ONTARIO POWER GENERATION

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October 2, 2013

BY RESS (non-confidential information only) and OVERNIGHT COURIER

Kirsten Walli
Board Secretary
Ontario Energy Board
27th Floor - 2300 Yonge Street
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

Re: EB-2013-0321 - Application by Ontario Power Generation Inc. For 2014-2015 Payment Amounts (the "Application")

In accordance with Rule 10 of the Ontario Energy Board's ("**OEB**" or the "**Board**") *Rules of Practice and Procedure* and section 5.1 of the OEB's *Practice Direction on Confidential Filings* (the "***Practice Direction***"), Ontario Power Generation Inc. ("**OPG**") requests confidential treatment for certain portions of the following documents included as part of the pre-filed evidence:

1. The revenue comparison tables located at Exhibit G1-1-2, Table 1, Exhibit G2-1-2, Table 1, and Exhibit I1-1-1, Tables 2 and 3 (collectively, the "**Revenue Comparison Tables**").
2. The Darlington refurbishment contract strategies located at Exhibit D2-2-1, Attachment 6 and Darlington Refurbishment Detailed Planning Definition Phase Partial Release located at D2-2-1, Attachment 5 (collectively, the "**Darlington Refurbishment Contract Strategies**").
3. The engagement letter with Concentric Energy Advisors located Exhibit D2-2-1, Attachment 7 (the "**Concentric Energy Advisors Engagement Letter**");
4. The business case summaries for:
    a. Hydro Thermal business – found at Exhibit B1-1-2, Attachment 1, and Exhibit F1-3-3, Attachment 1;
    b. Nuclear business – found at Exhibit D2-1-3, Attachment 1, Exhibit D2-2-1, Attachment 8 and F2-3-3, Attachment 1;
    (collectively, the "**BCSs**").
5. The 2013-2015 business plans located at:
    a. Corporate Business Plan - Exhibit A2-2-1, Attachment 1;
    b. Hydro Thermal Operations Business Plan – Exhibit F1-1-1, Attachment 1;
    c. Nuclear Business Plan – Exhibit F2-1-1, Attachment 2;
    (collectively, the "**Business Plans**").
6. The 2013-2015 business planning instructions located at Exhibit A2-2-1, Attachment 2 (the "**Business Planning Instructions**").

7. OPG's 2012 income tax returns located at Exhibit F4-2-1, Attachment 1 (the "**2012 Income Tax Returns**").

OPG has set out below the reasons for the confidentiality request, and the reasons why public disclosure would be detrimental to OPG.

Also, as set out further below, OPG is retaining certain redactions without disclosure, save to the OEB, in the Hydro Thermal Business Plan, the Corporate Business Plan, and the Business Planning Instructions. The particular redactions relate to OPG's unregulated business. They are similar in nature to certain redactions accepted by the OEB in OPG's last payment amounts application (EB-2010-0008) as provided for in Procedural Order No. 3 for such matters.

As a result of the various categories of redactions in its filing, OPG attaches with the hard copy this letter (for the electronic copy filed through the RESS, only this letter and the non-confidential documents are attached), the following:

1. **Attachment A** - *Confidential* - Unredacted, confidential versions of the Revenue Comparison Tables, Darlington Refurbishment Contracting Strategies, Concentric Energy Advisors Engagement Letter, BCSs, Business Plans, Business Planning Instructions, and 2012 Income Tax Returns. The redactions relating to the unregulated business and irrelevant confidential information continue to show as redacted, since as described above, the fully unredacted version in respect of this particular information is for the OEB's review only. The documents in Attachment A are intended for review by those intervenors who sign the OEB's confidentiality undertaking.
2. **Attachment A.1** – *Non-Confidential* – Redacted versions of the documents referenced in Attachment A (already part of OPG's pre-filed evidence).
3. **Attachment B** – *Confidential* - One fully unredacted hard copy of each of the Hydro Thermal Business Plan, the Corporate Business Plan, and the Business Planning Instructions for the **OEB's consideration only**. Those portions which are requested to be for the OEB's review only are identified in the document by way of "boxes" around the applicable portion. These documents are sent to the attention of the OEB Panel in a sealed envelope.
4. **Attachment C** - A copy of the 'Board's review only' request for confidential treatment of unregulated facilities information by OPG in EB-2010-0008 and the Board's responding letter of confirmation dated August 5, 2010. ;
5. **Attachment D** -Procedural Order No. 3 in EB-2010-0008; and
6. **Attachment E** - Declaration and Undertaking in the form set out in Appendix D of the Practice Direction.

In accordance with the Practice Direction, this letter is being provided to the OEB along with six (6) copies of each of the documents (save for Attachment B for which 3 hard copies are provided to the Commission Panel in a sealed envelope).

As an interim measure and in the interests of efficiency, prior to the OEB making its final determination on OPG's request for confidential treatment of the documents as requested, OPG is content that the OEB makes provision that intervenors proceed as though OPG's request has been granted. In so doing, OPG requests that the OEB provide that each intervenor requesting a copy of the confidential documents complete and sign a Declaration and Undertaking in the form included at Attachment “E”, being the form set out in Appendix D of the Practice Direction and file it with the Board in order to be given a copy of the documents, save those which are for the OEB’s review only.

On a final determination, should the OEB grant OPG’s request for confidentiality, OPG proposes that the OEB order the documents be disclosed, subject to any conditions the OEB may find appropriate, to only those persons that by then have already signed, or that subsequently sign, the Declaration and Undertaking referenced in the paragraph above.

In addition, OPG requests that any reference to the confidential information, if determined to be such, be conducted in camera so as to preserve its confidential nature.

In the event that the confidentiality request is refused and OPG in turn requests that the information be withdrawn in accordance with section 5.1.12 of the Practice Direction, all persons in possession of the said information will be required to destroy or return to the OEB Secretary for destruction the confidential information in accordance with section 6.1.6 of the Practice Direction.

Request to Retain Certain Redactions

Reasons for Retaining Redactions in the Hydro Thermal Business Plan, Corporate Business Plan, and Business Planning Instructions

OPG received OEB approval in EB-2010-0008 with respect to certain permanent redactions in OPG’s filings. That is, redactions relating solely to OPG’s unregulated business and facilities (reflecting no aspect of the regulated business), continued to be redacted in the confidential versions of such documents. A copy of the particular request for confidential treatment by OPG in EB-2010-0008 and Procedural Order No. 3, whereby the Board accepted the above referenced approach, are attached to this letter as Attachments C and Attachment D, respectively. A copy of the OEB’s letter dated August 5, 2010 to OPG returning OPG’s confidential information is also at Attachment C.

In this Application, OPG seeks similar confidential treatment of similar information in the Hydro Thermal and Corporate Business Plans and the Business Planning Instructions. This is on the same basis as set out above.

Additionally, the information contained in slide 16 of the Corporate Business Plan (and also referenced in other parts of this Business Plan) has been redacted on the same basis. Its content is highly confidential and is not relevant to this proceeding. The activities contemplated in this slide (and related bullets throughout) are in respect of a time frame beyond 2015.

In accordance with the practice approved in EB-2010-008, Attachment B hereto is being provided solely to the OEB for the purpose of allowing the Board to determine whether the information in these Hydro Thermal Business Plan, Corporate Business Plan, and Business Planning Instructions which continues to be redacted is in fact related solely to the unregulated business and/or is irrelevant to this Application. OPG requests that the manner in which the OEB determines this request be per EB-2010-0008.

Reasons for Confidential Treatment of the Business Plans

The redacted portion of the Nuclear Business Plan relates to staffing arrangement for a specific contractual arrangement with a third party. OPG considers and treats this information as commercially sensitive. Disclosure of this commercially sensitive information would prejudice OPG's competitive position in relation to future contracts for such arrangements. This information is disclosed in the *confidential* unredacted version filed in Attachment A.

The redacted portions of the Hydro Thermal Business Plan, Corporate Business Plan and Business Planning Instructions relate to information reflecting the combined regulated and unregulated assets and business of OPG. This information should be protected as confidential because disclosure of this aggregated information (combined with information regarding the regulated business already disclosed) would allow for the disclosure of information related to the unregulated business and facilities. OPG consistently treats information relating to its unregulated business as confidential financial information and commercially sensitive. Similar requests for confidential treatment of such combined information was accepted by the Board in EB-2010-0008, as provided for in Procedural Order No. 3. As set out above, this aggregated information is disclosed in the *confidential* unredacted versions attached as Attachment A.

Reasons for Confidential Treatment of Revenue Comparison Tables

The information redacted from the Revenue Comparison Tables located at Exhibit G1-1-2, Table 1, Exhibit G2-1-2, Table 1, and Exhibit I1-1-1, Tables 2 and 3, relates to OPG's sales and proceeds from its heavy water sales business or aggregate information that would allow determination of such information. This information has consistently been treated as confidential by OPG, as it relates to commercially sensitive information. OPG requests that this information be protected as confidential as its disclosure will prejudice OPG's competitive position and will interfere significantly with any future negotiations being carried out by OPG. The confidential nature of this information was approved by the Board in its decision in EB-2010-0008 (see p.64 Reasons for Decision, dated March 10, 2011).

As mentioned above, this information is disclosed in the *confidential* unredacted versions filed in Attachment A.

Reasons for Confidential Treatment of the Business Case Summaries and Darlington Refurbishment Contracting Strategies

The Regulated and Newly Regulated Hydroelectric business case summaries have been assembled and filed as Exhibit D1-1-2, Attachment 1 and Exhibit F1-3- 3, Attachment 1 of OPG's pre-filed evidence. The Nuclear business case summaries have been assembled and filed as Exhibit D2-1-3, Attachment 1, Exhibit D2-2-1, Attachment 8 and F2-3-3, Attachment 1 of OPG's pre-filed evidence. The Darlington Refurbishment Contracting Strategies are located at Exhibit D2-2-1, Attachments 5 and 6.

The redacted portions of the BCSs and Darlington Refurbishment Contracting Strategies should be protected as confidential as this information includes commercially sensitive information such as contingencies, expected efficiency gains, certain costs for contracted or purchased work or materials, or aggregate information that would allow determination of commercially sensitive information. Disclosure of the redacted portions of the BCSs and Darlington Refurbishment Contracting Strategies that include OPG commercially sensitive information would prejudice OPG's competitive position and significantly interfere with its negotiations and existing relationships in a variety of aspects of its business. Furthermore, similar information was treated as confidential by the OEB in OPG's previous application, EB-2010-0008.

As mentioned above, this information is disclosed in the *confidential* unredacted versions filed in Attachment A.

Reasons for Confidential Treatment of the Concentric Energy Advisors Engagement Letter

The Concentric Energy Advisors Engagement Letter is located at Exhibit D2-2-1, Attachment 7**.**

The redacted portions of the Concentric Energy Advisors Engagement Letter relate to the firm's hourly rates and should be protected as confidential as this information includes commercially sensitive information in relation to a third party.

Reasons for Confidential Treatment of 2012 Income Tax Returns

The 2012 Income Tax Returns located at Exhibit F4-2-1, Attachment 1, should be protected as confidential because they include a significant amount of information that relates to the unregulated aspects of OPG's business, both at the OPG corporate level and with respect to unregulated entities. This information is not relevant to this Application and OPG consistently treats it as confidential financial information. The 2012 Income Tax Returns are also the type of information that the OEB has previously assessed to be confidential with respect to entities that are regulated by it. The confidential nature of this information was approved by the Board in its decision in EB-2010-0008.

As mentioned above, this information is disclosed in the *confidential* unredacted versions filed in Attachment A.

Respectfully submitted,

[Original signed by]

Colin Anderson

cc: Carlton D. Mathias, OPG
Charles Keizer, Torys

ATTACHMENT A – CONFIDENTIAL

[Confidential materials filed in accordance with Practice Direction on Confidential Filings]

ATTACHMENT A.1 – NON-CONFIDENTIAL

[redacted versions of the documents referenced in Attachment A (already part of OPG's pre-filing)]

ONTARIO POWER GENERATION

Recommendation for Submission to the Board of Directors

May 16, 2013

Board Approval of OPG's 2013-2015 Business Plan

EXECUTIVE SUMMARY:

OPG is seeking Board approval of its 2013-2015 Business Plan. The 2013 budget, approved by the Board, is reflected within this 3-year plan and will be used as the control base against which actual results will be measured and assessed.

In consultation with its Shareholder, OPG has developed strategies to improve its financial outlook while considering the impact on customers. There are two main components to the revenue strategy, intended to improve revenue and cash flow for the 2013-2015 period. Revenues from non-contracted, unregulated hydroelectric assets would be regulated effective January 1, 2014, facilitating the full recovery of operating costs and earning the approved OEB rate of return. OPG also plans to file a cost of service application with the OEB to increase base rates for its currently regulated facilities starting in 2014. Successful implementation of these two strategies is required to achieve sufficient income and cash flow, and improve credit metrics to threshold levels.

[redacted] OPG expects to record a one-time extraordinary gain of approximately $300 M in 2014, related to the recognition of a regulatory asset for income taxes upon implementation of price regulation for the currently unregulated hydroelectric stations.

The 2013-2015 Business Plan is subject to several significant risks, including the results of regulatory filings and the effective date of the revenue strategies. Should either of the key strategies not be achieved, mitigation measures will be required to address cash flow challenges.

