been added to the MFC DCP to address unforseen design changes prior to the DCP revision.	Low
Installation costs for the U5 Gas Chromatograph may be higher than budgeted due to delays or unforseen interferences.	cost over run	Medium	Scope of Work documents prepared and submitted to contractor to ensure full understanding of scope. TIS Sheets and Contractor Estimates have been received for all remaining work. A specific contingency of [redacted] has been added to address delays and unforeseen interferences. Another specific contingency of [redacted] has been added to this DCP in case there is a compressed outage window during P751.	Low
Scope				
The scope of work for DCPs 406 & 601, is fairly well understood, however the designs are not finalized and	cost over run	Low	Preliminary COMS has been completed on the revision to DCP 601. Final COMS has been completed on the revisions to DCP 406.	Low

the scope may increase or decrease depending on stakeholder input.				
Addition of MFC on Hydrogen Addition System is new unproven technology.	cost over run	**Low**	Different Alternatives were presented during the Preliminary COMS meeting. The Mass Flow Controllers was accepted as the preferred alternative. Recent OPEX has shown that a similar device was installed on Pickering 'A' without success. A review is being conducted by Design to confirm the Mass Flow Controller is a viable option.	**Low**
Schedule				
There is a Potential for Delays During Outage Installation Work.	Any delays in the installation can impact critical path during the Outage and incur extra Contractor costs. These delays were noted in the cost section and a contingency applied.	**Medium**	The installation of the Gas Chromatograph for P751 will be on the fourth and final Unit. All lessons learned from previous installations have been incorporated into Work Plans. A contract has been let out to the same vendor that performed the last two intallations to ensure the schedule is met.	**Low**
Changes to the IOP Schedule for not meeting T minus targets.	The schedule for the installation of the MFCs and the Duplex Strainers will all be done using the IOP process. Delays on the IOP schedule will mean that the modifications will have to remain open longer and potentially incur more costs.	**Medium**	Project Engineers will attend T minus meetings to ensure project stays on the IOP schedule. A contingency of 2 months has been built into the schedule to allow for IOP delays.	**Low**
Delay to DCP Revision.	Installation will be impacted if Design does not meet their agreed upon dates for the revisions of DCPs 406 and 601. T-26 milestones need to be met to ensure a timely installation and maintain the proposed budget.	**Low**	Design has provided TIS sheets for the two jobs. They have also provided a TCD date for DCP revisions that will be added to the target P3 file. A float of 2 weeks has been allocated to ensure no overrun in the Design Schedule.	**Low**
Resources				
Project Engineers are removed from their modifications (DCPs 601 & 406) for use on other projects.	Removal of project engineer (MTL) from DCP 406 or 601 will delay the schedule of the DCP and the project.	**Medium**	Adequate project resources have been assigned for anticipated work load.	**Low**
Projects cannot obtain adequate station resources For IOP Work.	The Modification would not be completed as per schedule.	**Low**	Installation and commissioning tasks will be properly assessed and scheduled. All tasks will be "C" tasks, which means they have to	**Low**

			be completed in the week they are scheduled.	
Vendor not available during commissioning of GC.	Delay would impact on Commissioning of Gas Chromatograph. If the vendor is not available during commissionig of the Gas Chromatograph, it will impact the return to service of the system, which could potentially affect the Outage End Date.	**Medium**	A rigorous COMS review has been conducted on all remaining modifications. Two of the remaining three modifications are rework to the original modification. The GC is the final unit install and no rework is anticipated. Stakeholders have been involved in COMS reviews and challenge meetings.	**Low**
Technical				
Modifications Do Not Meet the Design Intent and/or Design Requirements	Modification would require significant redesign or rework.	**Medium**	A rigorous COMS review has been conducted on all remaining modifications. Two of the remaining three modifications are rework to the original modification. The GC is the final unit install and no rework is anticipated. Stakeholders have been involved in COMS reviews and challenge meetings.	**Low**
Regulatory				
No Significant Risk				
Environmental				
No Significant Risk				
Health & Safety				
Workplace Injury of Serious MRPH Event	Unplanned intake/exposure to tritium and/or gamma. Potential for personal injury.	**Low**	The use of experienced trades personnel, the completion of the COMS process, as well the use of Event Free Tools (including procedural compliance) will help minimize and eliminate any such events. Work Plans have all been reviewed by Conventional Safety and Radiological Safety. Pre-job briefings are given every shift. JSAs will be prepared for all modifications.	**Low**

Personnel Contamination	Possible high MRPH, fire, explosion, or peronal injury.	**Medium**	One leg of the Hydrogen Addition System will be isolated at a time to perform the modification. This will ensure that hydrogen levels are not increased in the system which wil prevent an explosive mixture in the D2O Storage Tank. Blue Coveralls will be worn during the installation of the modification. All work plans will be reviewed by Conventional Safety.	**Low**
Investment				
Modifications Do Not Meet Design Requirements	Higher Costs to Rectify Problems	**Low**	Modification details have been extensively reviewed and critiqued by all stakeholders. An in depth OPEX review and analysis has been done on all modifications and lessons learned incorporated. No new technologies are being installed. All modifications involve equipment previously used in the Nuclear Industry.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2008	Jun 2009	Manager, Chemistry

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Performance Criteria and Reliability	Design Requirements	Modifications meet the performance and reliability criteria specified in the Design Requirements	Design acceptance of the Commissioning Report	Project Manager
2.	Stakeholder Acceptance of AFS	Installation and Commissioning of the modifications is as per DCN Packages	AFS Report	Signed Final AFS Declarations an acceptance of any Open Items	Project Manager
3.					
4.					
5.					

Appendix "A"

Glossary (acronyms, codes, technical terms)

Abbreviations and Acronyms

AFS - Available For Service
BCS - Business Case Summary
BTU - Building Trade Unions
CMO - Contract Management Office
CNSC - Canadian Nuclear Safety Commission
COMS - Constructability, Operability, Maintainability, and Safety
CSA - Cost and Schedule Analyst
CWP - Comprehensive Work Plan
DA - Design Authority
DCN - Design Change Notice
DCP - Design Change Package
DOM - Director, Operations and Maintenance
DTL - Design Team Leader
ECC - Engineering Change Control
ECN - Engineering Change Notice
ECR - Engineering Change Request
EPSCA – Electrical Power Systems Construction Association
FIPR - Fabrication and Installation Package Release
FLM - First Line Manager
FTL - Field Team Leader
GC - Gas Chromatograph
He - Helium
HOR - Holder of Record
ICP - Inductively Coupled Plasma
IIP - Integrated Improvement Program
IIPA - Independent Integrated Performance Assessment
IX - Ion Exchange
ITP - Inspection and Test Plan
MA - Maintenance Authority
MFC - Mass Flow Controller
MR - Material Request
MPSR - Major Project Summary Report
NPMR - Nuclear Project Management Reporting
OAR - Organizational Authority Register
OM&A - Operating, Maintenance and Administration
OPEX - Operating Experience
OPG - Ontario Power Generation
P3 - Primavera Scheduling Tool
PCRAF - Project Change Request Authorization Form
PDRI - Project Definition Rating Index
PEP - Project Execution Plan
PHTS - Primary Heat Transport System
PLEP - Pickering 'B' Plant Life Extension Project
PIR - Post-Implementation Review
PMO - Project Management Office
PO - Purchase Order
PSM - Plan Start Milestone
QA - Quality Assurance
SCR - Station Condition Record
SPOC - Single Point Of Contact
SWC - System Window Coordinator
TCU - Temperature Control Unit
UV - Ultraviolet
WBS - Work Breakdown Structure

Appendix "B"

Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency)									
			Cumulative Values								
Release Type	Month	Year	2002	2003	2004	2005	2006	2007	2008	Later	Total
Full	Feb	2001	3,996	1,222							5,218
Superseding	Aug	2004	4,188	1,770	3,133	4,729	2,672	281			16,772
Adjustment	Apr	2005	4,188	1,770	1,568	4,500	4,700	1,684			18,410
Superseding	May	2007	4,188	1,770	1,568	3,591	3,702	2,082	1,509		18,410
											0
											0
											0
LTD Spent	Jan	2007	4,188	1,770	1,568	3,591	3,702	149			14,968

Comments:

In April 2005, funding was adjusted to $18.4M to accommodate Head Office IIP costs relating to the development of a CEM Environmental Software Module that had been charged to the project.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Estimate includes specific contingencies for:

- Duplex Strainer Modification [redacted]
- Mass Flow Controller
- Gas Chromatograph
  Total

Cost of Stopping the Project estimated to be $400K (project management and design)

Cost of delaying the project for one year is estimated to cost $500K for demobilization / remobilization and 5% for cost increases.

LTD Jan 2007 Spending = $14,968 (including $1.0M 2006 write off)

LTD Jan 2007 In Service Declarations = 14,340K

Write off for "Stop the Project" = $14,968K less $14,340K = $628K (2007)

Financial Assumptions:

WACC = 7%

Project / Station End of Life Assumptions:

Units 5, 6, 7 Spring 2014
Unit 8 Spring 2016

Energy Price / Production Assumptions:

N/A

Operating Cost Assumptions:

Labour costs for Hydrogen Addition estimated at [redacted]per year
Cost to repair metering valves estimated a[redacted]every 5 years

Other Assumptions:

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008					Later	Total
Project Management (OPG)	938	249	132						1,319
Engineering & Drafting (OPG)	3,808	145	162						4,115
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Installation Support (FE)									
D_20 Upgrader write off									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	14,819	2,082	1,510	-	-	-	-	-	18,410
2007-2011 Business Plan	17,117	4,030	120						21,267
Variance to Business Plan	(2,298)	(2,243)	1,095	-	-	-	-	-	(3,447)
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	14,819	1,787	1,215	-	-	-	-	-	17,820
Total Release (incl contingency)	14,819	2,082	1,510	-	-	-	-	-	18,410
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	No	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007.

Reviewed By:

Vince Tzambazis March 28 2007
Vince Tzambazis
Project Manager
Date:

Approved By:

Randy Ludlow 2007-3-29
Randy Ludlow
Eng & Mods Manager (Strat IV)
Date:

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2006	Total Project Last BCS May 2004	Total Project This BCS Feb 2007	Variance	Comments
Project Management (OPG)	938	1,066	1,318	252	Additional project management required due to rework.
Engineering & Drafting (OPG)	3,808	3,564	4,115	551	Cost overrun to resolve deficiencies identified during commissioning.
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
Installation Support (FE)	[redacted]				
D_2O Upgrader Write Off	[redacted]				
Interest (Capital Project Only)	[redacted]				
roject Costs (excl contingency)	[redacted]				
eneral Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	**14,819**	**17,410**	**18,410**	**1,000**	
Committed Cost				-	
Inventory Write Off Required				-	
Spare Parts / Inventory				-	
Total Release (incl contingency)	**14,819**	**17,410**	**18,410**	**1,000**	
Total Release (excl contingency)	**14,819**	**15,142**	**17,820**	**2,678**	
Ongoing OM&A (non-project)				-	
Removal Costs (incl in above)				-	

Comments:

1. An underestimation in the cost of BTU trades. Numerous discovery issues such as degraded interfacing equipment have been encountered. There have also been numerous delays such as late delivery of materials. Mitigating actions to perform more shop fabrication and testing has helped but these activities were not budgeted. Also support activities such as Holder of Record Duties, Maintenance Authority duties, material tracking, training, EPSCA travel, supervision, coordination, and reporting were all unfunded.

2. Shortened outage schedules have required additional shift coverage which resulted in more work turnovers and additional premium pay.

3. An underestimation in the cost of Field Engineering support. Discovery issues have required additional oversight as well as revisions to ITPs, FIPRs, and Comprehensive Work Packages (CWP). Also, changes to work processes including the Pressure Boundary process have increased the Field Engineering workload.

4. Design deficiencies, including the plugged strainers on the Boiler Steam and Sampling Panels and flow control problems on the Hydrogen Addition system that were discovered during commissioning will require design rework as well as additional work to install and commission the revised design.

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
03	Jul	2007	He Sampling Gas U5 AFS
01	Feb	2008	Hyrogen Addition U8 (MFC) AFS
25	Feb	2008	BS&W U8 Final AFS
01	Apr	2008	Hydrogen Addition U5 (MFC) AFS
09	Apr	2008	BS&W U5 Final AFS
01	May	2008	Hydrogen Addition U6 (MFC) AFS
05	May	2008	BS&W U6 Final AFS
02	Jun	2008	Hydrogen Addition U7 (MFC) AFS
16	Jun	2008	BS&W U7 Final AFS
15	Dec	2008	Chemistry Standards Project Complete

A Project Execution Plan (PEP) will be approved by May 2007

Comments:

ONTARIOPOWER GENERATION

OPG Confidential	Page: 1 of 18
BUSINESS CASE SUMMARY	

Darlington Fire Protection Upgrade - Phase III 16 - 79148

Superseding Business Case D-BCS-78000-10001- 005

Routing	***Location***	***Action***	***Signature***	***Date***
T. Chong Manager - Design Projects Darlington Projects & Modifications Division 703-3520	BW702	Review BCS	Tony Chong	15 Sept 2006
G. Brown/ R. Leavitt/ J. Beech [illegible] Nuclear Finance 400-7226	TCH09	Review BCS	[illegible]	Sep 20, 2006 Sept 20/06
M. Arnone Director, Projects & Modifications 701-6063	P72-2	Review BCS	[illegible]	25 SEPT 2006
S. Seedhouse Director, Engineering - Darlington 703-7584	D08-ES3	Review BCS	S Seedh	2 Oct 2006
G.O.D. Smith Senior Site VP - Darlington	D08-ES3	Submit BCS	Gregory Smith	5 Oct 2006
P.R. Charlebois Executive Vice President and Chief Nuclear Officer	P82	Review BCS		
D. Power Director, Investment & Business Planning	TCH07	Approve BCS	[illegible]	Mar 8/07
J. Hankinson President & CEO	TCH19	Approve BCS	[illegible]	Mar 9/07
R. Bali Senior Financial Analyst -4084	P82-3B6	Return For Distribution		

ONTARIO POWER GENERATION

OPG Confidential	Page: 2 of 18
BUSINESS CASE SUMMARY	

Darlington Fire Protection Upgrade - Phase III 16 - 79148

Superseding Business Case D-BCS-78000-10001-R005

1/ RECOMMENDATION:

We recommend:

1. The removal of Non REG C items from the scope of work (approximately $800k).
2. The release of an additional $6.2M, including contingency, for completion of the REG C scope of work.

The project met the Canadian Nuclear Safety Commission (CNSC) REG C commitment, A/R # 28030880, on December 30, 2005. Outstanding work to complete the project includes Available for Service actions, discovery work, and project close out activities. As of May 31, 2006 the project has spent $26.1M which exceeds the released funding of $23.5M. This unapproved expenditure of approximately $2.6M has been documented by SCR D-2006-03180 and reviewed by the ensuing B2 (detailed root cause) analysis.

In order to complete the REG C work by December 31, 2005 all Non REG C work such as the Inaccessible Smoke Detectors and Fire Works was deferred. It is now recommended that this Non REG C work be examined under a new stand alone project where a thorough review of needs will be conducted and lower cost alternatives (including do nothing) assessed.

A Superseding Business Case was signed by the Site Vice President, Darlington in December 2005; however, it has been subsequently revised to correct OAR elements and incorporate the latest cost estimates to complete Available for Service actions, discovery work, close-out activities, and cost over runs.

The revised cost estimate of [redacted] (excluding contingency) is [redacted] more than the 2006-2010 Business Plan and [redacted] more than the 2006 Budget. These variances will be addressed through the portfolio management process.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Full	20,591	2,475	422					23,488
Requested Now	Superseding	3,550	863	1,791					6,204
Future Funding Req'd	Choose								-
Total Project Costs		24,141	3,338	2,213	-	-	-	-	29,692
Ongoing Costs									-
Other Costs									-
Grand Total		24,141	3,338	2,213	-	-	-	-	29,692

Investment Type	Class	NPV or IEV	IRR	Discounted Payback
Regulatory	Capital	Not Applicable	Not Applicable	Not Applicable

Submitted By:

G.O.D. Smith 5 Oct 2006
Senior Site VP - Darlington Date:

Finance Approval:

D. Power Date:
Director, Investment & Business Planning

Line Approval (Per OAR Element 1.4 Variance):

J. Hankinson Mar 9/07
President & CEO Date:

2/ BACKGROUND & ISSUES

The Full Release Business Case Summary D-BCS-78000-10001 R004 for this project was approved on January 12, 2005 for $23.5M, including contingency. The project scope included resolution of Code Compliance Review (CCR) and Fire Safety Analysis (FSA) deviations, which was a CNSC REG C commitment, as well as Non REG C work.

The drive to meet the REG C committed date, productivity issues, as well as an underestimation of scaffolding costs and labor rates resulted in higher than estimated costs for the CCR/FSA Fire Detection Work Package of approximately $8.0M and for the Sprinkler & Standpipe Work Package of approximately $1.3M. This includes contractor over expenditures and Available for Service actions such as re-commissioning a part of the fire detection system. It also includes discovery work such as resolution of an engineering change breakthrough event associated with booster pump over pressure (SCR D-2006-00222) and Power House Annex issues and project close-out activities.

To limit the unapproved cost variance, all close-out activities have been placed on hold. Also, this variance has been partially offset by $1.6M due to creative solutions (see below) for other REG C work packages, reducing the number of devices installed by 16% (approximately $1.5M) and the drawing down of the project contingency of $2.5M.

An alternate resolution has been successfully negotiated and implemented for the Public Address (PA) system resulting in a saving of approximately $1.1M from the original estimate. The CNSC has been informed of the alternate resolution which consists of a system surveillance program where audibility and functionality of the PA system will be routinely monitored.

We have also successfully negotiated to retain the CO2 fire detection system "as is" and remove the CO2 extinguishing systems from the Darlington site except for the fuel storage tank rooms located inside the EPS-FM Building. CNSC has been informed of this alternate resolution. This has resulted in a saving of approximately $0.5M.

In order to complete the REG C work by December 31, 2005 and limit cost variances the Non REG C work was deferred. It is now recommended that the Non REG C work be removed from this project so that it can be evaluated in more detail under a separate project. The Non REG C work primarily relates to the resolution of inaccessible smoke detectors for inspection and maintenance, removal of obsolete smoke detectors, tie-in of bypass switch panel for ease of maintenance, resolution of existing main control room fire alarm re-flash annunciation issues, and installation of a fire panel graphical user interface (Fire Works). The detailed scope of work for a significant portion of this Non REG C work is not yet defined. Cost estimates to complete this work has escalated very significantly (from $0.8M in the original release to upwards of $4.5M). As the business objective is to reduce the current level of OPG staff effort required to perform periodic maintenance, a financial evaluation will be completed to assess lower cost alternatives.

See Attachment A, B and E for further detail.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended) Full Cost	Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5	Alt 6
Project Cost		29,692	6,204		34,192			
NPV (after tax)								
Impact on Economic Value								
IRR%								
Discounted Payback (Yrs)								

Stop the Project - Not Recommended

Stopping the project is not recommended, since outstanding work associated with the REG C such as re-commissioning a part of the fire detection system, resolution of the booster pump over pressure issue, discovery work and project close-out activities would remain incomplete. This would run counter to the CNSC's expectation to resolve and close-out these items.

Alternative 1 - Do Less - Recommended

It is recommended that only the REG C work be completed under the scope of this project and that Non REG C items be removed from the scope of this project.

This allows for the completion of Available for Service actions, discovery work, and close-out activities associated with the REG C work. It also permits the re-evaluation of the needs versus wants and development of the detailed scope for the Non REG C work under a separate project so that an assessment of lower cost alternatives (including do nothing) is completed.

Alternative 2 - Delay Project - Not Recommended

CNSC verbally agreed to the completion of the December 31, 2005 REG C on the condition that all outstanding items are completed on an urgent basis. Delay of the project is not recommended, as it shows lack of commitment to the regulator and would disrupt project efficiency the close-out stage (incurring additional stop/start costs).

Alternative 3 – Complete Project within Original Plan - Not Recommended

The original plan was to complete the REG C and Non REG C work by December 31, 2005.

REG C committed work is to resolve deviations identified in the Darlington Code Compliance Review and the Darlington Fire Safety Assessment.

Non REG C work is associated with removal of obsolete smoke detectors, resolution of inaccessible smoke detectors for inspection and maintenance, tie-in of bypass switch panel for ease of maintenance, resolution of existing main control room fire alarm re-flash annunciation issues, and installation of a fire panel graphical user interface (Fire Works).

Completing the original plan is not recommended because the scope of the Non REG C work is not fully defined, the cost estimate of Non REG C work has escalated significantly and requires re-evaluation and review of the needs so that an assessment of lower cost alternatives (including do nothing) is concluded.

Alternative 4 – Do More - Not Recommended

The scope is based on recommendations provided in the Fire Protection Code Compliance Review and Fire Safety Assessment Reports. There is no plan or justification to increase the scope of work. In the event that the CNSC challenges any of the CCR/FSA resolutions previously submitted, new projects are to be created by the stakeholders as required to resolve these issues.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The proposal is for the:

1. Removal of the following Non REG C items from the scope of this project so that they can be reviewed and approved on their own merit under a separate project:
   a. Obsolete smoke detector removal.
   b. Inaccessible smoke detector resolution.
   c. Maintenance bypass panel.
   d. Control room fire alarm re-flash resolution.
   e. Fire Works installation.
2. Approval of funding for completion of REG C related items, specifically to:
   a. Cover the cost variance to May 31, 2006 of $2.6M (SCR D-2006-03180).
   b. Complete the following Available for Service actions:
      i. Work Package #2: Fire Suppression
         - Standpipe close-out.
      ii. Work Package #7: Fire Detection
         - Investigation of alarms in Local Unit Control Equipment Room (SCR D-2006-02283).
         - 3rd Party verification of duct detectors, pump annunciation, and door interlocks.
         - Removal of HVAC tie-in, pending CNSC approval.
         - Waste Handling Door spare parts review, drawing updates, Final AFS, and close-out.
         - Update and issue detection drawings/documentation.
   c. Complete the following discovery work:
      i. Work Package #1: Fire Doors, Seals, and Exit Signs
         - Unit 2 stairwell grating replacement design, installation, and close-out (SCR D-2006-01082).
      ii. Work Package #2: Fire Suppression
         - Booster pump over pressure resolution, design, installation, and close-out (SCR D-2006-00222).
      iii. Work Package #6: Fire Barriers, Power House Annex
         - Insulation and door replacement.
   d. Complete project close-out activities.

Refer to Attachment D for further detail.

Note that the REG C commitment has been met.

5/ QUALITATIVE FACTORS

This project will:

1. Increase safety to the public and to employees.
2. Improve the ability to prevent, contain, and minimize damage or loss of asset from fire.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Cost of Non REG C items exceeds the released funding.	Additional funding required.	Medium	Removal of Non REG C items from scope for re-evaluation and review of the needs under a separate unrelated project.	Low
Project cost exceeds estimate.	Additional funding required.	Low	Majority of work is close-out/clean-up. For 2 items with outstanding design it is > 50% complete, installation estimates obtained, and [redacted] specific contingency available for items with risk.	Low
Re-initiation of interest charges.	Additional funding required.	Low	Confirmed with Station Finance that Equipment In Service declaration is at 100%; hence, no further interest charges to the project.	Low
Scope				
Undefined scope for Non REG C items.	Additional funding required.	Medium	Removal of Non REG C items from scope for re-evaluation and review of the needs under separate unrelated project.	Low
Duct detectors do not meet performance requirements.	Increased cost due to duct smoke detector relocation/re-adjustment.	Medium	[redacted] specific contingency available for duct detector re-work & HVAC tie-in.	Low
Standpipe hangers and fittings do not meet performance requirements.	Increased cost due to standpipe hanger and fitting replacement.	Medium	[redacted] specific contingency available for replacement.	Low
Schedule				
Business case approval delayed.	Project completion date extended.	Medium	Project close-out activities put on hold. Risk remains MEDIUM until this business case is approved. Station (IPG) scheduling requirements to be followed upon project re-initiation.	Medium

Lack of CNSC confirmation on duct detector & HVAC tie-in proposal.	Unable to complete close-out of detection design package.	**Medium**	If no response received by December 2006 letter to be submitted in January 2007 to the CNSC stating that the proposal is assumed to be accepted due to lack of response and tie-in will be deleted.	**Low**
Redundant detection removal included in current design.	Unable to complete close-out of detection design package.	**Medium**	Close-out notes to include Action Tracking for new Non REG C project to remove detection.	**Low**
Resources				
Resources not available to support the outstanding work.	Project completion date extended.	**Medium**	Commitments obtained from Design, Field Engineering, and CMO. Station resources (Operations/Maintenance) will be acquired via IPG scheduling process.	**Low**
Technical				
Over pressure flow switch design not concurred to by 3rd Party.	Higher design/installation costs due to re-work. Project completion date extended.	**Medium**	[redacted] specific contingency avialable for re-design and [redacted] for installation of jockey pumps. Factory acceptance testing to validate design pior to scheduling field installation included in the estimate.	**Low**
Fire alarms in Local Unit Control Equipment Room (LUCER).	Increased operating cost due to municipal fire department visits. Increased cost for room clean-up and repair of damaged equipment not associated with the project.	**Medium**	Equipment operating as per design (i.e. sensing smoke/smoke like particles). Any repairs to smoke/fire damaged equipment or cleaning of the room to remove dust particles is outside the scope of this project.	**Low**
Door interlock operation not concurred to by 3rd Party.	Increased cost for room and HVAC repairs not associated with the project.	**Low**	Replicate standard room conditions, via temporary alteration of the HVAC, and repeat test to the 3rd Party to demonstrate interlock operation. Room/HVAC repairs is outside the scope of this project.	**Low**
Regulatory				
CNSC does not accept the dispositions to the standpipe, sprinkler, and other CCR/FSA deviations.	Additional work required to address CNSC concerns.	**Medium**	3rd Party Reviews submitted to CNSC, satisfying the license requirement. Estimate includes time for technical review of CNSC challenges. Probability of not resolving challenges is low. Disposition of any future unresolved challenges is outside the scope of this project. New projects (approx. $6M) to be initiated by stakeholders as required.	**Low**

CNSC requests duct detector & HVAC tie-in.	Increased cost to complete duct detector & HVAC tie-in.	**Medium**	[redacted] specific contingency available for duct detector re-work & HVAC tie-in.	**Low**
Environmental				
Poor installation and commissioining practices.	Release to environment.	**Low**	Compliance to corporate and nuclear environmental procedures.	**Low**
Health & Safety				
Unsafe labour practices.	Personal injury.	**Low**	Compliance to corporate and nuclear health and safety procedures.	**Low**
Investment				
Modifications do not work as planned.	Higher costs.	**Medium**	Industry experts/3rd Parties used during design, installation, and commissioning to supplement OPG experience.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2007	Dec 2007	Manager, Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Resolve/disposition all CCR and FSA deviations	No deviations resolved at start of project	3rd Party concurrence of all resolutions and dispositions to CCR and FSA deviations	Written 3rd Party acceptance	Manager, Performance Engineering (Project Sponsor)
2.	Completion of Available for Service (AFS) for CCR and FSA modifications	No modifications completed at start of project	AFS acceptance of modifications by December 31, 2005	AFS acceptance meetings	Manager, Design Projects (Project Owner)
3.	Complete CNSC REG C Commitment A/R 28030880	REG C due date of December 31, 2005 at start of project	REG C commitment met by December 31, 2005	Completion letter submitted to CNSC	Manager, Regulatory Affairs
4.					
5.					

Appendix "A"

Glossary (acronyms, codes, technical terms)

AFS:	Available for Service
A/R:	Action Request
BCS:	Business Case Summary
B&M:	Black & McDonald, installation contractor
CCR:	Code Compliance Review
CD:	Crossby Dewar, installation contractor
CMO:	Contract Management Office
CNO:	Chief Nuclear Officer
CNSC:	Canadian Nuclear Safety Commission
CO2:	Carbon Dioxide, inert gas based fire suppression system
CSA:	Common Secondary Area
DCP:	Design Change Package
EC:	Engineering Change
EPS:	Emergency Power Supply
EPS-FM:	Emergency Power Supply - Fuel Management
EST:	Edwards Systems Technology, manufacturer of fire panels & fire protection equipment
EST-3:	Fire Panel model supplied by Edwards Systems Technology
FFAA:	Fueling Facility Auxiliary Area
Fire Works:	Graphical user interface to EST-3 fire panels by Edwards Systems Technology
FSA:	Fire Safety Analysis
HVAC:	Heating, Ventilation, and Air Conditioning
IRR:	Internal Rate of Return
LTD:	Life to Date
LUCER:	Local Unit Control Equipment Room
MOCPER:	Main Output Control and Protection Equipment Room
N/A:	Not Applicable
NPV:	Net Present Value
OAR:	Organizational Approval Registry
OM&A:	Operating, Maintenance, and Administration
OPEX:	Operating Experience
OPG:	Ontario Power Generation
PA:	Public Address
PHA:	Power House Annex
PHT:	Primary Heat Transport
PIR:	Post Implementation Review
PMOD:	Permanent Modification
REG C:	Type of CNSC regulatory commitment
SCA:	Secondary Control Area
SCR:	Station Condition Record
TMOD:	Temporary Modification
VESDA:	Very Early Smoke Detection Apparatus, air sampling based smoke detection system by Edwards
WTP:	Water Treatment Plant

Appendix "B"

Project Funding History

$ 000's Release Type	Month	Year	2001	Cumulative Funding 2002	2003	2004	2005	2006	2007	Later	Total	
Developmental	Nov	2000	100								100	
Partial	Aug	2001	1,470	430							1,900	
Interim	May	2002	1,470	930	1,000						3,400	
Interim	Feb	2004	1,470	930	1,000	3,800					7,200	
Full	Jan	2005	1,470	930	1,000	3,945	13,246	2,475	422		23,488	
Superseding	Aug	2006	1,470	930	1,000	3,945	16,796	3,338	2,213		29,692	
LTD Spent	May	2006	1230	813	1412	3906	16780	1933			26,074	

Comments:

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:

Not applicable.

Financial Assumptions:

Not applicable.

Project / Station End of Life Assumptions:

Not applicable.

Energy Price / Production Assumptions

Not applicable.

Operating Cost Assumptions

Not applicable.

Other Assumptions:

Darlington Fire Protection Upgrade - Phase III 16 - 79148

Superseding Business Case D-BCS-78000-10001-R005

Attachment "A"

Project Cost Summary

$000's Capital	Work Package	LTD Prior Years 2005	2006	2007	2008	Total	LTD This Mth May 2006	LTD %
Project Management	[redacted]							
Detailed Eng	[redacted]							
Fire Doors, Seals, & Exit Signs	[redacted]							
Fire Suppression	[redacted]							
Stairwell Enclosures	[redacted]							
Emergency Lights	[redacted]							
Public Address Fire Alarm	[redacted]							
Fire Barriers - Powerhouse Annex	[redacted]							
Fire Barriers - PHT Pumps	[redacted]							
Radiant Energy Fire Barriers	[redacted]							
CO2 Fire Detection	[redacted]							
Inaccessible Detectors/Removal	[redacted]							
Fire Works	[redacted]							
CCR/FSA Fire Detection	[redacted]							
Procedures	[redacted]							
Interest	[redacted]							
Close-out	[redacted]							
Overhead	[redacted]							
Sub total (REGC)	[redacted]							
General Contingency	[redacted]							
Specific Contingency	[redacted]							
Grand Total		24,141	3,338	2,213	-	29,692	26,074	N/A
Ongoing OM&A								
Inventory Write Off Required								
Spare Parts / Inventory								
Grand Total (incl contingency)		24,141	3,338	2,213	-	29,692	26,074	
2006-2010 Business Plan		24,141	938	-	-	25,079	N/A	N/A
Variance to Business Plan (excl conting)		-	(2,400)	(1,363)	-	(3,783)	N/A	N/A

Specific Contingency:

[redacted]

Basis of Estimate					
Design Complete	Up to ~40%	Contracts in place	No	Competitive Bid	N/A
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Sponsor Cost Estimate	N/A	Phase 1 Actual Used	Yes

Other:

Reviewed By:

Ken. Piggott

R. Piggott
Project Manager

15/09/06
Date:

Approved By:

T. Chong
Eng & Mods Manager (Strat IV)

15 Sept 2006
Date:

Darlington Fire Protection Upgrade - Phase III 16 - 79148

Superseding Business Case D-BCS-78000-10001-R005

Attachment "B"

Project Variance Analysis

$000's Capital	Work PKG	Last Release 12-Jan-05	This Release 31-Aug-06	Variance	LTD May-06	Out Standing	Explanation
Project Management	All	[redacted]					
Detailed Engineering	All						
Fire Doors, Seals, & Exit Signs	1						
Fire Suppression	2						
Stairwell Enclosures	3						
Emergency Lights	4						
PA Fire Alarm	5						
Fire Barriers - PHA	6						
Fire Barriers - PHT Pumps	6						
Radiant Energy Fire Barriers	7						
CO2 Fire Detection	7						
Inaccessible Detectors	7						
Fire Works	7						
CCR/FSA Fire Detection	7						
Procedures	8						
Interest	All						
Close-out	All						
Overhead (prior 2004 Charges)	All						
Sub Total							
Contingency							
Grand Total							

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
08	June	2007	Unit 2 Grating Replacement - AFS
25	June	2007	Booster Pump Over Pressure Resolution - AFS
21	Dec.	2007	Project Complete

Comments:

Attachment "D"
Scope of Work and Status

	Scope of Work	Status/Outstanding Items
Work Package #1 Fire Doors, Seals and Exit Signs	Modify/replace non-code compliant fire doors. Inspect/repair fire rated barrier seals and penetrations in the exit stairwells. Install exit signs as per fire code requirements.	Discovery work: Unit 2 floor grating replacement design, installation, and close-out.
Work Package #2 Fire Suppression	Sprinklers: 1. Install 5 additional sprinklers heads in the CSA Stores. 2. Restrict height of material in the storage racks. 3. Sprinkler upgrades in the East and West FFAA. Standpipe: Complete hydraulic calculations of Standpipe System. Resolve deficiencies: low system pressure, additional fire hose connections, relocate fire hose cabinets, etc.	Sprinklers: 1. Complete 2. Complete 3. Complete, sprinklers kept "as is". Standpipe: AFS action: Documentation close-out. Discovery work: Booster pump over pressure issue.
Work Package #3 Stairwell Enclosures	Upgrade the eight Turbine Hall stairwell enclosures on the 115 m elevation to the required fire rating.	Complete
Work Package #4 Emergency Lights	Part A: Upgrade the emergency lighting in the WTP and Pump Houses. Part B: Provide handheld portable lights for Operation staff.	Part A: Complete Part B: Complete
Work Package #5 Public Address Fire Alarm	Perform technical evaluation for the continued use of the PA system as an alternate disposition for fire alarm notification. Seek concurrence from the 3rd Party Reviewer and inform CNSC.	Complete
Work Package #6 Fire Barriers	PHA: Correct deficiencies in the powerhouse annex link to Unit 4. PHT Pumps: Install dikes at entrance to PHT pump rooms.	PHA: Discovery Work: Insulation/door replacement and close-out. PHT Pumps: Complete
Work Package #7 Fire Detection	Part A: Install detection in LUCER/MOCPER/SCA. Install Bypass Switches (Non REG C) to facilitate maintenance on fire detection EST-3 system. Part B: Install Rediant Energy fire barriers to protect affected cable pans identified in the FSA deviation report. Part C: 1. Install fire detection and pull stations in various locations to resolve CCR and FSA deviations. 2. Inaccessible Detectors (Non REG C): Assess and seek alternate disposition to make approximately 340 smoke detectors accessible for routine maintenance and testing. Part D: Install Fire Works (Non REG C) to interface with the EST-3 fire panels.	Part A: Complete AFS follow up action: Investigation of VESDA alarms (Unit 1 & 4 LUCERs). Bypass Switches (Non REG C): To be removed from project. Part B: Complete Part C: 1. Complete AFS follow up actions: • 3rd Party verification of duct detectors, pump annunciation, and door interlocks. • Waste Handling Door spares review, drawing update, Final AFS, and close-out. • Pending CNSC approval, remove HVAC tie-in. • Issue documentation/drawings. 2. Inaccessible Detectors (Non REG C): To be removed from project. Part D: Fire Works (Non REG C): To be removed from project. Scope has grown to include resolution of an existing fire alarm re-flash annunciation issue.

	Scope of Work	Status/Outstanding Items
Work Package #7 Fire Detection (Continued)	Part E: Review and seek alternate resolution to disposition the CCR deviations relating to inappropriate fire detector location, lack of pull stations, lack of pre-discharge and discharge alarms inside the CO2 protected areas. Part F: 1. Modify breaker interlock. 2. Re-route EVEN EPS bus related cables.	Part E: Complete Part F: 1. Complete, no modification required. 2. Complete, no modification required.
Work Package #8 Fire Protection Procedures	1. CCR Deviation: Revise the identified fire protection inspection, testing and maintenance procedures to comply with the fire codes. 2. FSA Deviation: Revise and issue Operating Procedure for Emergency Response Manual Fire Actions by Authorized Nuclear Operator.	1. Complete 2. Complete

Attachment "E"

Outstanding Scope/AFS Actions/Discovery Activities

Item	Forecast ($000's)	Notes
Unit 2 Stairwell Grating Modification	87	Discovery work – Design, implementation, and close-out outstanding.
Booster Pump over pressure resolution	768	Discovery work – TMOD implemented. PMOD design, implementation, and close-out outstanding.
PHA Door AFS & close-out	20	Discovery work – Combustible insulation removal and fire door replacement completed, AFS and close-out outstanding.
3rd Party verification & VESDA investigation	193	AFS Action – 3rd Party verification of detection and investigation of alarms in Unit 1 and Unit 4 LUCERs.
Waste Handling Doors	55	AFS Action – Spares review, drawing update, and Final AFS outstanding.
Duct Detection/HVAC tie-in deletion	182	AFS Action – Pending CNSC approval, de-engineer HVAC tie-in via DCP revision and remove affected cabling from the field.
Standpipe close-out	309	AFS Action – Contractor and documentation close-out outstanding.
Detection close-out	552	AFS Action – Contractor and documentation close-out outstanding.
Project Management	622	Oversee completion of remaining activities.
Contingency	[redacted]	General Contingency: [redacted] Specific Contingency: [redacted] redesign of Booster Pump over pressure resolution [redacted] installation of redesigned Booster Pump over pressure resolution [redacted] r hanger and fitting replacement [redacted] for duct detector relocation and HVAC tie-in
Total	[redacted]	

ONTARIOPOWER GENERATION

OPG Confidential	Page: 1 of 19
BUSINESS CASE SUMMARY	

DNGS D2O Storage and Drum Handling Project 16 - 31555

Developmental Release Business Case Summary D-BCS-38000-10001- 001

Routing	Location	Action	Signature	Date
Shawn Bremner Modification Team Leader x 701-2070	P72-3	Prepare BCS	for S Bremner	Nov 8/06
Edmond Wong Project Leader x 701-3991	P72-3	Review BCS		Nov 8/06
Stephanie Tham Project Manager x 701-4203	P72-3	Review BCS		Nov 8/06
Peter Floyd Manager, Design Projects, Pickering A x 701-4053	P72-1	Review BCS		Nov 8/06
Gord Brown Controller, NOSS x 702-5059	P82-3	Review BCS		8 Nov 06
Aileen Sullivan Manager, TRF x 703-1361	D08-ES3	Review BCS		Nov 21/06
Mark Arnone rector, Projects & Modifications 701-6063	P72-1	Review BCS		Nov 8/06
Rumina Velshi Director, Commercial Activities x 702-5100	P82-4	Submit BCS		[illegible]
Randy Leavitt Director, Investment Management x 702-5085	P82-3	Approve BCS		Nov 22, 2006
Larry Nichol Director, TRF x 703-7450	D08-ES	Approve BCS		Nov 7/06
Ball nior Financial Analyst 2-4084	P82-3B6	Return For Distribution		

DNGS D2O Storage and Drum Handling Project 16 - 31555

Developmental Release Business Case Summary D-BCS-38000-10001-R001

1/ RECOMMENDATION:

We recommend approval of a Developmental Release of $3,600k (including $840k contingency) to complete preliminary design, initiate detailed design, initiate Requests for Quotations for long-lead materials and develop a Partial Release for the DNGS D_2O Storage and Drum Handling Project by November, 2007. A Partial Release will be requested upon completion of preliminary engineering to facilitate a seamless transition to detailed design, long-lead material procurement, initiate Requests for Proposal for the construction contract and develop the Full Release. This funding strategy will minimize cost and schedule delays.

The business objectives of this project are as follows:

- Improve detritiation capability within OPG.
- Improve operational flexibility and ability to segregate different streams of D_2O to support various operation and outage scenarios in DND (ie: unit outages, SCO/VBO or upgrader outages)
- Improve the management of drum inventories in DND.
- Allow Isotope Sales Department to pursue new business opportunities.

Kinectrics was commissioned to study the Heavy Water storage and drum handling issues from an overall OPG perspective. The recommended modification for DNGS is to extend the existing HWMB to house additional 8 x 50Mg multi-purpose storage tanks and to provide additional drum handling/storage space, and install a drum testing facility. The recommendation is based on the understanding that DNGS's drums will be cleaned off site at PNGS's new drum cleaning facility, and the additional DNGS tanks will provide storage flexibility that benefits PNGS's detritiation program.

Choose One	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	N/A								-
Requested Now	Developmental		1,872	1,728					3,600
Future Funding Req'd				3,992	13,253	14,938	600		32,783
Total Project Costs		-	1,872	5,720	13,253	14,938	600	-	36,383
Other Costs									-
Ongoing Costs									-
Grand Total		-	1,872	5,720	13,253	14,938	600	-	36,383

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Value Enhancing	Capital	13,654	14.8%	9.8

Submitted By:

Rumina Velshi
Director, Commercial Activities

Date:

Finance Approval:

Randy Leavitt
Director, Investment Management

Nov 22, 2006
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Larry Nichol
Director, TRF

Nov 21, 2006
Date:

2/ BACKGROUND & ISSUES

OPG needs to improve its overall ability in managing its D_2O inventories to support continuous station operations in a safe and cost efficient manner. In December 2004, Kinectrics Inc. completed a study "Strategic Option Study for OPG Heavy Water Storage and Drum Handling", (Ref; K-011043-001-RA-0001-R00A). In April 2006, Kinectrics Inc. was contracted by this Project to further investigate the issues at Darlington and Pickering and to develop options which would address OPG's D_2O management needs.

The main objectives of this project are as follows:

1. Improve the detritiation process within OPG.
2. Improve operational flexibility and ability to segregate different streams of D_2O to support normal operation and outages.
3. Improve the management of drums in the station and to reduce to associated drum handling-related, radiological and conventional safety hazards.
4. Allow Isotope Sales Department to pursue new business opportunities.

Plant Life Extension and P2/P3 decommissioning are not part of the scope of this project. However, the impact of plant life extension on this project was considered in the choice of location (Reference Section 3).

With respect to DNGS, the Kinectrics study identified problems in three areas of the D_2O Management System with regard to the project objectives. They are reactor grade D_2O storage, downgraded D_2O storage, and drum storage and handling.

rea 1: Reactor Grade D_2O Storage

Storage & Inventory (S&I) Tanks are used for the storage of reactor grade D_2O such as TRF Feed, TRF Product, Moderator D_2O, PHT D_2O, and Station Upgrader Product (SUP).

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
1) Lack of storage at DIOTS limits TRF flexibility to build up a large volume of Hi-Ci feed stock and/or Low Ci TRF product.	• TRF's Hi-Curie (Ci) feed stock relies heavily on the ability from other stations to ship, and that their shipment may not align with the TRF availability or ability to receive. • Inadequate volume of tankage for low Ci TRF product to fully support OPG's detritiation program or to support Isotope sales.	• Inefficient use of TRF & OPG resources as less overall tritium is removed from the entire fleet of nuclear units for the same TRF operating costs. • The inability to fully support PNGS's detritiation program endangers PNGS's OP&P limit. • Inability to meet contractual obligation (estimated in loss of revenue through Isotope Sales, at [redacted] since 2001 from [redacted] and restricts Isotope Sales from pursuing new business with domestic customers of up to [redacted]
2) Insufficient storage space to support moderator drain in a planned outage.	• All existing moderator grade D_2O must be emptied out (~ 100Mg) & relocated from S&I tanks to DIOTS or offsite to accommodate a moderator drain.	• If DIOTS is used, then this interrupts TRF shipping & receiving (see item #1) • May require offsite storage which can cost $1.5M for each occurrence. • Risk of delaying outage if offsite storage is unavailable.

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
4) Insufficient storage space to support SCO or VBO.	• More PHT grade D_2O must be accumulated prior to an SCO or VBO to accommodate 4 units shrinkage & loss make-ups	• Failure to accumulate PHT D_2O could potentially cost OPG [redacted]o lease D_2O (140Mg) from an external source. • Risk of delaying outage if external source is unavailable.
5) Insufficient storage space to support PHT Low Level Drain (LLDS) in SCO/VBO	• With the extra PHT grade D_2O accumulated prior to SCO/VBO there is insufficient storage space to accommodate the swell associated with re-starting 3 units while the 4th unit remains in the LLD state	• If PHT grade D_2O is stored in the moderator S&I tanks to accommodate the swell & LLD it increases the risk of downgrading moderator grade D_2O, with a potential cost to OPG of $1.5M to re-upgrade. • If DIOTS is used to store PHT D_2O see item #1.

Area 2: Downgraded D_2O Storage

Downgraded D_2O storage tanks are used at the IXCU for the collection and process of downgraded recovery water

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
6) Insufficient downgraded D_2O storage space to support acute recovery events or SUP outage.	• Alternate temporary storage methods such as using reactor grade D_2O tanks at DIOTS or drums to bridge the gap.	• Increased risk of downgrading reactor grade D_2O. This situation downgraded 60Mg of moderator D_2O in 2003, which cost DNGS approximately $0.9M to upgrade. • The use of drums increases housekeeping issues, and add drum purchasing cost of approx. $30K / yr. • Also see item #1
7) Insufficient downgraded storage to provide operational flexibility when processing high TOC D_2O.	• When high TOC levels are present in the downgraded D_2O after being processed through the IXCU system the TOC must be removed prior to processing through the SUP. After the TOC is removed, via the UV system, this D_2O must then be reprocessed through the IXCU to remove increased conductivity created by the UV system.	• The SUP is forced to go onto reflux due to lack of feed while the D_2O is being cleaned up. (SUP capacity factor reduced). • The recycling of 'UV processed' D_2O through the IXCU further reduces the downgraded storage availability. • It may also lead to storing downgraded water in DIOTS or in drums (see item 1).
8) Insufficient downgraded storage space and flexibility to support the efficient segregation and processing of high and low Ci recovery streams of D_2O during an extended TRF outage.	• During an extended TRF outage, the only source internal to DNGS to obtain more low Ci make-up PHT D_2O required to keep DNGS units within OP&P limits is by processing the high and low Ci recovery streams separately through the "single" clean-up and upgrading system. When switching from high Ci to low Ci stream, low Ci D_2O is required to flush the system (creating a mid Ci product) for a sufficient time before the low Ci product is produced at the SUP.	• The lack of downgraded storage space requires more switching between the 2 streams & thus requires more flushing which reduces the availability of low Ci products. If the amount of PHT makeup D_2O falls below 210Mg then DNGS would be required to: a) Lease low Ci D_2O from [redacted]which had cost OPG [redacted]ay. b) Mix in available higher Ci D_2O with the available lower Ci D_2O (this would increase the tritium levels in the PHT system) to maintain the level. This increases the risk

		of approaching OP&P limits and increases fuel burn-up cost. c) Use virgin D_2O as makeup to the PHT system. This will cost OPG $300 /Kg. • The frequent switching of streams further stress the inadequacies of downgraded storage (see item 6 & 7).

Area 3: Drum Storage and Handling

This area is required to receive, ship and handle (ie: pressure testing and cleaning) drums used by the DNGS units to temporarily store recovered D_2O, store downgraded D_2O with high TOC for processing, or from external sources in support of Isotope Sales.

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
9) Insufficient floor space available in the HWMB to store & handle D_2O drums.	• Drums are spread around in the HWMB and inside the station. Some of the locations that are storing these D_2O drums may not be designated normally for this purpose. • Increase rework as drums need to be moved around or relocated more than once. • Minimal space available for drums from external sources.	• D_2O drums that are stored in re-designated areas can impede normal flow of operation & increase chance for human performance errors. • Increased difficulties to maintain proper housekeeping within HWMB or the station. • Increased workers' health and safety concerns with additional drum handling. • An inefficient use of Operators. • Restricts Isotope Sales from pursuing new business, (i.e. importing drums of D_2O from foreign customers). This contributes to a potential increase revenue up to $4M/yr
10) Lack of on-site drum pressure testing facility, and or cleaning facility.	• Drums are sent off site to be pressure tested before they can be reused for D_2O shipment. • Lack of available clean drums requires operators to re-using dirty drums that will contaminate relatively 'clean' D_2O.	• Cost of external testing of drums is [redacted] or [redacted] • Drums that cannot be cleaned before reuse amplify the storage & housekeeping problem, and increase reworks when "clean" D_2O is contaminated. .

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Choose One	Alt 1 (Recommended)		Alt 2 Delay	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost				
Revenue	-	87,790	87,790	69,610			
Project Cost	-	(34,588)	(34,588)	36,639			
NPV (after tax)	(9,206)	4,448	4,448	(3,905)			
Impact on Economic Value (IEV)		13,654	13,654	5,301			
IRR%	N/A	14.8%	14.8%	N/A			
Discounted Payback (Yrs)	N/A	9.8	9.8	N/A			

Status Quo - Not Recommended

Maintaining the status quo is not recommended. Continuing to operate as is will result in DNGS experiencing the current issues identified in section 2 with associated costs and risks.

The lack of TRF Feed and Product storage limits HWMB's ability to receive and store D_2O. This restricts its ability to process more high Ci feed, which contributes to the inefficient operation of the TRF, and limits TRF from processing more D_2O from external customers ([redacted] in potential sales). It also contributes to the difficulties for OPG to adhere to its detritiation program which causes continued increase in the tritium levels in OPG, particularly at Pickering. Increasing tritium levels result in increased tritium emission with environmental impacts, increased fuel burn-up costs, increased dose expenditure and regulatory impact due to potentially exceeding the OP&P limits.

The lack of D_2O storage limits DNGS's ability to plan and execute its maintenance outages for the station, SUP and TRF with the following potential costs and risks; $1.5M to ship moderator D_2O off site, $1.5M to upgrade D_2O, and/or [redacted] to lease low Ci D_2O for PHT make-up.

The lack of recovery storage limits DNGS's ability to support acute events and high TOC recoveries. This causes backlog at the cleanup systems and increases the use of drums. As the station ages and more maintenance is performed on reactor systems, more acute events and recoveries with high TOC are anticipated. It also limits DNGS' ability to recover adequate low Ci products to support units' operation during an extensive TRF outage.

The lack of space to store drums results in poor housekeeping in the station & HWMB, and inefficient use of operator resources, which costs DNG approximately $64K/year. Workers will continue be exposed to increased health and safety concerns related to drum handling. Also, the lack of drum storage restricts Isotope Sales from pursuing new external customers, contributing to the potential [redacted] in increased sales.

Without a drum testing facility, DNGS will have to incur an expense of approximately [redacted] to continue to ship drums offsite for testing, which limits its flexibility to manage its shipments in a timely manner.

Alternative 1 - Build a 26m x 12m addition with 8x50Mg storage tanks and with drum storage and testing facilities - Recommended

Construct a 26m x 12m HWMB extension to house 8x50 Mg multi-purpose storage tanks, a 12m x 14m drum storage area, and drum testing facility.

Tank ID	Tank Spec	Proposed usage
1A/1B	2 x 50 Mg – class III	High Ci – Moderator/TRF Feed/SUP Product
2A/2B	2 x 50 Mg – class III	Low Ci – PHT / TRF Product
3A/3B	2 x 50 Mg – class III	Downgraded Dirty
4A/4B	2 x 50 Mg – class III	Downgraded Clean

The additional multi-purpose tanks can be used to store either reactor grade D_2O or downgraded D_2O. This addition will address all the problem areas, minimizing the risks and costs identified above.

It will also achieve the main objectives of this project

1. Improve the detritiation process within OPG:

   The additional reactor grade D_2O storage at DNGS allows more schedule flexibility to ship or receive D_2O to/from the TRF to support OPG detritiation program. This additional flexibility can help to relieve some storage pressure at PNGS as their high Ci D_2O can be shipped for detritiation more readily. The additional space also allows TRF to accumulate a larger volume of high Ci D_2O to support continuous TRF detritiation operation and to accumulate a larger reservoir of TRF product to support OPG operations or detritiation efforts. This will improve TRF efficiency and the annual TRF's through-put as more tritium is removed for the same unit operating cost and will relieve some reliability pressure on TRF.

2. Improve operational flexibility to segregate different streams of D2O:

   The additional reactor grade D_2O storage will allow storage of either high or low Ci products. This improves flexibility for D2O movement & planning and enhances shipping & receiving capability. It also provides additional reactor grade D_2O storage capacity to support moderator drains, SCO/VBO and extended TRF outages without having to ship D_2O off site or deal with the risk of downgrading reactor grade D_2O.

   The additional downgraded D_2O storage will provide adequate storage capacity to support normal operations and outages even during acute recovery events or high TOC scenario. This will ensure 'clean' feed is always available to the SUP and reduces the amount of time it is forced to go into reflux mode and improve SUP capacity factor. It will also reduce recovery backlogs, operator work-arounds and amount of drumming required during acute events, which further improves housekeeping and associated worker health and safety issues. The additional downgraded storage also improves the flexibility to process the high or low Ci recovery streams separately with less switching of streams when processing through the SUP. This improvement allows more low Ci D_2O to be available during an extended TRF outage, thereby reducing the risk & cost of leasing low Ci D2O from other sources.

3. Improve the management of drums :

   A new 'designated' Drum Storage & Handling Facility (DS&HF) in HWMB that can store up to 350 drums will allow all D_2O drums to be stored in a central location. This capability will improve the management of drums & D_2O inventory. The facility will improve housekeeping, reduce rework and reduce drum handling-related radiological and conventional safety hazards

   A new Drum Testing Facility (DTF) will eliminate the costs associated with having drums tested by a 3rd party including shipping and handling cost. It will allow HWMB to manage its drum QA requirements in house and provide the flexibility for operations to certify drums on a as needed basis to meet sales commitments.

   A new Drum Cleaning Facility (DCF) will be proposed to be installed in PNGS. The new DCF will help in the overall management of drums within OPG.

4. Allow Isotope Sales Department to pursue new business opportunities

   The operational improvements in the HWMB and the improved efficiency of the TRF will provide the flexibility and capacity for Isotope Sales Department to meet current contractual obligations and to pursue new business. The forecast for the increased business is estimated to be [redacted] in gross revenue.

Note: The recommended modification is less than what was originally proposed in the Charter. This recommendation was reviewed and subsequently agreed to by the stakeholders in the Project Challenge Meeting on August 18, 2006 that it can satisfy their needs and resolve the issues at DNGS.

Alternative 2 - Delay Project - Not Recommended

Delaying the project is not recommended. This would require DNGS to continue its dealing with current operational issues and the risks & costs similar to the "Status-Quo" option longer and reduce the number of years available to recover project costs through increased sales.

If OPG makes the final decision on Plant Life Extension (PLE) in the future, the proposed site location for this project will still have sufficient space to build a second addition to install more D_2O tanks. An alternative option is to include a basement area in the current proposed site to accommodate more D_2O tanks in the future when needed. However, this decision must be made now in order to be incorporated into the current design, and this will increase the current cost estimate and further impose project risks from any unknown discoveries when the geotechnical analysis of the soil is performed.

Alternative 3 – - Not Recommended

Alternative 4 – - Not Recommended

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The following are the objectives and deliverables of this Developmental Release BCS:

- Prepare and award a Design contract for Preliminary Engineering & Detailed Design
- Complete Preliminary Engineering, (up to 40% Detailed Engineering).
- Issue Tech Spec for Long Lead Material
- Review/approve Preliminary Engineering
- Initiate Detailed Design
- Prepare Preliminary PEP
- Issue a Partial Release BCS

Refer to Appendix C for a list of the project milestones.

5/ QUALITATIVE FACTORS

The successful completion of this project will improve the following:
Government Relations

- Reduce tritium emissions throughout OPG
- Reduce risk of infringing on regulatory limits

Customer Relations

- Increasing OPG's capability and flexibility to process D_2O will improve customer relations by meeting contractual obligations with Bruce Power for detritiation services and provide the ability to increase detritiation services.

Technical/Operational Considerations

- Improve efficiency of TRF operation and increase the overall amount of tritium removed from the OPG D_2O inventory.
- Improve availability of low Ci reactor grade D_2O for operational & outage needs
- Improve HWMB capability & flexibility to support any outage or acute events thus reducing the risks and cost to extend an outage.
- Improve management of detritiation programs particularly at Pickering by reducing the dependency on TRF availability

Health & Safety

- Reduced tritium levels will reduce worker dose.
- Additional drum storage will improve housekeeping and reduce drum handling requirements, thereby reducing the related health and safety concerns.
- Reduce operator work arounds and extra operator actions that are required to maneuver various grades of D2O into unconventional storage arrangements.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Overall project cost exceeds current estimate	Unable to accomplish all project objectives without further release of funds	**High**	Detailed conceptual study completed by Kinectrics. Helyar review of project cost. Adopt optimal contracting strategy to mitigate cost excalation. Further fine tuning of overall project schedule and cost via partial BCS.	**Medium**
Changes to the funding release strategy and/or fine tuning of contracting stategy may impact overall cost and schedule	Could cause a delay to the schedule & increase costs	**High**	Review contracting stategy and design and installation requirements with Supply Chain, Procurement, Design & Legal	**Medium**
Scope				
Preliminary/Detailed Design may result in an increase in scope.	Changes in scope will delay the schedule and add cost to the project.	**Medium**	Further scope identified during preliminary design will be challenged by projects & have to be agreed by all stakeholders & sponsor.	**Low**
Schedule				
Delay in the issuing of Design contract due to rigorous management, supply chain and legal reviews of the RFP.	Schedule delay	**High**	Early involvment of Supply Chain, Legal, Taxation etc to ensure that all the required information is included in the RFP	**Medium**
Fine tuning of contracting stategy may impact overall cost and schedule	Require changes to funding release strategy which could cause a delay to the schedule & costs	**High**	Review contracting stategy and design and installation requirements with Supply Chain, Procurement, Design & Legal	**Medium**
Insufficient information to determine accurately the	Delay to schedule	**Medium**	Fine tuning of final design deliverables timeline is available via partial BCS	**Low**

timeline of design deliverables				
Design deliverables not on time	Delay to schedule		Select approved vendor, provide clear scope & deliverables. Review progress regularly & establish and monitor effective design performance metrics	
Resources				
Insufficient OPG design resources available	Delay project schedule & milestones.	**High**	Design will be contracted out to external agency. OPG Projects Design have committed to provide DTL support for this project.	**Low**
Availability of qualified vendors to perform design and subsequent implementation	Delay in issuing contract due to need to amass variuous interfacing risks and vendor qualification issues and contracting language.	**Medium**	Obtain OPEX from other OPG projects of similar nature, early involvment with Supply Chain and various other deparments or potential vendors and the associated contracting strategies.	**Low**
Technical				
Meeting seismic requirements	Increase cost to the project due to unkown civil upgrade to meet the seismic requirement.	**High**	Seismic qualification considered as part of conceptual study. Seismic qualification requirements to be included in Preliminary Design	**Low**
Discoveries from geotechnical analysis of soil	Delay and added cost to the project due to the prefered site not being suitable for building addition. Increase cost to the design and installation to meet the requirements identified	**Medium**	Test drill site to determine the soil composition prior to completing preliminary engineering to ensure the design takes this into account. Method & cost to implement corrective actions will be challenged & documented.	**Low**
Legacy issues on Design, and interface issue with other related D2O prpjects	Re-eingineering may be required if there are legacy and interface issues with systems that the project is modifying. This would add scope to the project which may cause delays and will increase project costs	**Medium**	Site walkdowns have been completed. Complete drawing review on system impacted during Preliminary Engineering, and ensure there are open dialog with other projects.	**Medium**
Increased scope of work due to discovery work	Changes in scope will delay the schedule and add cost to the project.		Drawing rieview has been conducted to identify any possible underground services that may require relocation. Field survey to be completed during Preliminary Engineering	

Regulatory				
Regulatory approvals (CNSC & TSSA) requiring more time then anticipated	Delay in project & potential cost impact to contract	**Medium**	Identify required time allowance in project schedule. Incorporate approved time in contracting strategy. Review OPEX with other similar projects	**Low**
Environmental				
n/a				
Health & Safety				
n/a				
Investment				
Cost benefit information obtained from stakeholders was not correct	NPV and IRR results may be less optimistic than calculated	**Medium**	Line management was involved in provoding the information based on historical perfomance of the system	**Low**
Inability to recover investment such as TRF production is unreliable	Insufficient time to recover capital investment before stations' end of life	**Medium**	The current NPV and IRR indicate a positive return on investment before stations' end of life. Impelement ongoing TRF improvement initiative to improve reliability.	**Low**
Early end of life of DNGS or TRF	Insufficient time to recover capital investment if end of life is earlier then currently forecast	**Low**	Using the current forecast of DNGS end of life date the current NPV and IRR indicate a positive return on investment before stations' end of life	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	TBD in Next Release Choose Year	TBD in Next Release Choose Year	Rumina Velshi

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

AECL – Atomic Energy Canada Limited
AFS - Available for Service
CNSC - Canadian Nuclear Safety Commission
DG – Downgraded
D_2O – Heavy Water
DIOTS – Darlington in/Out Transport System
EC - Engineering Change
EOL - End of Life
HWMB – Heavy Water Management Building
IXCU - Ion Exchange Clean Up
LLD – Low Level Drain
NPV - Net Present Value
OP&P - Operating Policies and Principles
PHT - Primary Heat Transport
RFP – Request For Proposal
RG – Reactor Grade
SCO – Station Containment Outage
S&I - Storage and Inventory
SUP – Station Upgrader
TDO – Tritiated Heavy Water
TOC – Total Organic Carbon
TRF – Tritium Removal Facility
TSSA – Technical Specification
UV – Ultra Violet
VBO – Vacuum Building Outage

Appendix "B" Project Funding History

Choose			Previous Releases (incl contingency)								
				Cumulative Values							
Release Type	Month	Year	2004	2005	2006					Later	Total
None											0
											0
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:
The current estimate of $36.4M (including contingency and interest) is a conceptual quality estimate (estimate band of +60% to -25%), and has an estimated available for service (AFS) date in Q4 of 2010. The estimate has been independently verified by Helyar ($35.7M). The variance between the two project cost estimates is due to labour escalation each year and additional Project Management resources are required to complete close-out in 2011 which were not included in the Helyar estimate. Given that the estimate is performed based on conceptual information, there is a risk that this estimate may escalate (refer to section 6 Risk Table).

Project funding in the amount of [redacted] (excluding contingency) is listed in the current approved Business Plan 2007 to 2011. The variance to the business plan will be addressed through the portfolio management process. There is $0 capital spending released today to this project.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

OPG staff will provide project management & support role during design and implementation
Material cost assumptions based using class 3 tanks, hangers, piping and associated equipment
Design and installation work will be contracted out

Financial Assumptions:

Escalation rate of 2% on revenues
Escalation rate of 3% on employee wages
See attached for assumptions regarding NPV calculations

Project / Station End of Life Assumptions:

Darlington end of life is 2019

Energy Price / Production Assumptions

N/A

Operating Cost Assumptions

New operating costs are negligible.
Cost to upgrade D_2O [redacted]
Cost to lease D_2O from [redacted]

Other Assumptions:

OPG to provide unrestricted access to work area
All work is within the secured area with incumbent restrictions
All Nuclear grade materials purchased by OPG

Project Name 16 - 31555

Partial Release Business Case Summary D-BCS-38000-10001-R001

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr	This Release 2007	This Release 2008	Future Release 2008	Future Release 2009	Future Release 2010	Future Release 2011	Later	Total
Project Management (OPG)		546	390	454	1,020	948	152		**3,510**
Engineering & Drafting (OPG)		379	195	236	280	679	226		**1,995**
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	-	1,872	1,728	3,992	13,253	14,938	600	-	36,383
2006-2010 Business Plan		1,500	1,800	6,700	4,700	5,000			**19,700**
Variance to Business Plan	-	(59)	(481)	(3,605)	5,559	6,628	458	-	8,500
Committed Cost		-	-	-	-	-	-		-
Inventory Write Off Required		-	-	-	-	-	-		-
Spare Parts / Inventory		-	-	-	-	-	-		-
Total Release (excl contingency)	-	1,441	1,319	3,095	10,259	11,628	458	-	28,200
Total Release (incl contingency)	-	1,872	1,728	3,992	13,253	14,938	600	-	36,383

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Zero to Minimal		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Jan 2007.

Reviewed By: Nov 8/06

Stephanie Tham
Project Manager

Date:

Approved By:

Peter Floyd
Eng & Mods Manager (Strat IV)

Nov 8/06

Date:

Project Name 16 - 31555

Partial Release Business Case Summary D-BCS-38000-10001-R001

Attachment "B" **Project Variance Analysis**

Capital	LTD Nov 2006	Choose One: Last BCS N/A N/A	Choose One: This BCS Nov 2006	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
30	NOV	2006	Developmental BCS Approved
01	FEB	2007	Project Start
10	May	2007	Major PO/Contract Award - Design Contract
19	SEP	2007	Long Lead Material Identified
01	NOV	2007	Partial BCS Approved
22	NOV	2007	Preliminary Design Complete (40%)

A Project Execution Plan (PEP) will be approved by May 2007

Comments:

Attachment to D-BCS-38000-10001-001
NPV Calculation Assumptions for Revenue & OM&A Costs

Category	Cost	Rational
CAPITAL EXPENDITURES	$36,388,000	**Cost to build HWMB addition, install 400Mg of new tanks, drum storage area & drum pressure testing equipment. (Including [redacted] contingency & [redacted] interest)**
OM&A Costs		
New Drum Purchases	[redacted]	Drums assumed @ [redacted] /drum -> 300 drums x [redacted] over 5 years [redacted]
Cost to ship 100 Mg of Moderator D2O off site	[redacted]	Cost to ship 100 Mg of D2O and have it stored at [redacted] to accommodate a Moderator Drain estimated @ once every 2 years
Cost to re-upgrade D2O in the event of downgrading reactor grade D2O.	$1,500,000	20% chance of downgrading event of 100 Mg Eliminate the practice of using S&I or DIOTS tanks to store downgraded D2O during TRF & SUP outages
Cost to borrow Low Ci D2O from AECL to provide PHT make-up during SCO/VBO.	[redacted]	[redacted] @ [redacted] = [redacted] Lease for [redacted] ays (2003) = [redacted] Risk of sufficient overpacks available to ship this water Potentially occur every SCO &/or VBO
Operator time lost due to moving drums to make space	$64,000	800hrs @ 80/hr=64000
Cost to pressure test drums off site	[redacted]	[redacted] x 200 drums/year = [redacted]
ADDITIONAL/NEW REVENUE		
Bruce Power	[redacted]	Detritiation services for new Units starting @ [redacted] @ [redacted]
External Business (excess capacity)	[redacted]	Excess capacity of TRF [redacted] @ $ [redacted] Provide detritiation services to [redacted]
Additional sales	[redacted]	Import more drums of D2O from external customers [redacted] cleanup D2O and sell to [redacted] for loss makeup [redacted]

DNGS Maintenance Facility 16 - 31717

Partial Release Business Case Summary D-BCS-28200-10003-R000

Routing	Location	Action	Signature	Date
Shawn Bremner MTL, Design Projects 701-2070	P72-3	Prepare BCS		31/JAN/2008
Mike Nairne Project Leader, Design Projects 701-3571	P72-3	Review BCS		4/FEB/2008
Stephanie Tham Project Manager, Design Projects 701-4203	P72-3	Review BCS	Ian Fung for Stephanie Tham	4/Feb/2008
Dianne Gaine Manager, Design Projects 701-4181	P72-1	Review BCS	Dianne Gaine	Feb 4/08
Mark Arnone Director, Projects & Modifications 701-6063	P72-1	Review BCS		4 FEB 2008
Dwight Zerkee Manager, Investment Management 702-5058	P82-3A6	Review BCS		7 Feb 08
James Whyte Manager, Maintenance Production 03-7505	D01-A2	Review BCS	James Whyte	14 FEB 08
u Seedhouse Director, Operations & Maintenance 703-7496	D01-OSB2	Review BCS		15 Feb 08
Randy Leavitt Director, Nuclear Investment Management 702-6878	P823-315	Review BCS		Feb 20, 2008
Wayne Robbins SVP - Darlington	D08-ES3	Review BCS	Wayne Robbins	2008-02-25
Jim Beech VP Nuclear Finance	TCH07-E19	Review BCS		Feb 25, 2008
Donald Power VP Corporate Investment Planning REC'D Apr. 2/08	TCH07-D06	Review BCS		May 20/2008
Tom Mitchell CNO Added executive control limit of $2M	P826A-1	Submit BCS		31 MAR 08
Donn Hanbidge SVP & CFO	TCH19-F27	Approve BCS	D Hanbidge	May 22/08
Pierre Charlebois Chief Operating Officer	TCH19A21	Approve BCS		May 26/08
m Hankinson esident & CEO	TCH19-A24	Return For Distribution		May 26/08

DNGS Maintenance Facility 16 - 31717

Partial Release Business Case Summary D-BCS-28200-10003-R000

1/ RECOMMENDATION:

Approval is requested for this Partial Release of $6,935K capital (including contingency) to facilitate the demolition of the Power House Annex (PHA), FE Calibration Shop, Bldg 6 Security Change Room, & ERT Offices at Darlington as well as to complete the design for the relocation of buried services and to start the Preliminary Engineering portion only for the new Maintenance Facility. At this stage, present estimated total project cost is $44.6M ($57.7M including contingency) $1,600K of which is required for building demolition. A Full Release BCS is scheduled for May 2009.

The objective of this project is to provide new permanent shops and office space for DNGS maintenance staff with a safe and effective work environment. Failure to implement this improvement would leave the station vulnerable to decreases in maintenance productivity and effectiveness, potential increase of industrial accidents, and potential outage extensions due to lack of facilities for rehearsal space for RM and IMS.

The (PHA), FE Calibration Shop, Bldg 6 Security Change Room, & ERT Offices are in the footprint of the proposed new site of the Maintenance Facility and must be removed as a pre-requisite. These buildings are vacant and life-expired and will require removal regardless of whether the new Maintenance Facility goes forward as a Project.

This Partial Release BCS strategy has been adopted to facilitate removal of the PHA in 2008 and to facilitate timely engagement of engineering activities to minimize cost and schedule risks of the overall Maintenance Facility Project by obtaining a clearly defined scope of work for the buried services relocation and building plant and service tie-ins prior to the issuance of the EPC contract

Specifically, this Partial Release will complete:

- Decommissioning and removal of the existing DNGS PHA, Security Change Room, FE Calibration Shop & ERT Offices.
- Detailed Engineering of the Buried Services relocation and Tie-Ins required at the proposed site of the new Maintenance Facility.
- Issue Request for Proposal (RFP) and evaluate bids for a contract to install Tie-Ins and Buried Services relocations.
- Issue an RFP and complete bid evaluations for a Commercial Engineer, Procure, and Construct (EPC) contract for the new Maintenance Facility.
- Preparation of PO for the Preliminary Design portion for the Maintenance Facility to start design work for the new maintenance facility.
- Prepare a Full Release BCS.

Acres Sargent & Lundy (ASL) was commissioned to perform a study and develop several alternatives based on the priority of needs specified by the sponsor. The option selected by management is a new 2 story 60,000+ sq. ft building which meets all the needs identified except a welding shop.

This project will be executed between 2007 and 2011:

2007 - Preliminary Design for the PHA removal. (complete)
2008 - Removal of the PHA and associated buildings.
- Complete Detailed Engineering for the Buried Services relocations and Tie-Ins at the proposed site.
- Issue an RFP for a Commercial EPC contract for the proposed new Maintenance Facility, receive & evaluate bids.
2008/09 - Preliminary and detailed design of the Maintenance Facility.
2010/11 - Construction and turnover of the Maintenance facility to OPG Operations and Maintenance.
2012 - Close-out

Note that this project estimate does not include costs for moving existing maintenance equipment, purchase of new maintenance equipment, purchase of radiation monitoring equipment.

Full project cost estimates are conceptual at this time (+60% / -25%) and include approximately [redacted] contingency. Before requesting full funding release, detailed estimates will be completed and independently validated by a third party vendor.

An Executive Control limit of $50 Million has been placed on the project as a whole; expenditure beyond this limit must receive formal approval by the Chief Nuclear Officer and the Chief Operating Officer prior to expenditure or cost commitment.

BUSINESS CASE SUMMARY

000's (incl contingency)	Funding	LTD 2007	2008	2009	2010	2011	2012	Later	Total
Currently Released	Developmental	1,369	234						1,603
Requested Now	Partial	(861)	3,960	3,836					6,935
Future Funding Req'd	Full			15,096	19,985	13,599	521		49,201
Total Project Costs		508	4,194	18,932	19,985	13,599	521	-	57,739
Other Costs									-
Ongoing Costs									-
Grand Total		508	4,194	18,932	19,985	13,599	521	-	57,739

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	Capital	$1,4[illegible]	13.4%	N/A

Submitted By:

Tom Mitchell May 08, 2008 Date:

Tom Mitchell
CNO

Finance Approval:

D Hanbidge

Donn Hanbidge Date:
SVP & CFO

Line Approval (Per OAR Element 1.1 Project in Budget):

Jim Hankinson May 26/08 Date:

Jim Hankinson
President & CEO

BACKGROUND & ISSUES

DNGS needs to improve its overall maintenance capability to support continuous station operations in a safe and cost effective manner. Darlington initially commissioned a study of a Maintenance Facility under a partial release in 2002, that release was later cancelled due to changing station priorities. Subsequent studies by Wardrop (2005), Acres Sargent & Lundy (ASL) (2006), and most recently ASL to provide a revision to their 2006 study were commissioned; several iterations to the study were required due to changing maintenance strategies, changing management directives, station priorities, and budgetary constraints on the scope of the work.

The Maintenance Facility Conceptual Study rev 00 performed by ASL, which was issued November 13th, 2006, had four developed layouts and conceptual cost estimates, which significantly exceeded the portfolio budget. A new scope of work was provided by the Sponsor on December 13th, 2006 with scope ranked by priority and a cost ceiling for the new Maintenance Facility. ASL was re-engaged and an additional three new conceptual layouts, schedules, and cost estimates produced as a result of the iterations required to be developed to determine the optimal building layout while adhering to the stipulated scope priority and budget limitation.

The (PHA), FE Calibration Shop, Bldg 6 Security Change Room, & ERT Offices are in the footprint of the proposed new site of the Maintenance Facility and must be removed as a pre-requisite to the new build. These buildings are vacant and life-expired and will require removal regardless of whether the new Maintenance Facility goes forward as a Project. The removal & decommissioning cost is estimated at $1.6M (+60/-30%) and was obtained from rev 00 of the ASL conceptual report. The current construction change room is also in the foot print of the proposed Maintenance Facility. The removal of this building is being completed under project 31718 "New Construction Change Room".

As a result of DNGS progressing through its life cycle, changes in technology, new maintenance strategies, and loss of expired temporary buildings, the current maintenance facilities at Darlington are no longer adequate. The issues that were evaluated to develop the recommended option include the following:

Increased Maintenance Requirements/Original Facilities are Inadequate

1. Increased maintenance staff – Control Maintenance from 140 to 209, Mechanical Maintenance from 135 to 195, and Inspection Maintenance Services (IMS) personnel from 0 to 30. Maintenance staff has increased by > 160 personnel since plant was commissioned.
2. Maintenance strategy is now being focused on day crews as opposed to shift crews. Hence, the total accumulated crew size to be accommodated on days has increased from 40 to 188 maintenance personnel.
3. IMS was never originally provided space for permanent shops and offices. They had been housed in the PHA but this building has been since vacated and condemned.
4. Offices and shops had been built in the path of a potential secondary side pipe failure. These shops were removed and this has resulted in some work groups having inadequate offices and labs. Reference TOE 98-01234-20100-3981-01.
5. Some of the existing shops and offices do not meet the National Building Code and/or ASHRAE 62.1 standards. These areas include MM M&TE lab, CM M&TE lab, MM/CM Valve shop, MM RV shop, MM Seal Lapping shop, and MM Supervisors offices.
6. CM/MM M&TE labs do not have adequate humidity and temperature control. This results in these labs being unavailable for certain critical calibration activities ~ 30% of the time.
7. Greater emphasis on safety resulting in the following requirements:
   a. Pre-job briefing spaces.
   b. Rehearsal and Mockup areas for both IMS and Reactor Maintenance work to maximize efficiency & minimize potential outage delays.
8. Computers now play an important role in delivering work instructions, providing additional information and documenting the work. Hence, offices facilities and computer work stations are required to house them.
9. Changing technologies resulting in the requirement for specialized crews' complete with customized shop space and required FLM/FLMAs such as Fix-It-Now crews and Predictive Maintenance crews.

10. As a result of DNGS progressing through its life cycle, the original plant facilities did not adequately accommodate or foresee current aging plant considerations or license requirements. These considerations include:
    a. Maintenance strategy implementing transition from corrective to preventative/predictive maintenance requires as per industry benchmarking experience a 30% increase in required shop space. Overhaul/refurbishment programs for major breakers, pumps, and valves have or are being developed as part of this strategy.
    b. Space for IMS Quality Control labs and personnel.
    c. IMS Periodic Inspections Programs.
    d. Reactor Maintenance - specialized component repair programs for Pressure Tubes and End Fittings, Feeders, Horizontal and Vertical Flux Detectors, and Adjustor Rods.
11. No provision for adequate Breaker and Relay maintenance. This is currently being performed in the Sequence Event Monitoring computer rooms which were never designed for this purpose.
12. Reactor Maintenance (RM) shop was never provided. Currently RM is housed in a temporary building with inadequate space, no permanent services, and an underrated floor loading capacity.
13. As a result of IMS not having permanent facilities, it takes an extra 2 weeks with 6 people to set up their equipment every outage. IMS also incurred a 2 day outage delay while trying to remove the CIGAR (Channel Inspection and Gauging Apparatus) inspection head from the channel. SCR D-2005-03661 (B3 category). This can be attributed to the lack of proper facilities to do maintenance and rehearsal on CIGAR.

Refurbishment/Upgrade

As part of the 2006 ASL study, a review of the feasibility and cost of upgrading existing ships and offices was performed as a potential option for building a new facility. The following areas were not considered for upgrade as they do not currently exist or exist in an area that was not originally intended for its current use:

- Reactor Maintenance Shop
- CM Breaker and Relay Maintenance Shop
- IMS QA Group
- IMS Pressure Group Inspection Program
- Civil Maintenance FLM offices

The following areas were considered for upgrade at an estimated cost of $33.5M:

- CM M&TE Lab - $4M
- MM M&TE Lab - $5.45M
- CM Valve Shop - $6.3M
- MM RV Shop - $6.46M
- MM Seal Lapping Shop - $6.65M
- MM FLM offices - $4M
- MM Welding Shop - $750K

Refurbishment of these areas was not recommended by ASL due to high costs as a result of a high level of contingency needed due to the risk of performing modifications in an operating plant. In addition existing plant configuration may place limitations on the level of improvements that can be achieved by upgrades. (i.e. existing Common Service Area (CSA) HVAC system may not support required ASHRAE 62.1 and M&TE clean requirements, precise humidity and temperature control specifications without major improvements)

Contracting Out Considerations

Contracting out of maintenance services has been briefly investigated by DNGS Maintenance management. However this strategy was never fully developed, documented, or costed out. The following issues are some of the contributing factors:

1. Damage may occur to sensitive equipment if shipping offsite is required.
2. Emergency type situations where 24/7 response is needed may not be available if a contractor is utilized.
3. Costs and delays associated with Unconditional Transfer Permits and security requirements when shipping offsite and outside the protected area.

The contracting out of major breaker maintenance as part of the OPEX and EPRI recommended developed overhaul program was quoted as $10K per breaker in 2005 which equates to 980 breakers x $10K = $9.8M. This would be required for all 980 breakers on a 12 year cycle. This has not been implemented to date as pilot contracts (both onsite and offsite) were not successful due to quality and timeliness of contract work.

Combined Facilities

Wardrop as part of the 2005 conceptual study was commissioned to assess the viability of an OPG shared site facility. Due to the major decisions pertaining to Pickering A U2/U3 Safe Storage and the pending decision in 2009 for Pickering B refurbishment, this assessment could not be completed and ultimately it was decided by the CNO in 2006 that a combined site maintenance strategy was not viable at this time and the project mandate was changed to a Darlington only project.

DNGS Maintenance has recently investigated preliminarily a combined PNGS/DNGS offsite MM/CM M&TE lab option with OPG Real Estate Services Division and received a quote for $1M for a "leased permanent" fully customized build to suit industrial unit plus $400k per year on a lease agreement. Alternatively a quote of $400k was received for a "leased portable" prefabricated relocatable M&TE lab structure that could be placed in an industrial unit which would then also require a ~ $180k yearly lease cost. These estimates are only for the space and do not include any other costs such as equipment, utilities, IT, etc. or the costs in transporting the tools offsite from both sites on a daily basis under Radiological Transfer Permits. This simplistically works out to a cumulative cost of $9M for the customized build or $4M for the prefabricated relocatable lab assuming a 20 year lease. The proportional cost of the M&TE labs based on the estimated 2410 ft^2 net of new ~ 60,000 ft^2 Maintenance Facility is ~ $1.8M. These costs have not been vetted through by the consultants and have been reflected here to facilitate option comparison.

Hybrid Solution

As part of the 2006 ASL study, a hybrid solution was considered. A hybrid solution consisting of refurbishment of existing lab/shops combined with a new facility was never developed as an option due to the estimated cost for refurbishment for existing areas of $33.6M. This $33.6M combined with the cost associated for a new ~ 25,000 sq. ft building for the remaining areas would have seen cost estimates easily exceeding $55M - $60M before contingency. As a result of these costs this option was deemed prohibitive from a cost perspective and not evaluated any further.

Additional Background and Issues

The ASL cost estimates are only for the construction of the new Maintenance Facility and required building services. The cost of computers, modular office furniture, and telephones are included but as these costs cannot be capitalized along with the building they will be accounted as minor fixed assets in subsequent BCS's. The cost estimates do not include any costs such as: moving existing maintenance equipment, purchase of new maintenance equipment, radiation monitoring equipment, signage, etc.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Incremental Cost	Alt 2 Delay	Alt 3 MF Option H	Alt 4 MF Option I	Alt 5
Revenue							
OM&A	-	(1,600)			(1,244)	(1,244)	
Capital	-	(54,543)			(47,416)	(45,527)	
NPV (after tax)	(150,699)	(99,238)			(100,491)	(108,252)	
Impact on Economic Value (IEV)	N/A	51,461			50,208	42,447	
IRR%	N/A	13.4%					
Discounted Payback (Yrs)	N/A						

Status Quo - Not Recommended
This option is not recommended since the need for upgraded maintenance facilities at Darlington was first identified in 2002, and has escalated since. The risks to employee health and safety, potential outage extension, and loss of productivity would continue to rise incrementally.

Alternative 1 - Maintenance Facility Layout G from Revised Conceptual Study - Recommended

Option Comparison	Option G	Option H	Option I
CM M&TE Lab	✓	Excluded	Excluded
MM M&TE Lab	✓	Excluded	Excluded
MM Relief Valve Shop	✓	Excluded	Excluded
MM Seal Lapping Shop	✓	✓	Excluded
Reactor Maintenance Shop	✓	✓	✓
CM Breaker Maintenance Shop	✓	✓	✓
CM/MM Valve Shop	✓	✓	✓
IMS Pressure Tube Area	✓	✓	✓
IMS QC Labs & Offices	✓	✓	✓
Civil FLM Offices	✓	✓	✓
MM FLM Offices	✓	✓	✓
MM Welding Shop	Excluded	Excluded	Excluded

Proceed with the scope defined in the revised Conceptual Study Option G by ASL with a space estimate of 57,300+ sq. ft at a cost estimate o[redacted]excluding contingency. This alternative will address all the areas identified in the revised Charter except the welding shop. The new facility will increase maintenance productivity and effectiveness, mitigate the potential increase of industrial accidents, mitigate potential outage extensions, and potential future cost savings realized by not moving labs/shops permanently offsite into a leased industrial space. The scope of this recommended option based on the priority specified by the sponsor will consist of the identified shops, labs and offices above under Option G. This alternative has a positive NPV of 54.4M$. See Attachment E for a breakdown of this NPV.

Alternative 2 - Delay Project - Not Recommended
N/A

Alternative 3 – Maintenance Facility Layout H with "leased portable" M&TE lab - Not Recommended
This option provides a new facility similar to Layout G with the exclusion of the CM and MM M&TE labs, and MM Relief Valve shop. The space estimate for this option is 48,900+ sq. ft. and the cost estimate associated with this alternative is ~ $39M excluding contingency. This option does not effectively meet all the current and identified future DNGS Maintenance needs and will result in further management intervention to mitigate the needs of these excluded areas in the future.
NPV was calculated including the purchase of a $400K relocatable CM/MM M&TE lab plus an estimated industrial lease cost of $180K per year. These estimates are preliminary and only for the space and do not include any costs such as equipment, utilities, IT, etc. or the accurate costs in transporting the tools offsite from both sites on a daily basis under Radiological Transfer Permits.

Alternative 4 – Maintenance Facility Layout I with "leased portable" M&TE lab - Not Recommended
This option provides a new facility similar to Layout H with the further exclusion of the MM Seal Lapping shop. The space estimate for this option is 45,500+ sq. ft. and the cost estimate associated with this alternative is ~ $37.4M excluding contingency. This option does not effectively meet all the current and identified future DNGS Maintenance needs and will result in further management intervention to mitigate the needs of these excluded areas in the future.
NPV was calculated including the purchase of a $400K relocatable CM/MM M&TE lab plus an estimated industrial lease cost of $180K per year. These estimates are preliminary and only for the space and do not include any costs such as equipment, utilities, IT, etc. or the accurate costs in transporting the tools offsite from both sites on a daily basis under Radiological Transfer Permits.

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

The Following are the objectives and deliverables for this Partial BCS:

Building Removal & Decommissioning
- Completion of Detailed Design.
- Preparation of decommissioning workplans.
- Issue PO for the decommissioning and removal of buildings.
- Completion of contract for the decommissioning and removal of buildings
- AFS for the building removal and decommissioning

Relocate Buried Services and Establish Tie-In Points
- Issue PO for Detailed Design.
- Complete Detailed Engineering of the Tie-Ins and Buried Services relocations
- Issue Request for Proposal (RFP) and evaluate bids for an installation contract.
- Preparation of workplans.

Maintenance Facility
- Preparation of an EPC contract for the construction of the new Maintenance Facility.
- Issue a RFP for a Commercial EPC contract for the new Maintenance Facility
- Receive bids from proponents and complete bid evaluations
- Issue a PO for the Preliminary Design of the Maintenance Facility
- Issuance of a Full Release BCS.

In the Full Release BCS the following items will be included as per Nuclear Oversight Committee/Board of Directors specific request:

1. Analysis of existing space currently used by Maintenance staff for the various functions and an explanation of why each function must be moved to the new location (eg, tabulate: function/space currently used for this function/why the function must be moved to a new location).

2. Detailed benchmarking data for similar building construction on a cost-per-square foot basis.

5/ QUALITATIVE FACTORS

The successful completion of this project will improve the following:

Staff relations
- New maintenance facility shops and offices will relieve overcrowding and congestion and result in improved staff morale.

Health and Safety
- New maintenance facility shall be compliant with ASHRAE 62.1 air quality requirements, relieve overcrowding and congestion, and result in improved health and safety inefficiencies.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Overall project cost exceeds current estimate. Current cost estimates are conceptual. Cost estimate accuracy is +60%/-25%	Potential adjustment required on scope and cost of the project.	**High**	The conceptual study layouts have been independantly cost estimated by an external 3rd party estimator Altus Helyar. Construction quote can be obtained after detailed design for the Full Release BCS. A second independent cost estimate will be commissioned when the scope is more defined before the Full Release BCS.	**Medium**
Changes to the funding release strategy and/or fine tuning of contracting stategy may impact overall cost and schedule (owner only vs owner constructor) This is a 1st time strategy for implementing an owner only contract inside the protected area. Lessons Learned can be utilized for future projects that may result in schedule and cost savings.	Could cause a delay to the schedule & increase costs.	**Medium**	Review and finalize contracting stategy and impact to design and installation requirements with Supply Chain, Procurement, Design & Legal before Full Release BCS is issued. The estimates used for this BCS were conservatively assumed to be Owner/Constructor contracts. Early involvement of serior station management in investigating contracting strategy.	**Medium**

Cost for demolition of Power House Annex exceeds conceptual estimate of $2.0M due to: - Impact on adjacent building - Waste removal and recycling requirements - Cost for the design and installation for the relocation of underground services and building service tie-ins exceeds conceptual estimate	Potential increase in scope and cost of project.	**Medium**	Cost to remove the PHA was estimated by ASL in the 2006 conceptual study. Impact to other affected structures due to removal of the PHA has been identified and mitigation discussed with Sponsor. Sponsor has concurred that removal of adjacent trailers at this time is a cost effective solution. Waste removal and recycling plan being developed. [redacted] contingency added in 2008 cash flow to cover potential added cost of waste removal. Cost to complete the relocation of underground services and building tie-ins was estimated by ASL in the 2006 conceptual study. A drawing reivew was completed to identify underground services in the area during the conceptual study	**Medium**
Scope				
Final scope of the new Maintenance Facility may require further cuts due to OPG budget constraints.	Further changes in scope will delay the schedule and increase OPG project management costs.	**High**	A Detailed design will be performed to identify the detailed scope of buried services, and tie-ins before the scope is finalized for the Full Release BCS. A more accurate cost estimate will be available in the next release for management decision making.	**Low**
Preliminary/Detailed Design may result in an increase in scope.	Changes in scope will delay the schedule and add cost to the project.	**High**	Further scope identified during the design will be challenged by projects & have to be agreed by all stakeholders & sponsor.	**Medium**
Increase scope of work due to discovery work (ie re-route buried services in building footprint).	Increase in cost and schedule or further reduction in shop space to ensure approved budget is maintained.	**High**	Preliminary drawing review has been conducted to identify any possible services that may require relocation. Field survey to be completed during Technical Evaluation.	**Medium**

Schedule				
Insufficient information to determine the scope and timeline of design deliverables accurately.	Increase in cost and schedule.	**Medium**	Fine tuning of Detailed Design deliverables will be completed after Technical Evaluation and included in subsequent RFPs for Buried Service relocation, Maintenance Facility construction, Building service and plant system tie-ins etc. These will be detailed in subsequent BCS's.	**Medium**
Fine tuning of contracting stategy may impact overall cost and schedule.	Require changes to funding release strategy which could cause a delay to the schedule & costs.	**High**	Review and finalize contracting stategy and design and installation requirements with Supply Chain, Procurement, Design & Legal before the Full Release BCS is issued.	**Medium**
Design deliverables not on time.	Delay to schedule.	**Medium**	Select approved vendor, provide clear scope & deliverables. Review progress regularly & establish and monitor effective design performance metrics.	**Low**
Resources				
Insufficient OPG design resources available.	Delay project schedule & milestones.	**High**	Design will be contracted out to external agency. OPG Projects Design have committed to provide DTL and any additional design support for this project.	**Low**
Availablility of qualified vendors to perform design and subsequent implementation (procure, construct).	Delay in issuing contract due to need to assess various interfacing risks, vendor qualification issues, and contracting language.	**Medium**	Obtain OPEX from other OPG projects of similar nature. Early involvement with Supply Chain and various other departments or potential vendors and early review of the associated contracting strategies. Supply chain is currently in the process of qualifying more vendors for N286.1 "procurement".	**Medium**
Technical				
Legacy issues on Design.	Re-engineering may be required if there are legacy and interface issues with systems that the project is modifying. This would add scope to the project which may cause delays and increase	**Medium**	Preliminary site walkdowns have been completed. Complete drawing review on systems being impacted to be performed during Technical Evaluation and subsequent Engineering efforts.	**Low**

	project costs.			
Discoveries from geotechnical analysis of soil.	Delay and added cost to the project due to the prefered site not being suitable for building addition which could then subsequently lead to Increased costs to the design and installation to meet the requirements identified.	**Medium**	Test drill site to determine the soil composition prior to completing Technical Evaluation to ensure the design takes this into account. Method & cost to implement corrective actions will be challenged & documented.	**Low**
Regulatory				
There are no regulatory risks.		**N/A**		**N/A**
Environmental				
Excavation and Construction waste may not be suitable for shipment to a clean landfill site due to radiological contamination.	Added cost to the project due to disposal costs associated with contaminated waste.	**Low**	A Geotechnical Analysis and Radiological testing by Kinetrics will be performed during the Technical Evaluation. A Waste Disposal plan will also be developed and submitted to OPG for acceptance.	**Low**
Waste from demolition of buildings may not be suitable for recycling or for shipment to a clean landfill site due to radiological and/or conventional contamination.	Added cost to the project due to disposal costs associated with contaminated waste.	**Low**	All building material to be scanned and tested for radiological, asbestos, mold and other contaimination prior to demolition of buildings	**Low**
Health & Safety				
Personnel injured during demolition of buildings.	Personnel injury or death Delay to project	**Low**	Adherence to OPG Policies and Procedures will be maniditory during the removal of buildings. Contractor's safety record wil be part of the criteria during bid evaluation.	**Low**
Asbestos, mold or other conventional hazardos material present in the buildings to be removed.	Personnel injury or long term health concerns. Added costs and/or delay to project.	**Low**	All building material to be scanned and tested for asbestos, mold and other contaimination prior to demolition of buildings. Ensure personnel protect themselves with the apporpriate PPE per OPG Policies and Procedures	**Low**

Investment				
Cost benefit information cannot justify proceding with the project. The final scope of the what that is to be included in the maintenance facility is not yet known.	Return on investment cannot be realized.	**Medium**	End users have been interviewed to gather critical data for calculation of the NPV. Investment Finance and Station Long Range Strategic group will further scrutinize validity of assumptions for the next release based on the final scope decision after the Technical Evaluation is complete	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	TBD in Next Release	TBD in Next Release	

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

BCS	Business Case Summary
PHA	Power House Annex
RFP	Request For Proposal
EPC	Engineer, Procure, Construct
IMS	Inspection Maintenance Services
TOE	Technical Operability Evaluation
QC	Quality Control
CIGAR	Channel Inspection and Gauging Apparatus
SCR	Station Condition Report
ASL	Acres Sargent & Lundy
NPV	Net Present Value
CM	Control Maintenance
PO	Purchase Order
DTL	Design Team Leader
OPEX	Operating Experience
TBD	To Be Determined
PIR	Project Implementation Report
PWU	Power Workers Union
BTU	Building Trades Union
PEP	Project Execution Plan
AFS	Available For Service
IEV	Impact On Ec Value
IRR	Internal Rate of Return
RM	Reactor Maintenance

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Developmental	Jul	2007	1,369	234							1,603
Partial			(861)	3,960	3,836						6,935
Full			508	4,194	18,932	19,985	13,599	521			57,739
											0
											0
											0
											0
											0
LTD Spent	Dec	2007		508							508

Comments:
Previous release of $450k was obtained in 2002 to provide seed money for the first Acres Sargent & Lundy conceptual study of which $116k was spent. $34k in capital interest charges has accumulated against this amount to date.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

-
- OPG staff will provide project management & support role during design and implementation
- Design and Installation work will be performed by contractors with oversight and support for OPG Project Design
- Current P3 resource costs were used thru 2009. Escalation rate of 4% was used for 2010 & 2011
- DNGS Strategic Planning has prepared a Monte Carlo Crystal Ball risk model analysis of all alternatives to develop the NPV figures. All assumptions used for this model were based on ASL submissions, OPG reliable sources, or from individual area stakeholders. Attachment D has the relevant information from this analysis for the recommended Option G with an overview of the NPV figures for Base and Options H and I. The appendix also includes the assumptions, Long Term Disability statistics. This model has been reviewed and accepted by OPGN Investment Management for the purpose of the Economic Analysis values used for this Developmental BCS.