The attached document provides details with respect to OPG's 2013-2015 Business Plan. The Business Plan incorporates the 2013-2015 OM&A expenses and capital expenditure plans provided to the Committees of the Board in November 2012 for Nuclear, Hydro Thermal, and Business and Administrative Services. This business plan information was updated to remove the planned Pickering Unit 7 outage from the business planning period.

RECOMMENDATION:

That the Board of Directors approves the 2013-2015 Business Plan. The 2013 budget reflected in the plan will be used as the control base against which actual results will be measured and assessed.

Recommended By:

"Original Signed By"
Donn Hanbidge
Chief Financial Officer

Approved for submission to the Board of Directors:

"Original Signed By"
Tom Mitchell
President and Chief Executive Officer

This Board memorandum was reviewed and approved for submission to the Board of Directors by the Audit and Finance Committee on May 15, 2013.

OPG's 2013-2015 Business Plan

OPG Board of Directors

May 16, 2013

Donn Hanbidge, CFO

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Outline

- Executive Summary
- Key Planning Assumptions
- Headcount Reductions and Efficiencies
- OM&A Expenses
- Capital Expenditures
- Financial Outlook
- Segmented Results
- Financing Outlook
- Risks and Uncertainties
- Appendix
  - Credit Rating Outlook and Implications
  - OPG's EBT on the Province's Fiscal Basis
  - Operating Statement
  - Balance Sheet

Executive Summary

- OPG's earnings and Funds From Operations continue to decline in 2013, reflecting low prices for unregulated generation, and no increase in regulated base rates since 2008. In the absence of strategies to address these revenue deficiencies, a credit rating downgrade and cash flow challenges would result.
- OPG has developed strategies to improve its financial outlook while considering the impact on customers
- OPG's 2013-2015 Business Plan assumes regulation of the currently unregulated non-contracted hydroelectric ("unregulated hydroelectric") assets, and submission of a 2014/2015 balanced rate application for new nuclear and hydroelectric regulated base rates and riders
- [redacted]
- OPG's net income before extraordinary gain is expected to [redacted] mainly as a result of:
  - Regulating the unregulated hydroelectric assets – OPG is the only entity that receives Ontario spot market electricity prices. Spot market prices have declined significantly over the past 5 years, resulting in revenues that are insufficient to recover the costs of operations and provide an adequate return for these assets. A strategy to address these losses is to regulate all unregulated hydroelectric operations.
  - New regulated base rates for nuclear and the currently regulated hydroelectric facilities – New rates will reflect cost recovery and a return for the Niagara Tunnel, and current cost and generation assumptions
  - Continuing to achieve efficiencies and headcount reductions – Headcount from ongoing operations will be reduced by 2,000 over the 2011-2015 period. Headcount reductions of 1,000 has been achieved over the 2011-2012 period.
- Net income in 2014 includes a one-time extraordinary gain of ~$300 M related to the recognition of a regulatory asset for income taxes, effective upon the implementation of price regulation for the currently unregulated hydroelectric stations
- To moderate the customer impact of resetting regulated base rates, OPG plans to defer the recovery of certain costs from 2014/2015 to subsequent years. OM&A expenses and income for 2014 and 2015 reflect cost deferrals of $465 M in 2014 and ~$60 M in 2015.
- Despite the planned increases in revenue, OPG will continue to moderate Ontario electricity prices, as the average revenue earned by OPG is forecast to be ~35 to 40% lower than revenues earned by all other generators in Ontario

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Key Planning Assumptions

Production

- Nuclear production ranges from 48 to 50 TWh/yr over the 2013-2015 period. The 3 year planned outage cycle for Darlington units results in two planned outages and lower production in 2013. The Darlington Vacuum Building Outage (VBO) in 2015 reduces production by ~3 TWh.
- Regulated hydroelectric production increases in 2014 and 2015, primarily due to the Niagara Tunnel

Production - TWh	Actual 2012	Budget 2013	Business Plan 2014	Business Plan 2015
Nuclear	49.0	48.0	49.7	48.0
Regulated Hydrelectric	18.5	18.0	18.5	19.3
Unregulated Hydroelectric (contracted and non-contracted)	[redacted]			
Thermal				
Total OPG Production				

- [redacted]

Pension and OPEB Costs

- Pension Fund investments are assumed to earn 6.25%/yr over the period
- Discount rates for valuing pension and other post retirement benefits range from 4.2% to 4.4%

Other

- Nuclear Funds investments are assumed to earn 5.15%/yr over the period
- The plan incorporates the impact of the ONFA update on accounting for nuclear waste obligations and depreciation, and changes to the accounting service lives of the Pickering units to reflect expected operation to ~2020, effective December 31, 2012

Key Planning Assumptions

Regulated Rates and Revenues

- Regulated base rates remain unchanged in 2013. Regulated rate riders increase by $1.94/MWh for nuclear and $4.69/MWh for hydroelectric in 2013, as a result of the OEB's decision on the recovery of variance and deferral account balances at December 31, 2012.
- OPG plans to file an application with the OEB to establish new nuclear and hydroelectric rates for 2014/2015
  - Nuclear base rate increases in 2014/2015 primarily reflect recovery of costs not currently included in rates, such as changes in pension and OPEB and nuclear waste liabilities, and the impact of the Darlington VBO
  - Hydroelectric base rate increases in 2014/2015 primarily reflect the in-service of the Niagara Tunnel
  - OPG's planned rate proposal defers the recovery of costs totalling $465 M in 2014 and ~$60 M in 2015 for subsequent recovery, in an effort to balance the impact of rate increases on ratepayers with the need to recover costs and earn an appropriate return

	Actual 2012	Budget 2013	Business Plan 2014	Business Plan 2015
Revenue Rates - $/MWh				
Nuclear Base Rate	52	52	57	67
Nuclear Rider	4	6	8	5
Regulated Nuclear Rate	56	58	64	73
Hydro Base Rate (current regulated assets)	36	36	45	43
Hydro Rider	(2)	3	7	5
Regulated Hydro Rate	34	39	52	48
OPG Unregulated Hydro Price	[redacted]	[redacted]	50	50
HOEP	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas - US$/mmBTU	[redacted]	[redacted]	[redacted]	[redacted]

- The plan assumes regulation of unregulated hydroelectric assets effective January 1, 2014, at a rate of ~$50/MWh, and the application of rate regulated accounting for these assets, effective January 1, 2014
- A longer-term rate smoothing mechanism is still required to address rate impacts of the Darlington refurbishment

Unregulated Revenues

[redacted]

Electricity Prices

- OPG's total average electricity price over the period is expected to remain ~35 to 40% below the average price received by all other Ontario generators

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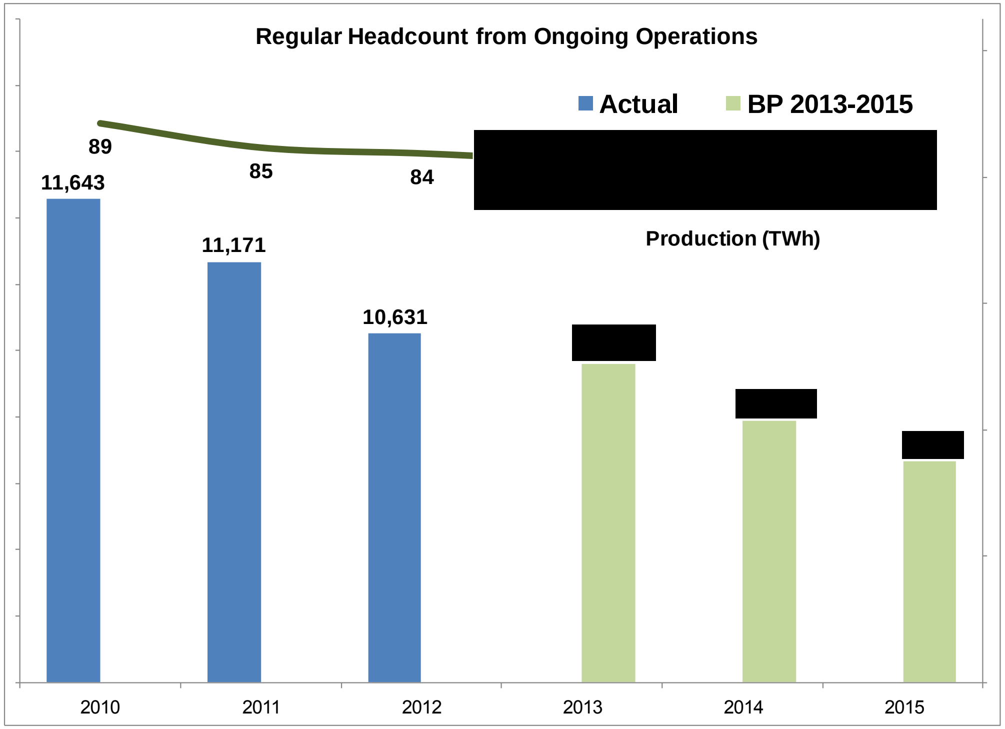
Filed: 2013-09-27
EB-2013-0321
Ex. A2-2-1
Attachment 1

Headcount Reductions and Efficiencies

OPG has achieved headcount reductions from ongoing operations of 1,000 over the 2011-2012 period. Through Business Transformation, headcount will be further reduced by 1,000 over the 2013-2015 period.

- Through implementation of Business Transformation initiatives, total headcount from ongoing operations will be reduced by ~2,000 over the 2011-2015 period, [redacted]
- Headcount reductions of ~1,000 has been achieved over the 2011-2012 period
- OPG's productivity, as measured by GWh/headcount, improves by 14% (normalizing for the Darlington VBO) over the 2012-2015 period, as Business Transformation impacts more than offset the impact of lower generation



- OM&A savings from headcount reductions accumulate to $700 M over the 2011-2015 period

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Headcount Reductions

The additional reduction in headcount from ongoing operations of 1,000 over the 2013-2015 period will be achieved by aggressively pursuing efficiencies and restructuring

	Actual	Budget *	Business Plan *	
	2012	2013	2014	2015
Nuclear Operations	5,510	5,325	5,195	5,083
Nuclear Projects	728	713	701	698
Hydro/Thermal Operations	[redacted]			
CO&E	176	176	165	153
Total Operations	[redacted]			
BAS	1,083	1,039	980	924
Finance	382	361	335	308
People & Culture	598	623	596	573
Corporate Office	158	156	149	144
Total Support Services	2,221	2,179	2,060	1,949
Ongoing Operations	[redacted]			
Darlington Refurb	180	247	266	276
Nuclear New Build	33	23	21	21
Total OPG	[redacted]			

*Headcount numbers are adjusted for organizational changes

- Nuclear headcount decreases by ~425 or 8% over the 2013-2015 period through various efficiency initiatives, including the amalgamation of the Pickering A and B stations

[redacted]

- Support Services headcount decreases by ~275 or 12%, over the 2013-2015 period through Business Transformation initiatives. Under a centre-led organizational structure, Support Services now includes certain operational functions such as: Business and Administrative Services includes Supply Chain and warehousing operations; Finance includes Nuclear Oversight; and People and Culture includes the Nuclear Training division.
- Darlington refurbishment headcount increases over the period as engineering, operations and oversight staff join the project organization during the detailed planning stage
- Nuclear new build headcount remains steady until such time as a decision is made on the future of the project. The plan currently does not assume execution of this project, hence there is no increase in headcount.

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OM&A Expenses

OM&A expenses from ongoing operations, excluding nuclear outage and pension/OPEB costs, decline over the 2013-2015 period, as efficiencies and cost reductions more than offset the impacts of inflation and other factors

- Total OM&A expense savings related to headcount reductions through Business Transformation are $700 M over the 2011-2015 period, [redacted] The advancement of headcount reductions compared to the 2012-2014 Business Plan results in additional savings of ~$90 M in 2013/2014.
- Nuclear operations OM&A expenses fluctuate based on outage activity. A second Darlington outage in 2013 increases overall expenses by ~$100 M, and the VBO and other outage work increase expenses by ~$75 M in 2015. Expenses for nuclear also increase compared to 2012, due to higher pension and OPEB costs of $35-$60 M/yr.
- [redacted]
- Support Services groups continue to reduce headcount and costs, and increase efficiency over the planning horizon. The increase in OM&A expenses in 2013 compared to 2012 is primarily due to higher pension and OPEB costs.