Financial Assumptions:

- 7% discount rate
- PHA cost of removal will be expensed to accumulated depreciation monthly as incurred.
- Maintenance Facility Design and Construction costs were estimated by ASL with the assistance of an external constructor Ball Construction. A [redacted] additional premium was added over equivalent commercial costs due to the fact that this work is inside the DNGS protected area and subject to OPG ECC processes and Safety Regulations. OPG Project Management and Support costs were developed between ASL & OPG Design Projects and substantiated via an independent 3rd Party estimator Altus Helyar.
- See Attachment "D" for BCS NPV Assumptions and Analysis.
- Note that this project estimate does not include costs for moving existing maintenance equipment, purchase of new maintenance equipment, purchase of radiation monitoring equipment

Project / Station End of Life Assumptions:

- Darlington end of life ~ 2050
- Maintenance Facility nominal end of life 2050

Energy Price / Production Assumptions:

- See Attachment "D" for BCS NPV Assumptions and Analysis

Operating Cost Assumptions:

- See Attachment "D" for BCS NPV Assumptions and Analysis

Other Assumptions:

- OPG to provide unrestricted access to work area
- All work is within the secured area with incumbent restrictions

Project Name 16 - 31717

Partial Release Business Case Summary D-BCS-28200-10003-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr	This Release 2008	This Release 2009	Future Release 2009	Future Release 2010	Future Release 2011	Future Release 2012	Later	Total
Project Management (OPG)	164	570	356	357	875	484	184		2,990
Engineering & Drafting (OPG)	54	325	190	190	175	190	117		1,241
Material	[redacted]								
Installation – PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
	[redacted]								
	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
Project Costs (incl contingency)	**508**	**4,194**	**3,836**	**15,096**	**19,985**	**13,599**	**521**	**-**	**57,739**
2008-2012 Business Plan	1,170	2,140	2,951	11,418	15,154	11,556	-		44,389
Variance to Business Plan	**(662)**	**1,105**	**-**	**194**	**219**	**(1,095)**	**401**	**-**	**182**
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	**508**	**3,245**	**2,951**	**11,612**	**15,373**	**10,461**	**401**	**-**	**44,551**
Total Release (incl contingency)	**508**	**4,194**	**3,836**	**15,096**	**19,985**	**13,599**	**521**	**-**	**57,739**

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)	137	1,463							1,600

Basis of Estimate

Design Complete	Zero to Minimal		Quality of Estimate		Conceptual + 60% to - 25%
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	N/A
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	No
Similar Projects	No	Contracts in place	No	Competitive Bid	No

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF is not required

Reviewed By:

Stephanie Tham
Project Manager

4 Feb 2008
Date:

Approved By:

Dianne Gaine
Eng & Mods Manager (Strat IV)

Feb. 4/08
Date:

Project Name 16 - 31717

Partial Release Business Case Summary D-BCS-28200-10003-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2007	Choose One: Last BCS Jul 2007	Choose One: This BCS Jan 2008	Variance	Comments
Project Management (OPG)	164	2602	2990	388	Add resources for 2012 project closeout
Engineering & Drafting (OPG)	54	888	1141	253	Add resources for 2012 project closeout
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	**508**	**57701**	**57739**	**38**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**508**	**57701**	**57739**	**38**	
Total Release (excl contingency)	**508**	**44420**	**44551**	**131**	
Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
18	Apr	2008	PHA DCP Approved
21	Jul	2008	Work package Assessment complete - PHA Demo.
07	Oct	2008	Start of PHA Demolition
07	Feb	2009	AFS PHA Demolition
16	Apr	2008	RSTI Design Contract PO Issued
05	Aug	2008	RSTI Preliminary Design Complete
10	Dec	2008	RSTI DCP Approved
15	Apr	2009	RSTI Work Package Assessment Complete
19	June	2009	Full Release BCS Approved

A Project Execution Plan (PEP) will be approved by Jun 2009

Comments:

Attachment "D"

DNGS Long Range Planning - Recommended Option NPV Calculation

- Result Summary
- Assumptions
- LTA source assumption
- Individual area results

NPV Option Result Summary

Up to Retube - 2021	NPV (k$)
Base Case	(67,274)
Option G	(67,430)
Option H (with leased Portable M&TE lab)	(64,482)
Option I (with leased Portable M&TE lab)	(67,250)

After Retube - 2050	NPV (k$)
Base Case	(150,699)
Option G	(99,283)
Option H (with leased Portable M&TE lab)	(100,490)
Option I (with leased Portable M&TE lab)	(108,251)

Attachment E

Briefing Note: 31717 DNGS Maintenance Facility
Breakdown of the 54M$ Preferred Alternative NPV

		%		NPV (M$)
Backlog Improvement (1)		3.5		1.8
LTA Reduction (2)		0.1		0.1
Productivity Gain (3)		13.1		6.7
Planned Outage extension reduction (4)				28.8
- Reactor maintenance shops	27%			
- IMS Pressure Tube Insp prog	10%			
- MC Valve shop	10%			
- Other shops	9%			
subtotal	56%	56.0		
Forced Outage extension reduction (5)				11.6
- IMS Quality group	8%			
- MC Breaker & Relay shop	7%			
- Other shops	8%			
subtotal	23%	22.6		
Rebuilding, not buying, Seal parts (6)		2.0		1.0
Breaker overhaul inhouse (7) & various other		2.6		1.3
		100.0		51.4

(1) Online Elective Maintenance Backlog improvement will reduce Forced Loss Rate which will impact on generation and incremental Forced Outage Cost.

(2) Existing facilities are overcrowded and noisy with poor air quality which may cause potential Health and Safety incidents.

(3) Overcrowded locations, lack of Pre-Job Briefing areas, lack of crane equipment, extra equipment shuffling, lack of Mockup/Rehearsal area, and insufficient temperature/humidity control resulting in overtime to recover productivity losses.

(4) Improve response time on tool calibration, breaker preparation, valve work, Channel Inspection and Guaging Apparatus for Reactor work, Single Channel Fuel Replacement work, and minimize delays as the Mockup/Rehearsal facility and crane are always in place.

(5) Improve response time on tool calibration, Release Valve decontamination, Seal preparation, breaker preparation, Channel Inspection and Guaging Apparatus for Reactor work, and minimize delays as the Mockup/Rehearsal facility and crane are always in place.

(6) Facility to rebuild old Seal parts instead of buying new ones will result in significant savings.

(7) Performing major breaker maintenance in house instead of outsourcing.

ONTARIOPOWER GENERATION

DNGS SDS Aging Management 16 - 33955

Developmental Release Business Case Summary D-BCS-68000-10002-R000

Routing	***Location***	***Action***	***Signature***	***Date***
Perrik Le Dreff Design Engineer Safety Related Computers	P82-5F4	Prepare BCS	[illegible]	Nov. 16 2006
Mike Viola Section Manager Safety Related Computers	P82-5F4	Review BCS	[illegible]	Nov 16/2006
Rick Hohendorf Manager Computers and Control Design	P82-5F6	Review BCS	[illegible]	Nov. 16/2006
Axel Kleer Senior Financial Analyst Investment Management	P82-3A5	Review BCS	[illegible]	21 Nov 06
Bill Qualtrough Manager Performance Engineering, Darlington	D08-ESB2	Submit BCS	[illegible]	Nov 21/06
Randy Leavitt Director Investment Management	P82-3	Approve BCS	[illegible]	Nov 22, 2006
Stu Seedhouse Director [illegible]ation Engineering, Darlington	D08-ESB3	Approve BCS	[illegible]	28 Nov 2006
Gregory Smith Senior Vice President Darlington	D08-ESB3	Approve BCS	[illegible]	29 Nov 2006
[illegible]el Kleer [illegible]ior Financial Analyst [illegible]estment Management	P82-3A5	Return For Distribution		

DNGS SDS Aging Management 16 - 33955

Developmental Release Business Case Summary D-BCS-68000-10002-R000

1/ RECOMMENDATION:

Approval is requested for this developmental release of $1.55 million (excluding contingency) to perform preliminary engineering to address the aging and obsolescence issues of the Darlington NGS Shutdown System (SDS) computers. This includes funding of $110K for hardware and software purchases for engineering evaluation to confirm the path forward in the detailed engineering phases.

The Business Objective is to manage the current threat to generation posed by the 57 aging SDS computers. It is currently deemed that the system in its current state is at risk of not operating to the 2018 end-of-life target. The operator workarounds imposed by the SDS computers as well as the hardware obsolescence issues are reflected in the SDS health reports by red performance indicators. This indicates a system at risk and, due to the critical nature of the SDS computers, their unavailability would directly result in unit unavailability. The hardware obsolescence issue cannot simply be addressed with spare parts procurement since most of the critical equipment is no longer available. As well, replacement components and/or computers must be qualified for use and/or designed.

During the preliminary engineering phase, detailed material condition assessments of the SDS computers will be carried out to determine their end-of-life. Due to the currently known operator and hardware obsolescence issues, the SDS1 and SDS2 Monitor computers will be replaced first. Preliminary engineering will re-evaluate the existing system requirements of the Monitor computers, and assess replacement software and hardware platforms. SDS2 Trip Computer components facing a critical shortage of parts will be evaluated for replacement.

The preliminary engineering phase will allow for a full plan to be established for a timeline of computer replacements to reach the 2018 end-of-life target and will forecast the feasibility of maintaining the systems for approximately 20 years beyond 2018.

The preliminary engineering is targeted for completion in December 2008.

The project is included in the 2007-2011 Business Plan at a value of $65 Million. A Project Execution Plan (PEP) for the preliminary engineering phase is scheduled for completion by December 15, 2006.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	None	-	-						-
Requested Now	Developmental	-	345	1,438	-				1,783
Future Funding Req'd	Full		-	-	8,000	5,000	5,000	45,000	63,000
Total Project Costs		-	345	1,438	8,000	5,000	5,000	45,000	64,783
Other Costs									-
Ongoing Costs									-
Grand Total		-	345	1,438	8,000	5,000	5,000	45,000	64,783
Investment Type		Class		(EV) Impact on Ec Value		IRR		Discounted Payback	
Sustaining		Capital		N/A		N/A		N/A	

Submitted By:

Nov 21/06

Bill Qualtrough
Manager, Performance Engineering,
Darlington

Date:

Finance Approval:

Nov 22, 2006

Randy Leavitt
Director, Investment Management

Date:

Line Approval (Per OAR Element 1.2 Project not in Budget):

Nov 30, 2006

Gregory Smith
Senior Vice President, Darlington

Date:

2/ BACKGROUND & ISSUES

The Darlington NGS SDS computers comprise a network of 14 computers per reactor unit connected to one Shutdown System Monitor Computer (SSMC) that is common to all four reactor units. The SDS computers are classified as part of a Special Safety System that Darlington NGS depends on to:

a) Automatically initiate a reactor shutdown via the SDS1 and SDS2 Trip computers.
b) Display SDS parameters at the main control panels (as well as the secondary control area in the case of SDS2) via the SDS1 and SDS2 Display/Test computers.
c) Provide a facility whereby the trip measurements, logic and reactivity devices can be tested from the Main Control Room via the SDS1 and SDS2 Monitor computers and the SSMC.
d) Monitor the SDS routinely to detect and notify the Operator of conditions which adversely affect production, reliability or SDS availability.

Currently, the SDS computers (totaling 57 computers for the entire station) use old technology that is increasingly difficult to maintain and for which there is no OEM support.

- The vendors of this equipment are no longer in business.
- Circuit board level repair, where possible, has been achieved though the use of existing parts; however, some critical parts are no longer available. For the SDS2 Trip Computer there is a major concern that, due to the technology employed, board level repair may not be possible.
- Failures of peripherals have caused an increased maintenance burden and spare parts for these are no longer available from the suppliers.

In addition to the hardware obsolescence issues, the SDS Monitor computers suffer from intermittent problems that are related to hardware limitations of the older technology.

There have been over 70 SCRs concerning SDS computers raised in the last several years.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Incremental Cost	Alt 2 Delay	Alt 3 Do More	Alt 4 Do Less	Alt 5
Revenue							
OM&A							
Capital		1,550					
NPV (after tax)							
Impact on Economic Value (IEV)	N/A						
IRR%	N/A						
Discounted Payback (Yrs)	N/A						

Do Nothing (Status Quo) - Not Recommended

There is a current need to address obsolescence issues with the SDS computers. The System Health Reports show a red status for Spare Parts/Obsolescence and Operator Workarounds. There is currently a critical shortage of components that are no longer repairable and have no OEM support; this situation will ultimately result in station outages when the components inventory is exhausted and no replacements are available. There are also no projections of failure rates established to determine when the stock of spare parts will be exhausted; due to the existing shortages in spare parts, it is not prudent to do nothing.

Alternative 1 - Proceed with Preliminary Engineering - Recommended

Perform a thorough material condition assessment of the SDS computers. Due to the currently known operator and the hardware obsolescence issues, as a minimum, proceed with the replacement of the SDS1 and SDS2 Monitor computers and the SDS1 and SDS2 Display/Test Computer CRT monitors. Also, as an interim solution to the development of a replacement Monitor Computer, initiate the replacement of the existing Monitor Computer hard disk whose stock is critically low and is at risk of being depleted. The SDS2 Trip Computer components facing a critical shortage of parts will also be evaluated for replacement. This approach would provide the best solution by addressing the most critical needs proactively and establishing an aging management strategy which would provide a clear path to 2018 and beyond.

Alternative 2 - Delay Project - Not Recommended

There is a clear need to begin the preliminary engineering immediately to perform thorough material condition assessments of the SDS computers. It is also important to initiate any replacements to mitigate a situation where a replacement component/computer is not available when the stock of parts runs out. Detailed failure rates of critical components are not known and, therefore, predicting when future failures of components will occur is very difficult. Also, staff with knowledge of the SDS computers is scarce and declining.

Delaying the project would increase the risk that equipment failures will exhaust any spare parts available before a replacement could be ready. Due to the current uncertainty of the future failure rates of the aging equipment, it is not prudent to delay the project.

Because the Trip computers comprise a safety-critical Category I software based system, qualification work will attract regulatory scrutiny and the prescribed processes and procedures that must be applied increase the elapsed time needed to put an acceptable replacement component/computer in place.

Alternative 3 - Do More - Not Recommended

A full SDS computer replacement is not feasible within the current business plan cycle (2007-2011) due to the need to address the most pressing SDS computer issues in a shorter time frame than the time that would be required to accomplish a full computer replacement. No outage of sufficient duration for full replacement is scheduled during this period. Furthermore, the aging management strategy has not yet been developed to provide the optimum computer replacement path.

Alternative 4 – Do Less - Not Recommended

Perform the material condition assessments of the SDS computers but do not proceed with the replacement of the SDS1 and SDS2 Monitor computers, and the SDS1 and SDS2 Display/Test Computer CRT monitors. Doing less than the recommended alternative would introduce an unnecessary and likely consequential delay since the currently identified replacements are of high importance to continued plant operation. Because the critical replacements have been identified during the conceptual phase of this project, it would be best to initiate these initiatives in parallel with determining the material condition assessments to establish the SDS aging management strategy to mitigate operational risk for the station. Also, knowledgeable SDS computer staff is declining and the situation will only get worse with time.

4/ THE PROPOSAL

The developmental funds requested in this release will fund the preliminary engineering activities. They are:

a) Determine the detailed material condition and component failure trends of the SDS1 and SDS2 Trip computers, the SDS1 and SDS2 Display/Test computers, and the SSMC.
b) Initiate the replacement of the SDS1 and SDS2 Monitor computers, and the SDS1 and SDS2 Display/Test Computer CRT monitors. The Monitor Computer replacement will incorporate the existing functionality of the SSMC and, as a result, the SSMC shall be eliminated when all of the new Monitor computers have been installed. These activities include the qualification of the hardware and software for acceptability of use.
As an interim solution to the development of a replacement Monitor Computer, initiate the replacement of the existing Monitor Computer hard disk.
d) Evaluate the replacement of SDS2 Trip Computer components facing a critical shortage of parts.
e) Determine the replacement strategy for the SDS computers to ensure reliability is sustained at current levels or improved for the current station lifetime (2018) and ensure an upgrade path exists for plant life extension or for prior replacement, if necessary.
f) Align resources for detailed engineering work including external resources.

The preliminary engineering will conclude by Q4, 2008. Prior to December of 2008, approval will be sought by subsequent BCS documents depending on the detailed plan that results.

For preliminary engineering milestones, see Attachment C.

5/ QUALITATIVE FACTORS

Qualitative benefits gained from implementing the recommended alternative are as follows:

- Reduced operator burden by eliminating or minimizing any operator workarounds.
- Derive a thorough understanding of the material condition of the SDS computers.
- Reduce regulatory risk by having a clear obsolescence plan for the most critical computers in the station.
- Improve the predictability of system reliability up to 2018 and beyond

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Underestimation of the preliminary engineering efforts.	Cost overruns	**Medium**	A detailed breakdown of the complete preliminary engineering activities provides good assurance for the cost estimates. Include [redacted] contingency on the overall estimate. Contingency to be released only if justified and approved.	**Low**
Scope				
During preliminary engineering, scope of work expands.	Increase in costs and more personnel needed	**Medium**	Scope of preliminary engineering is well defined via good stakeholder involvement up front to assess the past/present and future issues of the system. Include [redacted] contingency on the overall estimate. Contingency to be released only if justified and approved.	**Low**
Schedule				
Scheduling	The risk to the schedule is related to the scope, resources and technical issues.	**Medium**	Control the scope and ensure resources are allocated as soon as a detailed schedule is produced. Identify up front of any constraints in resources and funds available in the target period.	**Low**

Resources				
Unavailability of skilled and knowledgeable internal or external staff.	Shortage of engineering personnel with expertise of the SDS computers. Less experienced persons will require more time to perform tasks.	**Medium**	Personnel resources shall be identified as early as possible in the preliminary design phase. Availability of resources already identified shall be confirmed in early 2007. Include time for personnel with little or no SDS knowledge to become familiarized with the systems to tackle their tasks. Contingency has been allocated for external resources.	**Low**
External resources	Obtaining resources from external agencies for early 2007 may be challenging.	**Medium**	Early discussions have been held with external agencies such as AECL and SWI to establish staffing availability.	**Low**
Technical				
Material condition worse than initial estimates.	Material condition assessments reveal that there are more critical spares shortages and that failure rates are much higher than anticipated (operating on right of bathtub curve)	**Medium**	Adverse findings will affect the scope/schedule/cost during the preliminary engineering but in the short and long term getting a solid material condition assessment will lead to a better solution being implemented in the detailed engineering phase. The risk mitigation has been to obtain as much knowledge of the material condition, as is feasible, in the conceptual phase. Include [redacted] contingency on the overall estimate. Contingency to be released only if justified and approved.	**Medium**

End of life of each SDS computer cannot be adequately defined	Lack of failure history, product information, or data for analysis may result in imprecise end-of-life estimates. This would force a more conservative end-of-life and would move forward in time more of the SDS computer replacements. It would have impact on resources, cost, scheduling.	**High**	The recommended alternative addresses the most challenged SDS components first as determined in the conceptual design phase of the project. This prioritization of the computer/component replacements reduces the risk of not being able to assess the end-of-life for the remaining computers since they have already been assessed as being in less critical need of replacement.	**Medium**
Regulatory				
Increased regulatory requirements	CNSC may decide that a major SDS computers overhaul will require the application of more strict hardware requirements and/or separation requirements which were not previously imposed on the legacy system.	**Low**	Consistent with past obsolescence projects, during the preliminary engineering phase, the CNSC will be provided with an overview of our objectives and we can address any potential concerns they might have.	**Low**
Environmental				
N/A				
Health & Safety				
N/A				
Investment				
N/A				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
N/A			

Comments:

PIR plan not required for a Developmental BCS.

Appendix "A" Glossary (acronyms, codes, technical terms)

AECL	Atomic Energy of Canada Limited
CNSC	Canadian Nuclear Safety Commission
CRT	Cathode Ray Tube, a video display
OEM	Original Equipment Manufacturer
SDS	Shutdown System
SDS1	Shutdown System 1 – A system which uses neutron absorbing "shutoff" rods to rapidly shutdown the reactor due to an abnormal condition.
SDS2	Shutdown System 2 – A system which uses neutron absorbing "poison" (gadolinium nitrate) to rapidly shutdown the reactor due to an abnormal condition.
SSMC	Shutdown System Monitoring Computer. Note that this is not the SDS1 or the SDS2 Monitor Computer. The SSMC is a single computer which collects data from all of the 8 SDS1 and SDS2 Monitor computers.
SWI	Systemware Innovation

Appendix "B"

Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency)									
				Cumulative Values							
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Developmental	Jan	2,007	345	1,438							1,783
Full					8,000	5,000	5,000			45,000	63,000
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:

The only project funding to date has been Conceptual Seed money from the Projects and Modification organization to produce the Developmental BCS and the PEP. The funding was $50K acquired in 2005 and spent in 2006. The spending to date (as of November 9, 2006) of the seed money has been $26K.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

To assess the cost of resources, it was assumed that 50% of the personnel would be internal and the other 50% external. An average internal rate is 70$/hr and a conservative external rate is [redacted] Therefore, a blended rate of 135$/hr was used for the cost estimates of the preliminary engineering tasks.

Financial Assumptions:

N/A

Project / Station End of Life Assumptions:

The SDS computers are required for the life of the station (up to 2018) and for any plant life extensions until the end of decommissioning.

Energy Price / Production Assumptions:

N/A

Operating Cost Assumptions:

No changes in operating staff are expected to operate/maintain the SDS computers.

Other Assumptions:

N/A

DNGS SDS Aging Management 16 - 33955

Developmental Release Business Case Summary D-BCS-68000-10002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008	2009	2010	2011		Later	Total
Project Management (OPG)		50	100						150
Engineering & Drafting (OPG)		200	1 090						1,290
Material	[redacted]								
Installation – PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
Future Project Costs (includes continengy and interest)	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
Project Costs (incl contingency)	-	345	1,438	8,000	5,000	5,000	-	45,000	64,783
2007-2011 Business Plan		300	3.700	8,000	5,000	5,000		43,000	65,000
Variance to Business Plan	-	-	(2,450)	-	-	-	-	2,000	(450)
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	300	1,250	8,000	5,000	5,000	-	45,000	64,550
Total Release (incl contingency)	-	345	1,438	8,000	5,000	5,000	-	45,000	64,783

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	N/A		Quality of Estimate		Conceptual + 60% to - 25%
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by June of 2008.

Reviewed By:

Nov 16/2006

ke Viola
roject Manager

Date:

Approved By:

Nov 16, 2006

Rick Hohendorf
Eng & Mods Manager (Strat IV)

Date:

DNGS SDS Aging Management 16 - 33955

Developmental Release Business Case Summary D-BCS-68000-10002-R000

Attachment "B" **Project Variance Analysis**

Choose One	LTD	Choose One		Variance	Comments
		Last BCS	This BCS		
	N/A	N/A	N/A		
	N/A	N/A	N/A		
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Not applicable since this BCS is not requesting a superseding release.

ONTARIOPOWER GENERATION

SG Controls Retrofit 16 - 33973

Developmental Release Business Case Summary D-BCS-49100-10001-R000

Routing	Location		Signature	Date
E. Thomas Project Leader 703-3529	BW7-02	Prepare BCS		14 Dec 2006
T. Cvitkovic Section Manager, Design Projects 703-3571	BW7-02	Review BCS		14 Dec 2006
J. Taras Section Manager, PMO 703-3528	BW7-02	Review BCS		14Dec06
J. Shemilt Manager, Projects Design 703-1963	ES3-L13-2	Review BCS	for J. Shemilt	14DEC '06
T. Chong Manager, Design Projects 703-3520	BW7-02	Review BCS		14 Dec 2006
W. Qualtrough Manager, Performance Engineering 703-7484	D08-ES2	Review BCS		15 Dec /06
A. Kleer Senior Financial Analyst [illegible]4110	P82-3B-6	Review BCS		13 Dec 2006
[illegible]rnone Director, Projects and Modifications 701-6063	P72-E4.4	Submit BCS		15 Dec 2006
R. Leavitt Director, Investment Management 702-6878	P82-F3-A6	Approve BCS		14 Dec 2006
S. Seedhouse Director, Station Engineering 703-7584	D08-ES3	Approve BCS		15 Dec 2006
[illegible]ll [illegible] Financial Analyst [illegible]2-4084	P82-3B6	Return For Distribution		

SG Controls Retrofit 16 - 33973

Developmental Release Business Case Summary D-BCS-49100-10001-R000

1/ RECOMMENDATION:

Approval is requested for this Developmental Release of $1536k (including [redacted] contingency) Capital to complete the Definition Phase of the Standby Generators (SG) Controls Retrofit project. In this phase we will select and engage the supplier of the control systems from an evaluation of six (6) prospective vendors, complete the preliminary engineering, prepare detailed estimates and obtain approval of a Full Release Phase 1 BCS for the implementation of the project.

The business objective of this project is to address the issue of unreliability and obsolescence such that the SG System Health can be maintained as white and generation risk avoided. This will be done by installing new control systems on all four SGs. The new control technology will also provide for remote monitoring and increased diagnostic capabilities to improve maintenance programs.

SG unavailability is a violation of OPG's Operating License that would require us to shut down all units if one SG could not be made available within twenty-four hours. SG Control System components are over 20 years old, are susceptible to unpredictable failure and are no longer supported by the original equipment manufacturer. Current trends indicate that our stock of critical spare parts will be depleted in an estimated 3 to 5 years, at which time the risk of concurrent SG failures will increase significantly.

Some effort has been focused on the search for alternate suppliers of spare parts, with no success to date. Similar projects performed at Darlington (Ref D-PIR-49200-10001) and Pickering B (Ref NK30-BCS-54600-00011-R000) were reviewed, and in both cases the control systems were completely replaced because no new sources of spare parts could be identified. Project costs in both cases were also consistent with our current estimates, however a better quality estimate for the overall project cost will be developed in this phase.

At least five SCRs have been raised to document problems with the existing SG control systems, and a continued decline in reliability will result in System Health degrading from white to yellow. Replacing the control systems will increase reliability and availability of spares, to maintain the System Health white.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released		-							-
Requested Now	Developmental	-	1,041	495					1,536
Future Funding Req'd	Full			1,155	4,406	7,100	3,740		16,401
Total Project Costs		-	1,041	1,650	4,406	7,100	3,740	-	17,937
Ongoing Costs									-
Other Costs									-
Grand Total		-	1,041	1,650	4,406	7,100	3,740	-	17,937

Investment Type	Class	NPV or IEV	IRR	Discounted Payback
Sustaining	Capital			

Submitted By:

M. Arnone
Director, Projects and Modifications
Date: 15 Dec 2006

Finance Approval:

R. Leavitt
Director Investment Management
Date: Dec 14, 2006

Line Approval (Per OAR Element 1.1 Project in Budget):

S. Seedhouse
Director, Station Engineering
Date: 15 Dec 2006

2/ BACKGROUND & ISSUES

Over the past few years, it has become evident that various control and monitoring components for the four Standby Generators (SGs) were obsolete. Manufacturers of the original components no longer provide replacement parts or service the equipment. In some cases these manufacturers no longer exist. At this time, there is a stock of critical spare parts but it is anticipated that within 3 to 5 years, this stock will also be depleted.

The known affected control and monitoring components are:

- Woodward Governor (some spares are available, calibrator parts are not available and neither technical nor parts support are available).
- Bentley Nevada Vibration Monitor (some parts are in stock and neither technical nor parts support are available).
- Rochester Annunciator (no spare parts in stock, neither technical nor parts support are available).
- Airpax Over Speed Unit (some spare parts in stock, manufacturer no longer in existence).
- Protection relays

The health status of the SGs is white (declining towards yellow). The system health reports have listed several SCRs which indicated that power supply circuit breakers have been found open, resulting in start failures or unavailability problems. The new control system would facilitate the early detection of these and other problems.

If the control system were to fail, the associated SG would be rendered unavailable. Repairs under such forced outage conditions could take several months to complete. If another SG were to fail during this time period or be unavailable due to scheduled maintenance or forced outage, the two remaining SGs must remain in the standby shutdown state. If only two SGs are available, the SGs must be placed in their preferred SG line-up with respect breaker selections per NK38-OM-49100-4.12, ODD/EVEN SG selection.

Although the minimum requirement per OP&Ps is one SG, maintaining the effectiveness of Class III Transfer System requires a minimum of two SGs to be available. At least one must be selected to the ODD bus and at least one to the EVEN bus. The Class III Transfer System will first pick up the mandatory nuclear loads to ensure a safe shutdown state is maintained (one SG can carry these). The economic loads will then be picked up. The second SG is needed to pick up the significant economic loads. Failure to pick up economic loads such as the turning gear auxiliaries and the Irradiated Fuel Bay, which will then begin to heat up, could result in damage to other station systems.

Several SCR's (D-2006-01672, D-2006-01413, D-2006-01821, D-2003-03331, D-2006-08173) document problems with the control system. The following significant issues were noted in the SCRs:-

- D-2006-01672 – Numerous alarms were identified on SG1 in February 2006. At the time SG3 and SG4 were already unavailable, resulting in 3 SGs being unavailable.
- D-2006-01413 – During a test run of SG3 in February 2006, the auto synchronization failed. The synchronization was done manually. During the second run-up SG3 tripped on high vibrations and was declared unavailable.
- D-2006-01821 – In February 2006, A low vibration indication was found on SG4 vibration probe. A vibration probe was ordered for installation during the upcoming outage. This was not possible because the required parts were unavailable.
- D-2003-03331 – In April 2003 the overspeed unit in SG2 was repaired by the manufacturer by obtaining a damaged board and replacing the burnt resistors, old capacitors and bad zener diode. This is a common problem for this board. The manufacturer questioned the wisdom of investing time and money in trying to extend the life of these units as opposed to replacing the whole system.
- D-2006-08173 – In September 2006 SG3 tripped on generator protection. The 21B phase back-up relay, which has a history of spurious operation and the 64 ground fault relay were found to be tripped.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ (	Do Nothing	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3 2 SGs Only	Alt 4	Alt 5	Alt 5
Revenue								
Project Cost	N/A	18,000	18,000	N/A	12,000			
NPV (after tax)								
Impact on Economic Value								
IRR%								
Discounted Payback (Yrs)								

Do Nothing (Not Recommended)

This alternative is not recommended because failure to improve reliability and maintainability of the SG Control System will not satisfy the requirements set out in the station OP&P and the Safety Report. SG Control System components are over 20 years old, are susceptible to unpredictable failure and are no longer supported by the original equipment manufacturer. Current trends indicate that our stock of critical spare parts will be depleted in an estimated 3 to 5 years, at which time the risk of concurrent SG failures will increase significantly. Continued operation under current conditions would lead to partial or complete failure of stand by Class III power.

Alternative 1 – Replace All The Control Systems (Recommended)

We recommend the replacement of all the control systems, because complete replacement of the control systems would guarantee the reliability of the SGs for the remaining life of the station. This consideration and the need to maintain the reliability and availability of the SGs within the limits set by the reliability model for safe operation of the station, favour a complete replacement of the control systems for all SGs.

Replacing the existing SG control systems will improve reliability and eliminate obsolescence issues by providing the following:

- Reliable and proven control systems that are of more recent design, with readily available parts and technical support.
- Increased diagnostic capabilities and remote monitoring of generators by the system engineer to ensure that preventive maintenance and surveillance programs are effective.
- A reduction of the incidence of start failures as per the reliability model for safe operation of the station, over the remaining life of the station.

This direction is consistent with similar projects performed at Darlington (Ref D-PIR-49200-10001) and Pickering B (Ref NK30-BCS-54600-00011-R000). Our current estimate for this alternative is also consistent with the project costs for both of these comparable cases. A better quality estimate for the overall project cost will be developed in this phase.

Alternative 2 - Delay Project - Not Recommended

recommended because all the SGs are of the same age and the anticipated problem of spare parts unavailability in 3 to 5 years could result in all four SGs being unavailable at the same time. Any further delays to the project schedule will result in an increased risk of concurrent SG failures.

Alternative 3 - Replace The Control Systems On Only Two SGs (Not Recommended)
Replace the control systems in only two of the four SG's, and salvage the removed components to increase the inventory of spares for the remaining two SG's.

This alternative is not recommended because:

- The reliability gains will be less than the recommended alternative.
- The cost of this alternative is marginally less than the recommended alternative, with continued reliability and maintainability issues with the unmodified SGs.
- Operating and maintaining two pairs of SGs with dissimilar control and diagnostic systems will introduce new issues and challenges for configuration management, documentation, maintenance procedures and training.

Alternative 4 - Compile Substitute Parts From Alternate Suppliers (Not Recommended)

Search for available parts from any suppliers and continue to repair the control systems until the end of life of the station. This approach is not recommended because the Darlington Scope Review Team already investigated the possibility of purchasing substitute parts from any available vendors, whether or not they are already approved by OPG. The intention was to diligently explore the possibility of identifying available parts anywhere in the world and subsequently try to approve such vendors through the normal OPG process. There has been no success to date with this approach. While this approach may have been economically viable, assuming that all other problems associated with the age of any available parts and the age of the systems themselves, could be overcome, no parts have been located up to this point in time.

Similar problems were encountered with the Darlington Emergency Power Generators (EPGs) and the Pickering B EPGs. In both cases the control systems were completely replaced (Ref D-PIR-49200-10001 and NK30-BCS-34600-00011-R000 respectively).

4/ THE PROPOSAL

The developmental release will be used to select and engage the preferred supplier through competitive process, complete the preliminary engineering, prepare estimates and obtain Full Release Phase 1 BCS.

This release will deliver the following:

- The Modification Outline, Design Scoping Checklist, Design Plan and Modification Design Requirements.
- Technical Specifications
- Issue RFP and evaluation of proposals from up to six prospective vendors
- Retention of preferred supplier
- Complete preliminary engineering
- Preparation of quality estimates
- Full Release (Phase 1) BCS

5/ QUALITATIVE FACTORS

- Increased diagnostic and remote monitoring capability will assist in establishing effective preventive maintenance programs and early detection of potential problems.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Expenditure may exceed released funds.	Cost overrun	**Medium**	Deliverables are clear; estimate is based on internal staff doing the work and good estimates are in hand; [redacted] contingency has been allocated for this phase of the project to ensure expenditure does not exceed the release limit.	Low
Scope				
Scope of this Phase may increase based on discussion with vendors	Schedule and cost overrun	**Medium**	The scope of this phase is defined and scope increase is unlikely, however, [redacted] contingency has been allocated.	Low
Schedule				
Schedule for completing the milestones may be delayed due to lack of resources	Schedule and cost overrun	**Medium**	Appropriate resources have been identified (eg. DNGD Projects Design, CCD - DNGD DCC) and will be used as soon as funding is released. [redacted] contingency has also been allocated.,	Low
Resources				
Lack of experienced engineering resources for this Phase of the project	Delay in completion of this Phase	**Medium**	Appropriate resources have been identified and their availabilty confirmed (e.g.DNGD Projects Design, CCD - DNGD DCC) and will be used as soon as funding is released. [redacted] contingency has also been allocated.	Low
Technical				

None				
Regulatory				
None				
Environmental				
None				
Health & Safety				
None				
Investment				

11 POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
N/A	N/A	N/A	N/A

Comments:
N/A for this phase.

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

SG - Standby Generator
SCR - Station Condition Record
CCD - Computer Control Design
DCC - Digital Control Computers
PEP - Project Execution Plan
PCRAF - Project Change Request Authorization Form
OP&P - Operating Policies and Principles

Appendix "B" **Project Funding History**

$ 000's Release Type	Month	Year	Timing of Funding Released (incl contingency) 2005	2006	2007	2008	2009	2010	2011	Later	Total
											0
											0
											0
											0
											0
											0
											0
											0
LTD Spent	May	2006	0	0	0	0	0	0	0	0	0

Comments:
Conceptual Funding of $135k was approved by the Director of Projects and Modifications in November 21, 2005.

Appendix "C" **Financial Model – Assumptions**

Project Cost Assumptions:

Conceptual Estimate +60% to -25%
See Basis of Estimate (Attachment A)

Financial Assumptions:

Project / Station End of Life Assumptions:

2018

Energy Price / Production Assumptions

Operating Cost Assumptions

Other Assumptions:

SG Controls Retrofit 16 - 33973

Developmental Release Business Case Summary D-BCS-49100-10001-R000

Attachment "A"

Project Cost Summary

$000's Capital	LTD Prior Yr 2006	Dev Release 2007	Dev Release 2008	Future Release 2008	Future Release 2009	Future Release 2010	Future Release 2011	Later	Total
Project Management (OPG)		138	79	70	170	170	170		797
Engineering & Drafting (OPG)		315	162	400	420	360	100		1,757
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Contract - Software & HFE									
Interest (Capital Project Only)									
Project Spending									
Committed Cost									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	-	1,041	495	1,155	4,406	7,100	3,740	-	17,938
Ongoing OM&A (non-project)									
Inventory Write Off Required									-
Spare Parts / Inventory									-
									-
Grand Total (incl contingency)	-	1,041	495	1,155	4,406	7,100	3,740	-	17,938
2006-2010 Business Plan	1,500	3,500		3500	3,000	2,850	-		14,350
Variance to Business Plan	(1,500)	(667)	(3,104)	924	525	2,830	2,992	-	-

Removal Costs (incl in above)									-

Basis of Estimate		**+60% / -25%**			
Design Complete	No	Contracts in place	No	Competitive Bid	No
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Sponsor Cost Estimate	No	Phase 1 Actual Used	No

Other:

Variances to 2006 Budget and 2006 -2010 BP will be addressed through the portfolio management process.

Reviewed By:

14 Dec 2006

...n Cvitkovic
Project Manager

Date:

Approved By:

14 Dec 2006

Terry Chong
Eng & Mods Manager (Strat IV)

Date:

SG Controls Retrofit 16 - 33973

Developmental Release Business Case Summary D-BCS-49100-10001-R000

Attachment "B"

Project Variance Analysis

Choose One	LTD Choose Choose	Choose One Last BCS N/A N/A	This BCS N/A N/A	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Spending					-
Committed Cost					
Project Costs (excl contingency)					-
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	**0**	**0**	**0**	**0**	-
Ongoing OM&A (non-project)				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Grand Total (incl contingency)	**0**	**0**	**0**	**0**	-

Comments:

No previous release. Not required

ttachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
02	Sep	07	Major Contract Awarded (MCA)
14	Feb	08	Preliminary Engineering (DES)
30	May	08	Full Release (Phase 1) BCS

Comments:

A Project Execution Plan (PEP) will be approved by September 2007

ONTARIO POWER GENERATION

PNGS-A D2O Storage and Drum Cleaning Facility 13 - 49251

Developmental Release Business Case Summary NA44-BCS-38000-00001-R000

Routing	Location	Action	Signature	Date
Tracy Leung Modification Team Leader x2767	P72-3	Prepare BCS	for T. Leung	Nov 17/06
Edmond Wong Project Leader x 3991	P72-3	Review BCS		Nov 17/06
Stephanie Tham Project Manager x 4203	P72-3	Review BCS		Nov 21/06
Peter Floyd Manager, Design Projects, Pickering A x 4053	P72-1	Review BCS	for Peter Floyd	Nov 22nd/06
Mark Arnone Director, Projects & Modifications x 6063	P72-1	Review BCS		22 Nov 2006
Dave Topolnisky Manager, Common Services x 3503	P05	Review BCS		Nov 22/2006
Dwight Zerkee Technical Advisor, Nuclear Analysis [illegible]02-4082	P82-3	Review BCS		21 Nov 06
[illegible]nina Velshi [illegible]irector, Commercial Activities x 702-5100	P82-4	Submit BCS		27 Nov 06
Randy Leavitt Director, Investment Management x 702-5085	P82-3	Approve BCS	R Leavitt	Nov. 27, 2006
Martin Tulett Director, Operation & Maintenance, Pickering A, x2099	P05-A2	Approve BCS		Nov 29/06
R. Ball [illegible]enior Financial Analyst [illegible]-4084	P82-3B6	Return For Distribution		

PNGS-A D2O Storage and Drum Cleaning Facility 13 - 49251

Developmental Release Business Case Summary NA44-BCS-38000-00001-R000

1/ RECOMMENDATION:

We recommend approval of a Developmental Release of \$2,506k (including [redacted] contingency) to complete preliminary design, initiate detailed design, initiate Requests for Quotations for long-lead materials and develop a Partial Release for the PNGS D_2O Storage and Drum Handling Project by November, 2007. A Partial Release will be requested upon completion of preliminary engineering to facilitate a seamless transition to detailed design, long-lead material procurement, initiate Requests for Proposal for the construction contract and develop the Full Release. This funding strategy will minimize cost and schedule delays.

There are three business objectives of this project as per Project Charter N-PCH-03800-10000:

1. Improve detritiation capability within OPG-N
2. Provide operational flexibility for the storage and segregation of different grades of D_2O
3. Provide a drum cleaning facility to manage the backlog of D2O drums in the station

Note: Plant Life Extension and Decommissioning of P2 and P3 are not part of the mandate of this project.

Kinectrics was commissioned to study the Heavy Water Storage and Drum Handling issues from the overall OPG-N perspective. The recommended modification for Pickering is listed below:

- Install 1x 16 Mg downgraded, low curie, oily D_2O tank
- Install 1x 16 Mg downgraded, high curie, oily D_2O tank
- Install 1 x 46 Mg downgraded, low curie, non-oily D_2O tank
- Install 1 x 19 Mg downgraded, high curie, non-oily D_2O tank
- Install a Drum Cleaning Facility

Detritiation difficulties at PNGS cannot be solely tied to a lack of storage capacity at the Storage and Inventory (S&I) system and, therefore, it is not recommended any S&I tanks to be installed in PNGS. However, Pickering will be able to utilize Darlington's S&I tanks, that are to be installed under Darlington Project 16-31555, as temporary storage as required or TRF product reservoirs to ensure low curie D_2O is always available to Pickering for detritiation. Similarly, there is insufficient justification to install a drum cleaning facility at DNGS and that the Pickering's Drum Cleaning Facility will be used to clean dirty drums from Darlington.

Choose One	Funding	LTO 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	None								-
Requested Now	Developmental			1,330	1,176				2,506
Future Funding Req'd					2,837	7,720	4,319		14,876
Total Project Costs		-	-	1,330	4,013	7,720	4,319	-	17,382
Other Costs									-
Ongoing Costs									-
Grand Total		-	-	1,330	4,013	7,720	4,319	-	17,382
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Sustaining		Capital		6,473		14.7%		7.8	

Submitted By:

Rumina Velshi
Director, Commercial Activities
Project Sponsor

27 Nov '06
Date:

Finance Approval:

Randy Leavitt
Director, Investment Management, NOSS

Nov. 27, 2006
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Martin Tulett
Director, Operations & Maintenance, Pickering

Nov 29/06
Date:

2/ BACKGROUND & ISSUES

Both Pickering Nuclear Generating Station A and B need to improve their overall ability to manage D_2O inventories to support continuous station operations in a safe and cost efficient manner. In December 2004, Kinectrics Inc. was requested to perform a strategic study on OPGN's Heavy Water Storage and Drum Handling Strategy. (Ref; K-011043-001-RA-0001-R00A). In April 2006, Kinectrics Inc. was engaged by the Project to fine-tune the initial study with clear assumptions and verified information for the stakeholders

The three main objectives of this project are as follows:

1. Allow large volume bulk swap of heavy water for detritiation to keep units running below the OP&P limit for tritium concentration.
2. Improve operational flexibility to segregate different streams of D2O to support normal operation and outages.
3. Improve the management of drums in the station and to reduce associated drum handling-related radiological and conventional safety hazards.

Decommissioning of P2 and P3 and Plant Life Extension are not part of the mandate of this project.

2.1 Large Volume Bulk Swap of Heavy Water for Detritiation

Pickering B units have exceeded their Administrative limits for tritium concentrations in both the Moderator and the Primary Heat Transport (PHT) system and are fast approaching the OP&P limits.

The current mode of detritiation is performed with the reactors online whereby high Curie Moderator D_2O is bled out from the unit and low Curie D_2O is fed from the Storage and Inventory System (S&I) into the unit simultaneously.

The preferred mode of detritiation of the station is to perform bulk detritiation on a unit during outages when the Moderator inventory is drained out and replaced by the same volume of low Curie D_2O which is often of a higher isotopic. As a result, the isotopic of the Moderator system is upgraded simultaneously. This mode of detritiation is opportunistic and requires more tanks for D_2O maneuvering; however, it is more effective since there will be no wastage of the low Curie D_2O being fed to the unit.

The following tables summarize the problems that are caused by the inability to perform large volume bulk swaps of D_2O for detritiation:

Table A. Problems caused by inability to perform large volume bulk swaps of D_2O for Detritiation

Problem	Issues	Impacts
There is inadequate Storage and Inventory (S&I) storage capacity to allow large volume bulk swap to be performed readily	• Reliance on online detritiation, as there is very limited capability to perform the more effective offline detritiation. • Require extensive planning and coordination with TRF and rearranging D_2O in S&I Tanks, even for on-line detritiation • Inability to efficiently perform moderator upgrading	• Less efficient reduction of tritium emissions to the environment • Less efficient reduction of dose absorbed by workers • Possibility of regulatory sanctions due to OP&P violations as a result of a lower efficiency of detritiation • Lower fuel-burnup efficiencies

2.2 Operational Flexibility to Segregate Different Streams of D_2O

The lack of storage capabilities for proper segregation of different streams of D_2O inventory is impairing operations. If off-site storage is required, or if operator work-arounds are warranted, then this increases costs and induces additional workload for operations

2.2.1 *Reactor Grade D_2O Storage & Segregation*

During normal or outage situations, the following inventories of D2O should be segregated:

- High Curie D_2O (including Sulzer-B Upgrader Product)
- Low Curie D_2O (including UPP-B Upgrader Product)
- Moderator D_2O (containing Gadolinium)
- Primary Heat Transport D_2O (contains Lithium)
- TRF Grade D_2O (Very Low Curie)

The following table summarizes the problems that are caused by not having enough Reactor Grade D_2O (S&I) Tanks for storage and segregation:

Table B. Problems caused by insufficient S&I tanks for Reactor Grade D2O Storage and Segregation

Problem	Issues	Impacts
Limited flexibility in reactor grade D_2O segregation during outages	• During outages, when S&I tanks are taken up by moderator drains or PHT drains, then the existing inventory does not have space for storage	• Pickering Incoming/Outgoing D_2O Transfer System (PIOTS) is often used to store Reactor Grade D2O during outages, impeding TRF receiving and shipping activities • When S&I tanks are taken up by drains from the outage unit, there is limited capacity to hold upgrader products from Sulzer-B or UPP-B, causing these upgraders to go into reflux • High probability of human performance errors when tanks that were specified to hold a certain grade of D_2O must be filled with another grade of D_2O due to lack of storage space
Limited flexibility to store assigned TRF product's quota to meet PNGS's Detritiation Plan	• Shipment and receiving of TRF Product rely heavily on the availability of TRF and S&I • Requires planning and resources to rearrange contents in S&I before shipping and receiving	• Reduce capability to meet PNGS's detritiation plan

2.2.2 *Downgraded D_2O Storage & Segregation*

The existing storage capacity at the Ion Exchange Clean-Up System (IXCU) is not adequate for segregating downgraded D_2O. The following grades of downgraded D_2O should be segregated for maximum IXCU operating efficiency:

- High Curie, Non-Oily D_2O
- Low Curie, Non-Oily D_2O
- High Curie, Oily D_2O
- Low Curie, Oily D_2O

Table C. Problems caused by Insufficient IXCU tanks for Downgraded D_2O Storage and Segregation

Problem	Issues	Impacts
The original design of the IXCU system is not adequate for the current recovery rates.	System Degradation, causing high leakage rates and a high load on recovery and clean-up systems	• When the load cannot be efficiently processed by the IXCU system, a large amount of backlog is accumulated, requiring all recoveries to be drummed, increasing drum handling, dose hazards and housekeeping issues
The IXCU system was not designed for high volumes of oily D_2O recoveries.	The Pickering fuelling machines leaks a hydraulic fluid which is collected in the Building Liquid Recovery system.	• Any backlogged oily D_2O is drummed, causing drums to become oily. • Oily recoveries may overflow into non-oily tanks, causing these tanks to become oily as well, contaminating clean recoveries. This further increases the oily load. • Additional expenses need to be incurred to clean the oil film off of the non-oily tanks every few years. • Oily recoveries process at a slower rate than non-oily recoveries, lowering the efficiency of the IXCU system. • Inadvertent leakage of oily recovery into the upgraders is a contributing factor to the degradation of upgrader's packing and to the reduction of heat transfer capability of the reboilers. • External upgrading services will be expensive and repacking of upgraders will cost millions.
IXCU was not designed to treat or segregate High TOC D_2O.	• Use of organic solvents and chemicals in the Reactor Building for cleaning and reactor components inspections causes high Total Organic Carbon (TOC) levels in recoveries • TOC is very difficult to remove and it requires sufficient time and segregation to be reduced to less than 1 ppm before they can be sent to the upgraders to prevent upgrader packing degradation and plugging of distributors.	• The degradation of upgraders due to TOC may be exacerbated to a point where external upgrading services are required. • Inadequate feed to the upgraders due to the inability to achieve specifications causes backlog at IXCU, while the upgraders to go into reflux, wasting operational resources • If a significant inventory cannot be upgraded, then the D2O must be made up from D2O rentals from external companies *Note: It is assumed that a UV-Oxidation Unit will be installed in Pickering, which is capable of reducing TOC from downgraded D_2O to the specified 1 ppm. The UV-Oxidation unit is designed to act as a polishing system to remove TOC after the majority of the contaminants are clean-up from the downgraded D_2O.*

2.3 Drum Cleaning Facility

Table D. Problems caused by a lack of a Drum Cleaning Facility

Problems	Issues	Impacts
Inability to process or reduce drum inventory	• Pickering has an inventory of 3000 drums around the station. • Oily drums being used to collect non-oily recoveries	• Drums that contain sludge cannot be disposed of • Housekeeping concern that has already instigated CNSC scrutiny • Drum Handling Hazards • Dose hazards • Takes up valuable real estate in the station • IXCU efficiency is reduced, causing a further backlog upstream, requiring the purchase of more drums to store the backlog @ \$700 to \$800/drum • If the inventory of unprocessable D_2O becomes too large to handle, then external cleaning services needs to be purchased

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

\$000's	Do Nothing	Alt 1 (Recommended)		Alt 2	Alt 3
		Full Cost	Incremental Cost		
Revenue	0	0	0	0	3,573
OM&A	(68,296)	(19,132)	(19,132)	(27,203)	(19,107)
Capital	0	(17,384)	(17,384)	(18,442)	(36,000)
NPV (after tax)	(26,817)	(20,344)	(20,344)	(22,985)	(32,390)
Impact on Economic Value (IEV)	N/A	6,473	6,473	3,832	(5,573)
IRR%	N/A	14.7%	14.7%	14.1%	N/A
Discounted Payback (Yrs)	N/A	7.75	7.75	7.96	N/A

Status Quo - Not Recommended

Status Quo is not a recommended option.

Pickering units need to achieve better detritiation efficiency in order to prevent reaching the OP&P limits for tritium content.

During normal operation, online detritiation performed in a large volume requires careful planning, coordination with TRF and movement of Reactor Grade D_2O in S&I tanks. This is due to the limitation of S&I tank storage space, which sometimes prevents online detritiation to be executed.

During outages, the receiving and shipping of TRF product is often impeded by the available S&I tank space, causing the station to miss valuable opportunities to detritiate.

The downgraded D_2O storage capability is not sufficient to meet current recovery rates, causing excessive drum usage that induces radiological and conventional hazards for workers. The lack of sufficient segregation of downgraded D_2O has caused the IXCU system to run below optimal efficiency, limiting the input to the upgraders. Engineering – Common Services has indicated that if IXCU tanks were not provided to them by 2014, then upgrader packing replacement would be inevitable. Packing replacement is an extensive overhaul to the upgrader and can cost over \$10M. During the years where the flowrates of the upgraders can no longer meet its demand, external upgrading services will need to be purchased, costing over \$1.3M for every 10kg/h variance, per year.

The drum problem is further exacerbated by the fact that Pickering has no capability to clean dirty drums, causing a housekeeping and dose issues that has drawn scrutiny from the CNSC.

Alternative 1 -
Install Additional Downgraded Storage Tanks and a Drum Cleaning Facility - Recommended

The recommended modification for Pickering is listed below:

Type of Tank	Size/Specifications	Location
Downgraded, low curie, oily D_2O tank	1 x 16 Mg	IXCU area, 274' el., RAB
Downgraded, high curie, oily D_2O tank	1 x 16 Mg	IXCU area, 274' el., RAB
Downgraded, low curie, non-oily D_2O tank	1 x 46 Mg	IXCU area, 274' el., RAB
Downgraded, high curie, non-oily D_2O tank	1 x 19 Mg	IXCU area, 274' el., RAB
Drum Cleaning Facility	Capable of cleaning a minimum of 10 drums/day	Between Solid Waste Handling Facility and PIOTS, 254' el., Service Wing

As a result of more rigorous review of the project needs vs. wants, the scope of the recommended option is leaner than that requested at the original project charter.

Installing additional downgraded storage tanks at IXCU and a drum cleaning facility will allow for the following (which are aligned with the project objectives):

1. Provide additional storage and segregation capability for downgraded D_2O to meet current recovery rates
   - Slow down degradation rates of upgraders to mitigate/delay costs to purchase external upgrading services
   - Mitigate costs to clean up oil-film build-up in non-oily tanks due to lack of proper segregation capability
   - Reduce the number of man-hours spent on tank maneuvering and backlog processing
2. Prevent the excessive use of drums
   - Reduce drum handling-related radiological and conventional hazards
   - Reduce the number of man-hours spent on drum handling
3. Allow Pickering and Darlington to clean oily drums
   - Prevents the use of oily drums to collect non-oily water
   - Reduce the number of drums in the station that are taking up valuable real estate
   - Mitigate costs to purchase external downgraded D_2O cleaning services.

The final recommendation does not include S&I tanks for the following reasons:

Since 1997, it was evident that "feed and bleed" detritiation has not been consistently performed. This increase in PNGS-B tritium concentration can be partially attributed to the lack of sufficient storage capacity for reactor grade D_2O at the S&I system. In addition, there are other factors that had contributed to this issue:

- Extended Tritium Removal Facility (TRF) outages which limited the amount of TRF product available for detritiation
- One 150 Mg S&I tank occupied with Gadolinium-D_2O for two years as a result of a previous attempt to perform bulk detritiation
- D_2O from Unit 4 Return-To-Service occupying S&I tanks
- Procedural issues associated with the safe execution of swaps that required 6-9 months to resolve
- Planning and resource coordination problems in shipments of D_2O to and from the TRF
- Detritiation can only be performed on weekends when the unit is in quiet mode

The additional S&I tanks installed at Darlington, as part of their D_2O Storage Project 16-31555 can alleviate Pickering's reliance on the availability of the TRF and can improve Pickering's opportunity to perform large volume bulk swaps. These tanks will act as temporary storage and TRF product storage tanks for Pickering when Darlington does not needs these tanks during outages. The utilization of Darlington's tanks in Pickering represents an additional investment mitigation of $18.6M.

Alternative 2 - Delay Project - Not Recommended

Delaying the project is **not** a recommended option. There is insufficient storage and segregation capability for downgraded D_2O since the recovery rates of downgraded D_2O have been increasing and the number of acute leakage events has been escalating. This causes backlog of recoveries that requires excessive drumming operations that may require more drum purchases. The number of drums in the station has already been causing housekeeping and dose issues that has drawn scrutiny from the CNSC. The backlog of drums maybe further aggravated when oily recoveries overflow to non-oily tanks causing clean recoveries to be contaminated with oil. Since oily D2O processes at a slower rate at the IXCU trains, this creates a vicious cycle of additional drum usage.

Furthermore, Engineering – Common Services has indicated that if IXCU tanks were not provided to them by 2014, then upgrader packing replacement would be inevitable. Packing replacement is an extensive overhaul to the upgrader and can cost over $10M. During the years where the flowrates of the upgraders can no longer meet its demand, external upgrading services will need to be purchased, costing over $1.3M for every 10kg/h variance, per year.

Alternative 3 –
Install Pickering's own Storage and Inventory Tanks, Install Additional Downgraded Storage Tanks and a Drum Cleaning Facility - Not Recommended

Although installing additional S&I tanks will benefit Pickering station by increasing its flexibility in storing and segregating reactor grade D2O, this is **not** a recommended option. Kinectrics has suggested that the inability to detritiate or improve moderator isotopics effectively over the last 10 years at Pickering cannot be solely tied to a lack of storage capacity at S&I. Although installing Pickering's own S&I tanks improves Pickering ability to detritiate and increase moderator's isotopic, the savings from dose reduction and better fuel burn-up cannot recover the investment required to complete this modification before end-of-life of the Pickering A and B units.

The total cost to implement this option is $36.0M, including contingency, with a +60%/-40% accuracy.

Alternative 4 – - Not Recommended

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

This Developmental Release of $2,505K (including contingency) will be used to complete the following deliverables:

- Provide project management support
- Provide OPG Design Support
- Prepare and award a Design Contract for Preliminary and Detailed Design
- Complete Preliminary Design (up to 40% Detailed Engineering)
- Issue Technical Specifications for Long-lead materials
- Review/Approve Preliminary Design
- Initiate Detailed Design
- Prepare Preliminary PEP
- Issue a Partial BCS

Refer to Appendix C for a list of the project milestones.

5/ QUALITATIVE FACTORS

Benefits to the Community/Regulator Relations

- Lower Tritium Emissions by using Darlington S&I tanks (Project 16-31555) to alleviate Pickering's reliance on the availability of the TRF, thereby ensuring a readily available supply of low curie product to detritiate Pickering's units.
- Eliminate scrutiny from CNSC of Pickering's tritium emissions

Health and Safety

- Effective utilization of the IXCU system will reduce the backlog of downgraded D2O in drums, reducing the occurrences of drum handling-related safety issues
- Clean drums can be re-used or disposed of to improve housekeeping in the stations

Operational Considerations

- Reduce operator workarounds, lowering the probability of human-performance errors

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Overall project cost exceeds current estimate.	Unable to accomplish all project objectives without futher release of funds	**High**	Detailed conceptual study completed by Kinectrics. Helyar review of project cost. Adopt optimal contracting strategy to mitigate cost escalation. Further fine tuning of overall project schedule and costs in a Partial BCS.	**Medium**
Fine tuning of contracting strategy & changes to funding release strategy may impact overall cost and schedule	Delay project schedule and increase costs.	**High**	Obtained agreement with line management on present funding strategy. Contracting strategy and design/installation requirements will be reviewed with Supply Chain, Procurement, Design and Legal.	**Medium**
Scope				
Unknown cost justification information not submitted to Projects causing cost and schedule impacts.	Rework will be required to evaluate impact of additional cost justification on preferred option. Additional costs and delays will be incurred.	**Medium**	Rigrous communication with stakeholders prior to submission of BCS to ensure that all cost justification information have been submitted.	**Low**
Preliminary Design/Detailed Design may result in an increase in scope.	Changes in scope results in delays in schedule and additional cost to the project.	**Medium**	Scope has been clearly defined, communicated, and agree to by stakeholders. Design will be reviewed and challenged by OPG.	**Low**
Schedule				
Schedule for completing contractor selection may be delayed due to rigorous management, supply chain and legal reviews of the RFP.	Schedule delay.	**High**	Reviewed OPEX & had adjusted schedule to allow more time. Early Supply Chain involvement to ensure that the tendering process for the contract is completed as soon as possible.	**Medium**
Fine tuning of contracting strategy & changes to funding release strategy may impact	Delay project schedule and increase costs.	**High**	Obtained agreement with line management on present funding strategy. Contracting strategy and design/installation requirements	**Medium**

overall cost and schedule			will be reviewed with Supply Chain, Procurement, Design and Legal.	
Insufficient information to determine the timeline of design deliverables accurately, and design deliverables may not be on time	Delay to Schedule	Medium	Finetuning of final design deliverable timeline is available via partial BCS. Select approved vendor, provide clear scope and deliverables, review progress regularly. Establish and monitor effective design performance metrics.	Low
Resources				
Insufficient OPG design resources available.	Delay project schedule and milestones	High	Design will be contracted out to an external agency. OPG Projects Design have committed to provide DTL support for this project.	Low
Availability of qualified vendors to perform engineering	Delay in issuing contract due to the need to assess various interfacing risks and vendor qualification issues and contracting language	Medium	Obtain OPEX from other OPG projects of similar nature. Early involvement with Supply Chain and various other departments on potential vendors and the associated contracting strategies.	Low
Technical				
Commercial drum cleaning equipment being recommended may be more complicated than anticipated when installed in a nuclear system.	Costs and schedule delays if extensive testing and re-engineering is required.	High	Potential design vendor will be informed that the equipment must be evaluated for suitability in the plant before equipment purchase and implementation.	Medium
Meeting seismic requirements	Increase cost to the project due to unknown civil upgrades to meet the seismic requirements	High	Seismic qualification considered as part of the conceptual study. Seismic qualification requirements to be included in Preliminary Design.	Low
Legacy issues on Design	Re-engineering may be required if there are legacy issues with the systems that the Project is modifying.	High	Completed preliminary system walkdown to identify potential legacy issues. Further detail reviews of documents and site scanning will be conducted to determine impacts at the Preliminary Engineering stage.	Medium
Regulatory				
Regulatory approvals (CNSC/TSSA) may require moer time than anticipated	Delay in project and potential cost impacts to the contract.	Medium	Identify required time allowance in project schedule. Incorporate approved time in contracting strategy. Review OPEX with	Low

			similar projects.	
Environmental				
Drum cleaning procedures may impact of MOE requirements.	The drum cleaning method is yet to be finalized at the Design Stage. The solvent used may impact of MOE requirements, requiring special treatment before disposal.	**High**	The most appropriate method of drum cleaning will be evaluated during the Preliminary Engineering phase. Perform testing at vendor site if necessary.	Low
Health & Safety				
N/A				
Investment				
Some of the cost assumptions in the base case are worst case scenarios based on engineering judgment.	NPV and IRR results may be less optimistic than calculated.	**Medium**	Stakeholder line management was involved in obtaining information from historical performances of the systems.	**Medium**
Inability to recover investment	Insufficient time to recover capital investment before stations' end of life.	**Medium**	The current NPV and IRR indicate a return of investment before stations' end of life.	Low
Early end of life of PNGS	Insufficient time to recover capital investment if end of life is earlier then currently forecast	**Low**	Using the current forecast of DNGS end of life date the current NPV and IRR indicate a positive return on investment before stations' end of life	Low

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	TBD in Next Release TBD in Next Release	TBD in Next Release TBD in Next Release	

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

CNSC	Canadian Nuclear Safety Commission
D_2O	Heavy Water
Downgraded D2O	Heavy Water of an isotopic that is not suitable for use in the moderator or the primary heat transport system
ECs	Engineering Changes
EOL	End of Life
IXCU	Ion Exchange Clean Up
OP&P	Operating Policies and Principles
PHT	Primary Heat Transport
Reactor Grade D2O	Heavy Water of an isotopic that is suitable for use in the moderator or the primary heat transport system
S&I	Storage and Inventory
Sulzer-B Upgrader	High curie heavy water upgrader
TOC	Total Organic Carbon
TRF	Tritium Removal Facility
UPP-B Upgrader	Low curie heavy water upgrader

Appendix "B" — Project Funding History

$ 000's Release Type	Month	Year	Previous Releases (incl contingency) Cumulative Values							Later	Total
None											0
											0
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:

The current total project estimate of $17.4M (including [redacted] contingency) is a conceptual quality estimate of +60%/-25% and has an estimated Available for Service Date in Q2 of 2010. Altus Helyar has independently verified this estimate and includes a contingency of [redacted] as recommended by OPG Finance. Given that this estimate is based on conceptual information, there is a risk that this estimate may escalate (refer to Section 6, Risk Table)

Project funding in the amount of $5.0M [redacted] is listed in the current approved Business Plan 2006 to 2010. There is $0 capital spending released to date for this project. The funding variance in the Business Plan will be corrected via PCRAF in 2007.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
OPG staff will provide project management and support role during design and implementation.
Material cost assumptions are based on using Class 3 tanks, hangers, piping and associated components and equipment.
Design and installation work will be contracted out.

Financial Assumptions:
Escalation rate on employee wages: 3%
Escalation rate on other expenses: Canada IPPI

Project / Station End of Life Assumptions:
As per memo J. Froats to D. Power, May 10, 2006, File No. NK30-01060 P, Pickering B Units 5,6 and 7 will have a End of Life of 2014 and 2016 for Unit 8.

See Attachment D for details of Expenses & Savings assumptions.

Energy Price / Production Assumptions
N/A

Operating Cost Assumptions
New operating costs are negligible.
External costs to upgrade D_2O is $15/kg
Cost to lease D_2O from AECL is $0.055/kg/day

Other Assumptions:
All work is within the secured area with incumbent restrictions.
OPG will procure all Nuclear Class and Pressure Boundary materials.

ONTARIO POWER GENERATION

OPG Confidential	
BUSINESS CASE SUMMARY	

PNGS-A D2O Storage and Drum Cleaning Facility Project 13 - 49251

Developmental Release Business Case Summary NA44-BCS-38000-00001-R000

Attachment "A" **Project Cost Summary**

Choose One Choose One	LTD Prior Yr 2006	This Release 2007	This Release 2008	Future Release 2008	Future Release 2009	Future Release 2010		Later	Total
Project Management (OPG)		435		671	748	538			2,392
Engineering & Drafting (OPG)		304		558	425	447			1,734
Material	[redacted]								
Installation – PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
	[redacted]								
	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
Project Costs (incl contingency)	-	1,330	1,176	2,837	7,720	4,319	-	-	17,382
2006-2010 Business Plan	200	1,000		3,000	800	-			5,000
Variance to Business Plan	(200)	15	898	(834)	5,093	3,297	-	-	8,269
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
[redacted] (excl contingency)	[redacted]								
Total Release (incl contingency)	-	1,330	1,176	2,837	7,720	4,319	-	-	17,382

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Zero to Minimal		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	N/A
Similar Projects	N/A	Contracts in place	N/A	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2006-2010 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Jan 2007.

Reviewed By: Nov 21/06

Stephanie Tham
Project Manager

Date:

Approved By: [signature] for Peter Floyd 22 Nov 06

Peter Floyd
Eng & Mods Manager (Strat IV)

Date:

ProjectPNGS-A D2O Storage and Drum Cleaning Facility Pr Name 13 - 49251

Developmental Release Business Case Summary NA44-BCS-38000-00001-R000

Attachment "B" **Project Variance Analysis**

Capital	LTO Nov 2006	Choose One: Last BCS N/A N/A	Choose One: This BCS Nov 2006	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation - PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:
N/A

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
21	DEC	2006	Project Start Milestone (PSM)
23	DEC	2010	Project Complete Milestone (PCM)
02	JAN	2009	Budget Quality Estimate Approved (BEA)
04	JUN	2009	Full Release BCS Approved (FR1)
17	JUL	2009	Major Contract Awarded (MCA)
19	NOV	2007	Preliminary Design Complete (DES)
03	DEC	2007	Engineering Work Scope Identified (ESI)
05	NOV	2007	Regulatory Approval Obtained (RAO)
17	SEP	2008	DCP Approved - Drum Cleaning Facility (DCP)
16	OCT	2008	DCP Approved - IXCU (DCP)
17	SEP	2008	Final Design Complete Phase 1 (FD1)
11	AUG	2009	Start of Installation (SOI)
07	JAN	2010	AFS - Drum Cleaning Facility (AFS)

A Project Execution Plan (PEP) will be approved by Aug 2007

Comments:
Other Key milestones:

26	APR	2010	AFS- IXCU (AFS)
1	JUL	2010	In-Service Declaration (ISD)
26	NOV	2007	Long Lead Materials Identified (LLT)

Attachement D: Incremental Costs & Expenses Assumptions

Category	Comments	
	Before PND-B End of Life (2007 to 2016)	After PND-B End of Life (2017 to 2026)
Expenses Without Drum Cleaning Facility (DCF)		
New Drum Purchases	[redacted]/drum x 20 drums/year; 0 drums/yr after AFS	15 drums/year after PB end of life; 0 drums/yr after AFS
Additional Drum Handling Cost	2.7 drums/day @ 3 hours/drum x [redacted] x 365d; 0 drums/yr after AFS	2.0 drums/day after PB end of life; 0 drums/yr after AFS
Costs to clean drum contents	[redacted] per event once every 2 years; $0 after AFS	
Costs on Drum Disposals	10 drums x 0.25 m3 x [redacted]/m3 disposal; $0 after AFS	7.5 drums after PB end of life ; $0after AFS
Leasing costs-D2O Makeup for unprocessable water	[redacted] x (0.3 drums/day x 365d/yr x 230 L/drum x 30% isotopic x 1 kg/L) x 200 days of lease; $0 after AFS	0.2 drums/day after PB end of life; $0 after AFS
Expenses Without Additional IXCU tanks		
Costs to cleaning IXCU Tanks	105K per event once every 2 years $0k after AFS	
erator Work Around for k Handling	2 FTE; 0 FTE after AFS.	
Upgrader Degradation - External Mitigation Costs (with escalation)	External upgrading cost= [redacted] when demand feedrate is less than upgrader's capability; Without IXCU, entire yearly load will be upgraded externally during repacking in 2014. Upgrader degradation rate: -8Kg/hr/yr :UV in service only in 2007, or -2kg/hr/yr: UV & IXCU in service in 2010; Demand feedrate reduces from 150kg/h to 105kg/h in 2015/2016 when 3 PB's units are out of service.	Same except the Demand upgrader feedrate reduces to [redacted] after PB end of life.
Packing Change Costs (with escalation)	[redacted] to repack in 2014 without IXCU tanks; or delayed to 2042 if IXCU is installed.	
Expenses Without Additional S&I tanks		
Offsite water storage - TDO Shipments Costs	[redacted]/TDO trip x 7.5 trips/year; 0 trip after AFS	5 trips/year after PB end of life; 0 trip/year after AFS
Incremental Operating Expenses of DCF		
Operation Expense of DCF - Labour	1FTE	
Incremental Operational Expense - Utilities	[redacted]/drum x 10 drums/day x 365days	
aste Disposal Costs of DCF	100 drums with sludge of 3.5" in each (ONE TIME COST of 0.0889m x (0.61m/2)^2*Pi x [redacted]3.	

Attachement D: Incremental Costs & Expenses Assumptions (Cont..)

Category	Comments	
	Before PND-B End of Life (2007 to 2016)	**After PND-B End of Life (2017 to 2026)**
	Savings After Additional S&I Tanks Installed	
Fuel Burn Up Savings	About 187Mg of the yrly TRF product shortfall can be received to detritiate & improve moderator isotope after AFS (reference: Kinectrics Report Appendix A for detailed calculation & yearly distribution).	
Dose (ALARA) Savings	About 187Mg of the yrly TRF product shortfall can be received to detritiate & improve ALARA after AFS (reference: Kinectrics Report Appendix A for detailed calculation & yearly distribution).	

ONTARIOPOWER GENERATION

BUSINESS CASE SUMMARY

PNGS-A Switchyard Relay Building Replacement Project 13 - 49266

Full Release Business Case Summary NA44-BCS-65130-00002-R000

Routing	Location	Action	Signature	Date
Leon Simeon Project Leader Design Projects, Pickering A	P72-2	Prepare BCS	Leon Simeon	Oct 12/20
Craig Verwey Project Manager Design Projects , Pickering A	P72-3	Review BCS	[illegible]	OCT 12/20
Peter Floyd Manager Design Projects, Pickering A	P72-1	Review BCS	[illegible]	Oct 17/07
Mark Arnone Director Projects & Modifications	P72-1	Review BCS	[illegible]	12 OCT 2007
Dwight Zerkee Manager Investment Manager	P82-3B6	Review BCS	Paul Mather (for)	18 OCT 2007
George Boyd Manager Systems Performance Engineering, Pickering A	P42E3	Review BCS	George Boyd	Oct 15/07
Robert Black Director Station Engineering Pickering A	P42E1	Review BCS	RKBlack	15 Oct 07
Mark Elliott Senior Vice President Pickering A ✓RK Black	P42E3	Submit BCS	RKBlack	15 Oct 07
Randy Leavitt Director Investment Management	P82-3	Review BCS	RLeavitt	Oct 18, 2007
Jim Beech Vice President Nuclear Finance	TCH09F06	Review BCS	[illegible]	Oct 18, 2007
Tom Mitchell Chief Nuclear Officer	P826A-1	Review BCS	TMitchell	22 OCT 2007
Donald Power Director Investment & Business Planning	TCH07D06	Approve BCS	DPower	Oct 31/07
Pierre R. Charlebois EVP & Chief Operating Officer	P826A-1	Approve BCS	P. Charlebois / See attached	Oct 31/07
Ball nior Financial Analyst 2-4084	P82-3B6	Return For Distribution		

PNGS-A Switchyard Relay Building Replacement Project 13 - 49266

Full Release Business Case Summary NA44-BCS-65130-00002-R000

1/ RECOMMENDATION:

We **recommend a Full Release of $7,452K (including contingency of** [redacted] to complete the commissioning of a new Unit 012 Protection, Control & Telecom (PCT) interface with Hydro One and preparations for Unit 034. This BCS covers the OPG portion of this Joint Project; Hydro One is funding the work related to their property and equipment.

The business objective of this project is to **improve the reliability of the station's Main Output system**. Failure to properly interface OPG equipment with new Hydro One switchyard protection and control systems will leave the station vulnerable to forced outages and associated financial losses. This will be achieved by modifying OPG equipment and systems to interface with the new PCT system being installed by Hydro One in the PNGS-A switchyard. The new PCT system will utilize an independent dual redundant design philosophy to comply with current NPCC/IESO guidelines to provide full separation of A and B protection channels in the switchyard.

This project will be **executed in several phases between 2007 and 2010**. Initial installation of the new PCT system and interfaces for Unit 012 will be undertaken during P711 in Fall 2007 followed by similar modification for Unit 034 in P841 (2008). Remaining work, including DCC alarm update, Sequence of Event Recorder update and final update of associated design documents, will be staged and implemented online or during successive outages as required in 2009 & 2010.

The installation of the trench, duct bank, cabling and terminal boxes have been covered under the **Partial Release of funding**. Refer to section 2.0 "Background & Issues" for additional information.

Full release funding is required now to **meet P841 milestones** and to **complete commissioning of U1/2** during P711. Refer to section 2.0 "Background & Issues" for additional information.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Partial	-	260	8,060					8,320
Requested Now	Full	-		1,125	3,350	1,867	841	269	7,452
Future Funding Req'd	None								-
Total Project Costs		-	260	9,185	3,350	1,867	841	269	15,772
Other Costs									-
Ongoing Costs									-
Grand Total		-	260	9,185	3,350	1,867	841	269	15,772
Investment Type Value Enhancing		**Class** Capital		**(IEV) Impact on Ec Value** 19,699		**IRR** 27.4%		**Discounted Payback** 7.3	

Submitted By:

16 OCT 2007

for M. Elliott
Site VP, Pickering A
Date:

Finance Approval:

Oct 29/07

D. Power
Director Investment Management
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Oct 31/07

P.R. Charlebois
EVP and COO
Date:

4/ BACKGROUND & ISSUES

As a result of a **major fire in early 2006 (SCR-P-2006-05953/07053)**, the **PCT equipment** in PNGS-A switchyard relay building **was damaged beyond repair**. Further investigation revealed a significant number of fire-damaged cables inside cable trenches in the relay building. The extent of the damage forced Hydro One and OPG to bypass the damaged relay building equipment with a **temporary protection & control solution** in order to maintain connection of Pickering A units to the grid.

Additionally, OPG Engineering & Maintenance and Hydro One observed **significant degradation of existing cables** connecting the station with the switchyard as a result of aging and submersion in water for extended durations. This condition also influenced Hydro One's final decision to **install a new PCT system** compliant with current NPCC/IESO guidelines. This modification will **enhance reliability of the switchyard** as well as **comply with current market rules** for the Bulk Electricity System. OPG is also obligated to operate within these guidelines.

OPG will **install new trenches, duct banks and cabling from the switchyard to the station** and modify the wiring as required to support the Hydro One independent and fully separated dual protection channel initiative.

Hydro One is responsible for installation costs related to the upgrade/replacement of their equipment. OPG is responsible for the costs related to the upgrade/replacement of OPG-owned equipment.

The **Unit 2/3 Safe Storage Project will be responsible** for costs associated with Unit 2/3 specific work not covered under the scope of this project. This project will ensure the ring bus protection for the Unit 2 & 3 SST is restored.

To meet these **objectives the project** will undertake the following:

- Design, install and commission a new interface for system interconnectivity between Hydro One and OPG station equipment.
- Implement revised Alarm and SOER signals from switchyard consistent with current standards.
- Update related design, operating and maintenance documents.

The scheduling of the project will be staged from 2007 thru 2010 outages with the initial primary focus to install and commission system interconnectivity between the station and the new PCT system on Units 012 during the P711 outage and Units 034 during the P841 outage.

<u>The following **work has been completed** under the **Partial Release, NA44-BCS-65130-00001: $6.3M**</u>

- Detailed design for all civil (U12/34) and U1/2 Electrical
- Installation of the East and West trench from the powerhouse to the security fence.
- Installation of cable duct from security fence to switchyard. Installation of a cable vault for the demarcation point.
- Installation of Marshalling boxes inside powerhouse and demarcation boxes in the switchyard.
- Installation of wall & floor penetrations in the powerhouse for new cable trays.
- Installation of new cable trays inside powerhouse and inside of the trenches.
- Pulling of new power cabling from the powerhouse to the new ATS building in the switchyard.
- Installation of two new circuit breakers for 600V power supply to the new ATS building. This work has completed a successful AFS.
- Pulling of new protection and control (P&C) cabling for U1/2 from Marshalling boxes in the powerhouse to demarcation boxes in the switchyard.
- Termination of P&C cabling for U1/2 in the Marshalling and demarcation boxes.

<u>**Outstanding work** which will covered by the remaining amount of the Partial Release</u>

- Pulling of U3/4 P&C cabling from the Marshalling boxes to demarcation boxes.
- Termination of U3/4 P&C cabling from the Marshalling boxes to demarcation boxes.
- Final grading, handrails and steps for the civil installation.

Contingency Funding from the Partial Release was used to cover the cost of the following: **$1.9M**

- Design and installation of the cable duct and vault in the switchyard. This risk was identified since the design was not available at the time of estimate and contingency funding was set aside to cover this risk.
- Cost of scaffolding for cable tray installation. The cable tray routing for power trays were not known at the time of estimate and contingency funding was set aside to cover this risk.
- Trench installation delays due to interferences and boulders during the boring under the security fence.
- Delays and rework due to the main service water break in the switchyard. The break was not a result of this project.

Full Release funding is required to complete the following work. **$7,452K**

- Increase in Hydro One commissioning cost for P711. Note Hydro One is responsible for installation costs related to the upgrade/replacement of their equipment.
- Increase in installation cost due to the ISTB project (double shifts / premium time for electrical contractor).
- Design for U3/4 execution during P841. TCD for this package is 28 Feb. 2008.
- Increase scope to include the U2/3 Safe Storage Alarm reduction into the execution Engineering Change Package.
- Increase scope to remove On Line Wiring covered under U2/3 Safe Storage packages
- Complete the commissioning for U1/2 during P711
- Start the detailed design for U3/4 and to complete the commissioning for U3/4 during P841
- Alarm cleanup for U1/2 during P911
- Alarm cleanup for U3/4 during P1041
- Close out

Explanation for increase ($1.2M) from the Partial Release

- Increase in commissioning cost during P711 outage
- Scope increase as some of the U2/3 Safe Storage scope (switchyard related) had to be brought into this projec to eliminate re-work and ensure configuration management was maintained.
- Inter-Station-Transfer-Bus impact as double shifts and premium time were needed to recover the time lost by the trades used to support this work.
- Increase in security cost. 24/7 coverage were required during the boring and work next to the security fence.
- Increase in design costs to start the U3/4 detailed design for P841.
- Soil removal cost.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue	(76,966)	(4,348)	(4,348)	(6,112)	(40,657)		
OM&A	(22,052)	(1,115)	(1,115)	(3,724)	(22,052)		
Capital	-	(14,052)	(6,637)	(7,041)	(905)		
NPV (after tax)	(28,492)	(14,972)	(8,793)	(11,198)	(19,544)		
Impact on Economic Value (IEV)	N/A	13,520	19,699	17,294	8,948		
IRR%	N/A	15.6%	27.4%	24.5%	41.2%		
Discounted Payback (Yrs)	N/A	11.20	7.33	9.25	4.00		

Status Quo - Not Recommended

This option is not recommended since it would not be possible to complete U1/2 installation, and the investment to date would be lost. Also, the existing temporary arrangement to bypass the damaged relay building equipment was intended to be a short term solution. This and the degradation of the existing cabling in the cable ducts connecting the OPG units to the relay building will not ensure proper protection & control of the PNGS-A units' grid connection and is not in compliance with the NPCC/IESO guidelines for grid protection.

Base on the cable fault history input from Performance Engineering, Hydro One and other stakeholders, it is predicted that the probability of a similar failure in the future is significantly high. Any such failure in the switchyard equipment will isolate both operating units (Units 1 and 4) from the transmission grid with substantial financial loss to OPG in the order of 500K$ per unit per day.

Hydro One is spending considerable resources and funding to upgrade reliability of the switchyard. To ensure full advantage of these upgrades is obtained, OPG must improve the reliability of the connection to these systems.

The project will be unable to complete the U1/2 installation & commissioning and the investment to date would be lost.

Alternative 1 - Full Copper Technology with New Cable Duct - Recommended

OPG will continue to design, install and commission an improved interface system for interconnectivity between Hydro One and OPG systems with the following features:

- Like-for-like replacement of protection and control functions to the extent practicable.
- Design, installation and commissioning of interface system based on all copper replacement.
- Replacement of existing copper cables which are degraded due to being submersed in water for long durations and end of life expectancy.
- Design and install a new dual buried duct system for routing the cables from switchyard to the station.
- Design and install the revised Alarm and SOER signals from the switchyard to the station.
- Design and install new dual independent AC feed from plant to the switchyard as required for the new Hydro One relay buildings.

Hydro One will replace the existing relay building equipment with a dual independent PCT system incorporating full separation in compliance with NPCC/IESO guidelines and interfacing based on copper technology.

This option is recommended since it is based on existing copper technology and like-for-like replacement of the functionality of the protection and control scheme. The new duct system will allow cable replacement and other major tasks outside the outage schedule without any risk of damage to the operating units.

Reliability of the Class IV Power system is enhanced consistent with Safety Analysis requirements and reduction of probability of forced outages due to equipment failures in the switchyard.

Alternative 2 - Delay Project - Not Recommended
Delaying this modification is not recommended since this will keep the PNGS-A units and equipment at a high risk of grid protection related forced outages. If grid protection & control is not updated the OGCC may not allow the generating units to be connected to the grid. Either scenario would result in a subsequent financial impact of ~ 500K$ per unit per day.

The rate of degradation of the existing cabling is unknown. Any cost savings to OPG by delaying would be offset by the increasing risk of forced outages. Additionally, OPG and Hydro One costs to defer due to remobilization and interest costs is estimated to be $2.2 M.

Alternative 3 – Complete U1/2 Work and Leave U3/4 As Is - Not Recommended
The old and the new switchyard relay buildings would need to be maintained and U3/4 reliability issues would still exist. In addition, if U3/4 work is not performed, OPG will not comply with the current market rules for the Bulk Electricity System, as set by the current NPCC/IESO guidelines.

Alternative 4 – Do more - Not Recommended
The recommended option has considered all necessary actions to take full advantage of the upgrade in the switchyard protection scheme by Hydro One and achieving optimal reliability from the switchyard functions.

Alternative 5 – - Not Recommended
None

4/ THE PROPOSAL

The following are the objectives and deliverables for this **Full Release BCS**:

- To complete commissioning of U1/2 with increased scope and ISTB impacts (see Section 2.0, Background).
- To complete the detailed engineering work including the On Line Wiring for the U3/4 cable cutting & termination and alarm cleanup.
- To complete the installation of the Unit 3/4 cabling from the demarcation to the marshalling boxes.
- To prepare detailed work plans, field installation packages and commissioning procedures for P841 work.
- To complete all installation and commissioning work for Unit 034 portion of the project during P841 outage.
- To complete the close out of U1/2 and U3/4 design packages
- Alarm cleanup for U1/2 during P911
- Alarm cleanup for U3/4 during P1041

5/ QUALITATIVE FACTORS

Replacement of switchyard PCT equipment and related interfacing equipment and cabling will increase reliability of the entire switchyard, enhance OPG unit and equipment protection in case of a grid failure and vice versa while complying NPCC/IESO guidelines for the protection scheme.

Class IV electrical power system reliability will be increased. The probability of unit trips and associated equipment stresses following unit trips will be reduced. Impairment of the protection systems' availability during fault situation due to cable failures would be minimized. This would result in avoiding potential catastrophic equipment failure causing extended outages and/or significant grid impact.

This reduced probability of transmission failure and enhanced protection of OPG plant equipment will have a positive financial impact for the rest of the expected plant life for Pickering A Units.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Since the U1/2 commissioning has not been completed there is limited Lessons Learned/OPEX information available for U3/4.	This might lead to higher level of engineering installation and commissioning cost	**High**	Rigorous planning and team work with stakeholders to identify any emergent abnormal situations that may arise. General contingency	**Medium**
Scope				
Discovery - Increase in scope	Increased costs and schedule impact	**Medium**	As most of physical installation is complete, risk is now limited to commissioning, documentation, and configuration management. General Contingency	**Low**
Schedule				
Inability to meet design Outage milestones for P841 due to the same resources working on P711.	Non compliance with N-PROC-MA-0013 & N-PROC-MA-0022	**Medium**	Design has committed to delivering the P841 design EC on Feburary 28, 2008 (Refer to SCR P-2007-16725).	**Low**
H1 commissioning longer than outage window	Increased costs Lost revenue	**High**	P711 outage Lessons Learned will be used to take required actions for P841	**Low**
				Low
Resources				
Insufficient OPG Design resources to support project.	Schedule delays	**Medium**	Contract out Project Design work to external design agency. Obtain commitment from OPG Project Design to support project.	**Low**

Limited Hydro One resources to support commissioning work during outage	Delay in outage schedule	**Medium**	Set up contracts with Hydro One in advance to ensure availability of their resources as per schedule.	**Low**
Limited OPG station support.	Delay in schedule of pre-reqs and outage.	**Medium**	Obtain commitment for OPG station support as per schedule.	**Low**
Technical				
Commission failure	Increase in outage schedule	**Medium**	Detailed commissioning work plan. Support on standby for outage troubleshooting	**Low**
Regulatory				
No regulatory approval required.		**N/A**		**Low**
Environmental				
There are no environmental risks.		**N/A**		**N/A**
Health & Safety				
Personal injury from working in vicinity of high voltage.	Potential serious personal injuries.	**High**	Proper pre job briefing, appropriate PPE and work protection.	**Low**
Investment				
No investment risk involved		**N/A**		**N/A**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2010	Jan 2011	George Boyd

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	600V power supply to new ATS building in the switchyard	Not in service	600V power supply to new ATS building n service	Successful AFS	Performance Engineering
2.	Unit 1/2 new Switchyard protection and control cabling in service.	Not in service	U 1/2 new protection and control cabling in service	Successful AFS	Performance Engineering
3.	Unit 3/4 new switchyard protection and control cabling in service	Not in service	U 3/4 new protection and control cabling in service	Successful AFS	Performance Engineering
4.	Configuration documentation	Existing configuration	Revised Configuration	ECC Close Out	Project Design

Appendix "A" — Glossary (acronyms, codes, technical terms)

AFS	Available For Service
BCS	Business Case Summary
NPV	Net Present Value
PCRAF	Project Change Request Authorization Form
PEP	Project Execution Plan
MWH	Mega Watt Hour
NPCC	North-eastern Power Coordinating Council
IESO	Independent Electricity System Operator
OGCC	Ontario Grid Control Center
PIR	Post Implementation Review
PCT	Protection, Control & Telecom
PNGS	Pickering Nuclear Generating Station
OPG	Ontario Power Generation
CT	Current Transformer
PT	Potential Transformer
SER	Sequence Event Recorder

ONTARIOPOWER GENERATION

Appendix "B" **Project Funding History**

				Cumulative Values							
Release Type	**Month**	**Year**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**Later**	**Total**
Partial	N/A	N/A	260	8,060	0	0	0	0	0	0	8,320
Full				1,125	3,350	1,867	841	269			7,452
None											0
None											0
N/A											0
N/A											0
N/A											0
N/A											0
LTD Spent	N/A		260	7,155							7,415

Comments:
2007 year to date values are up to the end of Fiscal week 093 in Scores.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
2007-2011 labor rates are used.

Cost of material, support and vendor design are taken from the conceptual budgetary estimates received from vendors and other OPG groups.

Financial Assumptions:
7% discount rate.

Project / Station End of Life Assumptions:
End of life expectancy for Pickering A station assumed ≤ 2024.

Energy Price / Production Assumptions
Energy Price at $49.5 / MWH
Production assumed as 510 MW per unit for Pickering A units (1 & 4)
Capacity factor 0.8
Revenue loss per unit for one year = 510x0.8x24 (hours)x365 (days)x$49.5 = $176,916,960

Operating Cost Assumptions

N/A

Other Assumptions:
Considering the previous cable fault records, inputs from Hydro One and Performance Engineering, the probability of similar fault reoccurring in future is considerable and is an increasing function with time.

For our calculation a simple exponential distribution of risk ($Y= M e^{0.1659 t}$) is considered for the rest of plant life up to 2024 with a base risk (5%) at present as shown in figure 1.
Y= Cumulative risk probability, M= Base risk factor, t= Plant life from now (0-18 Years)

In case of a severe failure due to current condition in the Pickering A switchyard both the units (U1 & U4) will be disconnected from the grid for a minimum 60 days period before it can be restored per input from Hydro One.

Revenue loss for any such failure is calculated with cumulative risk factor derived from the exponential distribution for that time period and generation and OM&A cost for 60 days forced outage for two units.
Generation revenue loss for 60 days forced outage for 1 unit = $177/365X60 = $29M / unit
Since two units (Unit1& 4) are connected to the grid via the PNGA switchyard the effective generation loss due to unavailability of the switchyard to be considered as two times the calculation = $29MX2= $58M
OM & A manpower, material and engineering cost for 60days outage to restore 2 units back to the grid
= Manpower(60 X 200 K$) + Approx. Engineering & Material cost (4000K$) ~ $16M

Total economic impact for 60 days outage = 58+ 16 ~ $74M
Estimated economic impact = (Total economic impact) X Risk Probability at that time.