	Actual	Budget*	Business Plan*	
$ millions	**2012**	**2013**	**2014**	**2015**
Nuclear	1,411	1,555	1,527	1,591
Hydro/Thermal Operations	[redacted]			
CO&E	36	43	42	39
Total Operations	[redacted]			
BAS	316	310	305	291
Finance	66	66	62	59
Insurance	27	28	32	34
People & Culture	113	120	117	113
Corporate Office	31	41	39	38
Law	7	8	7	7
Executive Office	6	16	13	10
Total Support Services	566	590	575	551
Total Business Unit Expenditures	[redacted]			
Centrally Held Pension/OPEB	345	475	385	379
[redacted]				
Total Ongoing Operations	[redacted]			
OEB Variance Account Offsets	(273)	(418)	(10)	(10)
Deferral of Cost Recovery			(465)	(57)
Darlington Refurbishment	3	18	20	18
Nuclear New Build	25	39	10	10
Total OM&A	[redacted]			

*OM&A numbers are adjusted for organizational changes

- Pension/OPEB costs, including centrally held costs and costs allocated to Operations and Support Services groups, increase compared to 2012, due primarily to a lower discount rate by: ~$240 M in 2013, ~$125 M in 2014, and ~$115 M in 2015
- The increase in OEB variance account offsets in 2013 is primarily due to higher pension/OPEB costs, and the continuation of the Pension/OPEB variance account for the currently regulated segments
- OPG's planned rate proposal is expected to impact OM&A expenses by deferring costs of $465 M in 2014, and $57 M in 2015 for subsequent recovery. This proposal is subject to OEB acceptance.

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Year-Over-Year OM&A Changes

OM&A expense changes reflect additional outage activities in nuclear in 2013 and 2015, coal closure activities, and headcount reductions. Regulatory variance accounts and the proposal to defer recovery of certain costs also impact OM&A expenses each year.

- OM&A expense savings related to headcount reductions increase by a further $50 M to $60 M each year over the planning period compared to 2012. In total, OM&A expense savings related to headcount reductions are $700 M over the 2011-2015 period, net of termination and relocation costs.
- OM&A expenses do not include any salary escalation beyond the increases in the collective agreement for PWU represented employees
- Nuclear outage costs increase by $103 M in 2013 compared to 2012, mainly due to a second Darlington outage in 2013. The VBO and other outage work increase expenses by $73 M in 2015.
- [redacted]
- Pension/OPEB costs increase by $241 M in 2013 as a result of a 1% reduction in discount rates from 2012. Pension/OPEB costs decrease in 2014 compared to the 2013 budget due to an increase in discount rates and changes in other assumptions

$ millions	Budget	Business Plan	
	2013	**2014**	**2015**
Previous Year OM&A	[redacted]		
Cost Factors - Increase/(decrease)			
Headcount reductions	(60)	(51)	(57)
Impact of PWU Settlement	16	12	11
Workforce Changes	**(44)**	**(39)**	**(46)**
Nuclear outage costs	103	(46)	73
Early Coal closure	[redacted]		
Operational Changes			
Pension/OPEB	241	(114)	(15)
Pension/OPEB Variance Account	(201)	393	
Deferral of Cost Recovery		(465)	408
Other Variance Accounts	59	15	
Darlington Refurb & Nuclear New Build	29	(27)	(2)
Inflation and Other	52	61	27
[redacted]			
Total Change	[redacted]		
Total OM&A	[redacted]		

- Regulatory variance accounts and the assumed rate strategy impact OM&A expenses over the period
  - Pension/OPEB variance account offsets pension/OPEB costs by an additional $201 M in 2013
  - While the plan does not reflect continued deferral of pension/OPEB costs in 2014/2015 due to the establishment of new base rates, the planned rate proposal defers the recovery of certain costs to moderate the impact on customer rates

Capital Expenditures

OPG's capital investment program is focused on ensuring the continued utilization of existing assets in an effective manner through sustaining and refurbishment activities, and development of new investment opportunities

- Sustaining capital expenditures aimed at ensuring strong performance of existing assets range from [redacted] consistent with the 2012-2014 Business Plan

Long-Term Energy Plan projects

- Hydroelectric development project expenditures primarily relate to the Niagara Tunnel and [redacted] projects
- Darlington refurbishment expenditures include Campus Plan expenditures to ensure readiness for a 2016 project start date, and an infrastructure upgrade to support the additional 30 years of station life
- [redacted]

$ millions	Actual 2012	Budget 2013	Business Plan 2014	2015
Sustaining Capital Expenditures				
Nuclear	161	170	197	144
Hydroelectric- Regulated	30	31	35	38
Hydroelectric- Unregulated	[redacted]			
Thermal				
Other				
Generation Development				
Hydroelectric Development				
Niagara Tunnel	231	184		
[redacted]				
Darlington Refurbishment	232	530	837	632
Thermal [redacted]				
Total Generation Development	[redacted]			
Total Capital Expenditures				

- [redacted]
- Due to uncertainties regarding the approval, scope, and timing of the Darlington nuclear new build project, it has not been included in planned capital expenditures

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Financial Outlook

[redacted]

- OPG is focused on improving income and cash flow from operations
  - OPG will seek increases in nuclear and hydroelectric regulated rates for 2014/2015. The regulated rate increases primarily relate to costs not currently included in rates such as changes in pension/OPEB and nuclear waste liabilities, the impact of the Darlington VBO, and the in-service of the Niagara Tunnel
  - As a result of low spot market prices, the plan assumes regulation of the unregulated hydroelectric assets effective January 1, 2014
  - OPG's Business Transformation initiative is focused on delivering significant cost savings from headcount reductions and efficiency improvements
- [redacted]
- Net income in 2014 includes an extraordinary one-time gain related to the recognition of a regulatory asset for income taxes effective upon the implementation of price regulation for the currently unregulated hydroelectric stations
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

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2013-2015 Net Income

[redacted]

➢ Higher nuclear outage costs and lower generation due to a second planned Darlington outage, with no change in nuclear base rates

[redacted]

- OPG is now forecasting net income of [redacted] in 2013. This reflects the impact of the settlement agreement on the deferral and variance account application, [redacted] and OM&A expense savings.
- In 2014/2015, net income improves primarily due to regulation of the unregulated hydroelectric assets and increases in base rates. Net income improves in 2014 as a result of:

  ➢ Obtaining a price of ~$50/MWh for unregulated hydroelectric generation that is consistent with the OEB approved rate of return

  ➢ An increase in regulated base rates to reflect the completion of the Niagara Tunnel, and updated hydroelectric and nuclear generation forecasts

  ➢ A one-time extraordinary gain related to the recognition of a regulatory asset for income taxes effective upon the implementation of price regulation for the currently unregulated hydroelectric stations

- [redacted]

ONTARIO POWER GENERATION

2013-2015 Segmented Results

Earnings before interest and taxes (EBIT) from the Generation segments improve in 2014/2015 due to the increase in base rates for the current regulated assets, the implementation of price regulation for the unregulated hydroelectric stations, [redacted]

- EBIT for the Nuclear segment is budgeted to decline by $310 M in 2013 compared to 201,2 primarily due to higher outage costs and lower generation as a result of a second planned Darlington outage in 2013, with no change to base nuclear rates. Earnings increase by ~$330 M to $360 M in 2014/2015 as a result of the forecast increase in regulated rates and assumed deferral of recovery of certain costs.
- Regulated hydroelectric earnings are forecast to decrease in 2013 due to an increase in OM&A expenses and changes in forecast energy production. Earnings increase in 2014/2015 as regulated rates are reset to reflect the completion and in-service of the Niagara Tunnel.

Earnings Before Interest and Taxes (EBIT)				
	Actual	Budget	Business Plan	
$ millions	2012	2013	2014	2015
Nuclear	364	54	415	382
Regulated Hydro	324	292	418	411
Unregulated Hydro	[redacted]			
Thermal				
Generation Segments				
Nuclear Waste Segment	(68)	(126)	(150)	(148)
Other Business	[redacted]			
Total OPG EBIT				

- Unregulated hydroelectric earnings [redacted] Earnings improve in 2014 as unregulated hydroelectric is assumed to be regulated effective January 1, 2014, [redacted]
- [redacted]
- [redacted]

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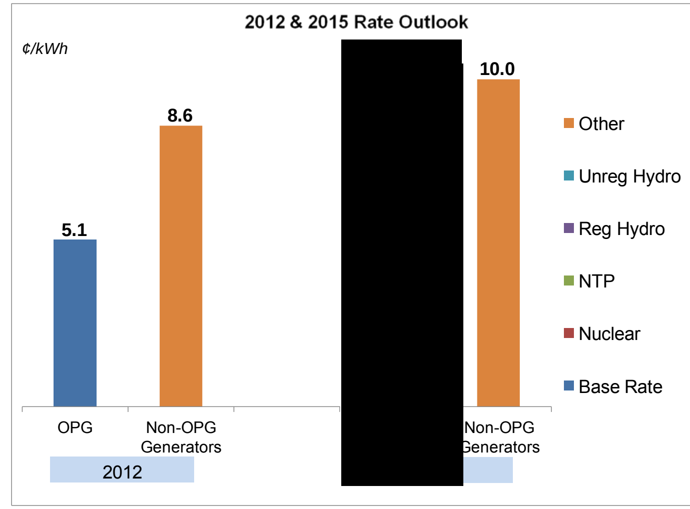
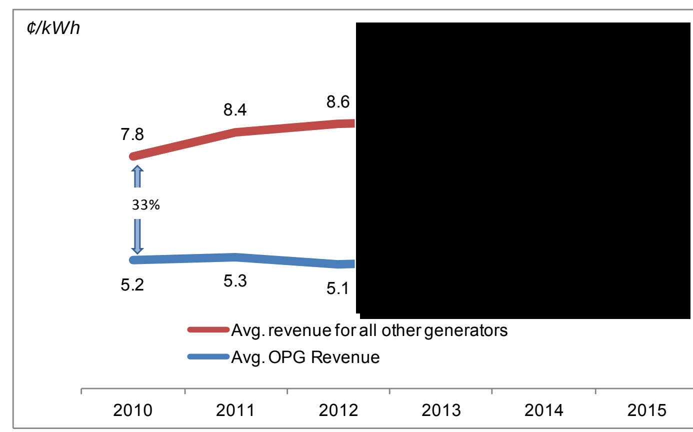
ONTARIO POWER GENERATION

OPG Will Remain Ontario's Low-Cost Generator

OPG's strategy to increase revenue from its regulated facilities and unregulated hydroelectric operations enables OPG to continue to moderate Ontario's electricity prices

- OPG moderates electricity prices in Ontario, and will continue to do so after resetting of base rates and addressing unregulated hydroelectric pricing
- Since OPG has not received a rate increase on its regulated base rates since 2008, those rates have not kept pace with inflation
- In 2012, OPG's average price of 5.1 ¢/kWh for generation was 40% lower than the average price received by other Ontario electricity generators of 8.6 ¢/kWh
- OPG's average price is expected to be [redacted] in 2015, after incorporating the impacts of the 2013 settlement agreement for the deferral and variance accounts, approval of the proposed 2014/2015 rate application, and establishment of a price for unregulated hydroelectric that will recover costs and earn an appropriate return
- The expected average price paid to other Ontario based generators in 2015 is 10 ¢/kWh. OPG's expected average price of [redacted] less than that received by other Ontario electricity generators.





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ONTARIO POWER GENERATION

Financing Outlook

Long-term debt is forecast to [redacted] from [redacted] during the 2013-2015 period to support development projects

- [redacted] It is critical that OPG achieve significant revenue increases commencing in 2014 to improve cash flow.
- OPG will continue to maintain adequate sources of liquidity in 2013. Liquidity resources are [redacted]
- OPG's long-term debt is expected to [redacted] from [redacted] during the 2013-2015 period
  - Net cash from operations ranges from [redacted]
  - Net cash required for investment [redacted] from [redacted] in 2014, due primarily to [redacted] in expenditures for the Darlington refurbishment
  - The [redacted] in long-term debt includes financing for: [redacted] Niagara Tunnel – $100 M; and [redacted] in general corporate debt, primarily due to financing requirements for the Darlington refurbishment
  - An OEFC facility of [redacted] is being pursued to support 2013 corporate requirements, including the Darlington refurbishment
  - The financing outlook is dependant on achievement of the current regulatory rate forecast
- OPG will continue to finance non-nuclear development projects from capital markets as appropriate. New debt and refinancing of debt held by OEFC can also be sourced from external markets, subject to Shareholder consent.

Liquidity Forecast

	Actual	Budget	Business Plan	
$millions	2012	2013	2014	2015
Opening Cash Balance*	[redacted]			
Net Operating Cash Inflows				
Interest				
Nuclear Funds Contribution				
Pension Fund Contribution				
Net Cash from Operations				
Capital Investments:				
Capital Expenditures (sustaining)				
Niagara Tunnel (NTP)				
Darlington Refurbishment				
[redacted]				
Thermal [redacted]				
Other Hydro				
Net Cash from Investment				
Financing Activities				
General Corp Debt - Debt Retirement				
- Debt Refinancing				
- Darlington				
Project Specific OEFC Financing - Niagara Tunnel				
Project Financing LM - LT Financing				
- ST Financing				
- Debt Retirement				
Securitization Repayment				
Net Cash from Financing				
Net Cash Flow for Period				
Ending Cash Position				
Long Term Debt*				

* Opening cash and debt balances for 2014 reflect the actual 2012 year-end balances and the current 2013 year-end forecast balances

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[redacted]

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Risks and Uncertainties

OPG's 2013-2015 Business Plan is based on several strategic, operational, and financial assumptions, and as such, is subject to the following significant risks:

- OPG's ability to achieve its forecast regulated revenue levels could impact income, cash flow, and borrowing requirements. While OPG has attempted to moderate its impact on 2014/2015 customer rates, significant risk and uncertainty remain with respect to the acceptance of OPG's rate proposal.
- OPG's metrics that support its current credit ratings remain weak. In order to avoid a credit rating downgrade, it is critical for OPG to achieve increases in revenue from its current regulated facilities and the unregulated hydroelectric operations in 2014/2015
  - The credit rating agencies will assess the risk and likelihood of OPG achieving increases in revenue and cash flow for 2014/2015 that are adequate to support OPG's current credit rating. There remains a risk of a credit rating downgrade in 2013.
- If the revenue strategies do not materialize, OPG will have to implement mitigation measures to address its cash flow requirements. This could include a significant reduction in project expenditures, and additional OEFC financing for key development projects.
- The ability to execute key operational initiatives
  - Planning and execution of work in support of the first Darlington refurbishment outage in 2016, and recovery of all costs
  - [redacted]
- Financial market performance
  - Changes in long-term interest rates have a significant impact on OPG's pension/OPEB costs. A 0.25% change in the discount rate would result in a change in pension/OPEB costs of ~$60 M/yr.
  - Achieving projected returns on the Nuclear Funds
- Compensation and wage constraints may adversely affect OPG's ability to retain and attract qualified executives and employees, and as a result, may affect OPG's operations and ability to successfully implement Business Transformation initiatives
- OPG's headcount reductions [redacted] are based primarily on attrition. Reductions in attrition levels could impact planned cost savings for the 2013-2015 period.