Assumed 1 year delay for the delay option (Alternative-2) with project cost escalation @ 3% per year of delay

Interest and remobilization costs are estimated at $2.2M

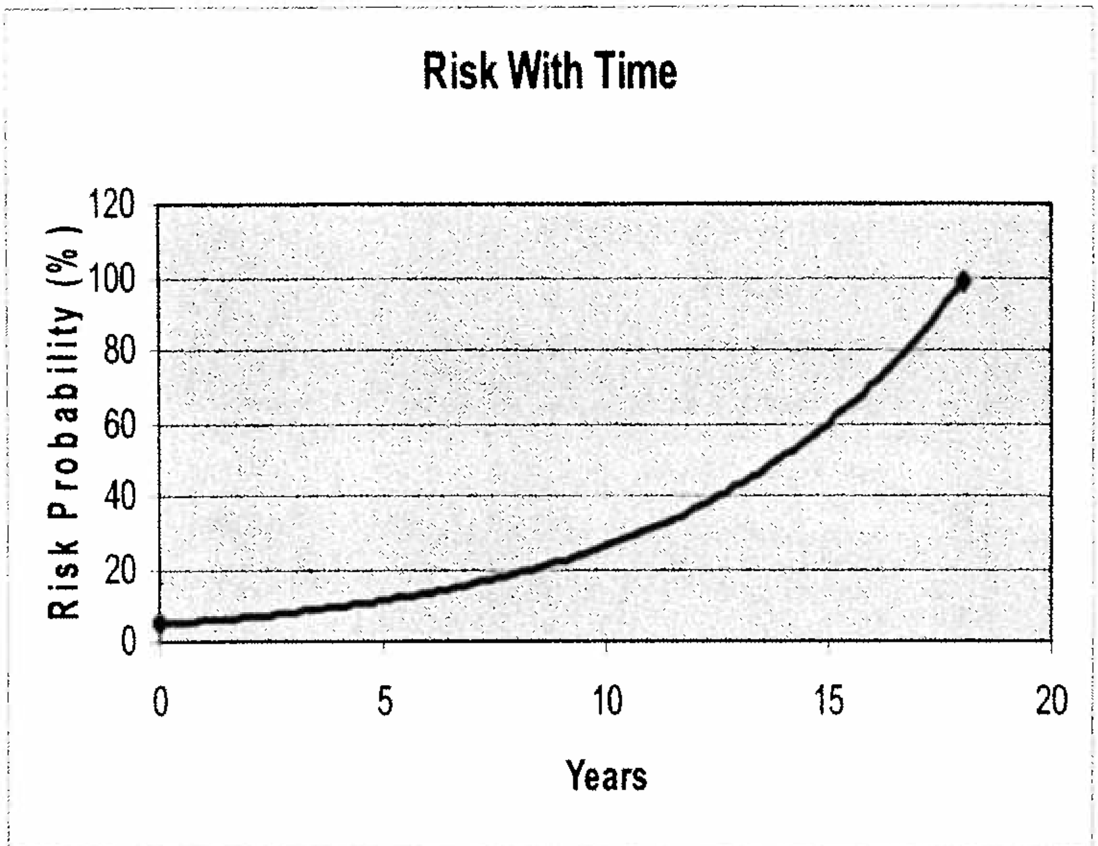
Risk With Time
Risk Probability (%)
120
100
80
60
40
20
0
0
5
10
15
20
Years

Figure - 1

PNGS-A Switchyard Relay Building Replacement Project 13 - 49266

Full Release Business Case Summary NA44-BCS-65130-00002-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr 2006	2007	This Release 2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011	Later	Total
Project Management (OPG)	24	568		575	461	286	123		2,037
Engineering & Drafting (OPG)		583	231	426	340	259	49		1,888
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	124	8,196	1,125	3,350	1,867	841	269	-	15,772
2007-2011 Business Plan		6,215		2,577	1,286	647	207		10,932
Variance to Business Plan	124	88	865	-	150	-	-	-	1,228
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	[redacted]								
Total Release (incl contingency)	124	8,196	1,125	3,350	1,867	841	269	-	15,772

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects	N/A	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Oct 2007.

Reviewed By: Oct 12/07

Craig Verwey
Project Manager

Approved By:

Peter Floyd
Eng & Mods Manager (Strat IV)

ONTARIOPOWER GENERATION

PNGS-A Switchyard Relay Building Replacement Project 13 - 49266

Full Release Business Case Summary NA44-BCS-65130-00002-R000

Attachment "B" **Project Variance Analysis**

Choose One	LTD Sep 2007	Full Release Last BCS N/A N/A	Full Release This BCS N/A N/A	Variance	Comments
Project Management (OPG)	594	2,109	2,109	-	No Change
Engineering & Drafting (OPG)	742	1,697	1,928	231	Additional amounts for On Line Wiring and scop increase for station initiative for Alarm reduction.
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	7,415	14,452	15,772	1,320	
Committed Cost				-	
Inventory Write Off Required				-	
Spare Parts / Inventory				-	
Total Release (incl contingency)	7,415	14,452	15,772	1,320	
Total Release (excl contingency)	7,415	11,117	12,132	1,015	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Life to Date for the project is based on 2006 and 2007 year to date values up to Fiscal Week 093 in SCORES.

\ttachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
30	Oct.	2007	Full Release BCS approved
16	Oct	2007	P711 outage pre req. complete.
28	Dec.	2007	U1/U2 PCT system commissioning complete and AFS'd.
28	Feb.	2008	P841 Detailed Design complete
12	Jun.	2008	Close out for U1/U2 PCT.
11	Aug.	2008	Pre req. work for P841 complete.
10	Dec.	2008	U3/U4 PCT commissioning complete and AFS'd.
10	Jun.	2009	Close out for U3/U4.
16	Nov.	2009	Alarm clean up for U1/U2 by P911 and AFS'd.
15	Jun.	2010	Alarm clean up for U3/U4 by P1041 and Final AFS.
15	Dec.	2010	Project close out complete.

A Project Execution Plan (PEP) will be approved by Jan 2008

Comments: Major installation and commissioning activities of this project are outage dependant and currently scheduled for P711 in 2007 and P841 in 2008.

DNGD: EQ Closure and Component Replacement Project 16 - 38457

Full Release Business Case Summary D-BCS-03651-10004-R000

Routing	Location	Action	Signature	Date
M. Arnone Director, Projects & Modifications	P72	Review BCS		2 Nov 2007
R. Leavitt Director, Nuclear Investment	P823-315	Review BCS		Nov. 2, 2007
J. Lehman Director, Station Engineering Darlington (Acting)	D08ES3	Review BCS		Nov 6/07
J. Beech Vice-President, Nuclear Finance	TCH07E19	Review BCS		Nov 7, 2007
W. Robbins Senior Site Vice-President Darlington	D08ES3	Submit BCS		2007-11-12
T. Mitchell Chief Nuclear Officer	P826A-1	Review BCS		2007/11/13
P. Charlebois Executive Vice-President & Chief ...erating Officer	TCH19A24	Review BCS		2007/12/14
... Power Vice-President Corporate Investment Planning	TCH07D06 REC'D DEC. 20	Approve BCS		2008/01/03
J. Hankinson Pesident & Chief Executive Officer	TCH19A24	Approve BCS		2008/[illegible]/27
R. Ball ...nior Financial Analyst ...2-4084	P82-3B6	Return For Distribution		

NOV 16 2007

Refer to:

DNGD: EQ Closure and Component Replacement Project 16 - 38457

Full Release Business Case Summary D-BCS-03651-10004-R000

1/ RECOMMENDATION:

We recommend approval of the release of $33.2M (including contingency), for a total release of $63.1M. This will allow the Environment Qualification (EQ) Closure and Component Replacement Project to complete the remaining component replacements which have been committed to the Canadian Nuclear Safety Commission (CNSC) and environmental qualification completion assurance activities. It will also permit the project to determine the most efficient means for maintaining full compliance with the environmental qualification requirements of the Darlington Nuclear operating license; and allow for preliminary engineering activities to begin for new EQ issues identified during this process.

The business objective of this project is to align Darlington systems and components with the EQ requirements of its Power Reactor Operating License (PROL). Action Assignment # 28058364 has been raised to track the completion of a Regulatory Commitment (REG C) made to the CNSC for the replacement of non-qualified components with EQ-qualified components by December 31, 2010.

A total of $29.9M was previously released in accordance with Organizational Authority Register (OAR) element 1.1. The funding was used to:

1. Complete designs associated with regulatory committed component replacements.
2. Replace components in the field in 2005, 2006 and 2007 as per the regulatory committed schedule.
3. Complete EQ List Development Packages (to be completed in November 2007)
4. Complete an EQ Program Self Assessment.
5. Complete a scope optimization study (to be completed in October 2007).

This request is to:

1. Replace the remaining components in the field in 2008, 2009 and 2010 as per the current regulatory committed schedule.
2. Carry out completion assurance activities for the components which have been replaced during the project and for those not expected to be affected by the scope optimization study.
3. Complete analysis to determine the most efficient means for Darlington Nuclear to meet the EQ requirement of its operating license. Develop the scope and business case for a new project to resolve new EQ issues arising from this analysis, if required.
4. Complete the transition the Project to the Station Sustaining EQ Program.

This release does not include any future detailed design, analysis or field work required to resolve anomalies outside of the scope currently committed to the CNSC, as shown in Attachment "D".

$M (incl contingency)	Funding	LTD 2007	2008	2009	2010	2011		Later	Total
Currently Released	Partial	26.7	3.2						29.9
Requested Now	Full		11.3	10.7	10.4	0.8			33.2
Future Funding Req'd									-
Total Project Costs		26.7	14.5	10.7	10.4	0.8	-	-	63.1
Other Costs									-
Ongoing Costs									-
Grand Total		26.7	14.5	10.7	10.4	0.8	-	-	63.1
Investment Type: Regulatory		Class: OM&A		(NPV) Impact on Ec Value: [illegible]		IRR: N/A		Discounted Payback: N/A	

Submitted By:

Wayne Robbins 2007-11-12

W. Robbins Date:
Senior Site Vice-President Darlington

Finance Approval:

2008-01-03

D. Power Date:
Vice-President Corporate Investment Planning

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson

2008/01/27

J. Hankinson Date:
President & Chief Executive Officer

BACKGROUND & ISSUES

The Ontario Power Generation Nuclear (OPGN) Environmental Qualification (EQ) program establishes an integrated and comprehensive set of requirements that provide assurance that essential equipment can perform as required if exposed to harsh design basis accident conditions and that this capability is preserved over the life of the plants. Under License Condition 7.1, Darlington must implement a program that is traceable, auditable and meets the OPGN requirements for EQ.

Requirements for Environmental Qualification (EQ) at Darlington Nuclear Generating Station (DNGS) were first spelled out in the Construction License and then formalized in 1978 with the first issue of the Design Guide. The "science" of EQ was in its infancy and formal EQ requirements did not apply to other CANDU stations. In the absence of Corporate, or National standards for EQ, a Darlington specific program manual was developed to provide governance for implementation of EQ. The list of equipment required to be qualified, the EQ Safety Related Component List (EQSRCL), was developed in a non-procedural, non-auditable manner and EQ was implemented at DNGS over the period 1986 to 1992.

The EQ program was handed over from Design & Construction to Operations in 1992. Lack of focus on the EQ sustaining program and the resultant degradation in component condition prompted the IIP EQ Restoration Program (Project EN009) in 1997. In November 1999, the CNSC proposed an amendment that became a part of the Darlington Power Reactor Operating License (PROL) requiring that the station provide evidence that required systems, components, protective barriers and structures in the facility are environmentally qualified by June 30, 2004.

The IIP Project was closed in 2001, with some scope necessary to comply with the PROL Condition outstanding. The transition plan identified the work to be completed, with an expectation that the majority of the issues would be completed by the end of 2003.

In May 2003 the CNSC provided acceptance criteria to clarify what was required to satisfy the PROL condition. At the direction of the Chief Nuclear Engineer the remaining EQ work was divided into two projects: one to complete activities necessary to satisfy the PROL condition due June 30, 2004 and a second to complete CNSC EQ commitments due after June 30, 2004 and establish a sustaining EQ Program.

The EQ Recovery Project (16-38411), which was completed June 30, 2004, involved completing the outstanding EQ assessments, completing gap analysis for components with a limited life and scheduling the resolution of issues remaining after June 30, 2004. Upon completion of project 16-38411, the current project, 16-38457 EQ Closure and Component Replacement was initiated to resolve the outstanding issues by December 31, 2010.

Under this project (16-38457), Darlington has followed the OPGN EQ list development process, as was done at the Pickering and Bruce sites, to update its EQSRCL; this process provides full traceability and compliance with the EQ design basis. During this exercise unqualified components that were not in the Darlington EQ program have been identified. As a result of these discoveries and other deficiencies the Senior Site Vice-President instructed the project to initiate a Darlington EQ Program Self-Assessment in 2006. One of the actions coming out of the self-assessment was the requirement for the EQ Project to perform a scope optimization study with the goal of identifying ways to reduce the scope and/or the cost of EQ.

The scope optimization study is scheduled to be completed in October 2007 at which time the recommendations will be used by the EQ Project and Darlington management to determine the most practical and economical path forward for EQ at Darlington.

Major deliverables achieved under previous releases of this project were:

1. Completion of EQ List Development Packages (TCD: November 30, 2007).
2. Completion of committed D541, D611, D631, D741, and D721 outage work (On track as per N-PROC-MA-0013).
3. Completion of committed 2007 online work (On track as per N-PROC-MA-0022).
4. Completion of design packages for remaining committed outage and online work (including discovery items for Limitorque actuators and ITT Cannon connectors - U1 packages complete, TCD for remaining packages: March 20, 2008).
5. Completion of an EQ Program Self-Assessment (Complete).
6. Completion of a scope optimization study (TCD: October 26, 2007).

The previous BCS (Ref. 7) was prepared prior to the current revision of the project charter (Ref. 6) which increased the scope of the project as described below:

1. Additional components which need to be replaced in the field were identified as a result of additional EQLDP packages being completed. (Only components currently committed to the CNSC, as detailed in Attachment "D", will be completed in this project)
2. It was identified that the transition to the EQ sustaining program will require a higher level of effort than originally anticipated from the project.
3. Requirement added to complete a scope optimization study.
4. Requirement to study fiber optical cables and determine a practical method to resolve the issues surrounding the requirement for them to be EQ. (This will not be addressed under this project.)
5. Requirement added to perform completion assurance activities for all EQ components. (In this project, completion assurance activities will only be completed for the components replaced under this project and those not expected to be affected by scope optimization.)

These changes have caused a small increase to the original cost estimate prepared under the previous BCS (Ref. 7), a new project is also expected to be required to address the deficiencies not covered by this project and new deficiencies which may be identified in the future.

In March 2007 the CNSC conducted an audit of Darlington's EQ program. The audit report (Ref. 5) has been sent to Darlington with several action notices and recommendations, the following are relevant to the EQ project:

- AN2 - Based on the requirements of OPG Environmental Qualification Program, N-PROG-RA-0006 and OPG procedure, N-PROC-RA-0092, Environmental Qualification Implementation and Preservation DNGS is required to expeditiously complete the Technical Basis Documents (TBD), EQSRCL, EQLDPs, EQAs, EQ cables list and On-Line Wiring. DNGS is also required to prepare an auditable EQSRCL, with sufficient references to basis documents and guidance for, how to fill and read this list.

- AN3 - CNSC inspectors observed lot of inconsistencies in the various documents as identified in Section 4.2 (of Ref. 5). DNGS need to revise these documents (EQ design guide, EQLDPs, EQA, EQSRCL, FIN procedure and EQLDP procedure).

- AN5 - DNGS has not qualified the fiber optic cables. We require DNGS to provide a schedule for the completion of EQ of the fiber optic cables.

- R4 - CNSC recommend DNGS that soon after the completion of all EQLDPs, the EQ RCM to be revised to provide conditions for all new rooms and areas, if needed.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions	Stop the Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay	Do Less	Do More	
Revenue	-	-	-				
OM&A	(2.67)	(63.11)	(39.08)	N/A	N/A	N/A	
Capital	-	-					
NPV (after tax)	(1.70)	(37.71)	(22.08)				
Impact on Economic Value (IEV)	N/A	(36.01)	(20.38)				
IRR%	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	N/A				

Stop the Project - Not Recommended

Stopping the project is not recommended. This would result in the outstanding committed scope of work to remain incomplete; as a result the REG C commitment would not be met.

Alternative 1 - Complete Committed Replacements & EQ Efficiency Analysis - Recommended

Completing committed component replacements (including completion assurance) and determining the most efficient means for maintaining full compliance with the EQ requirements of the license is recommended. The work is required to bring Darlington in compliance with its PROL and the failure to do so would result in the CNSC REG C remaining incomplete.

In order for Darlington to be successful in meeting its regulatory commitments it is critical that the installation activities for the committed scope of work continue as scheduled in parallel with the scope optimization study and other activities required to determine the most effective path forward for EQ at Darlington.

Alternative 2 - Delay Project - Not Recommended

Delaying the project is not recommended. The component replacements which are being done under this project have been committed to the CNSC for completion by December 31, 2010 under Action Assignment # 28058364.

Alternative 3 – Do Less - Not Recommended

Completing component replacements and not doing the EQ efficiency analysis is not recommended as it would jeopardize Darlington's ability to meet its regulatory commitment. The components which are being replaced in the field under this release are only those which have been previously committed to the CNSC (refer to Ref. 1 and Attachment "D"). The additional work being done is required to determine the best path forward for Darlington to comply with its PROL.

The project is making extensive use of Operating Experience (OPEX) from the Pickering and Bruce sites to ensure that the requirements of the Ontario Power Generation Nuclear (OPGN) EQ Program and Darlington's PROL are met at minimum cost.

Alternative 4 – Do More - Not Recommended

Due to the number of unknowns associated with maintaining full compliance with EQ requirements of the license, it is recommended at this time to release an additional $33.2M to allow the committed scope of work to be completed in accordance with the schedule. It will also allow the design basis documentation to be completed and an analysis to determine the most efficient method for maintaining full EQ compliance; if future work is found to be required for Darlington to meet its PROL it will be completed under a separate project.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The proposal is for the full release of $33.2M to allow the Environmental Qualification (EQ) Closure and Component Replacement Project to:

1. Continue work on the following activities that are critical to the REG C committed schedule (Attachment "D"):
   a. Replace components in the field during the D811, D931, D1041, and D1021 outages.
   b. Replace components in the field in 2008 through 2010 via the Darlington online program.

2. Prepare completion assurance packages for the components replaced during the project and for those not expected to be affected by the scope optimization study (~ 4000 tags). Address completion assurance requirements for cables.

3. Determine the most cost effective and efficient method for Darlington Nuclear to comply with the EQ requirements in its operating license by December 31, 2010, through the following activities:
   a. Preparation of draft EQ Technical Basis Documents and initiation of the station review of them.
   b. Initiation of a gapping analysis to determine the components which, in order to comply with EQ governance, require:
      i. Modifications.
      ii. Replacement, due to them being beyond their qualified life span.
      iii. Documentation updates.
      iv. Qualification testing.
   c. Use the scope optimization study as a cost benefit tool to determine the most efficient path forward for Darlington to comply with the EQ requirements of its PROL.

4. Initiate preliminary design / analysis / testing activities for deficiencies identified in the gap analysis and the selected scope optimization options (this may include procurement of long lead time materials). This includes, but is not limited to:
   a. Qualification of column line 11 as a steam barrier.
   b. Modification(s) required to address concerns with wet rooms.
   c. Qualification / replacement of BIW cables outside containment.

   Detailed engineering activities, procurement of short lead time materials and installation activities for this new scope will not be completed under this project. If required, the business case for a new project to resolve the new EQ issues arising from this new scope will be developed.

5. Complete the transition to the Sustaining EQ Program, this will be done through mentoring, transfer of software tools to the sustaining staff and preparation of desktop guides to promote the consistent application of EQ.

NOTE:
The correction of any configuration management issues identified during completion assurance walk-downs is not within the scope of this project.

The Project Execution Plan will be approved by December 2007.

5/ QUALITATIVE FACTORS

Environmental Qualification compliance and sustainability are licensing requirements. Qualitative benefits of the project are:

1. An improved ability to contain and minimize damage or loss of the asset due to a harsh design basis accident.
2. An increase in public and employee safety.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Underestimation of cost.	Higher cost.	**Medium**	TIS sheets, issued contracts and actuals for similar tasks were used in the preparation of the estimate, general contingency has been included to cover possible cost increases. A independent agency has been contracted to review the estimate for accuracy.	**Low**
Complete scope of activities for Darlington to comply with it's PROL not defined.	A new project may be required for Darlington to comply with its PROL. Current conceptual estimates for this project are in the range of $40M to $140M.	**Low**	Included in the scope of this project is a scope optimization study whose purpose is to find ways to reduce the overall scope and cost of EQ for Darlington.This project will only complete the scope of work detailed in section 4, any additional work required for Darlington to comply with its PROL will be managed through a new project, the new project will provide a detailed cost estimate for this new scope.	**Low**
More scaffolding required than estimated.	Higher cost.	**Medium**	Funding has been included in the estimate for scaffolding and general contingency is available for possible cost increases.	**Low**
Scope				
Configuration management issues identified during completion assurance walk-downs.	Challenge to schedule, increased station OM&A costs. Based on OPEX there is a risk that correction of these deficiencies could cost up to $50M.	**N/A**	Configuration management rework issues are not within the scope of this project however the risk remains for Darlington. A sample set of walk-downs under a "pilot project" will be completed to establish a better estimate for the amount of rework that Darlington should expected.	**N/A**

Complete scope of activities required for Darlington to comply with its PROL not defined.	A new project may be required for Darlington to comply with its PROL.	**Low**	Included in the scope of this project is a scope optimization study whose purpose is to find ways to reduce the overall scope and cost of EQ for Darlington. This project will only complete the scope of work detailed in section 4, any additional work required for Darlington to comply with its PROL will be managed through a new project. This new project will provide a completion date for the new scope.	**Low**
Uncertainty on the scope of the configuration walk downs.	Higher cost.	**Medium**	Specific contingency has been included to reduce the risk associated with walk downs.	**Low**
Schedule				
Delay in the schedule, increased cost, and missed REG C commitments.	Delay in the schedule, increased cost, and missed REG C commitments.	**Medium**	All work required to be completed under this project, as outlined in Attachment "D", has been scheduled in accordance with OPG governance. Adherance to this schedule is monitored regularly by the project and any threats will be communicated to Darlington management in a timely fashion.	**Low**
Complete scope of activities for Darlington to comply with it's PROL not defined.	Inability to complete full scope of work by December 31, 2010. Until the full scope of work required for Darlington to comply with the EQ requirements of its PROL is defined and understood a completion date cannot be provided.	**Low**	Current committed scope of work (as shown in Attachment "D") has been planned and scheduled to ensure its completion by December 31, 2010. A scope optimization has been initiated in order to find ways to reduce the overall scope. Once the full scope of work required to EQ Darlington is understood a new project may be required. In order to prevent delays funding has been included in this release to initiate preliminary engineering / analysis / testing activities prior to the initiation of the new project.	**Low**
Configuration management issues identified during completion assurance walk-downs.	Increased scope of work for station resources. If this work is not completed prior to Dec. 31, 2010 there will be a list of open items turned over to the station.	**N/A**	Configuration management rework issues are not within the scope of this project however the risk remains for Darlington. Walk-downs will be scheduled as early as possible to maximize the time available to station resources for the correction of any issues identified.	**N/A**

Resources				
Availability of qualified EQ staff.	Delay in the schedule.	**Medium**	The project has retained augmented staff with EQ expertise. The corporate strategy with respect to the use of augmented staff remains a risk however CNE agreement has been obtained that the EQ project will be permitted to use augmented staff. Managed task contracts will be used to obtain qualified personnel as required.	**Low**
Availability of qualified Design Agencies & station resources.	Delay in the schedule.	**Medium**	The use of preferred vendors is being used to mitigate the risk of Design Agencies not able to support the work due to a lack of internal resources. The project has obtained the Senior Site VP agreement to the priority of the project and signed TIS sheets have been obtained from key support organizations.	**Low**
Availability of station resources (Regulatory Affairs, Nuclear Safety, Plant Design) to TBD preparation.	Delay in the schedule.	**Medium**	The project has obtained the Senior Site VP agreement to the priority of the project. Agreement has been obtained from Regulatory Affairs, Nuclear Safety and Plant Design Managers.	**Low**
Technical				
Modifications do not meet performance requirements.	Additional cost and schedule delays due to rework.	**Medium**	The use of OPEX, regular technical reviews, and the application of lessons learned is being used to mitigate this risk.	**Low**
Regulatory				
New CNSC action items being imposed on Darlington as result of the March 2007 audit results being published.	Scope, Cost and schedule increases.	**Medium**	Regular communication and update with the CNSC. Potential scope additions resulting from the recently completed audit will be managed through a new EQ project.	**Low**
		Medium		**Low**
Environmental				
N/A.	N/A.	**N/A**	N/A.	**N/A**

Health & Safety				
Workplace injury or MRPH event.	1. Injury to workers. 2. Impact to the project schedule and cost.	**Medium**	Installations will be executed under approved work practices, OPG saftey requirements, and OPG oversite.	**Low**
High radiation fields in work areas.	Field resources could reach their one and/or five year limits on radiation dose.	**Medium**	ALARA principles are applied during work planning / execution.	**Low**
Investment				
Risk of rework and/or the implementation of unnecessary modifications.	Higher cost.	**Medium**	Work in this release incorporates OPEX and is required for compliance with the EQ requirements of Darlington's PROL. A scope optimization study is being completed to ensure that unnecessary work is not completed.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2010	Dec 2011	Director of Engineering - Darlington Nuclear

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Completion of CNSC REG C committed component replacements, Action Assignment #28058364.	As of Jan. 2007 the committed component replacements (as documented in Action assignment # 28058364) had a due date was December 31, 2010.	Completion of committed component replacements by December 31, 2010. See Attachment "D".	Completion letter submitted to the CNSC.	Regulatory Affairs Manager
2.	No EQ issues on the committed component replacements.	EQ Completion Assurance not completed on committed component replacements.	EQ Completion Assurance on committed component replacements.	EQ Completion Assurance documents in place for all replaced components.	Components & Equipment Manager
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

AFS:	Available for Service
BCS:	Business Case Summary
BTU:	Building Trades Unions
CNSC:	Canadian Nuclear Safety Commission
EQ:	Environmental Qualification
EQA:	Environmental Qualification Assessment
EQLDP:	Environmental Qualification List Development Package
EQSRCL:	Environmental Qualification Safety Related Components List
IEV:	Impact on Economic Value
IRR:	Internal Rate of Return
LTD:	Life to Date
MRPH:	Maximum Reasonable Potential for Harm
N/A:	Not Applicable
NPV:	Net Present Value
OAR:	Organizational Authority Register
OM&A:	Operating, Maintenance, and Administration
OPEX:	Operating Experience
OPG:	Ontario Power Generation
OPGN:	Ontario Power Generation Nuclear
PCRAF:	Project Change Request Authorization Form
PEP:	Project Execution Plan
PIR:	Post Implementation Review
PROL:	Power Reactor Operating License
PWU:	Power Workers Union
REG C:	CNSC Regulatory Commitment
SCR:	Station Condition Record
TBD:	Technical Basis Document
TIS:	Task Identification Sheet

Appendix "B" **Project Funding History**

$ Millions		All Existing and Planned Releases (incl contingency)									
			Cumulative Values								
Release Type	Month	Year	2004	2005	2006	2007	2008	2009	2010	Later	Total
Developmental	Oct	2004	4.56	2.64							7.20
Partial	Feb	2006	0.59	5.81	4.10						10.50
Partial	Apr	2006	0.59	5.81	11.52	6.95	1.25	1.25	2.50		29.87
Full	Nov	2007	0.59	5.81	8.52	11.78	14.45	10.73	10.41	0.83	63.11
											0.00
											0.00
											0.00
											0.00

LTD Spent	Aug	2007	0.59	5.81	8.52	7.61					22.53

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
The project cost for the committed scope of work was developed using estimates from the supporting work groups combined with historical charges against this project. The quality for this portion of the estimate is in the +30% to -15% range.

The remaining portion of the funding released under this BCS will be used to:

1. Perform completion assurance activities for the components replaced during this project and for those not expected to be affected by scope optimization. This is expected to involve:
   a. Walk-downs of ~4000 components and up to 9300 cables.
   b. PASSPORT updates.
   c. Documentation updates.
2. Determine the most cost effective and efficient method for Darlington Nuclear to comply with its operating license requirements for EQ by December 31, 2010.
3. Compete preliminary engineering / analysis / testing activities for newly identified scope. Money has been included for this activity only in 2008, it is expected that a new project will be initiated by Q4-2008 which will then be responsible for this scope of work.

There is greater uncertainty in this portion of the estimate which is mitigated by the inclusion of specific contingency for completion assurance walk downs and the overall value of the general contingency.

Financial Assumptions:
The PV_{Base} has been set to $0 for this project since completing this project is a CNSC Regulatory commitment and not doing the project is not a viable alternative.

Project / Station End of Life Assumptions:
Darlington's end of life was assumed to be 2020.

Energy Price / Production Assumptions:
N/A.

Operating Cost Assumptions:
N/A.

Other Assumptions:
It was assumed that the EQ project will be split from Darlington Design Projects prior to 2008, as a result overhead costs for a Stratum IV manager, an Administrative Assistant and a new Stratum III manager have been included in the estimate.

A new project is expected to be initiated by Q4-2008 at which time it was assumed that overhead costs would be shared by the two projects.

DNGD: EQ Closure and Component Replacement Project 16 - 38457

Full Release Business Case Summary D-BCS-03651-10004-R000

Attachment "A" **Project Cost Summary**

$Millions OM&A	LTD Prior Yr 2006	2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011		Later	Total
Project Management (OPG)	1.08	0.52	1.54	0.90	0.90	0.44			5.37
Engineering & Drafting (OPG)	0.81	0.57	1.30	0.48	0.35	0.14			3.65
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Augmented Staff									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	14.92	11.78	14.45	10.73	10.41	0.83	-	-	63.11
2008-2012 Business Plan	14.93	11.78	5.40	5.20	5.50	6.90			49.71
Variance to Business Plan	(0.01)	-	6.85	1.78	1.21	(6.32)	-	-	3.50
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	14.92	11.78	12.25	6.98	6.71	0.58	-	-	53.21
Total Release (incl contingency)	14.92	11.78	14.45	10.73	10.41	0.83	-	-	63.11

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	100%		Quality of Estimate	Budget + 30% to - 15%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process. A PCRAF is not required

Reviewed By: B. Beaudette 01NOV2007
B. Beaudette
Project Manager
Date:

Approved By: T. Chong 01 Nov 2007
T. Chong
Eng & Mods Manager (Strat IV)
Date:

DNGD: EQ Closure and Component Replacement Project 16 - 38457

Full Release Business Case Summary D-BCS-03651-10004-R000

Attachment "B" **Project Variance Analysis**

OM&A	LTD Aug 2007	Full Release Last BCS Apr 2006	Full Release This BCS Nov 2007	Variance	Comments
Project Management (OPG)	1.38	1.39	**5.37**	3.98	See below
Engineering & Drafting (OPG)	1.19	0.60	**3.65**	3.05	See below
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
Augmented Staff	[redacted]				
Future Funding Req'd	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	22.53	57.00	63.11	6.11	See below
Committed Cost				0.00	
Inventory Write Off Required				0.00	
Spare Parts / Inventory				0.00	
Total Release (incl contingency)	22.53	57.00	63.11	6.11	
Total Release (excl contingency)	[redacted]				
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Explanation of Variance:

The previous Partial Release BCS had an overall estimate of $27.1M for future release; it did not break down the estimate into the various categories. Hence, the high variances between the Last BCS and This BCS for the categories.

The project has achieved savings of approximately [redacted] through scope reductions relating to the Limitorque Actuators and PAWCS heat Exchanger packages.

Additions in scope including the ITT Cannon work and the increased number of Deltrol / Norgren valves which required modifications added approximately [redacted] to project costs. 60 addition EQLDP packages were also completed at a cost of [redacted]. The scope optimization study which was completed at the request of the Senior Site VP added [redacted] to the project's cost. Given the uncertainty surrounding completion assurance activities a specific contingency of [redacted] has been included.

[redacted] has been included to allow the project to initiate preliminary engineering activities to begin of newly identified scope of work prior to the establishment of the new project.

Additionally issues such as delays in obtaining vault access during outages, high radiation fields and legacy issues discovered during the project have caused challenges to the project team leading to increased costs.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
07	Jan	2008	PMM: Conceptual Design Input Complete (Scope Optimization)
19	Jan	2008	DCP: Design Pkgs App'd & issued – ITT Cannon Connectors (Online)
16	Feb	2008	LLA: Mat'l Contracts Awarded for D931S Outage
28	Mar	2008	SOI: Start of Installation for D811S Outage
15	Apr	2008	PTA: Passport Tasks set to Ready – Limitorque Valves (Online)
16	Apr	2008	DCP: Design Packages Approved & Issued for D931S Outage
16	May	2008	ICA: Installation Contracts Awarded for D931S Outage
30	Jun	2008	AFS: D811S Outage
07	Jul	2008	SOI: Start of Installation – Limitorque Valves (Online)
07	Jul	2008	PMM: Preliminary Design Input Complete (Scope Optimization)
25	Jul	2008	SOI: Start of Installation – A/L Hoses (Online)
20	Aug	2008	SOI: Start of Installation – ITT Cannon Connectors (Online)
15	Sept	2008	ICA: Installation Contracts Awarded for 2008 Online Packages
18	Sept	2008	PTA: Work Package Assessments Complete for D931S Outage
28	Oct	2008	PTA: Work Package Assessments Complete for 2008 Online Packages
19	Dec	2008	AFS: 2008 Online Packages
26	Jan	2009	LLA: Mat'l Contracts Awarded for D1041S Outage
30	Jan	2009	SOI: Start of Installation – Gould Transmitters (Online)
05	Mar	2009	ICA: Installation Contracts Awarded for D1041S Outage
20	Mar	2009	DCP: Design Packages Approved & Issued for D1041S Outage
16	Apr	2009	SOI: Start of Installation for D931S Outage
11	Jul	2009	AFS: D931S Outage
01	Aug	2009	LLA: Mat'l Contracts Awarded for D1021F Outage
18	Sep	2009	PTA: Work Package Assessments Complete for D1041S Outage
25	Sept	2009	DCP: Design Packages Approved & Issued for D1021F Outage
17	Oct	2009	ICA: Installation Contracts Awarded for D1021F Outage
28	Oct	2009	PTA: Work Package Assessments Complete for 2009 Online Packages
18	Dec	2009	AFS: 2009 Online Packages
26	Mar	2010	SOI: Start of Installation for D1041S Outage
26	Mar	2010	PTA: Work Package Assessments Complete for D1021F Outage
19	May	2010	AFS: D1041S Outage
01	Oct	2010	SOI: Start of Installation for D1021F Outage
24	Nov	2010	AFS: D1021F Outage
24	Jul	2011	PCM: Project Completion Milestone

A Project Execution Plan (PEP) will be approved by Dec 2007.

Attachment "D"

Outage	Outage Type	Unit	Norgren A/L Valves (31-Dec-09)	Ion Chamber BIW Cable (RRS and SDS1) (31-Dec-10)	Ion Chamber BIW Cable (SDS2) (31-Dec-08)	[redacted]	Horiz. Flux Detector Tetzel Cable (31-Dec-08)	Loganspot Air Sequencing Valves Airlocks (31-Dec-09)	Kopex Conduit Seals (A3 PG) (N/A)	[redacted]	[redacted]	[redacted]	[redacted]	Airlock Hoses & Norgren Addition (31-Dec-10)	Limitorque Actuators (31-Dec-10)	[redacted]	[redacted]	ITT Cannon Connector Replacement (31-Dec-10)
D411 (Spring 2004)	Major	1				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D431 (Fall 2004)	Minor	3				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D521 (Spring 2005)	Major	2				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D541 (Fall 2005)	Minor	4		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D631 (Spring2006)	Major	3	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D611 (Fall 2006)	Minor	1	[redacted]	[redacted]		[redacted]		[redacted]		[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D741 (Spring 2007)	Major	4	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D721 (Fall 2007)	Major	2	I/P		X	[redacted]	X	I/P		[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D811 (Spring 2008)	Major	1			X	[redacted]	X			[redacted]	[redacted]	[redacted]	[redacted]	X	X	[redacted]	[redacted]	X²
D901 (Spring 2009)	VBO	0				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D911 (Spring 2009)	VBO	1				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D921 (Spring 2009)	VBO	2				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D931 (Spring 2009)	Major	3	X¹	X		[redacted]		X¹		[redacted]	[redacted]	[redacted]	[redacted]	X	X	[redacted]	[redacted]	X²
D941 (Spring 2009)	VBO	4				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	
D1041 (Spring 2010)	Major	4				[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	X	X	[redacted]	[redacted]	X²
D1021 (Fall 2010)	Major	2		X		[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	X	X	[redacted]	[redacted]	X²

Non-Outage

Unit	Gould Transmitters (31-Dec-09)	[redacted]	Norgren Transfer Chamber Valves (31-Dec-07)	Kepner Transfer Chamber Check Valves (31-Dec-07)	[redacted]	Kopex Conduit Seals (31-Dec-07)	Airlock Hoses & Norgren Addition (31-Dec-10)	Limitorque Actuators (31-Dec-10)	[redacted]	[redacted]	ITT Cannon Connector Replacement (31-Dec-10)
0	X	[redacted]	X	X	[redacted]	X	X	X	[redacted]	[redacted]	
1		[redacted]	X	X	[redacted]	X	X	X	[redacted]	[redacted]	X²
2		[redacted]	X	X	[redacted]	X	X	X	[redacted]	[redacted]	X²
3		[redacted]	X	X	[redacted]	X	X	X	[redacted]	[redacted]	X²
4		[redacted]	X	X	[redacted]	X	X	X	[redacted]	[redacted]	X²

Notes
Non-Outage items identified are non-unitized schedule. Date indicated is for completion of all station IPG work for the particular item
C⁴ - Airlock 2 Complete
X¹ - Airlock 1 moved to D931 by Outage Management
X² - Added by Charter Rev 2 to be committed to CNSC November 2007
C* - Removed from replacement program through exemption/QL extension
C** - Replacement is being completed every outage through regular PMs
I/P - In progress
Completion dates highlighted in yellow indicate schedule changes from CNSC submission

REFERENCES

1. NK38-CORR-00531-13472, CNSC Letter from Senior Vice-President W. Robbins to Mr. G.R. Schwarz, Darlington NGS – 2006 Annual Update: Safety Significance of Remaining Environmental Qualification (EQ) Issues Post June 20, 2004

2. NK38-CORR-00531-12540, CNSC Letter from Senior Vice-President Gregory OD Smith to Mr. G. Schwarz, Darlington NGS – Safety Significance of Remaining Environmental Qualification (EQ) Issues Post June 30, 3004, dated November 30, 2004.

3. NK38-CORR-00531-12306, CNSC Letter from Senior Vice-President Gregory OD Smith to MS. B.A. Ecroyd, Safety Significance of Remaining Environmental Qualification (EQ) Issues Post June 30, 2004, dated May 31, 2004.

4. NK38-CORR-00531-12132, CNSC Letter from Senior Vice-President Gregory OD Smith to Mr. E. Leader, Progress in Addressing CNSC Environmental Qualification (EQ) Acceptance Criteria, dated December 18, 2003.

5. NK38-CORR-00531-13872, Action Item 20071314 CNSC Type I Inspection of Darlington NGS Environmental Qualification Program Conducted March 12 to March 30, 2007.

6. D-PCH-03651-10002-R002, EQ Closure and Component Replacements Project Charter.

7. D-BCS-03651-10003-R000, DND: EQ Closure and Component Replacement (Phase II) 16-38457, Partial Release Business Case Summary.

8. D-BCS-03651-10002-R000, DND: EQ Closure and Component Replacement (Phase II) 16-38457, Partial Release Business Case Summary.

9. D-BCS-03651-10001-R000, DND: EQ Closure and Component Replacement (Phase II) 16-38457, Developmental Release Business Case Summary.

ONTARIOPOWER GENERATION

Pickering B Steam Generator Locking Tab Replacement 13 - 40641

Full Release Business Case Summary NK30-BCS-33115-00007-R000

Routing	Location	Action	Signature	Date
J. Xiao Project Leader (Acting), Boiler Projects 701-8649	P72-3	Prepare BCS	Xiao	Jan 24, 07
P. Asgaripour Project Manager (Acting), Boiler Project 701-4680	P72-3	Review BCS	P. Asgaripour	JAN-26/07
G. Kotwa Section Mgr. Process Scheduling 701 - 3755	P72-1	Review BCS	G Kotwa	26 Jan/07
G. Keto Manager, Boiler Projects 701 - 2568	P72-3	Review BCS	Jerry Keto	Jan 26, 07
D. Williams Manager, Projects Design Pickering 701 - 4956	P72-3	Review BCS	for D. Williams	29/01
B. Morrill Manager, Comp. & Equipment 701-4926	P41-E3	Review BCS	M.L. Shanahan	2007-01-31
R. Ball Senior Financial Analyst 702 - 4084	P82-3B6	Review BCS	R Ball	5 Feb 07
R. Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Pickering B Steam Generator Locking Tab Replacement 13 - 40641

Full Release Business Case Summary NK30-BCS-33115-00007-R000

Routing	Location	Action	Signature	Date
M. Arnone Director Projects & Mods 701-6063	P71-1	Review BCS	[signature]	02 FEB 2007
R. Leavitt Director Investment Management 702-5085	P82-3	Review BCS	[signature]	Feb 19, 2007
P. Tremblay Senior Vice President Pickering B 701-3501	P41-E3	Review BCS	[signature]	Feb 20/07
J. Beech VP Nuclear Finance 400-7276	H9 F26	Review BCS	[signature]	Feb 23/07
T. Mitchell ~~EVP and~~ CNO 702-5294	P82-6	Review BCS	[signature]	28 Feb 07
D. Power, VP - Corporate Investment Planning ~~Director Investment & Business Planning~~ 400-7172	H7 D06	Review BCS	[signature]	March 8/07
P. Charlebois EVP and COO 400-8470	H19 A21	Review BCS	[signature]	Mar 20/07
J. Hankinson President & CEO 400-2121	H19 A24	Approve BCS	[signature]	Mar 20/07
R. Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Pickering B Steam Generator Locking Tab Replacement 13 - 40641

Full Release Business Case Summary NK30-BCS-33115-00007-R000

1/ RECOMMENDATION:

We recommend a full release of $20.5M (including contingency) to design, install, and commission new locking devices in all 12 Steam Generators (SGs) in Unit 7 during the 2008 outage and Unit 8 during the 2010 outage.

The business objective of this project is to remove the current requirement to shut down Unit 7 and Unit 8 after 6.3 Effective Full Power Years (EFPYs) because of the threat of fatigue failure of the cold leg locking tabs, by developing and installing a new design that will:

- Allow Units 7 and 8 to run until End of Life (EOL) without concerns of locking tab failure
- Reduce the overall project cost and dose uptake by ~$4.3M and 40% respectively (compared to Units 5 and 6)
- Align with the Pickering B 85/5 initiative by allowing installation within a 40 day outage schedule
- Allow inspection/maintenance to be conducted with minimal interference with the new design
- Allow for the removal and/or replacement of components of the new design with relative ease, if required

If a cold leg locking tab were to fail, it is speculated that it would cause significant damage to the Heat Transport System. More importantly, a broken cold leg locking tab could block Primary Heat Transport (PHT) water flow through feeder pipes and orifices. Lack of flow can cause overheating of fuel and result in fuel failure. In the worst case scenario, a broken cold leg locking tab could cause Pressure Tube failure leading to a Loss of Coolant Accident (LOCA). However, repairs to Units 7 and 8 can be postponed until March 2011 and October 2010 respectively since a Fitness for Service Evaluation of cracked hot leg locking tabs concluded that cold leg locking tabs will not fail prior to 6.3 Effective Full Power Years (EFPYs) and failure of hot leg locking tabs is not an operability issue. This analysis is based on a safety factor of 2. (see Glossary)

Locking tab design problems were first experienced when broken pieces of locking tabs and sealing skins were found on the hot leg (inlet) side of the Unit 5 SGs during the P551 outage. Similar problems were later found in Unit 6. The root causes were determined to be insufficient design analysis for the locking tabs and inadequate installation of the sealing skins. Repairs to both locking tabs and sealing skins were conducted on Units 5 and 6 because of the imminent threat posed by the sealing skin installation. Due to greater rigor applied during the installation of sealing skins in Units 7 and 8, there is no need to replace them prior to End of Life (EOL). Additionally, there is no need to replace the locking tabs on Units 5 and 6 as they are expected to operate without problems to EOL.

We have considerable experience in locking tab design and installation; however, a [redacted] contingency has been included to address the risk associated with designing, qualifying and installing a new design or defaulting to the Unit 5/6 design in the remote chance that the new design is ineffective and/or cost prohibitive.

$M (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	None	-	-	-	-	-	-	-	-
Requested Now	Full	-	-	0.6	9.4	0.5	9.7	0.3	20.5
Future Funding Req'd		-	-						
Total Project Costs		-	-	0.6	9.4	0.5	9.7	0.3	20.5
Other Costs									
Committed Cost				12.9	(6.4)	(1.0)	(5.5)		-
Grand Total Release		-	-	13.5	3.0	(0.5)	4.2	0.3	20.5

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	OM&A	645.0	238.5%	3.5

Submitted By:

Feb 20/07

P. Tremblay
Senior Vice President Pickering B

Date:

Finance Approval:

D. Power
Director Investment & Business Planning

March 8/07
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

for

J. Hankinson
President & CEO

Mar 20/07
Date:

2/ BACKGROUND & ISSUES

Adverse Condition

The Steam Generator Divider Plate sealing skin modification was performed on Units 1, 4, 5-8 starting with Unit 4 in 2001 and finishing with Unit 7 in 2004. The primary purpose of this modification was to address Divider Plate bolt degradation as well as the steady increase in Reactor Inlet Header Temperature (RIHT) which was forcing some units to run derated. All modifications were completed successfully as measured by the decrease in RIHT for each unit. When the first unit (U5) SG inspections were conducted during the P551 (Spring of 2005) Outage following installation of the sealing skin/locking tab modification, it was discovered that numerous pieces of locking tabs and divider plate sealing skin had broken off in the hot leg (inlet) side of the steam generators (refer to SCR P-2005-03243) due to high cycle fatigue cracking. Further inspections revealed that all 10 affected steam generators experienced locking tab failures, and 4 of 10 steam generators experienced divider plate skin failures. The root causes of this event were deemed to be insufficient design analysis for the new locking tabs and inadequate sealing skin contact with the Primary Head seat bar.

Repair Scope for Unit 7 and 8

During the original divider plate installations in P481 (Unit 8, 2004) and P471 (Unit 7, 2004), more rigor was applied for installation of sealing skins and design improvements to the skins were made. As a result there is a lower probability of sealing skin failure in these steam generators. This has been proven through subsequent inspections carried out during P681 (Spring of 2006) and P671 (Fall of 2006), as only 1 SG out of the 12 SGs inspected was found with minor, but acceptable skin failures. However, there were no changes made to the design of the locking tabs, so similar numbers of broken hot leg locking tabs have been seen in Unit 8 and 7. To date no broken locking tabs have been reported in cold leg (outlet) side of the any the inspected SGs.

A Fitness for Service Evaluation of cracked locking tabs for PNGS A and PNGS B (P-REP-33115-00001 R01) concluded that cold leg locking tabs will not fail prior to 6.3 EFPYs and failure of hot leg locking tabs is not an operability issue. This assessment allows the delay of the locking tab replacement until the 2010 Outages while development of an improved fastener design is underway to reduce the installation duration, dose and cost. Although it is acceptable from a Fitness for Service perspective to defer the locking tab replacement to 2010, performing this modification for all 24 SGs in 2010 is not aligned with the 85/5 initiatives. Thus, locking tab replacement will be completed in Unit 7 SGs in 2008 and Unit 8 SGs in 2010.

Similar Previous Replacement Campaigns

As mentioned, hot leg locking tab failures were first found in Unit 5. Similar failures were found in Unit 6 Steam Generators during P561 Outage. Upon this discovery, all of the sealing skins, locking tabs, and associated components in all Unit 5 steam generators (except for two steam generators which were previously modified in 1999 with a different Divider Plate design) and in all Unit 6 steam generators were replaced. These repair campaigns were costly, lengthy, and dose intensive as shown below:

Project #13-40932, Unit 5 – approximately $11M, 2 months, 33 Rem (10 steam generators)
Project #13-40632, Unit 6 – approximately $12M, 2 months, 65 Rem (12 steam generators)

This BCS covers the funding required for the development, qualification and testing of the new design along with field installation. This project will focus on locking tab replacement (currently installed sealing skins will be retained), and minimizing cost, time, and dose during execution. There are no plans to replace the locking tabs in Units 5 and 6 as they are evaluated to be operational to EOL.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Based on the fact that cold leg locking tabs will not fail prior to 6.3 Effective Full Power Years (EFPYs), we have several options for scheduling the installation work. The following analysis examines the impact of various options based on 40 days outages and planned Water Lancing for Units 7 and 8.

$ Millions	Status Quo	Alt 1 (Recommended) New Design in 2008 / 2010 Full Cost	Alt 1 (Recommended) New Design in 2008 / 2010 Incremental Cost	Alt 2 Old Design in 2008 / 2010	Alt 3 New Design In 2008	Alt 4 New Design in 2010	Alt 5 New Design in 2008 / 2010
SG's / Outages / Critical Path							
P871	0	12	12	6	12		6
P881	0			6	12		6
P1071	0			6		12	6
P1081	0	12	12	6		12	6
Waterlancing in Outage	N/A	2008 (U8) 2010 (U7)	2008 (U8) 2010 (U7)	2010 (U8) 2010 (U7)	2010 (U8) 2010 (U7)	2010 (U8) 2010 (U7)	2010 (U8) 2010 (U7)
Variance to Critical Path (1 outage)	N/A	-2-2	-2-2	+7+7+13+13	-2-2	+11+11	-2-2+4+4

Financials							
Loss of Revenue	(1,532.2)	0.0	0.0	(22.5)	0.0	(12.0)	(4.4)
Project Cost	0.0	(20.5)	(20.5)	(25.9)	(20.2)	(20.2)	(20.5)
NPV (after tax)	(656.9)	(11.9)	(11.9)	(26.8)	(12.0)	(16.8)	(13.7)
Financial Benefit (vs Status Quo)	**N/A**	**645.0**	**645.0**	**630.1**	**644.9**	**640.1**	**643.2**
IRR%	N/A	251.3	251.3	1.8	190.5	440.6	2.4
Discounted Payback (Yrs)	N/A	3.5	3.5	4.1	3.7	3.4	3.6
Ranking of Financial Benefits	**6**	**1**	**1**	**4**	**2**	**5**	**3**

Business Objectives							
Fits Current Generation Plan	No	No	No	No	No	No	Yes
Allows operation beyond 6.3 EFPYs	No	Yes	Yes	Yes	Yes	Yes	Yes
Allows operation to EOL	No	Yes	Yes	Yes	Yes	Yes	Yes
Aligns with 85/5 initiative	No	Yes	Yes	Yes	Yes	Yes	Yes
40% dose reduction	No	Yes	Yes	No	Yes	No	No
Benefit of new design	No	Yes	Yes	No	Yes	Yes	Yes

*See Alternative 1 description.

Status Quo - Not Recommended

Status Quo is **not** the recommended option. This alternative is unacceptable because we would have to shut down both units with revenue losses accruing to approximately $1.5 Billion from the end of 6.3 EFPYs to EOL.

Alternative 1 - Install 12 "New Design" Tabs in Unit 7 in 2008, 12 in Unit 8 in 2010 - Recommended

We recommend this alternative because it satisfies the Business Objectives and provides the greatest financial benefit (when measured against the Status Quo). This alternative minimizes the risk of an outage extension by avoiding concurrent Water Lancing and Locking Tab repair in the same outage. The recommendation is to advance Unit 8 Water Lancing by 2 years to 2008, install all Unit 7 Locking Tabs in 2008 and all Unit 8 Locking Tabs in 2010. This proposal has been accepted by the Site Management Board (SMB) and is being incorporated into the Generation Plan. Moving Unit 8 Water Lancing to 2008 is also supported by EMD due to the poor condition of Unit 8 SGs in terms of sludge build-up

Alternative 2 - Install Unit 5 and 6 Design Locking Tabs in Units 7 & 8- Not Recommended

We do **not** recommend this alternative because it doesn't satisfy the Business Objectives and provides the least financial benefit. This alternative is the contingency alternative should the new design not meet expectations.

Alternative 3 – Install 12 "New Design" Locking Tabs in Units 7 & 8 in 2008 - Not Recommended

Although this alternative meets the Business Objectives, we do not recommend it because there are increased schedule risks in completing both units in 2008. Moreover, the financial benefit is marginally less than the Recommended alternative.

Alternative 4 – Install 12 "New Design" Locking Tabs in Units 7 and 8 in 2010 - Not Recommended

We do **not** recommend this alternative because it doesn't align with the 85/5 initiative and provides only the 4th best financial benefit because of the outage extension. Moreover, leaving all Locking Tab installation until 2010 does not provide sufficient time to recover from unknown problems, without unfavourable financial impact.

Alternative 5 – Install "New Design" in 6 SGs per U7 & U8 in 2008, remainder in 2010 - Not Recommended

This is the current Generation Plan. We do not recommend this alternative because it has higher risk of extending the Outages than Recommended Alternative and provides only the 3rd best financial benefit.

4/ THE PROPOSAL

We propose a full release (as opposed to a developmental) at this time because:

- There is little or no risk that this project will be cancelled and the investment subsequently lost
- Major contracts need to be awarded by October 2007 in preparation for the Unit 7 Fall Outage in 2008
- Conceptual funding allowed us to determined the most technically viable and cost effective design from a number of locking tab replacement options
- An extensive risk profile with mitigating actions has been developed to reduce the overall risk to low
- We have considerable experience in locking tab design and installation; however, a [redacted] contingency has been included to address the risk associated with designing, qualifying and installing a new design or defaulting to the Unit 5/6 design in the remote chance that the new design is ineffective and/or cost prohibitive.

A Full Release will be used to:

- Complete the Design 100%
- Perform the Preliminary and Detailed Engineering
- Award a labour contract (for both units)
- Perform all pre-installation activities for Unit 7 (i.e. workplan preparation, work permits, space allocation, etc.)
- Install, commission, and AFS the modification for Unit 7 (P871)
- Revise Design Engineering documents as required (i.e. Design ECs, drawings, etc.) for Unit 8
- Complete pre-installation activities for Unit 8
- Install, Commission, and AFS the modification for Unit 8 (P1081)
- Close-out the Project

Refer to Appendix C for a list of the project milestones.

5/ QUALITATIVE FACTORS

None other than outlined in the Business Objectives.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Underestimation of cost.	Cost over run. A futher release of funds will be required	**Medium**	Regular review of project expenditures. [redacted] contingency available.	**Low**
Scope				
Results of Qualification Program could cause scope increase.	Change in scope resulting in changes in cost and schedule.	**Medium**	If scope growth too large, design installed in Units 5 and 6 is ready and available to be installed in Units 7 and 8. [redacted] contingency available.	**Low**
As-found conditions of SGs could invalidate analysis and/or uncover unexpected conditions.	Increase in scope of modification (i.e. skin replacement) resulting in cost and schedule overrun.	**Medium**	Inspections have been conducted on 6 SGs each of Unit 7 and 8 in 2006 and have no unexpected findings. Similar conditions are expected on the remaining SGs.	**Low**
Damage to SG internals during site execution.	Unplanned repair required.	**High**	SG internals will be protected during installation to preclude damage. Qualification testing as well as mock-up training will provide the basis for risk mitigation during execution.	**Low**
Schedule				
Delay in obtaining required materials for qualification testing.	Schedule overrun.	**Medium**	Materials required for qualification testing have been identified. Some materials have already been obtained, and the remainder will be ordered promptly.	**Low**
Delay in completion of Design packages.	Schedule overrun.	**Medium**	Additional design resources will be obtained in order to meet deadlines. There is sufficient float in the project schedule to accommodate minor delays with no impact to start of installation	**Low**

Extensive amount of welding rework during execution.	Increase in Outage critical path.	**High**	Qualification testing will be conducted to ensure limited access welds can be completed to meet acceptance criteria.	**Low**
Resources				
Design Engineering resources re-allocated to higher priority projects.	Delay in Design deliverables	**Medium**	Design support has been committed to this project.	**Low**
Lack of qualifiedTrades to perform qualification testing due to conflict with P751 Outae.	Delay in qualification testing potentially leading to a delay in Design deliverables.	**Medium**	Trades will be acquired as soon as the qualification plan has been agreed upon.	**Low**
Technical				
Locking Tab replacement option does not satisfy all contructability objectives	Constructability issues may impact design	**High**	Qualification testing will be done to ensure constructability issues are addressed and eliminated through completion of design.	**Low**
		Low		**Low**
Regulatory				
Regulator may not approve the re-start submissions of Unit 7 and 8.	Unable to restart Unit 7 and 8.	**Medium**	Re-start submissions have been approved for Units 5 and 6 for similar modifications.	**Low**
Environmental				
N/A				
Health & Safety				
Potential for safety related events during qualification and site execution due to several conventional and radiological	Injuries to personnel involved in qualification testing and installation.	**Medium**	Pre-job briefings will be conducted prior to commencement of qualification testing and during installation. Boiler bowls will be surveyed and cleaned if required, and lead	**Low**

hazards.			shielding will be installed prior to personnel entries. All personnel involved will be required to wear appropriate PPE. Review Lessons Learned from previous campaigns	
Investment				
The current requirement to shut down Unit 7 and Unit 8 after 6.3 (EFPYs) is not adequately addressed The overall project cost and dose uptake targets are not achieved The installation is not aligned with the 85/5 principles. The new design inteferes with inspection / maintenance activities Future Locking Tab problems prevent the operation of the Units to EOL The new design does not allow for easy removal and or replacement of components Premature failure of cold leg locking tabs currently installed.	higher cost higher dose uptake extended schedule outage extension	**Medium**	Locking Tab replacement option will be designed with a substantial amount of rigour. Qualification Program will be conducted to ensure that the new locking device can meet these project objectives.and ensure that the Locking Tab replacement option is robust and will not become Foreign Material. Results of qualification testing will be used to alter the design of the new locking device as required.	**Low**
	new project required to repair units possible forced outage higher costs	**Medium**	The Unit 5/6 design is available if this design proves to be too costly or not effective [redacted]contingency is included	
	Advancement in preparation and installation of the new design or Repair of Units 7 and 8 with old design (installed in Units 5 and 6). Both of these repairs would significantly impact schedule and costs.	**Low**	Analysis has been completed for the current design with a safety factor of 2 and locking tabs are not expected to fail prior to 6.3 EFPYs. Contingency Divider Plate sealing skin sets (12 in total) of the current design are on site and available to be used for an emergent repair campaign. [redacted]contingency is available and would provide sufficient funding in the remote chance that the Unit 5/6 design is required	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jan 2011	Feb 2015	Components & Equipment

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Durability of Steam Generator divider plate fastener locking device	Unit 7 and 8 Boilers were found with several broken locking tabs	Divider plate locking device to remain intact until end of SG life.	Perform as-found inspections during the first and second planned outages subsequent to installation of the locking devices. Each steam generator must be inspected to confirm the Divider plate assembly is intact.	Major Components Section, Components and Equipment Department
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

- AFS: Available for Service
- CNE: Chief Nuclear Engineer
- CNSC: Canadian Nuclear Safety Commission
- EC: Engineering Change
- EFPY: Effective Full Power Year
- EOL: End of Life
- HTS: Heat Transport System
- NPV: Net Present Value
- RIHT: Reactor Inlet Header Temperature
- PNGS: Pickering Nuclear Generating Station
- PROL: Power Reactor Operating License
- SG: Steam Generator
- SMB: Site Management Board
- TOE: Technical Operability Evaluation
- Safety Factor of 2: In analyzing the operational life of the locking tabs, the largest crack size was used to account for the worst condition. This crack size was then multiplied by a safety factor of 2 in the model to predict the tab life.

Appendix "B" Project Funding History

$ 000's Release Type	Month	Year	2006	Releases (incl contingency) Cumulative Values 2007	2008	2009	2010	2011	2012	Later	Total
Full	Nov	2006		13,326	3,148	0	3,990	61			20,525
											0
											0
											0
											0
											0
											0
											0
LTD Spent	Nov	2,006	0								0

Comments:

There have been no releases for this project to date as currently, conceptual funding is being used to perform preliminary work. A Full Release will be used to complete 100% design, installation, commissioning and AFS of the modification for Units 7 and 8 as well as the project close out. This approach will enable funding for early tender and award of installation contract.

Appendix "C" **Financial Model – Assumptions**

Project Cost Assumptions:

For the majority of engineering and design work, overtime has been assumed to be 10%. For field personnel, overtime has been assumed to be 25%. Installation estimate is based on Unit 5 and 6 experiences with assumed installation benefits for new design.

It is assumed that the Locking Tab replacement modification will be conducted over 2 outages as follows:

- Unit 7 during Fall 2008
- Unit 8 during Spring 2010

Financial Assumptions:

The rate of inflation estimated at 2% is consistent with Corporate guidelines.

Project / Station End of Life Assumptions:

Based on a memo to D. Power from J.P. Froats, "Pickering Units 5, 6, 7, and 8 End of Service Life Predictions", May 10, 2006, we have assumed that End of Life for Units 7 and 8 will be 1st quarter 2014 and 1st quarter 2016 respectively.

Energy Price / Production Assumptions

The price of energy is estimated based on Corporate System Economic Values. Production from each Pickering B unit is assumed to be 516 MW at a capacity factor of 85%.

Operating Cost Assumptions

N/A

Other Assumptions:

The cold leg locking tabs are expected to fail after 6.3 EFPYs which is assumed to be:

- **Unit 7:** September 2011
- **Unit 8:** October 2010

Repairs to Units 7 and 8 can be postponed until September 2011 and October 2010 respectively because a Fitness for Service Evaluation of cracked hot leg locking tabs concluded that cold leg locking tabs will not fail prior to 6.3 Effective Full Power Years (EFPYs) and failure of hot leg locking tabs is not an operability issue. This analysis is based on a safety factor of 2.

Pickering B Steam Generator Locking Tab Replacement 13 - 40641

Full Release Business Case Summary NK30-BCS-33115-00007-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr 2005	This Release 2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011		Later	Total
Project Management (OPG)	-	241	223	280	318	163			1,225
Engineering & Drafting (OPG)	-	118	40	10	37	25			229
Material	[redacted]								
Installation - PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Installation - IMS									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	-	626	9,448	526	9,664	261	-	-	20,525
2007-2011 Business Plan		700	6,300	1,000	6,000	-			14,000
Variance to Business Plan	-	[redacted]							
Committed Cost		12,700	(6,300)	(1,000)	(5,400)				-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	[redacted]							
Total Release (incl contingency)	-	13,326	3,148	(474)	4,264	261	-	-	20,525
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	100%		Quality of Estimate	Budget + 30% to - 15%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	N/A	Budgetary Quote(s)	No	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Jan 2007.

Reviewed By:

Jan 26/07

P. Asgaripour
Project Manager

Date:

Approved By:

Jerry Keto 26 Jan 07

J. Keto
Eng & Mods Manager (Strat IV)

Date:

Pickering B Steam Generator Locking Tab Replacement 13 - 40641

Full Release Business Case Summary NK30-BCS-33115-00007-R000

Attachment "B" **Project Variance Analysis**

OM&A	Total Project		Variance	Comments
	Units 5 and 6	Units 7 & 8		
Project Management (OPG)	824	1,225	401	Additional cost due to longer project duration - 4 years instead of 2 years for Units 5 and 6.
Engineering & Drafting (OPG)	529	229	(301)	Replacement of fastener only. No design for sealing skins is required.
Material	[redacted]			
Installation – OPG Support	[redacted]			
Contract - Design	[redacted]			
Contract - Installation	[redacted]			
Kinetrics	[redacted]			
Contract - Other	[redacted]			
Installation - IMS	[redacted]			
Sub Total	[redacted]			
Foreign Material Unit 6	[redacted]			
BARC/Open/ Close	[redacted]			
Unit 7 & 8 contingency	[redacted]			
Project Costs (excl contingency)	[redacted]			
General Contingency	[redacted]			
Specific Contingency	[redacted]			
Project Costs (incl contingency)	**26,234**	**20,525**	**(5,709)**	

Comments:

This project was identified in March 2006. Currently, conceptual funding is being used to start the Design work and prepare the Full Release BCS.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
28	Feb	2007	FR1: Full Release BCS Approved
15	Mar	2007	IDR: Design Requirements Approved and Issued
13	Oct	2007	FD1: Final Design Complete (Unit 7) DCP: Design Permanent Mods Documents Issued
01	Nov	2007	MCA: Major Contracts Awarded (2 Units)
20	Sep	2008	SOI: Start of Installation (Unit 7)
15	Dec	2008	AFS: Available for Service Meeting (Unit 7)
01	Feb	2009	FD2: Final Design Complete (Unit 8) DCP: Design Permanent Mods Documents Issued
15	Feb	2010	SOI: Start of Installation (Unit 8)
15	May	2010	AFS: Available for Service Meeting (Unit 8)
15	Feb	2011	PCS: Close-out Starts
31	Aug	2011	PCM: Plan Complete Milestone

A Project Execution Plan (PEP) will be approved by May 2007

Comments:
All outage milestones will comply with N-PROC-MA-0013 **Revision 5B** (Planned Outage Management).

ONTARIOPOWER GENERATION

Pickering B Steam Generator Maintenance Waterlancing 13 - 40645

Full Release Business Case Summary NK30-BCS-36340-00004-R000

Routing	Location	Action	Signature	Date
J. Xiao Project Leader (Acting), Boiler Projects 701-8649	P72-3	Prepare BCS	Xiao	April 2, 2007
P. Asgaripour Project Manager (Acting), Boiler Project 701-4680	P72-3	Review BCS	[illegible]	APR 3 / 2007
G. Kotwa Section Mgr. Process Scheduling 701 - 3755	P72-1	Review BCS	[illegible]	Apr 10/2007
G. Keto Manager, Boiler Projects 701 - 2568	P72-3	Review BCS	Gerry Keto	10 Apr 07
~~B. Morrill~~ M. W. SHANAHAN Manager, Comp. & Equipment 701-4926	P41-E3	Review BCS	M.W. Shanahan	2007 04 11
M. Arnone Director Projects & Mods 701-6063	P71-1	Review BCS	[illegible]	11 APRIL 2007
R. Ball Senior Financial Analyst [illegible]2 - 4084	P82-3	Review BCS	[illegible]	12 Apr 07
R. Ball [illegible]nior Financial Analyst [illegible]-4084	P82-3B6	Return For Distribution		

RECEIVED
by P. R. Charlebois
MAY 1 7 2007
Ref. to: ....

Pickering B Steam Generator Maintenance Waterlancing 13 - 40645

Full Business Case Summary NK30-BCS-36340-00004-R000

Routing	Location	Action	Signature	Date
R. Leavitt Director Investment Management 702-5085	P82-3	Review BCS		April 12, 2007
P. Tremblay Senior Vice President Pickering B 701-3501	P41-E3	Review BCS		April 13/07
J. Beech VP Nuclear Finance 400-7276	H9-F26	Review BCS		Apr 18/07
T. Mitchell EVP and CNO 702-5294	P82-6	Submit BCS		Apr 19/07
D. Power Director Investment & Business Planning 400-7172	H7-D06	Approve BCS		April 25/07
P. Charlebois EVP & Chief Operating Officer	H19-A21	Review BCS		May 22/07
D. Hanbidge S.V.P & C.F.O.	H19-F27	Review BCS		May/07
Hankinson President & CEO 400-2121	H19-A24	Approve BCS		21/5
R. Ball Senior Financial Analyst -4084	P82-3B6	Return For Distribution		

Pickering B Steam Generator Maintenance Waterlancing 13 - 40645

Full Release Business Case Summary NK30-BCS-36340-00004-R000

1/ RECOMMENDATION:

We recommend a Full Release of $25M (including contingency) to complete Water Lancing on all four Pickering B units from 2008 to 2010 as recommended in the Steam Generators Life Cycle Management Plan (LCMP) (NK30-PLAN-33110-10008), and the Steam Generator Investment Review (30 May 2006) (N-REP-33110-10018)

The business objectives of this project is to:

- Reduce / eliminate the risk of forced outages due to tube leaks caused by sludge build up.
- Reduce/eliminate the need for future Chemical Cleaning campaigns
- Maintain critical assets until units end-of-life

Under-deposit pitting due to sludge build-up is one of the main failure mechanisms causing tube leaks in the steam generators. A multifunctional Steam Generator Review team recently completed a study of this type of failure and came to the following conclusions:

- A Fitness for Service strategy of inspecting and plugging of tubes will allow us to operate all units until their current End of Life dates; however, this strategy will lead to a deteriorating and perhaps irreversible SG performance that will result in a large financial penalty and likely loss of regulatory credibility.
- The current Life Cycle Plan involving Water Lancing every four years will substantially reduce the likelihood of forced outages (under a Fitness for Service strategy) and will therefore provide a significant financial benefit.
- Other variations of the current LCP such as targeted and enhanced Water Lancing may provide marginally greater value but cost more and involve greater risk.

  Changes in this strategy should be considered if End of Life, Forced Loss Rate, and Planned Outage projections change significantly.

Based on the recommendations of this study we are therefore requesting approval of a Full Release of $25M to conduct Water Lancing on each PB unit from 2008 to 2010. Should further analysis or more definitive refurbishment / EOL dates suggest there is more value in an alternative strategy, we will submit a superseding BCS outlining the opportunities and risks.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	N/A								-
Requested Now	Full		486	6,318	11,487	6,287	395		24,973
Future Funding Req'd									-
Total Project Costs		-	486	6,318	11,487	6,287	395	-	24,973
Other Costs									-
Ongoing Costs									-
Grand Total		-	486	6,318	11,487	6,287	395	-	24,973

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	OM&A	38.9M	N/A	N/A

Submitted By:

April 18/07

P. Tremblay
Senior Vice President Pickering B
Date:

Finance Approval:

April 25/07

D. Power
Director Investment & Business Planning
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

2/5

J. Hankinson
President & CEO
Date:

2/ BACKGROUND & ISSUES

The historic operating trends for Pickering B SGs have shown a correlation between the tube leak and intervals between chemical cleaning and Water Lancing. The historical data illustrate absence of tube leaks for several operating years after completion of effective cleaning campaigns followed by escalation in the frequency of tube leaks in the hot leg tube sheet region. The chief mechanism for this phenomenon is known to be under-deposit pitting corrosion. Effective Water Lancing is a cost effective method (as opposed to chemical clean) to remove accumulated sludge during operating intervals to mitigate under deposit pitting.

According to studies, the sludge piles that form in the SGs are generally "kidney shaped" piles with the peak located near the center of the hot leg bundle. Over time the peak heights increase and the pile spreads outwards the periphery and the No Tube Lane (NTL) of the SGs. In a short time, the central tubes are covered with sludge and are at higher risk. The current LCMP calls for Water Lancing every four years at a minimum to reduce the corrosive environment created by sludge piles.

New improvements made to Water Lancing system and inspection equipment have produced favorable results in recent campaigns (2005-2006). This was achieved through the development of Inter tube flushing lance for the removal of sludge in the shadow areas and improved inspection strips for cleaning assessment respectively. Implementation of different strategies and better understanding of sludge profile has provided valuable information to produce enhanced results as the process will be customized to the unit conditions. The expected window for Water Lancing during a 40 day outage is expected to be approximately 17 days. In the bidding process vendors will be requested to demonstrate their ability to produce maximum results during this fixed period. Assessment of vendors cleaning capabilities along with cost will be used as selection criteria.

A multidisciplinary team comprised of engineers, operating, maintenance, and financial expertise was asked to review the Steam Generator (SG) Life Cycle Management (LCM) strategy for Pickering B (PB) in order to produce a report that summarized investment options, costs, and risks to OPG. The objective was to provide sufficient information as input to the 2006 Business Plan and to unit refurbishment decisions.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions	Base Case FFS Inspect/Plug All SGs every 2.5 yrs	Alt 1 Recommend Std. W / L All SGs every 4 yrs	Alt 2 Targeted Enhanced W/L only Bad SGs every 2 yrs	Alt 3 Enhanced W/L All SGs every 2 yrs	Alt 4 FFS Inspect/Plug All SGs every yr
Revenue					
OM&A					
Capital					
NPV (after tax)	-52.8	-13.9	-18.7	-35.2	-156.6
Impact on Economic Value (IEV)	N/A	38.9	34.1	17.6	-103.8

Note: All NPV calculations are based on executing the strategy being measured to EOL

Base Case: Fitness for Service (Minimum Inspection/Plugging every 2.5 years) - Not Recommended

The Base Case involves:

- minimum inspection / plugging to satisfy Fitness for Service requirements for a 2.5 year operating interval.
- No water lancing

We do not recommend the Base Case because, the multidisciplinary team concluded, in July 2006, that this strategy will allow us to operate all units until their current End of Life dates; however, it will lead to a deteriorating and perhaps irreversible SG performance that will result in a large financial penalty and likely loss of regulatory credibility.

Alternative 1 – Water Lancing ever four years (Current LCMP - Recommended

The recommendation involves:

- Standard inspection/plugging every 2 years
- Standard water lancing on all 12 SGs every 4 years

The conclusion of the team (July 2006) was that the current LCMP involving Water Lancing every four years is a sound strategy and should be followed. Although their analysis indicates that other strategies (namely targeted and enhanced Water Lancing) would generate marginally greater value, they cost more and involve greater risk. They also recommended that this strategy be reviewed should there be any change in End of Life, Forced Loss Rates or Planned Outage projections

Alternative 2 - Specific (Targeted) S.G. Life Cycle Management Plan - Not Recommended

This option involves:

- enhanced inspection/plugging (every 2 years) on "bad" steam generators
- enhanced water lancing on only "bad" SGs every two years

We do not recommend this strategy as it creates less value, the cost is higher and the risks are greater than the LCMP

Alternative 3 – Enhanced S.G. Life Cycle Management Plan - Not Recommended

This option involves:

- enhanced inspection/plugging every 2 years (per LCMP)
- enhanced water lancing on all 12 SGs every two years

We do not recommend this strategy as it creates less value, the cost is higher and the risks are greater than the LCMP

Alternative 4 – Fitness for Service (Minimum Inspection/Plugging every year) - Not Recommended

This strategy involves:

- minimum inspection / plugging to satisfy Fitness for Service requirements for a 1 year operating interval.
- No water lancing

This strategy is not recommended because it adds about 40 planned outage days per year (2 more outages per year). There is a risk regarding our capability to plan and resource 4 outages per year

4/ THE PROPOSAL

- Initiate a competitive bidding process in preparation of Water Lancing in planned outages in 2008-2010 for all Pickering B units. This may include but not limited to development of mock-up, on boiler equipment, sludge removal tool, qualification testing, new lancing flow diagram and registration.
- Assess vendor's proposal based on meeting acceptance criteria as outlined in the LCMP and award contract.
- Ensure all required materials/equipment and procedures are available for execution per outage milestones
- Ensure contractor is adequately trained for working at OPG nuclear sites
- Achieve Water Lancing cleaning results per EMD proposed scope
- Complete Water Lancing within the allotted budget and the Outage schedule

The requested amount of $25M is based on the estimated contracted cost and staffing levels required during preparation, execution and restoration phases of the previous Water Lancing campaigns. The validity of assumptions used for this estimate are confirmed using most recent Water Lancing campaigns (P681 and P671) OPEX.

5/ QUALITATIVE FACTORS

None other than stated in the Business Objectives.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Unexpected difficulties in equipment/flow diagram development and registration	Cost overrun	**High**	Monitoring and tracking contractor's preparation activities by OPG Projects	**Medium**
Scope				
Unable to complete scope during a fixed outage window	Inadequate tubesheet cleaning and increased risk of under deposit pitting as a result during the operation	**High**	Water lancing strategy will be customized to unit condition to maximize the effectiveness. Lessons learned from previous campaigns will be reviewed for improvements	**Medium**
Schedule				
Contract not awarded per P881 Outage Milestone due to the 2 year advancement of Unit 8 campaign and lack of funding	Not able to meet the Outage Milestone for P881 and delay in vendor's deliverables.	**High**	Boiler Projects staff will work closely with finance to ensure adequate funding is available to initiate a RFP for competitive bidding and award the contract in a timely manner for P881 execution.	**Low**
Station caused delays	Delay in Waterlancing onsite activities	**High**	Delays in Waterlancing schedule due to unforeseen station issues will be documented and communicated to outage management and recovery plans will be jointly developed. Review lessons learned from previous campaigns and improve alignment and awareness from station support.	**Low**
Delay in registration of Waterlancing process system (if new)	Unable to register and accept the new Waterlancing system	**High**	Boiler Projects will revie vendor's readiness for new system, and if necessary, sole sourcing the 1st unit execution (using the existing system) and competitively bidding the remaining units.	**Low**

Resources				
Lack of skilled trades and technicians	Unfamiliarity with Waterlancing process and working at nuclear sites, compromising quality and schedule.	**Medium**	Contract will be awarded to allow sufficient time for staff training	**Low**
Technical				
Failure of qualification testing (if new system)	Insufficient cleaning due to modification of process parameters	**Medium**	Stakeholders will be involved in qualification testing from the early stages to ensure process is qualified and effective	**Low**
Site execution issues	Contractor work practices impacting equipment condition and outage duration	**High**	Management expectations will be rolled out to contractor prior to site execution to ensure event free tools are effectively practiced	**Low**
Regulatory				
No significant regulatory risks are expected.				
Environmental				
Spill due to hose rupture or fitting failure	Unplanned release of radionuclide through lancing waste water or breach of containment	**Medium**	These concerns will be considered during design phase of the system and accepted by OPG prior to site execution	**Low**
Health & Safety				
High pressure water jets and spread of contamination	Personnel injury. Unplanned dose uptake	**Medium**	Use of mock up for training and implementing procedural barriers	**Low**
Investment				
No significant risk is expected				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2010	Jun 2011	Manager Pickering B Components and Equipment Department

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Cleaning effectiveness	Post water lancing results form previous campaigns	Removal of soft sludge snd returning SGs to post Waterlancing conditions of previous campaigns between 2005 and 2006	Visual inspection of pre and post Waterlancing of the same SG	Engineering Mechanics Department and IMS
2.	Tube pitting indications	Results from previous inspection	Comparable to recent histotrical data	Eddy Current inspection per the SG LCMP	Engineering Mechanics Department and IMS
3.					
4.					
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

EOL: End of Life
LCMP: (Pickering B Steam Generator) Life Cycle Management Plan
NTL: No Tube Lane
SG: Steam Generator
SMB: Site Management Board

Appendix "B" **Project Funding History**

$ 000's Release Type	Month	Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
		All Existing and Planned Releases (incl contingency) Cumulative Values									
Full				486	6,318	11,487	6,287	395			24,973
											0
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:

Appendix "C" **Financial Model – Assumptions**

See the Pickering B Steam Generator Investment Review N-REP-33110-10018 (Sections 5)

Pickering B Steam Generator Maintenance Waterlancing 13 - 40645

Full Release Business Case Summary NK30-BCS-36340-00004-R000

Attachment "A"

Project Cost Summary

$000's OM&A	LTD Prior Yr	This Release 2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011	Future Release	Later	Total
Project Management (OPG)		314	314	392	314	235			1,569
Engineering & Drafting (OPG)		20	40	20	10	8			
Material	[redacted]								98
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	-	486	6,318	11,487	6,287	395	-	-	24,973
2007-2010 Business Plan			1,000	11,000	12,000				24,000
Variance to Business Plan	-	[redacted]							
Committed Cost		18,197	(4,677)	(8,843)	(4,677)				
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	[redacted]							-
Total Release (incl contingency)	-	18,683	1,641	2,644	1,610	395	-	-	24,973
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	N/A		Quality of Estimate		Release + 15% to - 10%
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2006-2010 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Apr 2007.

Reviewed By:

10 APR / 2007

P. Asgaripour
Project Manager

Date.

Approved By:

11 Apr 07

J. Keto
Eng & Mods Manager (Strat IV)

Date:

Pickering B Steam Generator Maintenance Waterlancing 13 - 40645

Full Release Business Case Summary NK30-BCS-36340-00004-R000

Attachment "B" **Project Variance Analysis**

	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
	N/A	N/A	N/A		
	N/A	N/A	N/A		
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
15	05	2007	Full Release BCS approved
30	06	2007	Waterlancing contract awarded
18	02	2008	Unit 8 Waterlancing start
27	03	2008	Unit 8 Waterlancing complete
15	04	2008	Unit 8 Available for Service
09	03	2009	Unit 5 Waterlancing start
05	04	2009	Unit 5 Waterlancing complete
11	04	2009	Unit 5 Available for Service
02	11	2009	Unit 6 Waterlancing start
29	11	2009	Unit 6 Waterlancing complete
10	12	2009	Unit 6 Available for Service
01	11	2010	Unit 7 Waterlancing start
28	11	2010	Unit 7 Waterlancing complete
02	12	2010	Unit 7 Available for Service
31	05	2011	Project close-out complete

A Project Execution Plan (PEP) will be approved by Sep 2007

Comments:

ONTARIOPOWER GENERATION

OPG Confidential	Page: 1 of 15
ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Routing	Location	Action	Signature	Date
L. Yu MTL Design Projects	P24 AN	Prepare BCS		March 4/2005.
S. Von Svoboda Project Leader II Design Projects	P24 AN	Review BCS		Mar 7, 2005
G. Kotwa Section Manager Process Scheduling, PMO	P24 AB	Review BCS		Mar 7/2005
J. Marczak Project Manager Design Projects	P24 AN	Review BCS		2005 Mar 08
P. Floyd Manager Design Projects	P24 AB	Review BCS		Mar 8/05
R. Ball Senior Financial Analysts	P82-3	Review BCS		8 Mar 05
Brown troller - Engineering & Modifications	P82-3	Review BCS	*	8 MAR '05

~~* Sign-off subject to receipt/review of risk assessment, referred to on Page 11 of 15~~ KES

OK KES

ONTARIO POWER GENERATION

CPG Confidential	Page: 2 of 15
ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Routing	Location	Action	Signature	Date
M. Arnone Director Projects & Modifications	P72-2	Review BCS	[signature]	08 MAR 05
G. Paterson Manager, Components & Equipment PNGS-A	P42 E3	Review BCS	[signature]	09 Mar 05
M. Reid Director, Station Engineering PNGS-A	P42 E3	Review BCS	[signature]	2005 Mar 10
J. Coleby Site Vice President PNGS-A	P05 A2	Submit BCS	SEE ATTACHED	
D. Power Director, Investment & Business Planning	H07 D06	Review BCS	SEE ATTACHED	
D. Hanbidge Vice President - Controller	H19 F27	Review BCS	SEE ATTACHED	
Charlebois ef Nuclear Officer (Acting)	P82-6	Review BCS	SEE ATTACHED	
R. Dicerni Acting President & CEO	H19 E27	Approve BCS	SEE ATTACHED	
R. Ball Senior Financial Analyst ?01-8241	P72-2	Return For Distribution		

ONTARIOPOWER GENERATION

OPG Confidential	Page:
ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Routing	Location	Action	Signature	Date
M. Arnone Director Projects & Modifications	P72-2	Review BCS	SEE ATTACHED	
G. Paterson Manager, Components & Equipment PNGS-A	P42 E3	Review BCS	SEE ATTACHED	
M. Reid Director, Station Engineering PNGS-A	P42 E3	Review BCS	SEE ATTACHED	
J. Coleby Site Vice President PNGS-A	P05 A2	Submit BCS	John Coleby	Mar 8th 05
D. Power Director, Investment & Business Planning	H07 D06	Review BCS	[illegible]	
D. Hanbidge Vice President - Controller	H19 F27	Review BCS	[illegible]	March 10/05
P. Charlebois Chief Nuclear Officer (Acting)	P82-6	Review BCS	[illegible]	Mar 9/05
. Dicerni Acting President & CEO	H19 E27	Approve BCS	SEE ATTACHED	
R. Ball Senior Financial Analyst 701-8241	P72-2	Return For Distribution		

ONTARIOPOWER GENERATION

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Routing	Location	Action	Signature	Date
M. Arnone Director Projects & Modifications	P72-2	Review BCS	SEE ATTACHED	
G. Paterson Manager, Components & Equipment PNGS-A	P42 E3	Review BCS	SEE ATTACHED	
M. Reid Director, Station Engineering PNGS-A	P42 E3	Review BCS	SEE ATTACHED	
J. Coleby Site Vice President PNGS-A	P05 A2	Submit BCS	[illegible]	Mar 8th 05
D. Power Director, Investment & Business Planning	H07 D06	Review BCS	SEE ATTACHED	
D. Hanbidge Vice President - Controller	H19 F27	Review BCS	SEE ATTACHED	
[illegible]harlebois [illegible] Nuclear Officer (Acting)	P82-6	Review BCS	[illegible]	Mar 9/05
R. Dicerni Acting President & CEO	H19 E27	Approve BCS	[illegible]	Mar 11/05
R. Ball Senior Financial Analyst 701-8241	P72-2	Return For Distribution		

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

1/ RECOMMENDATION:

We recommend the completion of all detailed engineering work and pre-requisites required to support the PNGS-A Unit 4 Boiler Chemical Clean Project (13-49201), and the execution of the Boiler Chemical Clean process during the 2007 Unit 4 outage (with the option to advance execution to 2006). At this time, we require a **full release of $47.4M** for the project.

A successful Boiler Chemical Cleaning must be completed at Unit 4 to ensure generation revenues are protected by eliminating the requirement for boiler tube plugging and potential unit shutdown due to boiler tube denting. A target period of eight years of operation without tube denting can be expected after completion of boiler cleaning at Unit 4. A regulatory commitment to the CNSC has also been made for chemical cleaning the boilers in Unit 4 (REGC AR# 28026033).

In order to prepare for the planned execution of Unit 4 boiler chemical clean in 2007 (with the option to advance execution to 2006), design deliverables must be expedited to allow all installation and execution documentation and prerequisite modifications to be completed in time to allow the option of performing the 2006 Unit 4 boiler chemical clean. Favourable P541 boiler inspection results will defer Unit 4 boiler chemical clean to 2007 – P741 outage; however, planning must be in place now for the execution option in 2006.

In August 2004, a superseding developmental release (NA44-BCS-36330-00002) was approved to provide funding to complete preliminary engineering and initial detailed engineering work. The superseding developmental release brought the project cumulative release amount to $7.9M ($7.2M excluding contingency). With the initiation of detailed engineering, the project is in a position to request this full funding release.

The Unit 4 Boiler Chemical Clean Project is listed in the proposed 2005-2009 Business Plan at $44.3M. Variances will be managed via the Portfolio Management process in 2005.

$Million OM&A		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Developmental	7.9	7.2	Jan-05	Spent Life to Date:	4.2
Requested Now:	Full	47.4	38.9	2005-2009	Appr'd Business Plan (Tot Proj):	44.3
Cumulative Release:	Total to Date	55.3	46.1	2005-2009	Business Plan Variance:	1.8
Total Project Estimate:	+30% to -15%	55.3	46.1	2005	Budget (Current Year)	10.2
Current Year Estimate:	2005	17.4	14.5	2005	Budget Variance (Current Yr)	4.3
Type of Investment:	Regulatory	N/A	N/A	Cumulative Release Remaining:		41.9
NPV: Recommendation vs Delaying		116.0	N/A	Contingency on Remaining Release:		9.2
IRR: Recommendation vs Delaying		N/A	N/A	Contingency % on Remaining Release:		22.0%

Submitted By:

John Coleby 8th March '05

J. Coleby
Site Vice President, PNGS-A

Date:

Finance Approval:

for D. Hanbidge
Vice President - Controller

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

R. Dicerni
Acting President & CEO

Date:

2/ BACKGROUND & ISSUES

Boiler Operations & Maintenance

During normal, steady state operation of nuclear power plants, small amounts of metallic impurities, principally iron, nickel, zinc and copper, are transported via the feedwater to the secondary side of the boilers where they slowly accumulate. Although their concentrations are low, typically a total of ~2 ppb, over 20 years of operation the amount transported may be as high as several hundred kilograms. In addition, normal start-up evolutions contribute an estimated 10 – 50 kg per start-up.

PNGS has adopted a boiler chemical cleaning (BCC) practice as part of its Boiler Life Cycle Management Plan to remove these deposits to stop or slow the boiler tube degradation mechanisms, particularly tube denting and under-deposit pitting corrosion. Unit 4 boilers are showing early indications of pitting and tube denting (latest inspections results showed 19 dents / 362 pits in all 12 boilers (31000 tubes) inspected). The degradation is not as advanced as compared to other PNGS-A unit boilers, and the chemical controls in place since the Return to Service of this unit have been excellent. However, empirical data from other units has shown that the phenomenon can advance rapidly once initiated. Data on the rate and exact onset is somewhat limited. It is therefore important to address the boiler tube denting on Unit 4 in a timely fashion.

Prevention of boiler tube denting will minimize boiler tube failure due to stress corrosion cracking and also ensure continued unrestricted access of inspection probes to the boiler tube interiors to demonstrate tube fitness-for-service, and will reduce the requirements for tube plugging due to inaccessibility issues. Minimizing the number of plugged boiler tubes will sustain boiler life and protect station against generation revenue losses. Completion of boiler chemical clean can alleviate the Unit 4 boilers of tube degradation conditions for a target period of eight years.

Regulatory and Life Cycle Management Plan

OPG has a regulatory commitment (CNSC) to complete boiler cleaning at Unit 4 (REGC AR # 28026033). The Pickering 1-4 Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003) specifies the requirement for a Boiler Chemical Clean to be conducted on Unit 4 to ensure sustained life of the asset.

Process Selection & Estimate Development

Two process options are available for Boiler Chemical Cleaning: the Hot Boiler Cleaning (HBC) process or the Electric Power Research Institute/Steam Generator Owners Group (EPRI/SGOG) process. The HBC process is too corrosive to apply to Pickering-A boilers due to the large quantity of deposits to be removed, and the boiler material corrosion limits. Therefore, the EPRI/SGOG process was selected for Unit 4 BCC.

The original $31.5M estimate (2004 Business Plan) was based on a cost-sharing scenario with Unit 3 BCC for common design, prerequisite elements, and materials. With Unit 3 BCC project put on hold, the cost-sharing assumption is no longer valid, and the Unit 4 BCC project will have to fund all current BCC work. Additional analysis/reviews of cost assumptions have also been incorporated into the project estimates since this change.

The subsequent estimate of $54.3M (previously listed under the superceding developmental BCS) was based on the assumption that additional dedicated station resources will be available to the project. Further refinement of the project estimate led to two scenarios (detailed in table below): 2006 execution scenario at total project cost of $43.1M; and 2007 execution scenario with 2006 execution option at total project cost of $46.1M. This BCS submission is based on the 2007 Execution (with 2006 option) scenario, as this is expected to be the actual scenario realized. It must be noted that (towards the end of 2005) should a 2006 execution be deemed necessary, the project budget and Business Plan cashflows must be promptly increased to permit such execution.

Execution Scenarios Cost Estimates

Alt	$M (excluding contingency)	2003	2004	2005	2006	2007	2008	Total
1A	2006 Spring Execution	0.3 Actuals	3.4 Actuals	14.5	23.8	1.0	0	43.1
1	2007 Spring Execution (with 2006 Execution Option)	0.3 Actuals	3.4 Actuals	14.5	5.7	22.2	0	46.1

Past Experience

PNGS-A Unit 1 and Unit 2 boilers were previously cleaned using the EPRI/SGOG process. However, the change control environment in early 1990's was not as stringent as today's standards. The equipment and design registration requirements for Unit 4 BCC is much more rigourous than before, and the new engineering change control environment and pressure boundary program requirements are leading to higher overall project costs than previous EPRI/SGOG boiler chemical cleans.

The equipment used and process time for the HBC method is significantly different from the EPRI/SGOG process that will be used for cleaning Unit 4 boilers. These differences prevented the use of common equipment and processes previously developed, and added on to the cost of designing new equipment and processes that is required for EPRI/SGOG.

Project Cost & Schedule

A peer review performed by Helyar & Associates on the cost estimate based on the single-unit execution scenario resulted in a project total of [redacted] This is 35% higher than the OPG estimate of [redacted] Helyar's peer review was obtained by using OPG's cost estimate, scrutinizing and supplementing it with additional conservatisms to yield their value; there was no original estimate performed independently using field data. Through detailed planning and monitoring by the project team, and oversight by line management (Management Steering Committee), and through experience from previous boiler chemical cleaning campaigns, the presented estimate [redacted] is deemed to be reasonable for completion of Unit 4 BCC.

Pickering Unit 4 currently has planned outages scheduled for 2005 (Fall) and 2007 (Spring). This is based on the standard two year outage interval. Given prerequisite requirements, the project will not be ready for Boiler Chemical Clean execution in the 2005 outage. The earliest readiness date for execution would be 2006 (Spring). Pickering A operational requirements preclude delaying the planned 2005 (Fall) outage to 2006 (Spring). As a result, the current project schedule is aligned for a planned Unit 4 outage in 2005 (P541) for prerequisite activities, and is targeting for the execution outage in 2007 for boiler chemical cleaning with a 2006 execution option. The option would be invoked if boiler tube inspection results in 2005 indicate a requirement to advance the clean. Design deliverables must be expedited to allow all installation and execution documentation and pre-requisite modifications to be completed in time to allow the option of performing the 2006 Unit 4 boiler chemical clean. Pre-requisite activities include installation of access nozzles to boilers, installation of waste transport piping, modifications to boiler blowdown line, installation of containment penetrations, fabrication and testing of boiler cleaning equipment, transportation and staging of equipment, routing and connection of power supplies, development of procedures, and, training and mobilization of personnel.