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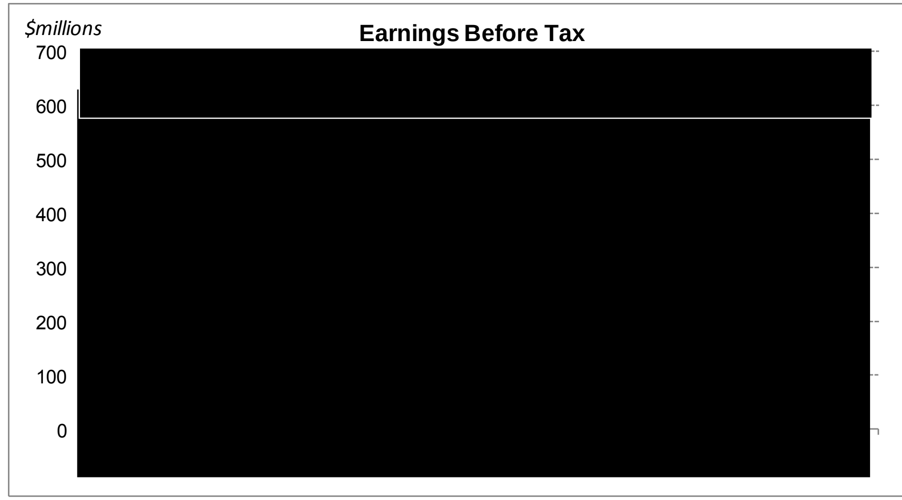
Appendix

Credit Rating Outlook and Implications

- Standard & Poor's "A-" rating with "negative outlook" (Feb. 2013)
  - Weak cash flow metrics, and exposure to regulatory delay and cost overruns related to new construction and refurbishment of existing facilities, were identified as key negative rating factors
  - OPG's rating could face a downgrade if:
    - Adjusted FFO to total debt stays below 8%-10%
    - Adjusted FFO interest coverage weakens to below 3.0x
- Dominion Bond rating Service: "A (low)" rating with "stable trend" (Mar. 2013)
  - Significant capital expenditure program, nuclear generation risk, political intervention, and future nuclear liabilities, were cited as major credit rating challenges
  - Increasing concern about political risk on cost recovery through potential rate freeze or extended cost recovery period, were identified as possible negative outcomes
- S&P and DBRS are expected to closely monitor OPG's financial outlook going forward for improvement in cash flow metrics and financial risk profile

OPG's EBT on the Province's Fiscal Basis

- For 2012/2013, OPG's earnings before tax of [redacted] the amount budgeted by the Province by [redacted]
- OPG's forecast of earnings before tax on the Province's fiscal basis is highly dependant on the assumption of timing of OEB decisions
  - The forecast assumes that the OEB decision to change the nuclear and hydroelectric rates, and establish a rate for the unregulated hydroelectric assets, is issued in Q2 2014



[redacted]

  - It is further assumed that the new rates are retroactive to January 1, 2014. As a result, any increase in revenue effective at the start of the year will be recognized after March 31, 2014, and therefore impact the 2014/2015 fiscal year of the Province.
- Taking into account the expected timing of the OEB decision, OPG's forecast earnings before tax in 2013/2014 [redacted] the Province's budget of [redacted] For 2014/2015, OPG's forecast earnings before tax is [redacted] compared to the Province's budgeted amount of [redacted]
- In its 2014 fiscal year, OPG also expects to recognize an extraordinary accounting gain of ~$300 M (related to income taxes) upon regulation of the currently unregulated hydroelectric assets
  - If an effective date of January 1, 2014 for regulating these assets is set by the Province, the gain will be recognized in Q1 2014, and in the Province's 2013/2014 fiscal year
  - If the effective date is established by the OEB, the gain is expected to be recognized in the Province's 2014/2015 year, consistent with the assumed timing of the OEB's decision of Q2 2014

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ONTARIO POWER GENERATION

Operating Statement

$ millions	[redacted]
Electricity Revenues	
Less: Fuel & GRC	
Gross Margin Generation Sales	
Net Trading Revenue	
Gross Margin Electricity Sales	
Non-Electricity Revenues	
Total Gross Margin	
OM&A Expenses	
Accretion on Nuclear Liabilities	
Earnings on Nuclear Funds	
Depreciation & Amortization	
Other Costs	
Financing Charges	
Income (Loss) Before Tax	
Income Tax	
Net Income (Loss) Before Extraordinary Gain	
Extraordinary Gain	
Net Income (Loss)	

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Balance Sheet

[redacted]

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ONTARIO POWER GENERATION

2013-2015
Business Planning
Instructions

Issued by:
Controllership-Business Planning & Reporting

July 20, 2012

ONTARIO POWER GENERATION

CONTACT INFORMATION

If you require further information on business planning assumptions, schedules, or requirements, please contact:

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1.0 2013-2015 BUSINESS PLANNING CONTEXT

As OPG begins the 2013-2015 Business Planning (BP) process, it faces a number of challenges with respect to its strategies, operations and finances, including;

- ***OPG faces a number of external challenges, including continuing low electricity demand, rising customer electricity bills, increasing regulatory oversight and large provincial financial deficits:*** Recent, and forecast, increases in consumer electricity prices due to factors such as the impact of the Green Energy Policy and the need to invest in aging infrastructure has created significant consumer concern. At the same time, Ontario's financial situation increases the expectation for OPG to generate appropriate financial returns for its shareholder.
- ***Increasing competition:*** OPG is facing increasing competition from gas, wind and solar generators, partially due to the generation mix identified in Ontario's Long Term Energy Plan (LTEP). In order to successfully compete, OPG must reliably and cost effectively generate electricity and create a scalable organization that will ensure its long-term sustainability. As OPG receives the lowest rates of all Ontario generators, and Ontario's HOEP remains at extremely low levels, the company must significantly increase its focus on cost control, implementation of efficiencies and its performance relative to benchmarking results.
- ***OPG's generation development projects are critical to its future:*** Current projects including the Niagara Tunnel [redacted] must be completed on-time on on-budget. OPG must ensure that appropriate agreements, which provide for cost recovery and a rate of return, are in place for shareholder-directed projects. OPG must plan and execute the Darlington refurbishment project in a manner that ensures the project's financial viability and maintains the confidence of its shareholder.
- ***OPG must ensure its long-term financial viability:*** To achieve a sustainable level of financial performance, OPG must strive to improve efficiency, increase revenues, reduce costs and earn an appropriate return on equity. Additionally, targets for key financial metrics must be achieved in order to maintain OPG's current credit ratings, and funding sources should be diversified in order to finance OPG's growing capital requirements.

OPG's mission is to be the electricity generator of choice in Ontario. Realizing this objective in such a challenging environment requires OPG to achieve its core strategies of performance excellence, project excellence and financial sustainability. OPG has undertaken a Business Transformation Project to ensure the achievement of these strategies.

Planning Direction

Over the past three Business Planning (BP) cycles, OPG has established aggressive targets for reducing headcount and cost levels. OPG is in the midst of implementing the Business Transformation Project to identify initiatives aimed at realizing these headcounts and cost reductions. The current environment demands that OPG continues establish increasingly aggressive operational and financial targets.

Planning Requirements and Scenarios

The "Preliminary Planning Scenario" shown below identifies the generation plan assumptions underlying the business plan. This scenario assumes Continued Operations at the Pickering site and Darlington Refurbishment beginning in 2016.

Assessment of longer-term implications will involve alternate scenarios:

- A "Low Investment" scenario, which assumes reduced investment in Hydro Development projects and constrained regulated revenue rates.
- A "High Investment" scenario, which includes New Nuclear, [redacted]

Details of these scenarios are identified in the following tables.

	2013 – 2015 Preliminary Planning Scenario	Change from 2012 Business Plan/ Long-term Plan
Pickering	• Continued Operations to 247k EFPH • P5 & 6; End of Life (EOL) 2019 • P1, 4, 7 & 8; EOL 2020 • P7 LM; 2015-2016	• Lengthened • Lengthened • Lengthened • Delayed
Darlington	• Refurbishment begins in Q3 2016 with D2 Based on 210k EFPH • Refurb Outages; 36 months each • Station Containment Outage in 2015 *Note: Nuclear assumptions under review*	
New Nuclear	• Not in base case; decision by end of 2013	• No change
Thermal	[redacted]	[redacted]
Hydroelectric	• Beck PGS remediation [redacted]	• No change [redacted]

Low Investment Scenario (Changes from Base Case)	
Regulated Rates	Constrained to 3%/year beginning in 2015
Hydroelectric	Beck Reservoir rehabilitation only

High Investment Scenario (Changes from Base Case)	
New Nuclear	DNGS; 2 x 1,200 MW in-service between 2022-2023; approval deadline set for the end of 2013
Regulated Rates	Possible smoothing of unconstrained rate
Thermal	[redacted]
Hydroelectric	[redacted] Lake Gibson

[redacted]

Further scenarios may be identified during the planning process; applicable BUs will be contacted directly to identify submission requests.

2.0 RESOURCE GUIDELINES

As described earlier in the planning context discussion, OPG faces significant financial and operational challenges on its planning horizon. OPG's 2012-2014 Business Plan responded to these challenges by committing to reduce headcount levels, based on attrition, in the later years of the plan, in recognition of expected changes in capacity and production. The resource guidelines for the 2013-2015 planning process confirm these commitments and specify an earlier timeframe for their implementation.

Guidelines – Headcount

		Guidelines			Change from Approved Plan	
	2012 Budget	**2013**	**2014**	**2015**	**2013**	**2014**
Nuclear Operations	5,542	5,347	5,210	5,114	(85)	(103)
Nuclear Projects	777	739	712	712	0	0
Hydro/Thermal Operations	[redacted]					
CO & E	197	170	159	146	(8)	(11)
Total Operations	[redacted]					
BAS	1,133	1,043	984	928	(60)	(79)
Finance	416	363	337	310	(16)	(37)
People & Culture	671	625	600	573	(12)	(19)
Corporate Office	140	122	117	112	(12)	(15)
Law	28	25	24	23	(2)	(3)
Executive Office	5	5	5	5	0	0
Total Support Services	2,393	2,183	2,067	1,951	(102)	(153)
Total Ongoing Operations	[redacted]					
Darlington Refurb	195	308	307	307	78	81
New Build	93	33	32	32	(268)	(408)
Total OPG	[redacted]					

Note – Headcount targets reflect attrition-based forecasts through 2015, [redacted]

Guidelines – OM&A

		Guidelines			Change from Approved Plan	
$ millions	**2012 Budget**	**2013**	**2014**	**2015**	**2013**	**2014**
Nuclear Operations	1,194	1,247	1,227	1,296	(27)	(42)
Nuclear Projects	205	238	228	243	(5)	(3)
Hydro/Thermal Operations	[redacted]					
CO & E	46	40	41	38	(2)	(3)
Total Operations	[redacted]					
BAS	335	322	314	308	(9)	(14)
Finance (Excluding Insurance)	72	66	63	61	(3)	(6)
Insurance	32	28	32	38	0	0
People & Culture	119	114	111	110	(3)	(6)
Corporate Office	52	43	40	41	(1)	(2)
Law	10	8	9	8	(0)	(1)
Executive Office	6	5	5	5	(0)	(1)
Total Support Services	625	586	573	570	(17)	(29)
Total (Excludes Centrally Held)	[redacted]					

Note – 2015 was re-based using OM&A per the long-term outlook, adjusted for Business Transformation (BT) organizational changes. The BT transfers in/out amounts were generally derived using 2014 data.