It should be noted that pre-BCC and post-BCC flushing work will be completed as part of the separate Unit 4 Boiler Flushing Project.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Stop the Project (NPV -$700M) (Not Recommended)
Fitness for service issue – Stop Project

This alternative is **not** recommended. The regulatory commitment (AR# 28026033) to the CNSC requires the completion of boiler cleaning at Unit 4. Potential boiler degradation/denting caused by crevice deposits will also limit unit operation and affect station assets, forcing a unit shutdown and negatively affecting generation revenues if boiler cleaning is not performed. (Reference Pickering 1-4 Steam Generator Life Cycle Management Plan – NA44-PLAN-33110-10003). A premature unit shutdown scenario causing loss of generation revenues could result. For the purposes of calculating a limiting NPV in this scenario: A premature unit shutdown from 2007 (extremely low probability) until its projected end-of-life of boilers (2017) with no mitigating work to restore/replace boilers would lead to an estimated NPV of approximately -$700M (after tax).

Alternative 1 – Prepare for 2006 Clean but Plan for 2007 Clean (NPV -$29M) (Recommended)
Complete all design & prerequisites, Support 2006 Execution Option & Perform Boiler Clean in 2007

Complete all design packages, documentation, prerequisite modifications, and perform boiler chemical cleaning at Unit 4 during the 2007 outage (P741) with the option to execute in 2006. Boiler chemical cleaning operations have successfully been completed on all PNGS-B units and on PNGS-A Units 1 and 2. Costs have been minimized to permit advancing execution to P641 if P541 inspection results are unfavourable (low probability, but contingency to be maintained), and internal and external resources have been optimized. This scenario also maximizes opportunities for execution readiness. The project cost estimate for this alternative is $55.3M (including contingency). Estimated NPV = - $28.7M (after tax).

lternative 1A – Execute Boiler Chemical Clean in 2006 (NPV -$33M) (Not Recommended)
ove 2007 and all subsequent outages forward by one year.

This alternative is **not** recommended. From a Business Planning perspective, project cost deferral to future years will permit better station cost management since more nuclear generation revenues are expected to be available with more nuclear units online in the near future. Executing BCC (and other major planned U4 outage work) in 2006 will impose a heavy cost load on the station, and subsequent advancing of future planned outages will also shift the cost load towards years with less generation revenues. The project cost estimate for this alternative is $51.7M (including contingency). This alternative should only be selected in the situation where boiler inspection results in 2005 strictly require the earliest execution of U4 BCC.

Alternative 2 - Delay the Recommendation (NPV -$144M) (Not Recommended)
No 2006 Preparation – 2005 inspection indicates Fitness for Service issue – Shutdown Nov 05 to Mar 07

This alternative is **not** recommended. Risk due to denting uncertainty makes this a less prudent option. Upcoming inspection results from P541 may indicate requirement for an earlier boiler chemical cleaning in 2006. If P541 inspection results indicate so, not having the 2006 execution option available will require unit shutdown post-P541 outage due to fitness for service consideration until after completion of U4 BCC in 2007 (though all efforts would be applied to further advance execution readiness should this scenario arise). Loss of generation revenues associated with this forced unit shutdown justifies maintaining the provision for the 2006 execution option.

Alternative 3 - Do Less (Not Recommended)

This alternative is **not** recommended. Chemical Cleaning all twelve Unit 4 boilers is required to satisfy CNSC REGC commitment and to maintain station assets and generation revenues. Costs have been minimized for the current project scope of Unit 4 boiler chemical clean.

Alternative 4 - Do More (Not Recommended)

This alternative is **not** recommended. The selected EPRI/SGOG process has been proven to effectively clean the PNGS-A boiler internals, while maintaining the corrosion levels within acceptable limits. This process has been timized to provide the degree of boiler cleaning required.

4/ THE PROPOSAL

This full release BCS will allow the completion of the following deliverables.

- Project Execution Plan (R1)
- Detailed Engineering for site modifications and process design packages.
  Packages include:
    - Station Tie-ins
    - RAB/TAB Utilities
    - RB Utilities
    - Containment Inserts
    - BCC System
- Purchase of materials for site modifications and vendor processes
- Development of all vendor and station documentation to support BCC
- Installation of site modifications to support BCC
- Testing and commissioning of process systems
- Execution of Unit 4 BCC
- Demobilization and waste disposal

Milestones Finish Date (D/M/Y)	Description
28-Feb-05	Preliminary Engineering Complete
25-Mar-05	Project Execution Plan (R1) Issued
25-Mar-05	Full Release BCS Approved
29-Mar-05	P541 Workplans Issued
31-May-05	Detailed Engineering Complete
1-Dec-05	P541 BCC Prerequisite Outage Activities Complete
31-Jan-06	P641/P741 BCC Go/No-Go Decision (Tentative)
15-Jun-06	P641 BCC Execution Complete (if 2006 execution option is selected)
15-May-07	P741 BCC Execution Complete
31-Dec-07	Project Close-out

5/ QUALITATIVE FACTORS

Boiler cleaning can result in the following benefits for the station:

- Prevention of further boiler tube denting which will
    - allow more comprehensive and efficient boiler inspections and hence shorter outage time
    - reduce boiler tube plugging requirements and hence lower probability of reactor derating and generation revenue loss or full shutdown
    - stop potential for tube cracking and hence prevent forced outages
- Prevention of corrosion-induced boiler tube leaks which will
    - reduce potential for forced outages
    - reduce potential for environmental releases

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Vendor contract to be time and materials type	Unlike a fixed-price contract, time and materials contract may result in cost escalations. Project could require additional funding.	**Medium**	Clearly define scope of work and introduce incentive / penalty clauses into contract. Detailed monitoring of field activities progress during execution. Allocation of a [redacted] contingency to project for unforeseen developments.	**Low**
Delays during outage execution (Also affects negatively execution schedule)	Staging of equipment and mobilization of execution resources will have to be extended. Delays may result in outage extension (day-for-day cost increase) and associated generation loss.	**Medium**	Plan in detail execution tasks and logics with Outage Department. Integrate with station Outage Operations and Maintenance departments for optimization of execution. Allocation of a [redacted] contingency to project for unforeseen developments. Using Framatome with their extensive world wide experience in the BCC area and OPG internal OPEX. Project managed to meet Outage Milestones (Materials/Plans/etc).	**Low**
Early Boiler Chemical Clean may be required based on P541 boiler inspections (advanced rate of denting).	Unit may require to be shut down following P541 or have a short operating period in 2006 prior to Boiler Chemical Clean. Late changes to Project Budget and Business Plan cashflows would be required, and large business plan variances may result.	**Low**	May require access to project contingency, CNO contingency, or re-balance of portfolio to support 2006 Boiler Chemical Clean execution.	**Low**
Scope				
Design and execution scope increase	Increased scope affects project cost and schedule.	**Medium**	Continue review with vendor design group and station stakeholders to define design and execution scope. Strict scope control processes implemented. Management Steering Committee oversight in place.	**Low**

Description of Risk *(this release only!!!!!)*	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Schedule				
Further schedule changes to project plan	Insufficient time and resources to accommodate late changes to project plan.	**Low**	Current project direction is for a 2006 boiler chemical clean execution, with prerequisite work to be performed during P541 or before start of P641. (Business Plan is indicating 2007 execution, with 2006 execution as option). Management Steering Committee oversight in place.	**Low**
Permitry issues during BCC execution	Delays to execution window. Need for re-application of permits. This may result in outage extension and associated generation loss.	**Medium**	Involve station Operations early during work planning stages/workplan preparations. Secure stakeholder support on schedule via Task Identification Sheets (TIS) and/or Interface Agreements.	**Low**
Delays during outage execution	See "Cost" category above.	**Medium**	See "Cost" category above.	**Low**
Resources				
Insufficient Project Engineering resources to support BCC. Expertise/experience lost through staff departure.	Backlog of project-related deliverables.	**Medium**	Continue to arrange for contract resources to augment regular staff, and seek knowledgable contractors with previous boiler cleaning experience. May result in delay in project development, but will not result in execution failure. Potential cost impacts/outage extensions are covered by the [redacted] contingency (see "Cost" above).	**Med to Low**
Limited station resources	Insufficient resources to support BCC execution. This may result in outage extension and associated generation loss.	**Medium**	Secure stakeholder resource support (Operations, Maintenance, Radiation Protection, etc.) via detailed planning and use of Task Identification Sheets and/or Interface Agreements. Reduce station resource reliance by optimizing station interface designs and by extending scope of contract execution support. Ensure continued oversight by Management Steering Committee (PNGS-A Site VP and vendor management as members). May result in delay in project development, but will not result in execution failure. Potential cost impacts/outage extensions are covered by the [redacted] contingency (see "Cost" above).	**Med to Low**

Description of Risk *(this release only!!!!!)*	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Technical				
Insufficient information on boiler nozzle interference to finalize design	Delays in issuance of design packages.	**Medium**	Arrange for boiler nozzle inspections during P541 and complete design packages based on inspection results.	**Low**
Chemical addition strategy	Incorrect concentration of chemicals may affect boiler internals during BCC.	**Low**	Qualification tests to be completed for EPRI/SGOG process prior to execution of BCC.	**Low**
Corrosion Monitoring System (CMS)	CMS functionally inadequate for BCC.	**Low**	CMS to be refurbished to support BCC with required level of functionality and reliability.	**Low**
Regulatory				
CNSC may not formally approve plan for deferred execution of BCC following 2005 Inspection results.	Need to alter plan to execute boiler chemical clean	**Low**	Sought and received initial CNSC concurrence on deferred execution of BCC. Actual BCC execution date to be determined by 2005 inspection results.	**Low**
Environmental				
Air and/or liquid emissions during boiler chemical clean beyond Certificate of Approval limits.	Unplanned release to the environment	**Low**	Continued monitoring of air emissions and liquid wastes generated during boiler chemical clean with reference to Certificate of Approval permitted levels.	**Low**
Metallic deposits removed (in solution form) cannot be disposed of.	Liquid waste remains in waste tankers during execution.	**Low**	BCC waste handling is an integral part of the project, and is being reviewed in detail during engineering design, and will be managed with continued project team oversight during BCC execution.	**Low**
Health & Safety				
Unsafe work practices during vendor execution of BCC. Potential chemical hazards associated with BCC solvents.	Event-Free Day resets / Injuries	**Low**	Oversight by Contract Administrators, Contract Monitors, and Contract Management Team to be emphasized during execution. OPG Contract Management processes implemented. JHSC to be involved early in process development.	**Low**

Description of Risk *(this release only!!!!!)*	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Investment				
Boiler Chemical Clean process does not remove boiler tube/crevice deposits as planned.	Boiler denting problems not remediated	**Low**	EPRI/SGOG BCC process was successfully applied to PNGS-A boilers in Units 1 and 2. EPRI/SGOG is a proven method of boiler chemcial cleaning. All refinements to the process for Unit 4 application will be pre-qualified.	**Low**
Boiler Chemical Clean process causes excess corrosion to boiler internals	Boiler life-cycle negatively affected.	**Low**	Selected EPRI/SGOG process has proven to cause acceptably low level of corrosion during boiler chemical cleaning. Corrosion monitoring system will be in place. Corrosion coupons will also be used to measure corrosion during execution of BCC.	**Low**

As part of the ongoing cost-saving measures, three options as part of detailed design have been identified for review. These options include continuing with detailed design with new BCC equipment (current design direction), relaxing the ECC rigour for detailed design, and pursuing detailed design using existing vendor equipment.
In order to allow the risks listed in the above table to remain comprehensive for the project, the details and specific risks associated with the cost-saving options are listed only in the reference documents below to maintain the clarity of this BCS document.

References:

1. Correspondence, G. MacDonald to J. Marczak, "FANP Assessment of Options for P4BCC", February 24, 2005.
2. Memorandum to File, "PNGS-A Unit 4 Boiler Chemical Clean Project – Risks Associated with Project Cost Savings Options", February 28, 2005.

7/ POST IMPLEMENTATION REVIEW PLAN

The Post Implementation Review (PIR) will be performed in accordance with the PIR Procedure (FIN-PROC-PA-012) and the Simplified PIR Template (FIN-TMP-PA-002). Design Projects, in cooperation with Finance, Engineering Mechanics & Codes Department; Chemistry, Metallurgy & Welding Department, will perform the PIR with a target completion date of December 2007. The results of the project will be documented and compared against the following baseline criteria (in development). Major lessons-learned from the project will be documented in a report. In addition, the boiler performance will continue to be monitored under the Pickering Unit 1-4 Steam Generator Life Cycle Management Plan.

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	**May 2007**	**Dec 2007**	**Manager, Components & Equipment, PNGS-A**

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Corrosion during BCC	N/A	Within corrosion limits (limits to be finalized in NA44-REP-36330-00001: EPRI/SGOG Chemical Cleaning Process for Pickering-A)	Via Corrosion Monitoring System (CMS) and corrosion probes & coupons.	CM&W Dept. & Engineering Mechanics Dept.
2.	Deposit removal	N/A	6500 - 8500 kg	Via Waste Solvent calculations.	CM&W Dept.
3.	REGC AR 28026033	N/A	Fulfillment of commitment	Via successful completion of BCC during outage.	Components & Equipment, PNGS-A.
4.	[Qualitative] Removal of Crevice Deposits	N/A	Crevices cleaned	Post BCC inspection results to be reviewed	CM&W Dept.
5.	[Qualitative] Reduction in Boiler Tube denting	N/A	Based on crevice deposit removal	Post BCC inspection results to be extrapolated	Engineering Mechanics Dept.
6.	[Qualitative] Reduction in corrosion induced boiler tube leaks	N/A	Consistent with Life Cycle Management Plan expected performance	Post BCC inspection results to be extrapolated	Engineering Mechanics Dept.

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2003	LTD Prior Years 2004	2005	2006	2007	2008	Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	106	411	1,880	1,400	1,870		5,667	635	11.2%
Engineering & Drafting (OPG)	169	649	1,380	620	660		3,478	863	24.8%
Material	[redacted]								
Installation – PWU, BTU									
Contract – Project Mgmt									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Sub Total (excl Contingency)									
Contingency									
Grand Total	**275**	**3,391**	**17,350**	**6,860**	**27,430**	**-**	**55,306**	**N/A**	**N/A**
2005-2009 Business Plan	275	4,672	10,180	5,400	22,750	976	44,253	N/A	N/A
Variance to Business Plan (excl Contingency)	[redacted]								

Table A: Cashflows and Breakdowns for Alternative 1 (Execution of U4 BCC in 2007 with 2006 Option).

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 40%**

Reviewed By: John Marczak 2005 Mar-08

J. Marczak
Project Manager

Date:

Approved By: P.L. Floyd March 8/05

P. Floyd
Eng & Mods Manager (Strat IV)

Date:

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44 -BCS-36330-00003-R000

Attachment "B" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2003	LTD Prior Years 2004	2005	2006	2007	2008	Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	106	411	1,880	1,880	650		**4,927**	635	**12.9%**
Engineering & Drafting (OPG)	169	649	1,400	700	140		**3,058**	863	**28.2%**
Material	[redacted]								
Installation – PWU, BTU									
Contract – Project Mgmt									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Sub Total (excl Contingency)									
Contingency									
Grand Total	**275**	**3,391**	**17,430**	**29,310**	**1,285**	**-**	**51,691**	**N/A**	**N/A**
2005-2009 Business Plan	275	4,672	10,180	5,400	22,750	976	**44,253**	**N/A**	**N/A**
Variance to Business Plan (excl Contingency)	[redacted]								

Table B: Cashflows and Breakdowns for Alternative 1A (Execution of U4 BCC in 2006).

Comparing against cost details of Alternative 1 (Attachment A), the following can be noted.

- Overall higher cost (mainly in Project Engineering and Installation) for Alternative 1 is associated with the need for:
  - Re-work of documentation (execution workplans, process procedures, etc.),
  - Re-training of execution crews & Re-mobilization,
  - Re-scheduling of execution activities for Outage schedule alignment.
  - Maintenance of resource readiness.

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 40%**

Reviewed By: 2005 Mar 08
Date:
Marczak
Project Manager

Approved By: March 8/05
Date:
P. Floyd
Eng & Mods Manager (Strat IV)

ENGINEERING & MODIFICATIONS
BUSINESS CASE SUMMARY

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Attachment "C" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2003	LTD Prior Years 2004	2005	2006	2007	2008	Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	106	411	1,320	1,960	1,870	-	**5,667**	635	**11.2%**
Engineering & Drafting (OPG)	169	649	970	1,030	660	-	**3,478**	863	**24.8%**
Material		[redacted]							
Installation – PWU, BTU		[redacted]							
Contract – Project Mgmt		[redacted]							
Contract - Design		[redacted]							
Contract - Installation		[redacted]							
Contract - Other		[redacted]							
		[redacted]							
		[redacted]							
		[redacted]							
		[redacted]							
		[redacted]							
		[redacted]							
		[redacted]							
Interest (Capital Project Only)		[redacted]							
Sub Total (excl Contingency)	**275**	[redacted]							
Contingency	-	[redacted]							
Grand Total	**275**	**3,391**	**12,155**	**12,085**	**27,420**	**-**	**55,326**	**N/A**	**N/A**
2005-2009 Business Plan	275	4,672	10,180	5,400	22,750	976	**44,253**	**N/A**	**N/A**
Variance to Business Plan (excl Contingency)	-	[redacted]							

Table C: Alt # 2 (Execution of U4 BCC in 2007 with Unit Shutdown from November 05 to March 2007).

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 40%**

Reviewed By: John Marczak 2005-Mar-08

J. Marczak
Project Manager
Date:

Approved By: P.M. Floyd March 8/05

P. Floyd
Eng & Mods Manager (Strat IV)
Date:

ONTARIOPOWER GENERATION

OPG Confidential	Page: 1 of 12
ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

U4 Boiler Flushing - Project# 13 - 49204

Full Release Business Case Summary NA44-BCS-36340-00002-R000

Routing	Location	Action	Signature	Date
A. Maxim Mod. Team Leader, Design Projects 701 - 3579	P24 AN	Prepare BCS	[signature]	2005/02/17
C. Verwey Project Leader, Design Projects 701 - 4327	P24 AN	Review BCS	[signature]	2005/02/17
G. Kotwa Section Manager, Process Scheduling 701 - 3755	P24 AB	Review BCS	P.L. Floyd for.	"
E. H. Wong Project Manager, Design Projects 701 - 4173	P24 AN	Review BCS	[signature]	2005/2/17
P. Floyd Manager, Design Projects 701 - 4053	P24 AB	Review BCS	Peter L. Floyd	Feb 17/05
R. Ball Senior Financial Advisor, Engineering and Modifications 701 - 8241	P72-2	Review BCS	[signature]	
G. Brown Controller, Engineering and Modifications 400 - 5991	H7 F20	Review BCS	[signature]	17-FEB '05
M. Arnone Director, Projects and Modifications 701 - 6063	P72-2	Review BCS	[signature]	18 FEB 2005
G. Paterson Manager, Components and Equipment 701 - 4141	P42 E2	Review BCS	[signature]	23 Feb, 2005
~~D. Power~~ ~~Director, Investment & Bus Plan OPG~~ ~~400 - 7172~~	~~H7 D06~~	~~Review BCS~~		
J. Coleby Vice-President, PNGS-A 701 - 3260	P05 A2	Submit BCS	John Coleby	26 Feb '05.
~~D. Hanbidge~~ D. POWER for Vice-President, Controller, OPG 400 - 2395	H7 D06 ~~H7 G26~~	Approve BCS	[signature]	02 Mar 05
P. Charlebois Chief Nuclear Officer 701 - 8221	P82-6 ~~P72-1~~	Approve BCS	[signature]	Mar 7/05
R. Ball Senior Financial Analyst 701-8241	P82-3 ~~P72-2~~	Return For Distribution		

U4 Boiler Flushing - Project# 13 - 49204

Full Release Business Case Summary NA44-BCS-36340-00002-R000

1/ RECOMMENDATION:

We recommend additional release of $13.1M [redacted] plus [redacted] contingency) for a project total of $14.7M ($12.8M plus [redacted] contingency) to secure the funding required to 1) complete development of the Boiler Flushing process, 2) execute the field pre-requisites (i.e. boiler nozzle installations, shroud hole repairs, and mechanical and electrical modifications) in P541 to support and equip for the Flushing and Boiler Chemical Clean (BCC) programs, and 3) execute the pre-BCC and post-BCC flushing in the P741 outage.

There is a possibility, as a result of the P541 boiler inspections, that the BCC and Flushing activities may be required prior to P741; therefore, the Flushing program must be planned and ready for execution in 2006 (P641).

The business objective of this project is: 1) to prevent the boiler tube degradation by removing the unhardened sludge deposits collected on top of the tube-sheet, and 2) support the BCC project (13-49201), which is to ensure generation revenues are protected by eliminating the requirement for boiler tube plugging and potential unit shutdown due to boiler tube denting. There is a regulatory commitment to the CNSC for chemical cleaning of the 12 boilers in Unit 4 (REGC AR # 28026033).

A previous developmental release of $1.6M was made under NA44-PLAN-36340-00001, of which $660k has already been spent to complete the preliminary engineering and start the detailed engineering on both the site modifications and the flushing process. More specifically, the preliminary design and the detailed engineering for the site modifications have been completed, while preliminary engineering has been completed and the development of the flushing process is being started. Consequently after the change in requirement to execute Flushing in the same outage as BCC, as evident through preliminary engineering (as per the scope in NA44-PLAN-33110-00004), the Flushing related activities were deferred from the 2004 schedule; this resulted in considerably less funds spent in 2004 than was budgeted.

This project is listed in the 2005-2009 approved business plan with a project total of $14.5M ($1340k was budgeted for 2004). See attachment "A" for details. Any cash flow variances to this Plan will be addressed through the Portfolio Management Process. Currently the BCC is under review, and will be presented to the Board of Directors in March 2005. If the BCC is not approved, a superceding release will be processed to reduce the amount of this project accordingly.

Choose One		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Developmental	1,600	[redacted]	Jan-05	Spent Life to Date:	660
Requested Now:	Full	13,100		2005-2009	Appr'd Business Plan (Tot Proj):	[redacted]
Cumulative Release:	Total to Date	14,700		2005-2009	Business Plan Variance:	
Total Project Estimate:	+30% to -15%	14,700		2005	Budget (Current Year)	
Current Year Estimate:	2005	5,765		2005	Budget Variance (Current Yr)	
Type of Investment:	Regulatory	N/A	N/A	Cumulative Release Remaining:		
NPV:			N/A	Contingency on Remaining Release:		
IRR:			N/A	Contingency % on Remaining Release:		

Submitted By: J. Coleby 26 Feb 2005

J. Coleby
Vice-President, PNGS-A

Date:

Finance Approval:

D. Hanbidge
Vice-President, Controller, OPG

Mar 2/05
Date

Line Approval (Per OAR Element 1.1 Project in Budget):

P. Charlebois
Chief Nuclear Officer

Mar 7/05
Date:

2/ BACKGROUND & ISSUES

Boiler Operations & Maintenance

During normal, steady state operation of nuclear power plants, small amounts of metallic impurities, principally iron, nickel, zinc and copper, are transported via the feedwater to the secondary side of the boilers where they slowly accumulate. Although their concentrations are low, typically a total of ~2 ppb, over 20 years of operation the amount transported may be as much as several hundred kilograms. In addition, normal start-up evolutions contribute an estimated 10 – 50 kg per start-up.

PNGS has adopted a boiler chemical cleaning (BCC) practice, as part of its Boiler Life Cycle Management Plan, to remove these deposits and stop or delay the boiler tube degradation mechanisms, particularly tube denting and under-deposit pitting corrosion. The Unit 4 boilers are showing early indications of pitting and tube denting (recent inspections showed 19 dents / 362 pits in all of the 12 boilers (31000 tubes) inspected). In comparison to the other PNGS-A unit boiler, the degradation is not as advanced, as the chemical controls in place since the Return to Service of this unit have been excellent. However, empirical data from other units have also shown that degradation can advance rapidly once initiated (data on the rate and exact onset is somewhat limited). It is therefore important to address the boiler tube denting on Unit 4 in a timely fashion.

Prevention of boiler tube denting will minimize boiler tube failure due to stress corrosion cracking, and ensure continued unrestricted access of inspection probes to the boiler tube interiors for tube fitness-for-service evaluations. It will also reduce the requirements for tube plugging due to inaccessibility issues. Furthermore, minimizing the number of plugged boiler tubes will sustain boiler life and protect the station against generation revenue losses. The completion of boiler chemical clean can alleviate the tube degradation conditions of the Unit 4 boilers for a period of eight years.

Regulatory and Life Cycle Management Plan

Flushing activities are required as on going "maintenance" activities as per the Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003) to control the secondary side deposits.

OPG also has a regulatory commitment to the CNSC to complete boiler cleaning of Unit 4 (REGC AR # 28026033). The Pickering Unit 1-4 Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003) and the Pickering Unit 4 – 2005 Steam Generator Outage Scope Plan (NA44-PLAN-33110-00004) specify the requirement for a Boiler Chemical Clean to be conducted on Unit 4 to ensure sustained life of the asset. To fulfill this requirement, boiler flushing must be performed prior to and after BCC. The Pre-Flush will remove the build up of "soft" deposits to expose the "hard" pile to the BCC process, while the Post-Flush will remove the deposits dislodged or "softened" by the BCC process.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Do Nothing (Not Recommended)

This is **not** recommended. OPG has a regulatory commitment to the CNSC to complete boiler cleaning of the Unit 4 boilers (REGC AR # 28026033). Pickering Unit 1-4 Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003 R0) outlines the need for the boiler flushing process in relation with BCC operations as well as to control the secondary side deposits. The nozzles installed under this project are required for BCC execution. Boiler tube fouling/denting will limit unit operation if BCC and Flushing operations are not performed.

Alternative 1 – Execute Boiler Pre-req's in P541 and perform Flushing in P741 (Recommended)

Execute the BCC and Flushing prerequisites (i.e. install boiler nozzles, repair shroud holes, and complete electrical and mechanical modifications) during the P541 outage in parallel with other boiler work. Develop a flushing process and execute the pre- and post- BCC flushing during the P741 outage. This approach is recommended. There is a possibility that execution of Flushing and BCC may be required prior to the scheduled P741 outage; thus, flushing developments need to be done early to accommodate a P641 outage.

Alternative 2 - Delay the Recommendation (Not Recommended)

2.1. Delay the prerequisites execution.

This is not recommended. The execution of prerequisites (i.e. nozzle installation, shroud repair and electrical and mechanical modifications) can be done during P541 in parallel with the Feedwater Nozzle Thermal Sleeve Replacement (TSR), and should have no impact on the P541 outage duration. If the boiler prerequisites are not executed in the P541 outage, and delayed until the next outage (P741), this activity will become a "series" activity with the Flushing and BCC activities and will increase the length of the outage by approximately 25 days.

2.2. Delay the Flushing development closer to the P741 outage.

This is not recommended, as there is the possibility that BCC and Flushing activities may be advanced to a P641 outage.

Alternative 3 - Do Less (Not Recommended)

3.1. Execute a pre-BCC Flush only or a post-BCC only.

This is not recommended. A post-BCC flush is required to remove the solid deposits from the boiler dislodged by the BCC process. If Flushing is not done prior to BCC to remove the build up of "soft" deposits to expose the "hard" pile, the BCC process will not be effective.

3.2 Execute Flushing activities only. (If BCC is not approved)

Although this will help address the secondary deposit issue, this will not fully address the requirements set out in the Life Cycle Management Plan – nor fulfill the REGC shown above.

Alternative 4 - Do More (Not Recommended)

4.1. Progress the development of the Flushing process and execute the Flush during P541 prior to P741 .

This is not recommended. Flushing must be performed in the same outage as BCC to remove "soft" deposits and expose the "hard" deposits for maximum benefits of BCC.

4.2. Execute a Flush in both P541 and P741

This is not required by the Boiler Life Cycle Management Plan and would significantly increase the duration of the P541 outage.

Alternative 5 – Other - N/A

4/ THE PROPOSAL

The additional release of $13.1M [redacted] contingency) will be used to complete the development of the Flushing process, award contracts with Vendor(s) to prepare and execute the boiler pre-requisites, and execute the pre- and post- BCC flushing activities. The project cost estimate is based on estimates received from vendors, and past and current flushing activities being performed on Pickering B boilers. The total project cost was also evaluated by a third party (Helyar); their estimate including contingency is approximately [redacted] higher. The difference is largely due to the third party's use of "conceptual quality" information and a higher amount for contingency.

The scope of work addressed with this release:

- project management support
- complete engineering activities
- finalize contracts with vendor(s)
- pre-mobilization activities (i.e. tooling, mock-ups, training, materials)
- develop an enhanced flushing process for PNGS-A boilers and sludge pile specific configuration
- work plans and ITP's preparation
- assessing activities
- QA and QS activities
- station support (i.e. maintenance, operation, radiation protection)
- contract management support
- permanent power supply installation (for Flushing equipment)
- prerequisites execution - P541 nozzle installation, shroud repair, and electrical & mechanical modifications
- flushing equipment maintenance, testing, preparation for storage
- scaffolding execution (for both the pre-req outage and the Flush/BCC outage)
- execution coordination support (for both the pre-req outage and the Flush/BCC outage)
- pre-BCC and post-BCC Flushing execution (for Flush/BCC outage)
- project / ECC closeout activities

Milestones Finish Date (D/M/Y)	Description
25-Feb-05	Approve Full Release BCS
29-Jan-05	Complete Detailed Engineering for P541 Pre-req Scope
31-May-05	Complete Detailed Engineering for P741 Flushing Scope (aiming to be ready for P641)
29-Mar-05	Finalize Contracts with Vendor(s) for P541 Pre-req Scope
30-Sep-05	Finalize Contracts with Vendor(s) for P741 (aiming to be ready for P641)
29-Mar-05	Issue P541 Workplans
30-Sep-05	Complete enhanced Flushing Development
30-Sep-05	Issue P741 Workplans (aiming to be ready for P641)
1-Dec-05	Complete P541 Flushing Prerequisite activities
3-Jul-07	Complete Pre and Post BCC Flushing activities
30-Dec-07	Complete Project Close-out activities

5/ QUALITATIVE FACTORS

Performing boiler flushing activities result in a more effective BCC. The combination of Flushing and BCC operations can result in the following benefits for the station:

- Prevention of further boiler tube denting which will
  - allow more comprehensive and efficient boiler inspections, and hence decrease outage time
  - reduce boiler tube plugging and hence lower the probability of reactor derating, generation revenue loss or full shutdown
  - minimize the potential of tube cracking and hence prevent forced outages
- Prevention of corrosion-induced boiler tube leaks which will
  - reduce the chances of forced outages
  - reduce the potential of environmental releases

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Higher than estimated vendor(s) cost for the preparation and execution of the P541 outage work.	Overall cost of the project may be greater than estimated.	Medium	-Project management has entered into negotiations with vendor and has received proposals from vendor for this work. -Fixed price contract where appropriate to minimize unexpected price increase. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -A portion of the contingency is allocated for this.	Low
Enhanced flushing execution may take longer than previous Pickering B flushing job, thereby increasing vendor(s) cost for the preparations and execution of the P741 outage work.	Overall cost of the project may be greater than estimated.	Medium	-Project management has entered into negotiations with vendor. The vendor will be requested to follow the outage schedule. -Extensive testing and qualification of the enhanced flushing lance in progress to meet OPG technical specification requirements. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -A portion of the contingency is allocated for this.	Low
Scaffold cost greater than estimated.	Overall cost of the project may exceed the estimate detailed in this BCS.	Medium	-Project management to work closely with scaffolding vendor to outline requirements and scope. Preliminary estimate from vendor has been received. -Work with other groups to review work plans to mitigate and avoid re-work. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -a portion of the contingency is allocated for this.	Low
Scope				
Changes in BCC requirements to increase the scope of boiler pre-requisite work.	Increase in cost and schedule.	Low	-Great efforts in the design phase of the BCC project has been made to minimize this threat.	Low

Schedule				
Vendor unable to finish execution work along outage schedule.	Increase in project execution duration leading to greater costs.	**High**	-Project Management to involve vendor with schedule development and outage logic, to allow for work to proceed on more than one boiler at a time. Proposals are to include tooling, training, and vendor execution resources. -Maintain close communication between Outage, Projects and Vendor. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -a portion of the contingency is allocated for this.	Low
Outage schedule may impact on execution of Boiler Flushing and pre-requiste activities.	Delay in project execution duration leading to greater costs.	**Medium**	-Maintain close communication between Outage, Projects and Vendor -P541 outage scope was frozen on Dec. 15, 2004.	Low
Advancement in Boiler Flushing and BCC work if P541 inspections deem necessary.	Execution schedule advanced to P641.	**Medium**	-Prepare workplans and develop enhanced flushing process early to accommodate for a P641 outage.	Low
Resources				
Insufficient Contract Administration support.	Delay in schedule.	**Medium**	-Projects is seeking pre-commitments. If CMO is unable to provide required support, Projects will staff up as required.	Low
Environmental				
Active Liquid Waste Management System unable to handle the volume of flushing waste.	Increase cost for handling waste.	**Low**	-Flushing activities previously executed in other units have produced similar effluents and anticipated volumes. -Projects to identify the system capabilities and arrange for an alternate flushing waste handling process if necessary.	Low
Health & Safety				
Unsafe work practices during vendor execution.	Potential for personnel injuries.	**Low**	-Oversight from contract administrators and monitors. -Workplans, Job Safety Analysis and pre-job briefings shall address adherence to procedures. -Implementation of OPG Contract Management processes.	Low

Investment				
Improper installation of nozzles.	Re-work required.	Low	-Vendors to apply past experience, as similar work was done previously on other units. -Tooling design reviews and mock-up training to be conducted. -Contract administrators and monitors are to ensure that proper procedures are followed. -QS validation to be conducted by Field Engineering.	Low
Damage to boiler tubes during flushing activities.	Repair work required leading to a schedule delay.	Medium	-Flushing tool design and development to be reviewed and accepted by OPG. Testing as well as mock-up training to be conducted. Enhanced lance provided with video camera. -Contract administrators and monitors are to ensure that proper procedures are followed, and qualified trades are performing the work.	Low

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2007	Jun 2008	Components and Equipment Manager

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Installation of 12 Boiler Nozzles.	12 boiler nozzles are required to be installed in U4.	12 nozzles installed in U4 during P541.	Available for Service (AFS) declaration signed and accepted.	Project Sponsor (Components and Equipment Manager)
2.	Execution of pre and post BCC boiler flushes.	Pre and post BCC Flushing required.	Pre and post BCC flushes executed in support of BCC during P741 (or P641 if schedule is advanced).	Boiler Inspection Report.	Project Sponsor (Components and Equipment Manager)

U4 Boiler Flushing 13 - 49204

Full Release Business Case Summary NA44-BCS-36340-00002-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2004	2005	2006	2007	2008		Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	440	530	410	510	-		1,890	440	23.3%
Engineering & Drafting (OPG)	140	165	130	170	-		605	140	23.1%
Material	[redacted]								
Installation – PWU, BTU	[redacted]								
Contract – Project Mgmt	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
	[redacted]								
	[redacted]								
	[redacted]								
	[redacted]								
	[redacted]								
	[redacted]								
	[redacted]								
Interest (Capital Project Only)	[redacted]								
Sub Total (excl Contingency)	[redacted]								
Contingency	[redacted]								
Grand Total	615	5,765	2,160	6,160	-	-	14,700	N/A	N/A
2005-2009 Business Plan	1,340	5,000	2,500	4,480	2,500		15,820	N/A	N/A
Variance to Business Plan (excl Contingency)	[redacted]								

Removal Costs included in above	0
Definition Costs included in above	0
Estimate Name, Quality, etc	Release Quality Est +15% to -10%
Design Complete:	40% to 90%

Reviewed By:

2/17/05
Date:

E.H. Wong
Project Manager

Approved By:

P. L. Floyd Feb 17/05
Date:

P. Floyd
Eng & Mods Manager (Strat IV)

U4 Boiler Flushing 13 - 49204

Full Release Business Case Summary NA44-BCS-36340-00002-R000

ATTACHMENT "B" **SUPERSEDING COST VARIANCE TABLE**

Not Applicable.

ONTARIO POWER GENERATION

OPG Confidential	Page: 1 of 15
BUSINESS CASE SUMMARY	

Pickering A Steam Generator Locking Tab Replacement 13 - 49248

Developmental Release Business Case Summary NA44-BCS-33115-00001-R000

Routing	Location	Action	Signature	Date
T. D'Angela Modification Team Leader 701 - 7768	P72-3	Prepare BCS		30 Oct 2006
G. Kotwa Section Mgr. Process Scheduling 701 - 3755	P72-1	Review BCS		30Oct2006
G. Keto Manager, Boiler Projects 701 - 2568	P72-3	Review BCS		[illegible]
D. Williams Manager, Projects Design Pickering 701 - 4956	P72-3	Review BCS		16 Mar 07
R. Ball Senior Financial Analyst 702 - 4084	P82-3B6	Review BCS		25 Jun 07
G. Brown Controller Eng & Mods 702 - 5059	P82-3A6	Review BCS	N/R	
M. Arnone Director, Projects & Modifications 701 - 6063	P72-1	Submit BCS		25 JUNE 2007
Leavitt Director Investment Management 701 - 6878	P42-E3	Approve BCS	RAL.	June 25, 2007
M. Reid Director Station Engineering, Pickering A 701 - 3645	P42-E1	Approve BCS		June 27, 2007
R. Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

Pickering A Steam Generator Locking Tab Replacement 13 - 49248

Developmental Release Business Case Summary NA44-BCS-33115-00001-R000

1/ RECOMMENDATION:

We recommend a release of $1.2M (including contingency) to complete Preliminary Design of the preferred Steam Generator Locking Tab replacement option, develop a Full Release BCS, and generate a contract strategy for the Pickering A (Units 1 and 4) Locking Tab Replacement project by March 2008.

The business objective of this project is to avoid a significant forced outage due to a locking tab failure on the cold leg of the Heat Transport System. A Fitness for Service evaluation has indicated that the cold leg locking tabs have a minimum lifespan of 6.3 EFPYs. If a cold leg locking tab were to fail, it is speculated that it would cause significant damage to the Heat Transport System, potentially including some components of the reactor core (i.e. fuel bundles). A forced outage would then be required to repair the damage at a projected cost of $100M and duration of 90 days. More importantly, a locking tab failure could potentially affect OPG's standing with the CNSC and our Power Reactor Operating License (PROL). Beyond 6.3 EFPYs in service, justification for continued operation would be required for Units 1 and 4.

The deliverables of this project are:

- Complete a mini-field campaign to remove and re-install the SG Clamping Dogs in support of inspection by IMS during the P711 Outage
- Develop a new locking tab replacement option which will minimize/eliminate interference with routine maintenance activities as well as meet or exceed SG life expectancy
- Develop a new locking tab replacement option which will minimize project cost, schedule, and dose uptake
- Replace the locking tabs currently installed in Unit 1 and 4 steam generators (SG) with a new design prior to the calculated 6.3 year expected lifespan of the locking tabs (2010 and 2011)

Currently, preliminary work has been conducted to acquaint the project team with the project objectives and current field conditions. In addition, a number of locking tab replacement options are being reviewed to determine the most technically viable and cost effective.

As this project is related to Pickering A, there are no issues/opportunities with respect to the ongoing life extension assessment.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	None	-	-	-	-	-	-	-	-
Requested Now	Developmental	-	850	385					1,235
Future Funding Req'd	Full	-	-		520	7,675	7,905	400	16,500
Total Project Costs		-	850	385	520	7,675	7,905	400	17,735
Other Costs									-
Ongoing Costs									-
Grand Total		-	850	385	520	7,675	7,905	400	17,735
Investment Type: Sustaining		Class: OM&A		(IEV) Impact on Ec Value: $148M		IRR: 79.2%		Discounted Payback: 5.9	

Submitted By:

25 June 2007

M. Arnone
Director Projects & Modifications
Date:

Finance Approval:

June 25, 2007

R. Leavitt
Director Investment Management
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

June 27 2007

M. Reid
Director Station Engineering Pickering A
Date:

2/ BACKGROUND & ISSUES

Adverse Condition
The Steam Generator Divider Plate sealing skin modification was performed on Units 1, 4, 5-8 starting with Unit 4 in 2001 and finishing with Unit 7 in 2004. The primary purposes of this modification were to address Divider Plate bolt degradation as well as the steady increase in Reactor Inlet Header Temperature (RIHT) which was forcing several units to run derated. All the modifications were completed successfully as measured by the decrease in RIHT for each unit. The steam generator inspections conducted in Unit 5 during the P551 (Spring of 2005) Outage were the first to be done for the PNGS B units following installation of the sealing skin/locking tab modification. These inspections revealed that numerous pieces of locking tabs and divider plate sealing skin had broken off in the hot leg (inlet) side of the steam generators (refer to SCR P-2005-03243) due to high cycle fatigue cracking. Further inspections revealed that all 10 affected steam generators experienced locking tab failures, and 4 of 10 steam generators experienced divider plate skin failures. The root causes of this event were deemed to be insufficient design analysis for the new locking tabs and inadequate installation of the sealing skins to ensure proper seal. Subsequent steam generator inspections in Units 6 and 8 uncovered more broken locking tabs and sealing skins. It is expected that Unit 7 steam generators will exhibit the same adverse condition. There have been no locking tab failures observed in the cold leg (outlet) side of any steam generator inspected. [Note that Pickering A Units 1 and 4 have had no locking tab or skin failures to date but are considered vulnerable to similar failures found in Pickering B SGs.]

Required Repair
The sealing skin modification installed in the PNGS A units was similar to that of PNGS B, but not identical. Due to the Unit 5 event, PNGS A was obligated to review locking tab design installed in Units 1 and 4 in order to allow for continued operation of the units (refer to SCR P-2005-03370). An Engineering Assessment (NA44-33110) of the locking tabs installed in the PNGS A SGs was performed. In addition, steam generator inspections were conducted and showed that there had been no locking tab failures in the SGs. These two activities allowed for both PNGS A units to run for a period of 1.8 EFPYs since the sealing skin modification. The rationale for continued operation was due to the determination that hot leg tab failures can be tolerated from a reactor safety point of view. Cold leg tab failures were deemed unacceptable as they could produce debris of broken tabs flowing downstream and blocking flow to the fuel bundle which could result in fuel failure. Thus, a Fitness for Service Evaluation of cracked locking tabs for PNGS A and PNGS B (P-REP-33115-00001 R01) was conducted. This evaluation proved that cold leg locking tabs will not fail prior to 6.3 EFPY. Thus, replacement of the locking tabs must be completed prior to 6.3 EFPY or 2010 (U4) and 2011 (U1).

Similar Previous Replacement Campaigns
As mentioned, hot leg locking tab failures were first found in Unit 5. Upon this discovery, all of the sealing skins, locking tabs, and associated components in all Unit 5 steam generators (except for two steam generators which were previously modified in 1999 with a different design) and all Unit 6 steam generators in the following outage (Units 7 and 8 were delayed in order to re-evaluate the repair strategy) were replaced. These repair campaigns were costly, lengthy, and dose intensive:

Unit 5 – approximately \$11M, 2 months, 33 Rem (10 steam generators)
Unit 6 – approximately \$12M, 2 months, 65 Rem (12 steam generators)

The replacement strategy for PNGS A will focus on locking tab replacement (currently installed sealing skins will be retained), and minimizing cost, time, and dose.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

		Cost	Cost				
Revenue	(164.5)	-	-	(6.5)	-		
OM&A	(336.5)	(17.7)	(18.0)	(33.5)			
Capital	-	-	-	-			
NPV (after tax)	(157.2)	(9.1)	(9.2)	(18.3)			
Impact on Economic Value (IEV)	N/A	148.1	148.0	139.0			
IRR%	N/A	79.2%	79.2%	117.2%			
Discounted Payback (Yrs)	N/A	5.9	5.9	6.8			

Status Quo - Not Recommended

Status Quo is **not** a recommended option. The Fitness for Service evaluation conducted on the Locking Tabs proved that cold leg locking tabs have a minimum lifespan of 6.3 EFPYs. After 6.3 EFPYs in service, the risk of cold leg locking tab failure increases, thereby increasing the risk to reactor safety. If a cold leg locking tab were to fail, it is speculated that it would cause significant damage to the Heat Transport System, potentially including some components of the reactor core (i.e. fuel bundles). A forced outage would then be required to repair the damage at a projected cost of $100M and duration of 90 days. More importantly, a locking tab failure could potentially affect OPG's good standing with the CNSC and in turn OPG's Power Reactor Operating License (PROL). In addition, beyond 6.3 EFPYs in service, justification for continued operation would be required for Units 1 and 4.

Alternative 1 - Replace Locking Tabs with new design - Recommended

Replacing the current locking tabs installed in Units 1 and 4 with a new design will allow for the following (which are aligned with the project objectives):

- SGs to run until End of Life (EOL) without the possibility of locking tab failure
- Ability for maintenance to be conducted with minimal interference from the new design which will replace the current locking tabs
- Ability to remove and/or replace components of the new design with relative ease, if required
- Installation to be less complex, optimizing cost, schedule, and dose

The Locking Tab replacement option will be designed with a substantial amount of rigour as per CNE Directive 05-01. As this modification cannot be commissioned, qualification testing along with required analysis will be performed to ensure that the Locking Tab replacement option is robust and will not become Foreign Material.

This is the only alternative which achieves all of the project objectives and in doing so, is this least expensive and has the greatest Net Present Value (NPV).

Alternative 2 - Delay Project - Not Recommended

Delaying the Project is **not** a recommended option. When the Technical Operability Evaluation (TOE) was first generated, it was determined that all affected units (Units 1, 4, 5, 6, 7, 8) would only be able to operate for 1.8 EFPYs since installation of the locking tabs and sealing skins. OPG Projects pursued locking tab life extension and successfully increased the minimum tab life from 1.8 EFPYs to 6.3 EFPYs. If the project is delayed past 6.3 EFPYs, there is a risk of cold leg locking tab failure which increases over time. As in the Status Quo option, this risk of cold leg locking tab failure is very costly, and has very severe Reactor Safety consequences. There is a slight chance that locking tab failure can be tolerated from a reactor safety point of view beyond 6.3 EFPYs in service, however justification for continued operation of Units 1 and 4 would be required.

Based on the current outage schedules for Units 1 and 4, the Locking Tab replacement will be conducted several months before the end of the minimum tab life (6.3 EFPYs). Thus, there is no benefit to having a separate outage specifically for the Locking Tab replacement, only a few months after the planned outage.

Alternative 3 – Replace Locking Tabs with Pickering B design - Not Recommended

Replacing the current locking tabs installed in Units 1 and 4 with a design similar to that of Pickering B (Units 5 and 6) is not a recommended option. Although this option allows the SGs to run until EOL without the possibility of locking tab failure, it does not meet all of the other project objectives previously outlined as is shown below:

- The locking tabs installed in Pickering B are welded on the Hot Leg side of the SG Primary Head and thus are not conducive to removal and/or replacement if required during maintenance activities.
- Due to the bolt configuration in the Pickering A SGs (i.e. uneven bolt spacing), installation of locking tabs similar to those in Units 5 and 6 would be quite difficult.
- Replacement of the Units 5 and 6 locking tabs during 2005 involved a tremendous amount of inspections and rework, and hence was costly, time consuming, and dose intensive.

In addition to the above, this option is more costly than Alternative 1. Therefore, replacing the locking tabs with a design similar to Pickering B is not recommended.

Alternative 4 – - Not Recommended

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

A Developmental Release will be used for a mini-campaign (to remove and re-install Clamping Dogs) in support of P711 SG inspections, Preliminary Engineering, to create a contract strategy and complete a Phase 1 BCS.