[redacted]

Guidelines – Capital

		Guidelines			Change from Approved Plan	
$ millions	2012 Budget	2013	2014	2015	2013	2014
Nuclear Operations	183	171	159	141	0	0
HTO [redacted]	[redacted]					
CO & E	0	0	0	0	0	0
Total Operations	[redacted]					
BAS	29	35	35	25	5	9
Finance	1	1	1	0	0	0
People & Culture	2	1	1	0	0	0
Corporate Office	[redacted]					
Law	0	0	0	0	0	0
Executive Office	0	0	0	0	0	0
Total Support Services	[redacted]					
Darlington Refurb	282	547	620	661	0	0
New Build	0	0	0	0	0	0
Total OPG	[redacted]					

[redacted]

BAS guideline reflects an allowance for one-time investments associated with BT projects. The allowance is subject to change pending decisions on accounting classification of the various projects.

3.0 KEY PROCESS CHANGES

The business planning process features a number of changes this year based on recommendations resulting from Business Transformation. Key changes and elements include the following;

3.1 BUSINESS TRANSFORMATION – "QUICK WINS"

CONTACT: JOHN MAUTI

Standard Labour Rate

- Establish an OPG-wide standard labour rate to replace the past practice of using BU-specific labour rates.

Reducing the number of Budget Holders

- Going forward, in order to hold a budget, it must be demonstrated that a minimum of twenty (20) staff are held or at least $5 M in financial activity is observed on an annual basis.

Holding the Payroll Burden fixed

- The payroll burden percentage will be available early in the BP process, but will remain fixed for BU planning.

Further discussion on these items may be found in section 5.3 of this document.

3.2 MAJOR PROJECT / CAPITAL OUTLOOK

CONTACT: ANDREW TEICHMAN

Over the next ten years, OPG faces potential capital constraints given the anticipated combination of revenue pressures and growing capital needs.

These capital challenges will need to be addressed through the development of corporate capital envelopes and strategic allocation of capital over an extended planning horizon. Therefore, development of an integrated corporate-level 10-year view of major project OM&A and capital initiatives is considered prudent to support efficient corporate capital allocation efforts and OPG's long-term financial sustainability.

Commencing with this year's BP cycle, Corporate Business Development and Finance are launching an initiative to develop a 10-year outlook of major project OM&A and capital expenditures. This initiative will be accomplished by engaging the major BUs (Nuclear Operations, Nuclear Projects, Hydro / Thermal Operations) and Corporate Business Development to develop an appropriate 10-year outlook. This approach will provide the flexibility to develop an appropriate long-term view given any variations in the information available and the uniqueness of the specific project portfolios.

Discussions will be undertaken over the next several weeks in parallel with normal BP activities, and where possible to leverage available information and reporting processes.

4.0 SCHEDULE

CONTACT: SANDRA RADCLIFFE

The following is a high level schedule of key BP activities. A more comprehensive schedule can be found on the Business Planning (BP) webpage.

Date	BUSINESS PLANNING ACTIVITIES
June	• Economic assumptions updated by Treasury – **June 8** • Preliminary staff level / job family submission – **June 19** • BU final labour rate review – **June 30**
July – Aug.	• Continuing site and BU plan development • Roll-out of initial estimate of payroll burden rate change – **July 13** • Preliminary Energy Production Plan – **July 17**

Sept. – Oct.	• Initial submissions to BP&R – **September 7** (BPS input for 2013-2015, program write-up and analysis)
	  – CEO/CFO reviews for Support Services – **September 13-September 28**
	  – CEO/CFO reviews for Operating Groups – **September 19-October 1**
	  – Revised submissions to Finance no later than **October 26** (if required), including sign-off by each respective Controllership Organization
	  – Controller sign-off of key accounting assumptions
	• Final Energy Production Plan – **September 14**

October	• Update BU costs (high-level) for burden – **October 5** • Finalization of corporate level information (allocations, variance accounts, interest, income taxes) • Shareholder review tentatively scheduled for – **October 26**
November	• EMT review(s) • Board mail out – **November 4** • BU, Support Services and Corporate Finance – monthly trending finalized by **November 9**, including OM&A, Capital, Fuel, Other Revenues, depreciation, accretion, regulatory accounting, balance sheet items • **Board approval of Business Plan – November 15**
December	• Finalization of cost-allocation and loading of budgets into reporting systems • Preparation of Results-Based Planning information for Shareholder on MOF Fiscal basis

5.0 BUSINESS PLANNING AND BUDGETTING INSTRUCTIONS

5.1 INFORMATION SUBMISSIONS

CONTACT: SANDRA RADCLIFFE

Business Plan submissions are required from each Business Unit (BU) and Support Services, and consist of the following:

- Quantitative resource and financial submission information submitted through BPS (short-term) and spreadsheets (long-term)
- Supporting analysis
- Business Plan PowerPoint presentation to be made to Senior Management

Resource and financial information with work program and resource type/cost element is the level of detail required for the short-term submissions. Summarized quarterly detail is sufficient as long as there is an emphasis on realistic forecasts for Q1 (Government's fiscal year-end), which include:

- OM&A
- Capital – balanced to project listings as directed in Section 5.5
- Minor fixed Assets
- Non-electricity revenues and costs
- Staff details – headcount by representation, FTE funding
- Nuclear provision expenditures – this includes items such as staff providing dedicated support services to Nuclear Waste Management Division (i.e. P&C, security) and Station decommissioning. (**note – deadline for this is August 17)**
- Other provision expenditures – draw-downs of environmental or First Nation provisions and non-Nuclear station decommissioning
- New Provisions

Note – all short-term information should be based on the May 1, 2012 Business Transformation organization.

The following additional information requirements are to be submitted electronically in spreadsheets or documents:

- Interest capitalization, retirements and in-service addition forecasts consistent with capital project plan details submitted in BPS and Project listings. If bottom-line adjustments have been used to balance capital submissions then these must be factored into interest capitalization and in-service additions.
- Quarterly details for the first three years are required. Note – the 2013-2015 interest capitalization rate has changed from 5.25% to 5.00%.
- Cash flow information for draw-downs of provision expenditures is based on payment forecasts
- Working capital items (annual detail sufficient initially);
    - Fuel inventory
    - Material and supplies inventory.
- Cost allocation – BUs must allocate all their costs to the station level, within Regulated and Non-Regulated OPG. See section 5.3.2. Due date – September 14
- Plan over plan and year over year analyses of all changes in business plan resources (OM&A, capital, fuel, and non-electricity revenues)
- Factors influencing year over year changes in performance

For production units, an analysis of the performance metric "Return on Assets" (ROA) must include:

- Forecast ROA – at the BU level
- Analysis of factors impacting ROA – year-over-year
- Plan-over-plan analysis of ROA compared to previous plan and 2012 year-end forecast
- ROA sensitivity to key inputs

Business Planning & Reporting (BP&R) will work with the BUs to provide appropriate forecasts for allocated costs and sales margins.

Similar to previous years, the Business Plan presentations should identify objectives, performance targets, resources, key initiatives, and risk and mitigation strategies. Comparisons to the current Business Plan and year-over-year differences, with analyses of changes in resources and programs, are required. A draft of the presentation must be provided to BP&R **three (3) business days** in advance of the review with Senior Management.

5.2 FINANCE REVIEW AND SIGN-OFF

CONTACT: JOHN MAUTI

Each BU Controller will complete a financial review and sign-off for the Business Plan for the BU that they support. The sign-off will confirm that they have reviewed the submissions and are in agreement with the financial assumptions and the basis of the investment decisions identified in the plan.

The sign-off will take the form of either an E-Mail or Memo sent to the VP & Chief Controller and will confirm that a Business Plan financial review has been completed. To assist in this review, a checklist will be sent out by BP&R in July to highlight specific areas that are to be reviewed. The submission from the Controller will confirm:

- Any major areas of concern
- Accounting and costing assumptions used in the plan for major projects and investments
- Confirmation that the accounting treatments for these projects are consistent with the determination of Corporate Accounting

In addition, Accounting will be completing an accounting review and sign-off of key accounting assumptions that have been applied to the respective Business Plans, including, but not limited to:

- Accounting implications and policy changes (notably any USGAAP vs. CGAAP changes)
- Identification and costing of provisions (i.e. decommissioning, aboriginal, environmental, etc.)
- Any changes to inventory obsolescence calculations and assumptions included in the Business Plan

5.3 INSTRUCTIONS FOR USE OF BPS

CONTACT: KAREN MOONEY

There will be three (3) versions of the Business Planning System (BPS) utilized for the years 2013-2015 for the Business Plan:

- **W01** will contain the labour rates and burdens used in the 2012-2014 Business Plan last year. All BUs will use BPS version W01 for planning.
- **W02** will contain new labour rates (with current burden rates) applied to the new plan submissions to isolate labour rate change impacts. Corporate labour rate review will be completed by June 30 and a move to W02 will only be undertaken at the request of the BU controllership.
- **W03** will be used to isolate the effect of the payroll burden rates on the new plans.

Note – New plans contained in W01 can be copied over to versions W02 or W03 at the request of the respective BU in order to determine the impacts from labour rate changes or burden updates. You must allow at least two business days for processing. All of the labour rates contained in Version W02 and W03 will be copied over to Version W01 in August at the request of the respective BU. Planning changes post September 4, 2012 will be done using new updated labour rates in W01.

Resource submissions and preliminary Business Plans for both operating and corporate groups are to be completed in W01 by September 7, 2012. The following details are required in order to consolidate the Business Plan:

- Work Program and Projects should be trended on a monthly basis for 2013 and 2014, which will be picked up through BPS.
- BUs must ensure their assumptions for hiring lags and project initiation reflect actual experience and realistic expectations. Assumptions in this area and comparisons to historical trends are to be highlighted in accompanying analyses.

- Total labour requirements must be balanced to total labour supply in the Labour Planning Module of BPS.
- BPS will be locked on the submission days to allow consolidation of data by BP&R.

By end of day on November 9, 2012, all trending and adjustments must be completed in W01 and BUs will be locked out of BPS. At that point, budget trending will be considered final and ready for upload to SAP and reporting systems.

The following three 'Quick Wins' are being implemented to increase the level of efficiency within the BPS process.

Quick Win #1: Moving to a Single Standard Labour Rate

Finance has implemented the use of a single company-wide Standard Labour Rate (SLR) table. The SLR will be calculated at the corporate level and will replace the past practice of calculating numerous BU-specific labour rate tables.

The benefit of this change will be a reduction from the current 21 unique labour rate tables to one, a significant reduction in analyses of rate variances, and the elimination of variances being held at station or BU levels. All variances will now be analyzed and held at a consolidated level. BUs and sub-units will not be responsible to track these variances and will not be accountable directly for them, particularly since they are driven by factors that are typically beyond their direct control. The OM&A and Capital guidelines provided in this document do not reflect the move to this single standard labour rate. The impact of this change at an overall corporate level will be nil, but individual BU guidelines will change as a result. These changes will be managed centrally and guidelines adjusted as required.

Quick Win #2: Reducing the Number of Budget Holders

Going forward, in order to qualify as a budget holder, a minimum staff level of twenty (20) or at least $5 M in financial activity – OM&A, Capital, Revenue or Provision-related costs must be identified.

The only allowable exceptions to these new requirements are as follows:

- ELT direct reports who do not meet these criteria may control a budget;

[redacted]

- Small Groups that control less than twenty (20) full-time employees and have less than $5 M in financial activity, but who have the potential for significantly higher costs may control a budget (for example, isotope sales);
- Joint Ventures;
- If a requirement exists to separate regulated activities that cannot otherwise be handled through an allocation process; and
- If other situations exist that determine the need for an isolated budget holder from a business perspective, the case must be presented to BU Controllership for approval.

Reducing the number of budget holders in the organization provides several benefits within the planning process and many of the downstream processes as well:

1) A reduction in the number of planning cost centres that must be set-up, planned, etc
2) A reduction in the volume of line manager cost reporting that must be conducted to monitor budget progress (fewer automated reports to push out, fewer line managers involved in detailed cost review, fewer finance resources required to monitor and correct for issues at a detailed line manager level).
3) Reduced transactional accounting complexity through fewer charge codes, simpler segment allocation process, and fewer manual transaction journals to correct or redistribute costs

Reducing the number of budget holders will result in budgets held at a level where true trade-offs and decision making is occurring within the organization. This level is generally higher than the over 700 positions that held budgets in 2012. Managers holding a budget in this new model are expected to work with their direct reports and teams to review financial status, make decisions/tradeoffs, and work together to be financially responsible and meet corporate cost control directions. The materiality level for budgets, established above, is targeted to achieve this objective, while reducing time and effort expended by both finance and line management.

Quick Win #3: Holding the Payroll Burden Fixed

Changes to payroll burden will be held at the BU level as a total dollar amount without changing the burden rate percentage. Once the burden is calculated in July, it will be incorporated into the SLR for all years of the BP time horizon.

Budget holders will only be charged with the fixed burden rate, while the change in late fall will be held at the BU level. BU leaders will be given the budget to equal this late fall change (either positive or negative).

The actual pay will incorporate the burden as determined in the later version (November/December). The rate variance account (primary pay) will be charged with actual pay, including the total burden, while the budget will only represent the fixed burden. The actual variable burden component will be journalized at the BU level on a monthly basis based on the pre-determined variable burden budget. The rate variance account will only hold the actual rate variance.