A Full release will then be requested to:

- Perform the Detailed Engineering
- Award a labour contract (for both units)
- Perform all pre-installation activities for Unit 4 (i.e. workplan preparation, work permits, space allocation, etc.)
- Install, commission, and AFS the modification for Unit 4
- Revise Design Engineering documents as required (i.e. Design ECs, drawings, etc.) for Unit 1
- Start pre-installation activities for Unit 1
- Complete pre-installation activities for Unit 1
- Install, Commission, and AFS the modification for Unit 1
- Close-out the Project

Refer to Appendix C for a list of the project milestones.

5/ QUALITATIVE FACTORS

Successful implementation of the locking tab replacement project will eliminate the reactor safety risk inherent to the design of the current cold leg locking tabs. Ease of maintainability will be a consideration during the development of the design.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Objectives stated in the Developmental BCS will cost more	Unable to accomplish objectives or will require futher release of funds	Low	Clearly defined scope. Regular review of project expenditures. [redacted] contingency available.	Low
Scope				
Preliminary design results in an increase in scope	Change in scope resulting in changes in cost and schedule	High	Scope has clearly been identified through several meetings and a preliminary evaluation of design options.	Medium
Schedule				
Conflict between Boiler activities (Inspection and Locking Tab replacement)	Increase in Outage duration	Medium	Schedule will be optimized to ensure that work is conducted in parallel as much as possible. Divider Plate work has already been moved to 2010 and 2011 to mitigate interference with the Boiler Chemical Clean.	Low
Resources				
Lack of Design Engineering resources	Delay in Design deliverables	Medium	Design support has been commited to this project	Low
Technical				
Locking Tab replacement option does not satisfy all project objectives	Constructability and maintenance issues with design	High	OPG Design and Components and Equipment are actively working together to ensure that an acceptable option is selected. Qualification testing will be done to ensure constructability and maintability issues are addressed and eliminated if possible.	Medium

Locking Tab replacement option fails prior to end of SG life.	Potential Foreign Material issue	**Medium**	Locking Tab replacement option will be designed with a substantial amount of rigour as per CNE Directive 05-01. Qualification testing along with required analysis will be performed to ensure that the Locking Tab replacement option is robust and will not become Foreign Material.	Low
Regulatory				
This modification does not require regulatory involvement or approval				
Environmental				
N/A				
Health & Safety				
N/A				
Investment				
Locking Tab replacement option interference with low row tube plugging	Removal of locking tab replacement components for low row tube plugging may require significant time and resources	**High**	OPG Design will determine the most viable locking tab replacement option taking into consideration the requirement for access to low row tubes when performing inspections or maintenance.	**Medium**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2011	Jul 2015	Components & Equipment

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Installation of replacement component(s) during P1041 and P1111 outages	N/A	Components installed during respective outages	Schedule review	PNGS A Components & Equipment
2.	Reliable performance (100% non-failure) of components to end of SG/plant life	6.3 EFPYs	Non-failure of components during life of SGs	1. Inspection of components during first and second SG inspection outages following replacement. 2. Confirmed non-failure at subsequent outages to end of SG life.	PNGS A Components & Equipment
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

- AFS: Available for Service
- CNSC: Canadian Nuclear Safety Commission
- EC: Engineering Change
- EFPY: Effective Full Power Year
- EOL: End of Life
- HTS: Heat Transport System
- NPV: Net Present Value
- RIHT: Reactor Inlet Header Temperature
- PNGS: Pickering Nuclear Generating Station
- PROL: Power Reactor Operating License
- SG: Steam Generator
- TOE: Technical Operability Evaluation

Appendix "B" Project Funding History

$ 000's Release Type	Month	Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
			Previous Releases (incl contingency) Cumulative Values								
Developmental				850	385	520	7,675	7,905	400		17,735
											0
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:

The Developmental Release will be used to cover the cost of a mini-campaign to support P711 SG inspections and complete ~40% of the design. The Full Release will be used to complete 100% of the design, install, commission, AFS the modification in Unit 4. Additionally, it will be used to prepare for Unit 1, install, commission, and AFS the modification in Unit 1, as well as complete Project Close-out.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

For the majority of engineering and design work, overtime has been assumed to be 10%. For field personnel, overtime has been assumed to be 25%.

Financial Assumptions:

The rate of inflation estimated at 2% is consistent with Corporate guidelines.

Project / Station End of Life Assumptions:

Based on a memo to D. Power from P.R. Charlebois, "Pickering Units 1 & 4 End of Service Life Predictions for Establishing Book Value", January 12, 2006, we have assumed that Station End of Life for Units 1 and 4 will be in 2021, thus requiring replacement of the Locking Tabs during 2011 and 2010 respectively.

It is assumed that the Locking Tab replacement modification will be conducted during Fall 2010 for Unit 4 and Fall 2011 for Unit 1.

It is assumed that the majority of design work will be completed well before the 2009 outage milestone.

Energy Price / Production Assumptions

The price of energy is estimated based on Corporate System Economic Values. Production from each Pickering A unit is assumed to be 516 MW at a capacity factor of 80%.

Operating Cost Assumptions

N/A

Other Assumptions:

It is assumed that if a Cold Leg locking tab were to fail, it would cause damage to the Heat Transport System (HTS). The forced outage required to repair the HTS is assumed to cost $100M and be 90 days in duration.

The risk of Cold Leg locking tab failure is assumed to be 5% starting in 2011 (U4) and 2012 (U1) and increasing at a rate of 5% per year.

The probability of Cold Leg locking tab failure in Units 1 and 4 simultaneously is too low to be considered. If a failure were to occur in one unit, the 2nd unit would be shut down immediately.

Pickering A Steam Generator Locking Tab Replacement 13 - 49248

Developmental Release Business Case Summary NA44-BCS-33115-00001-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr 2006	This Release 2007	This Release 2008	Future Release 2009	Future Release 2010	Future Release 2011	Future Release 2012	Later	Total
Project Management (OPG)	-	221	175	137	395	434	177		1,539
Engineering & Drafting (OPG)	-		160	86	157	168	96		666
Material	[redacted]								
Installation - PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Installation - IMS									
Kinectrics									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (Incl contingency)	-	850	385	520	7,675	7,905	400	-	17,735
2007-2011 Business Plan		300	100	500	7,100	7,100	300		15,400
Variance to Business Plan	-	400	235	(180)	75	105	-	-	635
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	[redacted]							
Total Release (incl contingency)	-	850	385	520	7,675	7,905	400	-	17,735

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Up to - 40%		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	N/A	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2006-2010 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007.

Reviewed By: APR/05/2007
Pejman Asgaripour
Project Manager
Date:

Approved By: Jerry Keto 16 April 2007
Jerry Keto
Eng & Mods Manager (Strat IV)
Date:

Pickering A Steam Generator Locking Tab Replacement 13 - 49248

Developmental Release Business Case Summary NA44-BCS-33115-00001-R000

Attachment "B" **Project Variance Analysis**

OM&A	LTD	Choose One		Variance	Comments
		Last BCS	This BCS		
	N/A	N/A	Sep		
	N/A	N/A	N/A		
Project Management (OPG)				0	
Engineering & Drafting (OPG)	[redacted]	[redacted]	[redacted]	[redacted]	
Material	[redacted]	[redacted]	[redacted]	[redacted]	
Installation – PWU, BTU	[redacted]	[redacted]	[redacted]	[redacted]	
Contract - Design	[redacted]	[redacted]	[redacted]	[redacted]	
Contract - Installation	[redacted]	[redacted]	[redacted]	[redacted]	
Contract - Other	[redacted]	[redacted]	[redacted]	[redacted]	
Kinectrics	[redacted]	[redacted]	[redacted]	[redacted]	
	[redacted]	[redacted]	[redacted]	[redacted]	
Interest (Capital Project Only)	[redacted]	[redacted]	[redacted]	[redacted]	
Project Costs (excl contingency)	[redacted]	[redacted]	[redacted]	[redacted]	
General Contingency	[redacted]	[redacted]	[redacted]	[redacted]	
Specific Contingency	[redacted]	[redacted]	[redacted]	[redacted]	
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

This project was identified in June 2005. Currently, conceptual funding is being used to perform minimal design work and to generate the Developmental BCS.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
30	Apr	2007	BCS: Developmental Release Approved
30	Jun	2007	PSM: Plan Start Milestone
16	Oct	2007	SOI: Start of mini Field Campgain (P711 Clamping Dog Removal/Re-install)
30	Apr	2008	FR1: Full Release BCS Approved
15	Apr	2009	FD1: Final Design Complete (Unit 1 and Unit 4)
15	May	2009	MCA: Major Contracts Awarded
15	Apr	2010	SOI: Start of Installation (Unit 4)
30	Jun	2010	AFS: Available for Service Meeting (Unit 4)
31	Dec	2010	ECC: EC Close-out (Unit 4)
31	Mar	2011	SOI: Start of Installation (Unit 1)
15	Jun	2011	AFS: Available for Service Meeting (Unit 1)
27	Jun	2011	PCS: Close-out Starts
21	Dec	2011	PCM: Plan Complete Milestone

A Project Execution Plan (PEP) will be approved by Jul 2008

Comments:

All applicable milestones will be in accordance with N-PROC-MA-0013 (Planned Outage Management) as the ocking tab replacement will be conducted during the 2010 and 2011 outages.

ONTARIO POWER GENERATION

New requests for project funding (including incremental funding for approved projects) must be documented in a Business Case Summary. This form must be completed for submission of all new funding requests to the Asset Investment Screening Committee.

Guidelines for Evaluation of New Funding Requests at Asset Investment Screening

FILE COPY

Part A – Issue Characterization (normally completed in conjunction with Project Charter)

Project Number: 49248	**Project Title:** Pickering A Steam Generator Locking Tab Replacement

Sponsoring Organization: Pickering A	**Classification:** OM&A
Most Recently Approved: Charter	**Funding Release to Date:** $ 0.00 Million
Investment Type: Sustaining	**Estimate Quality:** Conceptual

Base Case Analysis ("No Project" option)	The following section must be completed for the "No Project" option. The probability, consequences and urgency for the status quo situation are documented, with an estimation of the costs of the "no project" option for use as a benchmark for other alternatives.

Missed Opportunity or Risk/Adverse Condition to be Managed for "No Project" Option

The Steam Generator (SG) Divider Plate sealing skin modification was installed in Units 1& 4 to address Divider Plate bolt degradation as well as the steady increase in Reactor Inlet Header Temperature (RIHT) which was forcing units to run derated. All the modifications were completed successfully as measured by the decrease in RIHT for each unit. SG inspections conducted in Unit 5 during the P551 Outage revealed that numerous pieces of locking tabs and divider plate sealing skin had broken off in the hot leg (inlet) side of the steam generators due to high cycle fatigue cracking. The root causes of this event were deemed to be insufficient design analysis for the new locking tabs and inadequate installation of the sealing skins to ensure proper seal. Subsequent SG inspections in Units 6 and 8 uncovered more broken locking tabs and sealing skins. There have been no locking tab failures observed in the cold leg (outlet) side of any SG inspected. Pickering A Units 1 and 4 have had no locking tab or skin failures to date but are considered vulnerable to similar failures found in Pickering B SGs.

A Fitness for Service evaluation has indicated that the cold leg locking tabs have a minimum lifespan of 6.3 Effective Full Power Years (EFPY). If a cold leg locking tab were to fail, it would cause significant damage to the Heat Transport System: potentially including some components of the reactor core. A forced outage would then be required to repair the damage at a projected cost of $100M and duration of 90 days. Beyond 6.3 EFPY since the modification's in service, justification for continued operation would be required for Units 1 and 4.

Priority Coding	Probability (P)	Consequence (C)	Urgency (U)	Priority (P x C x U)
	4	4	4	64

Probability Coding	
1.	Improbable (< 10%)
2.	Unlikely (10% - 30%)
3.	Possible (30% - 70%)
4.	Likely (70% - 90%)
5.	Probable (> 90%)

Urgency Coding	
1.	Long Term (tolerable delay > 4 years)
2.	Flexible (tolerable delay 2 - 4 years)
3.	Some Flexibility (tolerable delay 1 - 2 years)
4.	Little or No Flexibility (tolerable delay 6 months - 1 year)
5.	Existing or Imminent Condition (tolerable delay < 6 months)

Consequence Coding (measured over remaining life of station)	
1.	Low (< $1M; small release; minor injury; regulatory non-compliance with few implications; minimal impact on employee engagement)
2.	Marginal ($1M - $10M; small release; minor injury; regulatory non-compliance with few implications; some employee dissatisfaction)
3.	Medium ($10M - $50M; moderate release; serious injury; regulatory non-compliance with implications; measurable impact on employee engagement)
4.	High ($50M - $200M; moderate release; serious injury; regulatory non-compliance with implications; potential for labour conflicts)
5.	Significant (> $200M; large release; potential employee/public fatality; significant regulatory non-compliance; major impact on employee engagement)

Issue Screening – Significance of the "No Project" Base Case on Business Drivers

A	Firm regulatory commitment with established due date; significant employee/public safety issue.
B	Potential plant shut down if not mitigated.
C	Potential unit shutdown if not mitigated.
D	Supporting or critical to the achievement of unit Business Plan objectives.

Issue Screen
C

Base Case Net Present Value

The NPV for the Base Case is the impact on shareholder's value of not implementing the project. It consists of all costs (expense and loss of revenue) that will take place in the future to operate in normal fashion or work around the condition if the project is not implemented. Because these costs are an outflow of cash, the value is negative (or zero); this serves as a benchmark against which to measure the NPVs of other alternatives.

NPV_{Base}: - $ 156.9

Part B – Option Characterization (normally completed in conjunction with Developmental Business Case Summary)

Option Analysis	The following section must be completed for the various project options investigated. NPV_{Alt} values are compared against the NPV of the Base Case, and specific screening gates are evaluated for the provided alternatives.

1 (recommended option)	Replacing the current locking tabs installed in Units 1 and 4 with a new design will allow for the following: ❖ SGs to run until End of Life (EOL) without the possibility of locking tab failure ❖ Ability for maintenance to be conducted with minimal interference from the new design which will replace the current locking tabs ❖ Ability to remove and/or replace components of the new design with relative ease, if required ❖ Installation to be less complex, optimizing cost, schedule, and dose The Locking Tab replacement option will be designed with a substantial amount of rigour as per CNE Directive 05-01. As this modification cannot be commissioned, qualification testing along with required analysis will be performed to ensure that the Locking Tab replacement option is robust and will not become Foreign Material.	NPV_{Alt}	- $ 9.1
		NPV_{Alt} - NPV_{Base}	+ $ 147.8
		Legal/Regulatory	8
		Safety/Environmental	8
		People/Political	8
		Resource/Financial	8
		Asset Preservation	10
		Do-ability Total	42

Required Cash Flow ($ Millions)	< 2006	2007	2008	2009	2010	2011	> 2011	Total
This Request	0	0.9	0.4	0.5	7.7	7.9	0.4	17.8
Project Total	0	0.9	0.4	0.5	7.7	7.9	0.4	17.8

Rationale for Selection as the Recommended Option

This is the only alternative which achieves all of the project objectives and in doing so, is this least expensive and has the greatest Net Present Value (NPV).

2	Delaying the Project is not a recommended option. As in the Status Quo option, this risk of cold leg locking tab failure is very costly, and has very severe Reactor Safety consequences. There is a slight chance that locking tab failure can be tolerated from a reactor safety point of view beyond 6.3 EFPYs in service, however justification for continued operation of Units 1 and 4 would be required. Based on the current outage schedules for Units 1 and 4, the Locking Tab replacement will be conducted several months before the end of the minimum tab life (6.3 EFPY). Thus, there is no benefit to having a separate outage specifically for the Locking Tab replacement, only a few months after the planned outage.	NPV_{Alt}	- $ 18.5
		NPV_{Alt} - NPV_{Base}	+ $ 138.4
		Legal/Regulatory	4
		Safety/Environmental	8
		People/Political	5
		Resource/Financial	8
		Asset Preservation	4
	☐ Alternative is clearly distinctive from the recommended option.	**Do-ability Total**	

Required Cash Flow ($ Millions)	< 2006	2007	2008	2009	2010	2011	> 2011	Total
This Request	0	0.1	0.7	0.3	0.7	7.9	8.5	18.2
Project Total	0	0.1	0.7	0.3	0.7	7.9	8.5	18.2

3	Replacing the current locking tabs installed in Units 1 and 4 with a design similar to that of Pickering B (Units 5 and 6) is not a recommended option. Although this option allows the SGs to run until EOL without the possibility of locking tab failure, it does not meet all of the other project objectives due to the following: ❖ The locking tabs installed in Pickering B are welded on the Hot Leg side of the SG Primary Head and thus are not conducive to removal and/or replacement if required during maintenance activities. ❖ Per Unit 5 and Unit 6 OPEX, the cost of installing welded locking tabs, sealing skins and clamping plate in Unit 5 and Unit 6 was $12M/unit. Installation of welded locking tabs alone accounts for 80% of total cost. ❖ Due to the bolt configuration in the Pickering A SGs, installation of locking tabs similar to those in Units 5 and 6 would be quite difficult. ❖ Replacement of the Units 5 and 6 locking tabs involved a tremendous amount of inspections and rework and was costly, time consuming, and dose intensive.	NPV_{Alt}	-$ 11.2
		NPV_{Alt} - NPV_{Base}	$
		Legal/Regulatory	
		Safety/Environmental	
		People/Political	
		Resource/Financial	
		Asset Preservation	
	☐ Alternative is clearly distinctive from the recommended option.	**Do-ability Total**	

Required Cash Flow ($ Millions)	< 2006	2007	2008	2009	2010	2011	> 2011	Total
This Request	0	0.9	0.4	0.5	9.6	10.0	0.4	
Project Total								

Part B – Option Characterization (continued)

4		NPV_{Alt}	$
		NPV_{Alt} - NPV_{Base}	$
		Legal/Regulatory	
		Safety/Environmental	
		People/Political	
		Resource/Financial	
		Asset Preservation	
	☐ Alternative is clearly distinctive from the recommended option	Do-ability Total	

Required Cash Flow ($ Millions)	< 2006	2007	2008	2009	2010	2011	> 2011	Total
This Request								
Project Total								

Do-ability Screening - Significance of Adding the Recommended Option to the Portfolio

Impact Category	High Potential (score 8 – 10)	Medium Potential (score 5 – 7)	Low Potential (score 1 – 4)	Showstopper (score 0)
Legal or Regulatory Issues	Few and easily contained items.	Defined and manageable issues.	Complicated and changing situation.	Overwhelming complications or changing situation.
Safety or Environmental Impact	No issues.	Defined and manageable issues.	Evaluation not complete; possible issues.	Major controversy or resistance.
People/Political Support	Strong support or no political element.	Support required and being sought.	Unpopular project; low visibility.	Strong resistance or unstable situation.
Resource/Financial Feasibility	Attractive financial conditions; resources available.	Not resourced or financed, but displaceable work identified.	Not resourced or financed; no displaceable work identified.	Questionable financial back-up or high risk.
Asset Preservation	Enhanced asset preservation; extended life of plant or system.	Implementation has no impact on life of asset.	Evaluation not complete; possible issues.	Implementation results in potential to reduce useful life of plant or system.

Prepared by:	Name [illegible]	Date 24 Apr 07
Approved for Submission to Asset Investment Screening Committee:	Name [illegible]	Date 26 April 2007

AISC Disposition:	☑ Approved ☐ Cancelled ☐ Deferred ☐ Returned for Rework	[illegible] Craig Sellers Vice President Engineering and Modifications and Chief Nuclear Engineer

ONTARIOPOWER GENERATION

OPG Confidential	Page: 1 of 15
ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

DCC Aging Management - Project- 10 - 62553

Full Release Business Case Summary N-BCS-66400-10001-R000

Routing	Location	Action	Signature	Date
R. Hohendorf Manager - Computers and Control Design (CCD) Department 702 5077	P82-5	Prepare BCS	[signature]	July 27, 2006
R. Ball Senior Financial Analyst 702 4084	P82-3	Review BCS		
G. Brown Controller Eng & Mods 702 5059	P82-3	Review BCS	[signature]	July 27, 2006
F.Dermarkar Director - Engineering Services Division 702 5066	P82-6	Submit BCS	[signature]	28 July 2006
~~J. Froats~~ G. Sellers Vice President - Engineering & Modifiications 702 5044	P82-6	Review BCS	[signature]	31 July 2006
Power Director - Investment and Business Planning	H7 D06	Approve BCS	[signature]	Aug 17/06
P. Charlebois Executive Vice President & CNO	P82-6	Approve BCS	[signature]	Aug 23 06
			RECEIVED by P. R. Charlebois AUG 1 3 2006 Refer to:	
Ball Senior Financial Analyst 702-4084	P82-3B6	Return For Distribution		

DCC Aging Management Project- 10 - 62553

Full Release Business Case Summary N-BCS-66400-10001-R000

1/ RECOMMENDATION:

We recommend a full release of [redacted] ($14.5M total project including contingency) for the DCC (Digital Control Computer) Aging Management Project. The two objectives of this project:

- Manage Pickering A and B DCC aging issues that challenge Unit operators and Control Maintenance staff and threaten reliable station operation and planned capacity targets.
- Participate in the joint CANDU DCC Replacement project COG JP4048 (CANDU Owners' Group Joint Project 4048) so that we will be in a position of readiness to replace the Pickering B DCCs for arising reliability reasons

The CANDU DCC Replacement joint project provides a unique opportunity to share resources with six other CANDU utilities. A $2.0M developmental release was approved in March 2004 to undertake sufficient preliminary engineering to confirm the technical and licensing viability of the DCC replacement, to validate system design, plans and processes and to produce a quality estimate and schedule. These objectives were achieved at a cost of only $0.6M when the chosen replacement platform eliminated the necessity to design, verify and validate a vertical slice of the DCC logic.

The following are the major elements of this DCC Aging Management Project:

- Joint CANDU DCC Replacement Project COG JP4048 [redacted]
- Replacement of Pickering A Main Control Room Operator Interface Computer System (PACE) [redacted]
- DCC training for Darlington, and Pickering A and B [redacted]
- Strategic spare parts for Pickering A and B (PA and PB) [redacted]
- PA test facility upgrade, PB field cable replacement, PA breakjack panel refurbishment, and PB scanner fix [redacted]
- Contingency [redacted]
- Total Project Estimate $14.5M

Approval of this request is in line with the approved Project Charter N-PCH-64000-00001, the 2006-2010 Business Plan and the 2006 Budget. A Project Execution Plan (PEP) already exists for the COG Joint Project and an overall PEP for this DCC Aging Management Project will be issued by December, 2006.

$000's OM&A		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Partial	2,000	[redacted]	Jan-06	Spent Life to Date:	[redacted]
Requested Now:	Full	12,492	[redacted]	2006-2010	Appr'd Business Plan (Tot Proj):	[redacted]
Cumulative Release:	Total to Date	14,492	[redacted]	2006-2010	Business Plan Variance:	[redacted]
Total Project Estimate:	+30% to -15%	14,492	[redacted]	2006	Budget (Current Year)	[redacted]
Current Year Estimate:	2006	1,600	[redacted]	2006	Budget Variance (Current Yr)	[redacted]
Type of Investment:	Sustaining	N/A	N/A	Cumulative Release Remaining:		[redacted]
NPV:		N/A	N/A	Contingency on Remaining Release:		[redacted]
IRR:		N/A	N/A	Contingency % on Remaining Release:		[redacted]

Submitted By:

28 July 2006

F. Dermarkar
Director - Engineering Services Division
Date:

Finance Approval:

14 Aug 06

Power
Director - Investment and Business Planning
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Aug 23/06

P.R. Charlebois
Executive Vice Presiedent & Chief Nuclear Officer
Date:

2/ BACKGROUND & ISSUES

The Pickering B WANO review (SCR P-2003-21245) and Obsolescence audit (SCR P-2003-20608) both indicated that obsolescence issues were being dealt with in a reactive manner, increasing risks to the forced loss rate. Engineers are not anticipating aging and practicing obsolescence management sufficiently to resolve these issues before system performance is affected; most obsolescence issues require years to resolve.

The need for the work covered by this BCS is consistent with the approved Project Charter, is focused on both the near-term and long-term viability of the DCCs, and pertains to the following:

- uncertain availability of DCC spare parts and excessive maintenance, and operational challenges
- old technology approaching the start of the upward edge of "bathtub curve" lifetime reliability
- operating experience (OPEX) on DCC field input cable degradation and an incipient problem at Pickering B
- impending loss of knowledgeable internal staff who are currently able to trouble-shoot and repair Varian DCC faults
- long lead time to engineer, qualify and license a DCC replacement.

Within OPG, work has been underway to improve the weakest aspects of the existing DCCs to try to keep them operational for the current station planned lifetimes. For Pickering B, Project 40505 (DCC Obsolescence and Operability) is in progress and is expected to be able to keep the existing Pickering B DCCs operating reliably in the near-term. For Darlington, Projects 33509 and 33977 are expected to keep the Darlington DCCs operating reliably to the current end-of-station life there. The DCCs on Units 1 and 4 at Pickering A have been replaced by emulators of the original IBM 1800 digital control computers. Since life extension has already occurred at Pickering A, further DCC replacement is not necessary there, except for its main control room (MCR) operator interface (PACE). PACE replacement is included in the release of this project.

The Varian DCCs, which are used at Pickering B for reactor/process control, are obsolete, not supported, becoming unreliable and unmaintainable, and there is no qualified replacement. Other CANDU stations also need to proceed with qualifying a replacement DCC system which is supported in the long-term.

2.1 COG Joint Project

OPG participation in the CANDU DCC Replacement JP4048 is viewed as:

1. insurance should an increasing trend of failures occur on DCCs at Pickering B
2. a DCC replacement path if station life extension decisions are made in the future for Pickering B

The scope of the Joint Project is to undertake sufficient preliminary engineering so as to be able to confirm the technical and licensing viability of the DCC replacement, to have a validated replacement product and processes and procedures in readiness for project implementation, and to have sufficient information to produce high quality project estimates and schedules. If OPG did not participate in the Joint Project, OPG would have to incur all the costs and risks by itself at a later date in the event of plant life extension. Not participating in the Joint Project would eliminate the availability of the low risk, low cost DCC emulator replacement alternative for Pickering B.

In Phase 1 of the Joint Project, the objectives have been achieved at lower than expected costs because selection of the particular replacement platform eliminated the need to design, verify and validate a vertical slice of DCC software-based control logic.

Recently, additional CANDU utilities (off-shore) joined the Joint Project. This has reduced OPG's share of Joint Project costs by an additional $650K. This is partly why 2006 and 2007 costs are below Business Plan estimates. (A PCRAF was approved on September 28, 2005 to lower the costs of project 62533 in line with the excluding contingency costs listed in Attachment A.)

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Stop the Project (Not Recommended)

This is not the recommended alternative since reliable DCCs are essential for CANDU plant operation.

- existing DCC technology is at least a quarter century old; if the Joint Project was not to proceed, the option to use a hardware emulator to replace the Pickering B DCCs would not be preserved. (The hardware, software, system and field cabling costs of replacing the DCCs using modern hardware in a necessarily different configuration would increase costs several times over, near to an order of magnitude in cost difference and with considerably greater technical risks.)
- DCCs at CANDU plants no longer have OEM (original equipment manufactuer) support. (DEC, Varian and SSCI are all out of business.)
- questionable ability to maintain trouble-shooting and repair expertise is a concern; for reasons of maintenance burden and DCC reliability (SCRs P-2004-01089, -02863, -15054), Pickering B Engineering management wants to acquire additional DCC spares to obviate the need to repair failed circuit boards and eliminate the risk in returning them into service
- the cables connecting field devices to the Pickering B DCCs have recently exhibited degradation (SCR P-2005-16456) with similarities to that seen at Pt. Lepreau where it was necessary to completely change out the degraded cables there
- the DCCs have been replaced on Pickering units 1 and 4, but the computers (PACE) which drive the operator interface in the Main Control Room (MCR) are a major reliability and maintainability burden and contain key circuit boards which are obsolete, in short supply and cannot be replaced
- the company which supplied the replacement DCC hardware at Pickering A is exiting the business. Purchase of the strategic spares needed for the remaining Pickering A lifetime needs to before this occurs would be prudent.
- training courses do not exist to train new engineering staff to support the DCCs at Pickering A and B and Darlington. New staff are displacing experienced contractors and many experienced staff are expected to retire soon; graduate hires need DCC training courses to acquire the necessary core qualifications.

If a Pickering B DCC were to fail and become irreparable (as the unreplaced Pickering A DCCs are currently threatening to do on Units 2 and 3), there would be no readily available replacement. The affected generating Unit would have to be shut down until either a replacement Varian DCC was built up from scrounged parts or a new DCC was designed, tested and installed. The latter approach would take upwards of three years and it is this potential Unit downtime that would be avoided by having a hardware emulator ready for use. Each of the seven utilities participating in the COG Joint Project recognize the inherent risk and the value of proactive action to mitigate this. The PACE system represents an analogous, but less time-critical situation at Pickering A.

Alternative 1 - Undertake the Necessary Sustaining Work (Recommended)

This is the recommended alternative. It enables Pickering B DCC performance and functionality to be sustained and improved with minimum cost and technical risk. It also addresses, for all OPGN stations, the residual DCC aging management issues which are not already covered by existing projects (see Section 4 – The Proposal)

Alternative 2 - Delay the Recommendation (Not Recommended)

This is not the recommended alternative. In May 2001, Hydro-Quebec undertook a pre-project study for the replacement of their digital control computers (DCCs). NB Power initiated similar work for life extension of Pt. Lepreau. OPG and Bruce Power recognized that, although their need is not as immediate, they also do not have a DCC replacement solution available now or for the time when life extension of the Pickering and Bruce plants will be considered. Design expertise on these DCCs is fading. Replacement by hardware emulators has been successful (e.g. at Pickering A), but there was major concern about the support from the vendor of the emulator (SSCI-890) successfully used to replace Varian DCC hardware in off-shore CANDU plants. The company, Second Source Computers (SSCI), gave notice that they were exiting the business. The most economical alternative was to purchase the intellectual property rights to the SSCI-890 emulator and arrange for a capable company to manufacture this product and guarantee the long-term product support needed by all the CANDU utilities. This is the essence of JP4048.

If this Joint Project was delayed by 2 or 3 years, the critical mass of knowledgeable staff would no longer be available to make it workable. (The JP4048 initiator from Hydro Quebec recently retired.) For only the next few years, we will still have access to disappearing DCC design expertise either at each Utility. Also, other utilities would not be interested in a delayed joint project because it would miss their need date.

The software within each DCC contains many functions important to the control of key station processes, including the reactor. Within each of these DCC functions, there are several modes of operation corresponding to different plant conditions and to the health of plant equipment. Once it is decided to proceed with a station life extension, there is no time to produce a prototype DCC product and then test the DCC software in all of these modes. All the life extension project time must go into implementation planning, preparing the engineering change packages and the field work plans, etc.

This overall DCC Aging Management Project 62553 has been structured to defer those elements which can be delayed without incurring excessive risk. For example, the Pickering A DCC System Health Report had identified operator interface system (PACE) obsolescence issues as a primary impediment to improving DCC health. However, the safe store of Units 2 and 3 will free up some otherwise unavailable spare parts for use in maintaining these computers. As a result, it has been possible to defer and stretch out this work. (This is reflected in lower near-term project costs relative to previous Business Plan estimates.) However, scarce knowledge of PACE design details limits the extent to which further deferral is prudent. The PACE replacement was originally to be done under Pickering A project 2004-PA-45. However, during the 2005 Business Planning process, it was decided to integrate this work into project 62553.

Alternative 3 - Do Less (Not Recommended)

Doing less would leave known problems unaddressed with corresponding risk to reliable station operation:

- core qualifications are already at risk due to the unavailability of DCC training courses
- there are only one or two staff knowledgeable enough to maintain the PACE systems operational and key circuit boards (such as the X.25 communications board) cannot be repaired or replaced
- the cable degradation on Pickering B poses a potential risk of DCC mal-operation
- recent SCRs have identified problems with DCC power supplier reliability (SCR P-2006-09680) and annunciation scanner operation (P-2005-11865) which cause operational and maintenance challenges and threaten reliable station operation.

Project elements have been critically reviewed in order to reduce project scope. For example, although Pt. Lepreau has decided to replace all their DCC field input cables, condition assessment of Pickering B cables has resulted in a more limited work scope of repairing or replacing them on an as-needed basis.

Eliminating selected project elements would cause the Business Objective of sustaining reliable DCCs (minimum system health colour of "White") not to be achieved. For example, adequate test facilities are necessary to thoroughly test DCC software and hardware changes prior to installation. Otherwise, breakthrough events will occur which cause Unit reactivity management events reportable to the regulator. Similarly, continued use of old DCC parts can challenge Unit operators and cause Unit output reductions, such as the 10% power reduction that occurred on Pickering Unit 7 on June 7, 2006 (SCR P-2006-09557).

Alternative 4 - Do More (Not Recommended)

This is not the recommended alternative since the actual replacement of the Pickering B DCCs would occur in concert with a positive decision on life extension. It is likely that G2, Lepreau and one of the Bruce stations will need to implement their DCC replacement first. OPG can benefit from the lessons learned from these prior implementation projects to further reduce all types of risks during the actual implementation of DCC Replacement at Pickering B. Similarly, it is not recommended to replace the DCC field cables in bulk at this time. If necessary, this would also be determined as part of the life extension decision. Based on a review of DCC System Health Reports at all OPGN stations, it is believed that all known risk-critical DCC aging management issues are covered by the scope of this BCS in conjunction with the other in-progress DCC projects.

Alternative 5 – Other - Use of a Modern Hardware System (Not Recommended)

The COG Joint Project in Phase 1 initially looked at DCC replacement using modern commercially-available distributed control systems. However, in-depth assessment confirmed that such a replacement was infeasible without a complete re-design of the system configuration and the DCC software. The Canadian Utilities applied a comprehensive set of assessment factors. Based on this evaluation, the Utilities unanimously concluded that use of a hardware emulator was the overwhelmingly superior alternative, both from economic and technical risk perspectives. In particular, if a Pickering B DCC failed irreparably prior to life extension, use of a modern replacement system would require the affected Unit to remain out-of-service for several times the duration required for replacement by a hardware emulator. Such a long and costly outage would be unjustifiable from either a financial or society point of view.

4/ THE PROPOSAL

The release will fund the OPG contribution to the COG DCC Replacement Joint Project 4048 which will:

- Apply the combined CANDU utility experience of knowledgeable DCC staff resources to minimize the technical risk
- Update proven in-house software engineering standards to conform to new IEC standards to minimize regulatory risks
- Share costs and combine staff resources to enable sufficient pre-project engineering to be done so that major technical concerns can be resolved and costs and schedules can be accurately estimated prior to launching the DCC replacement projects at each station
- Confirm that the replacement DCC will meet operability, functionality, reliability and performance needs and will be maintainable in the long-term
- The scope of the Joint Project will produce and validate replacement hardware that will then be available to realize a Pickering B DCC Replacement project at low risk and with a firm cost and schedule as part of life extension, or earlier, if necessary.

A major result of the Joint Project is the provision of a product which will be sustainable for use over a long time.

Joint Project Phase 2 Deliverables (for Pickering B)

- Proof of concept including production and testing of hardware prototype
- Proven QA program, with updated industry-compliant standards and procedures and established licensing framework (a letter received from the CNSC says the Joint Project as planned is "a very good approach for minimizing the implementation risk").
- Qualified platform, using a proven system architecture
- Confirmed detailed production and verification processes including an efficient test facility
- Confirmed long-term vendor support (contractually)
- Firm basis for estimating DCC replacement project costs and schedules

The cost of Phase 2 of JP 4048 is $5.85M. OPG, Bruce Power, NB Power, Hydro Quebec, SNN (Cernavoda), NASA (Embalse) and KHNP (Wolsong) comprise Joint Project participants. OPG is allocated two of nine shares of the direct project cost, or $1.3M.

This release will also fund the following necessary work:

- replacement of the obsolete, unreliable and difficult to maintain main control room (MCR) operator interface (PACE) on Pickering Units 1 and 4
- provision of DCC training courses to enable qualified core staff
- replacement of Pickering B DCC field cables, as needed (ref. SCR P-2005-19193)
- refurbishment of the Pickering A breakjack panels and Pickering B annunciation scanners, as needed
- strategic bulk spare parts purchase for Pickering A and B DCCs (including power supplies)
- upgrade Pickering A DCC test facilities for maintainability (ref. SCR P-2005-04754) and effectiveness reasons

Milestones Finish Date (D/M/Y)	Description
16-Dec-05	Prepare JP 4048 Phase 2 Project Execution Plan (complete)
19-Mar-06	System Design for prototype DCCZ (PDCCZ) (complete)

10-Dec-06	PACE Replacement Charter
22-Dec-06	System Documentation for PDCCZ
30-Apr-07	Acceptance Test of PDCCZ
30-Jun-08	Qualified Replacement DCC Available for Pickering B
15-Dec-09	Qualification of Pickering B software on PDCCZ
15-Dec-10	First Unit installation of PACE replacement
15-Dec-11	Second Unit installation of PACE replacement

5/ QUALITATIVE FACTORS

The qualitative benefits that would be realized by implementing the recommended Alternative (#2) are as follows:

- Reduced risks in the development of a common DCC replacement platform:
  1. Operating experience (OPEX) from existing stations already using the SSCI 890 is being fed back into the prototype production;
  2. the replacement DCC will be used first at other non-OPG sites

- The best solution will result by sharing the best scarce expertise contributions from each organization (OPG, NB Power, Bruce Power, Hydro-Quebec, and others)

- A common solution with other CANDU stations will enable future sharing of spare parts and of solutions to emergent problems, if encountered

- The Joint Project agreement includes sustained obsolescence avoidance as part of the long-term support agreement reached with the vendor. COG owns the Intellectual Property rights on behalf of the CANDU utilities

- It will no longer be necessary to retain internal maintenance expertise to repair failed parts; parts can be shipped to the long-term service provider for off-site repair; this will reduce workload burdens on Control Maintenance staff such that more focus can be applied to preventative maintenance

6/ RISKS

Description of Risk (this release only!!!!)	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
1. Underestimation of the engineering effort.	Work scope not able to be completed within approved funding.	**High**	Given the difficulty in accurately predicting the effort required, input from all CANDU utiliites was sought. A major goal of the preliminary engineering to be done as part of the joint CANDU DCC Replacement project was to be able to prepare a high quality estimate for the actual replacement projects. Use of a DCC hardware emulator in lieu of a system redesign substantially reduces the project risk. A separate detailed estimate was prepared for the PACE replacement, the other major project element.	**Low**
2. One of the utilities withdraws from the CANDU Joint Project	Increased costs to OPG.	**Medium**	All Canadian CANDU utilities have confirmed funding to the Joint Project. In addition, off-shore utilities have joined.	**Low**
3. The scope of some project elements may change as additional operational performance emerges	Work priorities may need to be adjusted in response to operational needs.	**Medium**	Costs will be captured against the differentiated project elements. Approval to allocate contingency funds will be sought if necessary.	**Low**
Scope				
1. Accurate establishment of all the DCC requirements	Delivered product would not meet OPG needs without redesign of DCC software.	**High**	Preliminary engineering was done as part of JP 4048 Phase 1 to produce a detailed specification. Technical reviews are taking place periodically.	**Low**
2. Accurate establishment of PACE requirements	Installed product would not meet operational needs	**Medium**	The original PACE requirements document has been located. A Human Factors Engineering Program Plan (HFEPP) and construcatability, operability, maintainability, and safety (COMS) reviews will also ensure operability.	**Low**
Schedule				
1. Shortage of skilled in-house staff	Schedule slippage	**High**	Identify needs and plan for the skills required early on. Hire contractors, if necessary, and make use of recent graduate hires as a learning experience.	**Low**
2. It is necessary that the CANDU	Latent deficiencies in the	**High**	Upon completion of the preliminary engineering done	**Low**

utilities band together to achieve the critical mass of knowledge needed to enable the emulator implementation with an acceptable level of risk.	replacement DCC		as part of the Joint Project, DCC Replacement implementation risks will be substantially reduced. OPG implementation risks will be further reduced as the result of lessons learned from antecedent CANDU utility projects.	
3. Work pressures at their own stations could prevent CANDU utilities from participating as actively in the joint project as planned.	Schedule slippage	**High**	A manager has been appointed for the Joint Project. Knowledgeable non-utility resources have been added to the Joint Project team. L3-MAPPS has been contracted to undertake most of the Phase 2 work.	**Low**
Resources				
1. Over time, staff knowledgeable about the design details of the DCC functionality and its interaction with station process systems and equipment have moved on.	Inability to maintain core DCC expertise.	**High**	Production of DCC training courses will preserve the core knowledge. New staff will gain exposure to the DCCs via participation in this project.	**Low**
2. Training Division does not have internal resources needed to prepare DCC training courses.	Inability to produce needed DCC training material.	**High**	Training Division has agreed to the use of external resources. Knowledgeable external companies have expressed interest and one has submitted a draft syllabus.	**Low**
Technical				
1. Unforeseen SQA issues	Schedule delays/increased costs	**High**	Proven internal SQA processes will be reviewed and upgraded where necessary to meet the intent of IEC standards.	**Low**
2. Unforeseen technical issues	Schedule delays/increased costs	**Medium**	Solution approach has been identified and is an incremental change only to systems already in use in off-shore CANDU stations.	**Low**
3. Unforeseen HFE issues	Schedule delays/increased costs	**Medium**	Minimal observable changes are planned to the MCR operator interface.	**Low**
Regulatory				
1. CNSC staff have already indicated interest in the standards to be adopted for the work and in human factors engineering aspects.	Schedule delays/increased costs	**Medium**	A common front of the CANDU utilities will minimize regulatory risks. CNSC letter has already stated that the planned approach is low risk. The same group that implemented PACE will implement the PACE replacement.	**Low**

Environmental				
None				
Health & Safety				
1. "Normal" health and safety concerns	Medically-treated accidents or lost-time accidents	**Low**	All work on the project will be conducted in accordance with all legal, OPG corporate, OPG Nuclear and site safety programs.	**Low**
Investment				
1. Life extension for Pickering B may not proceed, obvitating some benefits to OPG from the Joint Project.	OPG would not receive the maximum benefit from the Joint Project	**Medium**	Even if extending the life of Pickering B does not proceed, the project output would still have value as defense against an expected trend of increasing failure rates for existing DCCs. OPEX benefits have already accrued to OPG based on increased inter-utility co-operation on DCC issues.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2012	Jun 2013	Director, ESD

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Replacement DCC availability	Pickering B Life extension or declining performance of existing DCCs	Qualified DCC replacement available at end of COG Program (June 20, 2008)	Replacement DCCs obtainable at known cost and schedule	Pickering B Performance Engineering Manager
2.	Staff qualifications at risk	Currently, 23 qualifications within the Computers and Control Design (CCD) Department are at risk	Availability of DCC training courses reduces qualifications at risk to ≤ 5	Use of methodology defined by Human Resources	CCD Manager
3.	Pickering A Operator Interface (PACE) obsolescence	PA DCC System Health Report at risk of turning yellow	PA DCC System Health white or better as result of replacement of the obsolete PACE interface	Conformant with System Performance Monitoring standards	DCC system engineers
4.	Quality	Project Charter N-PCH-64000-0001	All project 62553 deliverables are completed and of acceptable quality	AFS completion for all project segments	Accountable project segment managers
5.	Reliability and Maintainability	DCC System Health Reports at all stations	System Health is white or better	Conformant with System Performance Monitoring standards	DCC system engineers

Project Name 10 - 62553

Full Release Business Case Summary N-BCS-66400-10001-R000

Attachment "A" **Project Cost Summary**

$000's Choose One	LTD Prior Years 2005	2006	2007	2008	2009	2010	Future	Total	LTD This Mth Feb 2006
Project Management (OPG)		40	40	40	40	50	140	**350**	
Engineering & Drafting (OPG)	16	212	350	610	655	490	430	**2,763**	4
Material	[redacted]								
Installation – PWU, BTU									
Contract – Project Mgmt									
Contract - Design									
Contract - Installation									
Contract - Other									
	[redacted]								
Interest (Capital Project Only)									
Sub Total (excl Contingency)									
General Contingency									
Specific Contingency									
Grand Total	**572**	**1,600**	**2,400**	**2,400**	**2,400**	**2,400**	**2,720**	**14,492**	**N/A**
2006-2010 Business Plan	825	2,209	3,000	2,000	2,000	2,000	2,380	**14,414**	**N/A**
Variance to Business Plan (excl Contingency)	[redacted]								

Removal Costs included in above	**0**
Definition Costs included in above	**572**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Zero to Minimal**

Reviewed By:

July 28, 2006

. Veilleux
roject Manager

Date:

Approved By:

July 27, 2006

R.J. Hohendorf
Eng & Mods Manager (Strat IV)

Date:

Attachment B

Cost Detail

	prior	2006	2007	2008	2009	2010	BP tot	future	total
COG Joint Project									
Eng JP	16	30	30	120	200	100	496		496
Eng S/W Std	0	20	20	30	40	30	140		140
Material	[redacted]								
Contract -Other									
Contract - Design									
JP Total	572	756	405	410	650	290	3083	300	3383
PACE									
Proj. Mgmt. (PM)		20	20	20	20	30	110	100	210
Eng		80	200	380	350	300	1310	300	1610
Material	[redacted]								
Install									
Contract - Design									
PACE Total	0	100	720	1000	1060	1100	3980	1100	5080
PB cables & Scanners & PA Breakjack Panels									
PM							0		0
Eng		22	20				42	50	92
Material	[redacted]								
Install									
Contract-Design									
PBC Total	0	32	175	25	55	230	517	200	717
PA Test Facility							0		0
PM							0		0
Eng			20	20	5		45		45
Mat	[redacted]								
PATF Total	0	0	20	85	5	0	110	0	110
PB Spares									
Eng		20					20		20
Mat	[redacted]								
PBS Total	0	220	200	0	0	200	620	0	620
PA Spares									
Eng		20					20		20
Mat	[redacted]								
PAS Total	0	202	200	200	0	0	602	0	602
DCC Training									
PM		20	20	20	20	20	100	40	140
Eng		20	60	60	60	60	260	80	340

	prior	2006	2007	2008	2009	2010	BP tot	future	total
Contract - Other		50	200	200	150	100	700	300	1000
DCCT Total	**0**	**80**	**280**	**280**	**230**	**180**	**1060**	**420**	**1480**
	prior	**2006**	**2007**	**2008**	**2009**	**2010**	**BP tot**	**future**	**total**
TOTAL									
PM	0	40	40	40	40	50	210	140	350
Eng	16	212	350	610	655	490	2333	430	2763
Material	[redacted]								
Install	[redacted]								
Contract - Design	[redacted]								
Contract - Other	[redacted]								
TOTAL - by SubCat	[redacted]								
TOTAL - by SubProj	[redacted]								
Gen Contingency	[redacted]								
Grand Total	**572**	**1600**	**2400**	**2400**	**2400**	**2400**	**11772**	**2720**	**14492**