The primary benefit of this approach to burden rates is to avoid unnecessary rework in the detailed costing of projects and work programs that occurs late in the BP cycle that is beyond the control of line managers. Late changes in burden rates are often the function of economic factors (such as discount rates) that are used in estimating pension and OPEB costs. These changes impact the accounting calculation of post retirement costs and need to be reflected directly in the BUs where the staff works. The need to recalculate all work costing details in the planning system is neither required, nor particularly helpful, in the late stages of setting the plan and next year’s budget.

The proposed approach aligns the costs for these changes, in aggregate, with the appropriate BU leader but does not result in re-costing of all planning detail (cost centres, projects, etc). It is also easier to isolate the impact of these late changes in planning assumptions by BU.

5.3.1 Labour Costs and Staffing

Businesses will use the BPS system for budgeting short term labour costs:

- The BPS system currently contains labour rates, burden rates and job families. Escalation assumptions for Society, PWU and Management Groups will be provided to Planners via E-Mail. Work is currently underway re the annual review of any necessary changes to job families, and other factors. Updated rates will be available for review in BPS in June and should be finalized by the end of the month.
- The roll-out of initial estimate of payroll burden rate changes is targeted for the end of July
- BUs will provide final workforce forecasts with their submissions. An assessment of the changes in current service costs will be undertaken at that time.
- Direct costs relating to AIP incentive plans will be budgeted at the Corporate Level.

5.3.2 Cost Allocations

CONTACT: PAUL CHABOT

In support of the Financial Reporting process, there is a requirement to load a complete set of financial statements for each year of the Business Plan into BPS. As in the past, Support Services are required to supply their rationale on management estimates for allocations. A template for this information will be provided and is expected to be submitted one week after the September corporate submission. The Support Services group will work with groups to incorporate their input to BPS.
Preliminary accountabilities for input to BPS are:

Commercial Operations & Environment:
- Electricity Generation Revenue

[redacted]

Business Units:
- Fuel and Fuel-related
- Non-electricity generation
- Cost of Goods Sold
- OM&A
- Fuel and Fuel-related
- Non-electricity generation

Business Planning & Reporting (BP&R):
- Accretion & Earnings
- Depreciation & Amortization
- Capital Tax
- Interest
- Income Tax

Other Corporate Finance:
- Regulatory accounting (Regulatory Finance)
- Centrally held costs (Support Services group)
- Property Tax (Property Tax group)

5.4 BUDGETING FOR SERVICE PROVIDERS CONTACT: LUBNA LADAK/BOSCO YUAN

Businesses should continue to work closely with service providers such as Information Technology (IT), Real Estate & Services, Supply Chain, etc., to jointly agree on service requirements and associated costs. The costs should be adequately reflected in the service provider's plan. All OM&A, provisions, and capital expenditures, including Minor Fixed Assets (MFA), will be held by the service providers on behalf of the businesses. Please ensure there is no duplication in budgets between the BUs and service providers. Service Level Agreements, as defined through Business Transformation, are a useful tool to accomplish these objectives.

Information Technology (IT) requirements should be identified to IT. The Business and Administrative Services' (BAS) business plan includes all business-related IT needs, IT projects, and IT components of business initiatives. These initiatives are only exclusive to Nuclear Refurbishment, Darlington New Build [redacted]

Each BU should incorporate the following IT expenditures into its Business Plan rather than in BAS:

- Process control hardware and software in Nuclear and Hydro/Thermal generation.
- Engineering tools (hardware) and new software in Nuclear and Hydro/Thermal generation (annual maintenance for most existing software is covered.)

Where the business is asking BAS to assume budget accountability for existing items (e.g., annual maintenance contracts), a list of the items and their related costs should be provided to BAS for inclusion in their plan. If there is uncertainty as to whether or not a particular contract is identified in the BAS plan, one of the contacts listed below should be consulted.

The Information Management Transformation (IMT) program has transitioned from the planning phase in 2011 to the execution phase for 2012 and 2013. Several workshops have been conducted in an effort to define the appropriate blueprints for attaining the desired future state of Information Technology (IT).

This program continues to require active leadership involvement, support, cross-organizational collaboration and strong change management in the execution phase to ensure success of the program. One key element is to have a cross-functional working team, comprised of subject matter experts from each BU, accountable for delivering the IMT program. Consequently, each BU is required to provide resources to the IMT program.

For the 2013-2015 Business Plan, each BU is required to include their resourcing costs relating to IMT program in their respective plans. IT Projects will meet with BU owners to discuss resources required to support these technology upgrades.

Currently, the IT project portfolio is fully loaded as projects are in the process of being locked down over the planning period as per previous business plan and the incremental Business Transformation Strategy approved initiatives.

For specific projects included in the plan, please contact your IT contacts as shown below:

- Nuclear – Warren Hobbs (702x5131 at Pickering)
- Hydro/Thermal/Corporate – Amir Shemranifar (x6981 at 700U)
- Energy Markets – Howard Mintz (x1826 at 700U)
- Information Management Transformation – Mike Borsch (8274 x at 700U)
- Business Transformation Strategy – Mike Borsch (8274 x at 700U)

Strategic Sourcing requirements

OPG will be embarking on a series of significant business events over the 2013-2015 planning period due to changes in generation assets.

For Hydro, Supply Chain continues to administer, negotiate, and execute contracts in support of the completion of Niagara Tunnel [redacted]

In Nuclear Supply Chain (NSC), cross-functional (plant-focused) performance measures adopted in 2011 will continue to drive the behaviours and results required. Key strategies underlying the 2013-2015 Business Plan are as follows:

Parts Availability

- Managing and organizing the acquisition and distribution activities in support of outage improvement strategy, work order readiness, vendor quality and supplier performance management.
- Improve equipment reliability and reduce replenishment material stocked out.

Inventory Management

- Work collaboratively with the power plants, and other Nuclear supporting organizations, to improve material availability via the work management, outage planning, and project management processes.
- An inventory strategy will be required to address Pickering's EOL such as disposing of dead stock; increasing consumption, adjusting the preventive maintenance program and adopting repair versus replace strategy.
- The addition of inventory provision funding will support safe storage and decommissioning activities at Pickering. To further optimize inventory levels and cost, NSC will put in place a plan to transition to a Nuclear material only warehouse operation.

Another strategic sourcing initiative is to leverage other agencies and regulatory bodies' purchasing power to deliver substantial cost savings to OPG.

Real Estate & Services requirements (new leases, renewals, facility enhancements/modifications, new furniture) for each BU (including Nuclear Refurbishment, New Build) are to be clearly identified to Real Estate & Services for consideration and inclusion in their work programs. Real Estate & Services will consolidate all facility costs in accordance with an overall leasing strategy and will identify any costs to be charged directly to the businesses.

Businesses are also reminded that under the OPG OAR, only Real Estate & Services has requisitioning authority for the acquisition, management, and disposal of real estate rights and interests, and related transactions.

Real Estate & Services has identified the following contacts by service area:

- Real Estate Services – Ron Murphy (x7201 at 700U)
- Facility & Project Services – Don Seedman (x3289 at 700U)
- Enterprise Services – Teri Lilley (x7790 at 700U)
- Fleet Services – Joe Werb (416-231-4111 x6048 at Kipling)

5.4.1 Work for Others

The Cost Transfer Model states organizations are to budget for all of the resources they control. During the 2013-2015 BP period, however, Support Groups may be requested to provide dedicated services to major projects. The VP, Finance and Chief Controller will determine which major projects will be eligible for cost transfers prior to Business Plan submissions. Darlington New Nuclear and Nuclear Refurbishment are already recognized as major projects during the 2013-2015 Business Plan period and are therefore eligible for cost transfers.

Accounting will provide direction on the costs that can be classified as directly attributable to these projects. Headcount will remain in the support group. For presentation and analytical purposes, both originating and receiving groups will show the gross and net costs associated with these transfers. This will ensure there is no duplication in budgets between the project and service providers.

5.5 CAPITAL, OM&A AND PROVISION-FUNDED PROJECTS

CONTACT: DOROTHY LAU BARTON

This section specifies the requirements and the schedule for submission of the 2013-2015 capital, OM&A and provision-funded project portfolio listing and supporting Planning Business Cases (BCSs). Business Units (BUs) are requested to provide their project information by **September 7, 2012 to Jack Fong** in Investment Planning (IP). BUs can provide their project information via email, by portable media, or by granting IP access to their project database (e.g., Prosight in Nuclear).

Section 5.6.1 specifies the listing requirements for the project portfolios. Section 5.6.2 provides the criteria for projects requiring Planning BCSs and the information requirements for Planning BCSs. Questions on these requirements should be directed to Dorothy Lau Barton (access 400, extension 4580) or Jack Fong (access 400, extension 4655).

Note – As a result of the Business Transformation process, the Corporate Business Development & CRO office led by Andrew Teichman will be assisting Jack Fong's group with the management of the long-term project portfolio. A separate note on this initiative can be found in Section 3.2 of this document.

5.5.1 Prioritized Project Lists

BUs are required to identify all capital, OM&A and provision-funded projects having cash flows within the Business Plan time horizon. The submitted projects must be prioritized to maximize value, while considering risks and OPG's business objectives as well as efficient alignment with business unit strategies, facility Life Cycle Plans (as applicable), Condition Assessments and shareholder expectations. We continue to focus on Return on Equity (ROE) and Return on Asset (ROA) trends over the BP period on cost elements that are controllable at the BU, plant groups and station level in measuring operational profitability.

The listing format and information requirements have not changed from last year and are provided in the ***Project Listing Template***, available on Corporate Finance's BP&R webpage. Definitions and explanations for the various fields in the template are provided in the ***Guidelines*** worksheet. To facilitate corporate review, consolidation and reporting, it is essential that BUs provide all information in the format specified in the listing template. We also request that each BU provide a description of their prioritization process.

Where the portfolio listing of projects does not add up to the total requested funding envelope, separate justification for the planned level of expenditures should be provided – e.g., benchmarking, historical spending, etc.

The final portfolio listing of projects coming out of BP will provide the basis for the semi-annual portfolio reporting to the Board around November and May.

To support the development of an OPG long-term integrated staff resourcing plan and an analysis related to skilled craft from the construction trades, the "program" category in the project listing template should be completed. This categorization is being used to identify the type, number of skilled craft and total project costs by year from the various construction trades. For additional information on these categorizations, and how this information will be used, please contact Laurie Gawel, Manager of Workforce Analysis Systems & Support (access 400, extension 2499).

5.5.2 Planning Business Cases

BUs are required to submit Planning BCSs, or an equivalent document, for projects listed in their portfolio that are **not fully released** and meet the following criteria:

- Projects planned for release in 2013 with cash flow > $1 M in 2013
- Projects planned for release in 2013, 2014, or 2015 with total project cost greater than $5 M

For the purpose of these instructions, **not fully released** projects include:
- Projects with no previous releases
- Projects with developmental (preliminary) and/or partial releases but the project has not been fully committed
- Previously released projects that are forecasting significant changes in scope/cost and a superseding release is planned/expected

The information requirements for Planning BCSs are specified in the ***Planning BCS Template***. Additional information and explanation are also provided in the ***Developing and Documenting BCS (OPG-STD-0076)***. Both of these documents are available on the Finance BP webpage, by following the links:

[redacted]

While the Planning BCS template sets out the information requirements, BU will often have existing documents that meet the specified information requirements. When such documents e.g. Type 1, 2 or 3 BCSs are available and up-to-date, especially with regards to cash flows, they can be submitted in place of the Planning BCS.

Planning BCSs are typically less than two pages in length, but the extent of information should be commensurate with the risk criteria of the project, and its stage of development at the time of submission. Among others, key information requirements are: the need for the project, its contribution to meeting OPG business objectives, linkage to asset strategy, quantifiable benefits, cash flow requirements, impact of deferring or not proceeding, key project risks and other considerations that can be used to establish a relative ranking. BUs are requested to focus special attention to documenting the impact of deferring or not proceeding with the project – this information will be used to make trade-offs amongst projects within and across BUs, if necessary.

Planning BCSs need to include a preliminary list of alternatives to illustrate the likely merit of the proposed alternative. If the project scope or cost estimate is highly uncertain due to timing, the use of range estimates is encouraged. For the purpose of setting budgets and evaluating the economics of alternatives, the expected value should be used.

All Planning BCSs should be reviewed and signed-off by the appropriate project sponsor (i.e., Asset Manager, Engineering Director, etc.) and the local Controller.

5.5.3 BCS Preparation Assistance

For assistance with BCS preparation, please contact your local Controller or Centre-Led Business Group. In addition, BCS training sessions can be arranged. For registration, please contact Silvester Wong of Investment Planning (access 400, extension 3842).

5.6 BUSINESS UNIT RISK SELF ASSESSMENT

CONTACT: TOM LUMLEY

As part of developing realistic, comprehensive, and transparent Business Plans, risks should be identified, assessed and incorporated, along with risk treatment plans, in each Business Plan. The goal of the Business Unit Risk Self-Assessment (BURSA) is to identify, assess, and document risks that could impact the achievement of BU objectives over the course of the Business Plan period (i.e. 2013-2015). Risks that are long-term in nature should also be documented, where possible.

As BURSA is also a part of the continuous Enterprise Risk Management (ERM) reporting process, on a quarterly basis this will involve an update of existing risks, along with the identification of new risks. In addition to being reported in the Business Plans, these risks form the basis for quarterly risk reporting to the Board of Director committees.

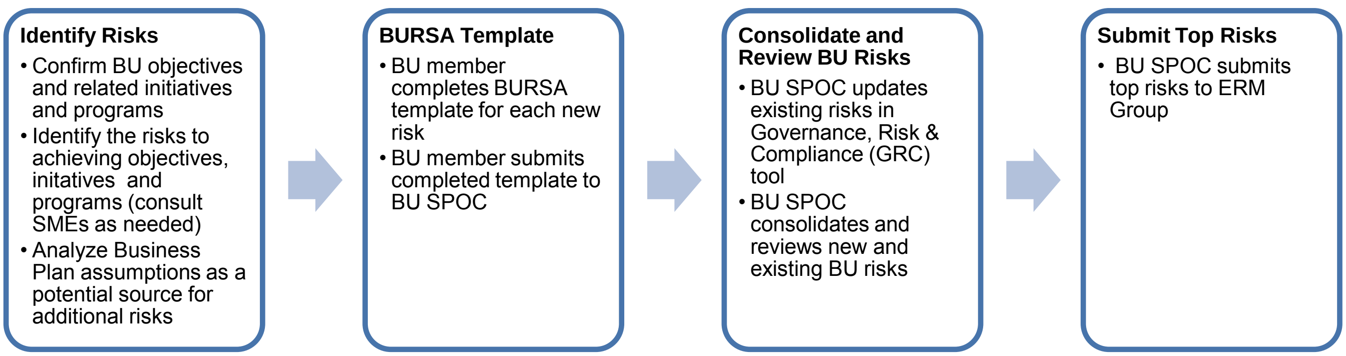
The following are the key BURSA submission dates:

- August 24 – BURSA kick-off email
- September 4 – 14 – ERM group meetings with BU Single Point of Contacts (SPOC)
- September 21 – BU SPOCs submit BURSA to ERM group

Further instructions, tools and templates will be distributed to all BU SPOCs by email from the ERM Group.

The BURSA Process

The main steps for the BUs to complete the BURSA are shown below:



The ERM group consolidates and reviews all individual BU risk submissions.

OPG senior executives will validate the list of prioritized risks to determine the risks which will be reported to the Board of Directors and which risks will not. This may result in updates to GRC.

There are three main outputs of the BURSA process:

- **BURSA Template** – Any new risks that have been identified should be documented in the BURSA template (to be provided).

- **GRC Update** – Any existing enterprise risks should be updated, similar to the quarterly ERM update process, within the GRC tool.

- **Business Planning (BP) Presentation** – The most significant risks stemming from the BURSA process should be captured in the Business Plans (presentation template to be provided).

5.7 INTEGRATED WORK FORCE PLANNING INFORMATION REQUIREMENTS

CONTACT: LAURIE GAWEL

In the past, there has been a requirement to provide detailed resourcing information in order to support the development of an integrated workforce plan. This level of detail will not be required for this BP period (2013-2015), but will be part of the requested information in future BP periods.

5.8 CORPORATE SAFETY GUIDELINES

CONTACT: MORRIS EDDY

With safety as a fundamental value, OPG is committed to continuous improvement and pursuing the ultimate goal of zero injuries. The Safety BP Guidelines include strategic programming and regulatory priorities that may impact planning and resourcing requirements in the BUs. These priorities are consistent with OPG's Strategic Objectives and Directions, which are found in the five-year Strategic Plan as well as the regulatory priorities. These Guidelines must be considered by the BUs in their safety planning activities.

5.9 FIRST NATIONS INITIATIVES

CONTACT: JOE HEIL

OPG's First Nations and Métis Relations Policy, which was approved in November 2009 and updated in August 2011, contains the following primary objectives:

- A commitment to deal with aboriginal communities in a respectful way
- A commitment to resolving past grievances
- A willingness by OPG to enter into commercial partnership(s) with aboriginal communities
- A commitment to building relationships with aboriginal communities including:
  - Community relations and outreach
  - Capacity building support within communities
  - Employment/Business contracting opportunities

All operating BUs, and other line organizations, that have regular contact with Aboriginal communities are required to develop programs in support of this Aboriginal Relations Policy. Program implementation is being staged over five years to facilitate an initial focus on the most critical areas. For this BP period, BUs are requested to identify a point of contact and prepare a First Nations and Métis Relations Program, which is to be reported quarterly and submitted to the Director of First Nations and Métis Relations.

For further guidance on program requirements:

[redacted]

5.10 ENVIRONMENT PLANS

CONTACT: ROB LYNG

Business Units (BUs) and functions are to plan work programs using the following assumptions:

- Plants and plant groups should plan to maintain ISO 14001 certification of existing environmental management systems through to the end of 2013. Existing EMS programs related to spills management, in particular, should be maintained through the business plan period.

- Other than the following specifics, assume the current environmental regulatory framework remains in-place with no major new initiatives or changes in Federal or Provincial environmental requirements:

  [redacted]

  - Evaluations required under the Heritage Act, if any, will be included in the Environment function's business plan.

- Implementation of best management practices for fish entrainment and impingement, determined in accordance with the DFO/MNR/OPG memorandum of understanding, must be initiated within the BP period.

All business units and functions are to identify planned activities and programs to fulfill relevant elements of the *Environmental Policy*.

Nuclear, Hydro-Thermal and BAS plans should address the following in their Environment plans:

- Changes in Significant Environmental Aspects (SEA).
- "Other Requirements" such as Wildlife Habitat Certification or other environmental commitments that the plant / plant group have adopted.

Further detail is available on the Environment website, including a template which may be used to submit the Environment Plan. BUs are free to use an alternative format as long as all relevant information is provided.

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

1. RECOMMENDATION:

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

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

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

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

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

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

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

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

2. SIGNATURES

Submitted by:

Carlo Crozzoli
VP, Hydroelectric Development — Date

Recommended by:

14 Sept 2011
John Murphy
Executive Vice President, Hydro — Date

Finance Approval :

Sept 16/2011
Donn Hanbidge
SVP and Chief Financial Officer — Date

Line Approval :

Sept 19, 2011
Tom Mitchell
President & CEO — Date

3. SCOPE, BACKGROUND & ISSUES

3.1 Scope of Definition Phase

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

3.2 General Background

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

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

3.3 Background Issues and Opportunities

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

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

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

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

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

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

4. DEFINITION PHASE ALTERNATIVES AND PRELIMINARY ECONOMIC ANALYSIS

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

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

II. Delay Definition Phase for the Project: Not Recommended

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

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

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

Economics of Recommended Alternative:

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

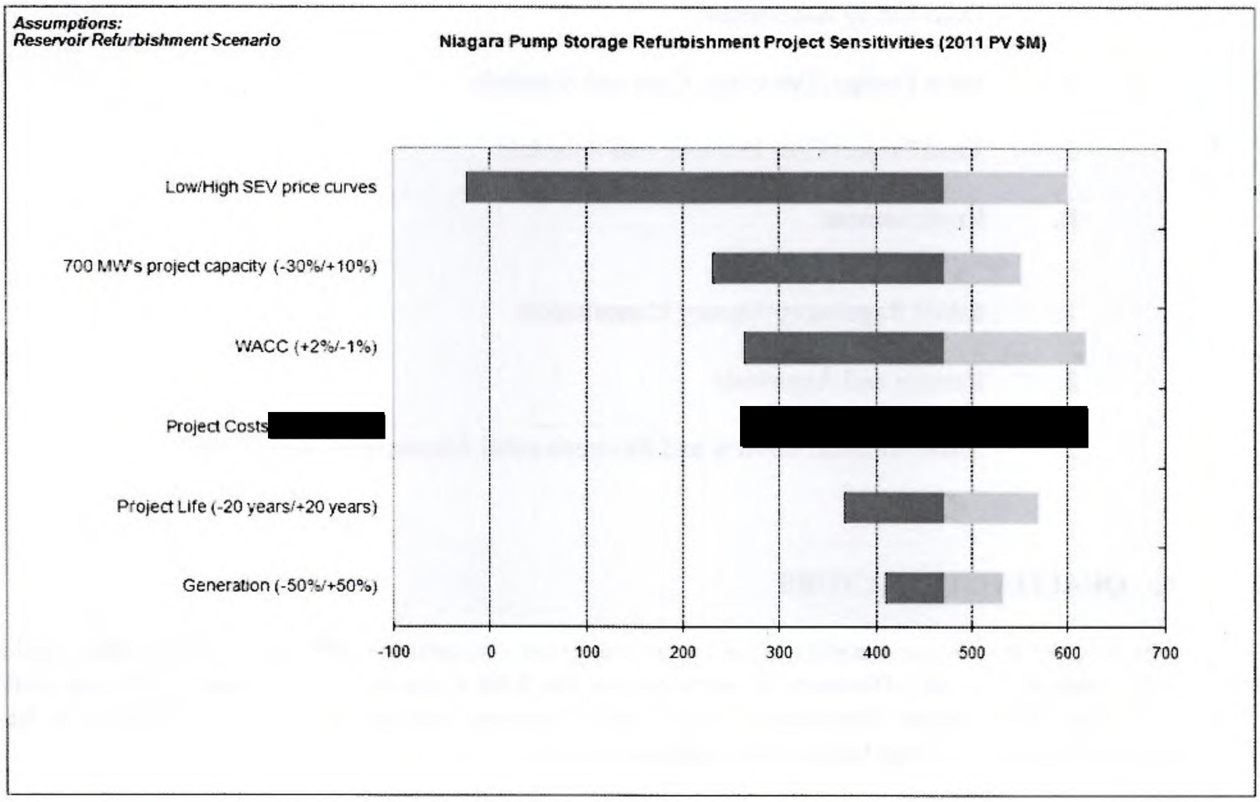
Net Present Value (NPV) calculations have used forecast market prices of electricity and System Economic Values for economic evaluation purposes. This demonstrates that the investment is beneficial to the electricity system.

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

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

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

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



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

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

5. THE PROPOSAL

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

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

A. Engineering

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

B. Environment

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

6. QUALITATIVE FACTORS

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

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

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

Refurbishment of SAB1 G1 and G2

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

Wind and Solar Integration

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

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

7. RISKS

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

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

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

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

The top risks are included in Appendix B.

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

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

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

APPENDIX A: Modeling Assumptions for Economic Analysis

Financial Model – Assumptions

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

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

Financial Assumptions:

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

Project Life Assumptions:

1. SAB PGS Reservoir life extended 50 years.

Energy Production Assumptions:

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

Operating Cost Assumptions:

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

Appendix B: Risk Register

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

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

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

Prepared by:

Mahir Aydin
Project Manager

Sept 13, 2011
Date

Approved by:

Tim Gigliotti
Project Director,

Sept. 13, 20
Date

SIR ADAM BECK 1 GS

G3 Upgrade - New Runner & Generator Rewind

Project Number: SAB10064

Niagara Plant Group

SCI #: NPG-08707.021-0001

SIR ADAM BECK 1 GS

G3 Upgrade - New Runner & Generator Rewind

SAB10064

1. RECOMMENDATION

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

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

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

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

Funding:

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

2. SIGNATURES

Submitted by:

19 JAN 11

Mike Martelli — Date
Plant Group Manager, Niagara Plant Group

Recommended by:

3 Feb 2011

John Murphy — Date
Executive Vice President - Hydro

Finance Approval:

Donn Hanbidge — Date
Senior Vice President and
Chief Financial Officer

Line Approval:

27 Feb 2011

Tom Mitchell — Date
President and CEO

3. BACKGROUND AND ISSUES

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

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

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

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

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

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

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

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

Business Objectives:

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

ALTERNATIVES & ECONOMIC ANALYSIS

Base Case (Do Nothing):

Do Nothing. ($0k Capital)

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

- **This alternative is not recommended.**

<u>Alternative 1</u>:

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

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

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

- **This is the recommended alternative**

<u>Alternative 2</u>:

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

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

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

- **This is not the recommended alternative**

Alternatives Considered But Rejected:

1. Minor Overhaul

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

2. Major Overhaul

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

Financial Analysis:

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

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

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

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

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

THE PROPOSAL

Results to be Delivered

Completing this project will result in the following:

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

Execution Phase Work Overview

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

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

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

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

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

Execution Phase Work Milestones

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

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

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

6. QUALITATIVE BENEFITS

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

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

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

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

7. RISK ANALYSIS

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

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

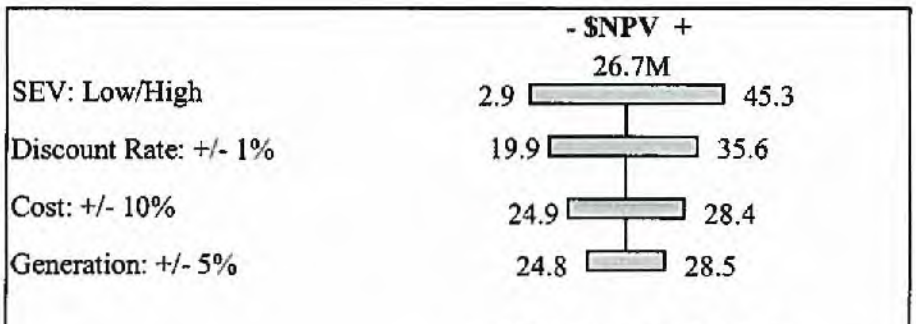
Graphical Representation of Risk using a Tornado Diagram:

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

SEV
Discount Rate
Capital Cost
Generation

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

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



TORNADO DIAGRAM

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

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

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

8. POST IMPLEMENTATION REVIEW

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

Type of PIR	Target Project In Service date	Target PIR Completion date
Simplified	2012	2013/2014

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

ONTARIO POWER GENERATION

HYDROELECTRIC
Summary of Estimate (k$)

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

Facility Name: Beck 1 GS

Project Title: G3 Upgrade, New Runner and Generator Rewind

Estimated Cost Distribution (k$)

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

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

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

Prepared by: Tobin Frost
Project Engineer

Approved by: Gord Allan
Gord Allan
Project Manager

APPENDIX 1

Assumptions

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

Project Cost Assumptions:

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

Financial Assumptions:

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

Project Life Assumptions:

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

Energy Production Assumptions:

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

Operating Cost Assumptions:

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

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

Niagara Plant Group Review:

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

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

Hydroelectric Generation Review

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

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

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

Corporate Finance Review

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

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

Recommended by:

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

Line Approval:

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

SIR ADAM BECK 1 GS UNIT 7

G7 GENERATOR FREQUENCY CONVERSION FROM 25HZ TO 60HZ

Project Number: SAB10032

Niagara Plant Group

SIR ADAM BECK 1 GS UNIT 7

G7 GENERATOR FREQUENCY CONVERSION FROM 25HZ TO 60HZ

SAB10032

RECOMMENDATION

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

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

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

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

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

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

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

2. SIGNATURES

Submitted by:

22 May 2007

John Murphy — Date
Executive Vice President - Hydro

Recommended by:

Aug 13/07

Pierre Charlebois — Date
Senior Vice President and
Chief Operating Officer

Finance approval:

Aug 17/07

Donn Hanbidge — Date
Senior Vice President and
Chief Financial Officer

Line Approval:

Jim Hankinson — Date
President and CEO

3. BACKGROUND AND ISSUES

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

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

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

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

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

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

4. ALTERNATIVES & ECONOMIC ANALYSIS

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

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

- **This alternative is not recommended.**

Alternative 1:

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

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

- **This is the recommended alternative**

Alternative 2:

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

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

- **This alternative is not recommended.**

Financial Analysis:

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

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

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

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

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

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

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

5. THE PROPOSAL

Results to be delivered:

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

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

Runner

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

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

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

Generator:

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

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

Transformer

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

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

Turbine Upgrade

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

Johnson Valve and Headgates

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

Other Major Items In Scope

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

A new exciter will be supplied for the new generator.

New switchgear will be supplied for the new generator.

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

Assessments by both Hydro One and the IESO are required prior to connecting new generation to the Ontario Grid. Agreements have been made with both parties, and funding provided in the developmental release to carry out the studies in order to maintain the project schedule.

Ongoing Operational and Maintenance Cost Impacts

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

Qualitative factors

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

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

Project management

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

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

Post Implementation Review (PIR)

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

The following unit performance parameters will be measured:

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

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

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

6. QUALITATIVE BENEFITS

Qualitative Factors & Sustainable Energy Development

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

7. RISK ANALYSIS

See Appendix 2 for Risk Management Table.

Cost Risk:

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

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

Assumed Benefits (Generation) Risk:

In order to determine the energy generation potential of G7, historic Niagara River flows were reviewed. The amount of water available at the plant for G7, incorporating water from the new Niagara Tunnel, was determined and the seasonal peak/ off-peak timing of this water was predicted. Historic water usage at the SAB Complex was extrapolated into the future and the amount of water available for G7 was determined. In order to optimize the water diversion, the Pump Generating station (PGS) was also optimized.

Schedule Risk:

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

Supply/ Procurement/ Quality Assurance Risk:

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

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

Graphical Representation of Risk using a Tornado Diagram:

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

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

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

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

- $M NPV +

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

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

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

ONTARIO POWER GENERATION

HYDROELECTRIC Summary of Estimate

Date March 14, 2007

Project # SAB10032

Facility Name: Beck 1 GS

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

Years (k$)	2007	2008	2009	TOTAL	%
Project Mgmt.	446	594	149	1,189	3.4
Engineering	300	400	130	830	2.4
Permanent Materials	[redacted]				
Construction/ Installation					
- Contractors	[redacted]				
Interest	307	1,298	433	2,038	5.8
Contingency	[redacted]				
TOTAL	7,900	23,364	3,946	35,210	100%

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

Prepared by:

Torben Frost

Torben Frost
Project Engineer

Approved by:

John Conlon

John Conlon
Project Manager

APPENDIX 1

Assumptions

Financial Model

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

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

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

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

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

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

APPENDIX 2

Risk Management Table for Full Project Release

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

Appendix 3

Major Component Cost Estimates

Unit Runner

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

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

New Generator

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

Replacement of the existing 25hz Transformer

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

Turbine Upgrade

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

Johnson Valves and Head Gates

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

Governor Control head

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

Electrical system and Connection to Hydro One

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

[redacted]

IESO System Impact Assessment and Hydro One Customer Impact Assessment

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

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

New Exciter

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

New unit Switchgear

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

Appendix 4

Impact of Tunnel Water on Generation with and without G7

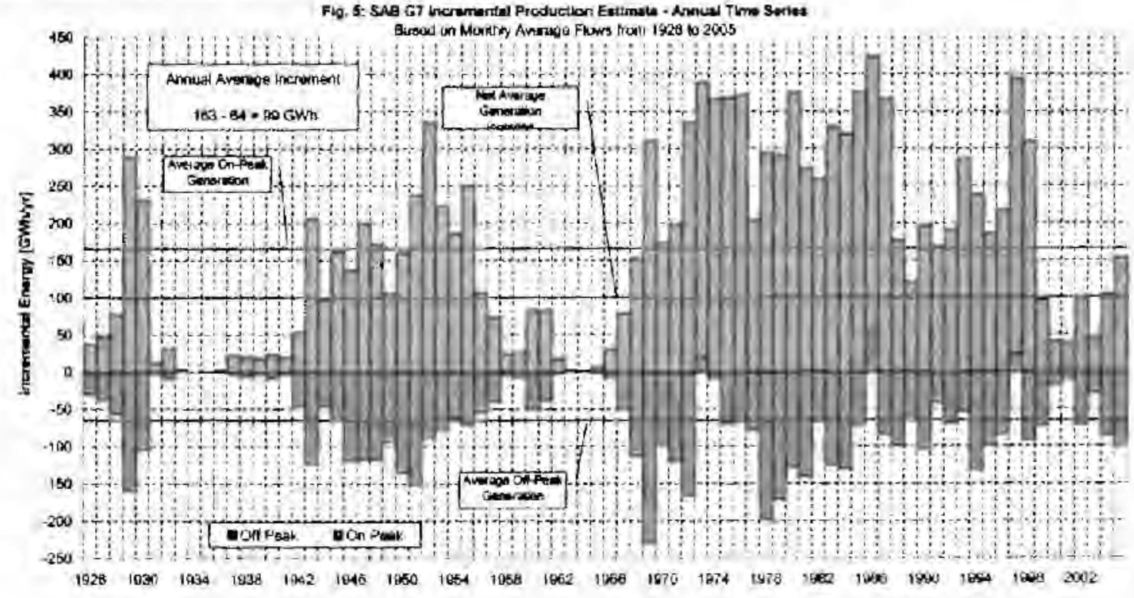
The Niagara Tunnel project assumed the Beck complex will increase its generation on average by 1.6 TWh as a result of increased water diversion. This generation is derived from additional water delivered and an increased ability to utilize PGS to pump. The additional generation would be generated by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

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

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

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

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



Appendix 5

Risk Mitigation Strategy for Queenston Flow West Transmission Limitation.

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

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

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

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

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

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

SIR ADAM BECK 1 GS

G9 REHABILITATION

Project Number: SAB10047

Niagara Plant Group

SIR ADAM BECK 1 GS

G9 REHABILITATION

SAB10047

1. RECOMMENDATION

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

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

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

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

2. SIGNATURES

Submitted by:

7 Aug 2008.

John Murphy — Date
Executive Vice President - Hydro

Recommended by:

Aug 11/08

Pierre Charlebois — Date
Executive Vice President and
Chief Operating Officer

Finance Approval:

August 10/08

Donn Hanbidge — Date
Senior Vice President and
Chief Financial Officer

Line Approval:

Aug 21/08

Jim Hankinson — Date
President and CEO

3. BACKGROUND AND ISSUES

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

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

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

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

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

4. ALTERNATIVES & ECONOMIC ANALYSIS

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

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

- **This alternative is not recommended.**

Alternative 1:

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

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

- **This is the recommended alternative**

The following options were considered and rejected:

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

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

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

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

Financial Analysis:

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

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

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

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

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

5. THE PROPOSAL

Results To Be Delivered:

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

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

Runner

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

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

Generator:

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

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

Transformer

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

Turbine Upgrade

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

Johnson Valve Liner

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

Other Major Items In Scope

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

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

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

Ongoing Operational and Maintenance Cost Impacts

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

Qualitative Factors

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

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

Project Management

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

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

Post Implementation Review (PIR)

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

The following unit performance parameters will be measured:

Turbine/ generator output: The Niagara Plant Group Production Department will verify that the generator output is 61.6 MW. Revenue metering equipment will be used to measure the output.

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

The Niagara Plant Group Project Department will review the project by comparing the planned cost and schedule milestones outlined in the Project Management Plan to the actual cost and schedule milestones.

6. QUALITATIVE BENEFITS

Qualitative Factors & Sustainable Energy Development:

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

7. RISK ANALYSIS

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

Cost Risk:

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

- The cost of the generator design/ supply/ install, the largest component of the project, is based on the purchase option obtained from GE Hydro at the time of the purchase of the SAB1 G7 generator. A defined escalation clause for labour and material will be applied to the G7 base cost. However, negotiations with Andritz VA Tech, the new owners of GE Hydro, for the purchase of the new generator have not been concluded.
- Preliminary price quotes have been obtained from the exciter, runner, transformer and Johnson valve liner suppliers in an effort to develop accurate cost estimates.
- Much of the work associated with the G9 project is similar to the work presently being undertaken on the G7 project. G9 project costs were developed with this knowledge.
- An overall contingency of [redacted] is included in the project cost estimate. The contingency has been determined by assessing the unique risk factors for each of the items in the estimate.

Schedule Risk:

- Discussions with Andritz VA Tech indicate that they will honour OPG's option to purchase a 61.6 MW generator similar to the SAB1 G7 generator currently being installed by GE. OPG has not concluded discussions with Andritz VA Tech regarding OPG's schedule for the installation of the generator. It is not known if the G9 generator can be slotted into the Andritz VA Tech manufacturing queue such that it can be manufactured and installed to meet the project schedule. If the Andritz VA Tech generator production plant is booked, the generator in-service date will be delayed.
- The project schedule is such that there may be numerous contractors on site at any given time, creating the possibility for interference. This concern will be managed by scheduling and coordinating site work appropriately.

Supply and Procurement Quality Assurance Risk:

- Supply Chain and Hydro Engineering will exercise due diligence and assess the capabilities of Andritz VA Tech prior to entering an agreement.
- Possible manufacture of runner and generator components overseas presents quality risks. Contracts for source surveillance will have to be put in to place. Inspection and test plans will be utilized to monitor the product quality throughout the manufacturing process.

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

Graphical Representation of Risk using a Tornado Diagram:

The project is considered to be sensitive to the following variables:
SEV (forecast market prices)
Discount Rate
Capital Cost
Generation

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

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

- $M NPV +

17.6 M

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

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

ONTARIO POWER GENERATION

HYDROELECTRIC Summary of Estimate

Date	July 15, 2008
Project #	SAB10047

Facility Name: Sir Adam Beck 1 GS

Project Title: G9 Rehabilitation

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

Notes:

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

2 Interest rate provided by Corporate Finance

3 Includes Removal Costs of: 1,100 k

4 Includes Definition Phase Costs of: 300 k

Prepared by:

Torben Frost
Project Engineer

Approved by:

John Conlon
Project Manager

APPENDIX 1

Assumptions

Financial Model

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

Project Cost Assumptions:

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

Financial Assumptions:

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

Project Life Assumptions:

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

Energy Production Assumptions:

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

Operating Cost Assumptions:

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

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

1. RECOMMENDATION

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

Total Investment Cost: $28M

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

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

2. SIGNATURES

Submitted by:

28 Jan 2008.
EVP - Hydro   date

Recommended by:

Feb 5/08
EVP & COO   date

Finance Approval:

Feb 1/08
SVP & Chief Financial Officer   date

Line Approval per OAR 1.1:

Feb. 11/08
President & CEO   date

3. BACKGROUND & ISSUES

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

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

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

4. ALTERNATIVES & ECONOMIC ANALYSIS

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

Base Case:
Do nothing – Replace upon failure

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

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

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

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

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

Alternative 2: (5 Transformers)

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

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

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

Alternative 3: (13 Transformers)

Replace with Single Phase – Air Cooled

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

This is the recommended alternative.

Other alternatives considered but discounted

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

Financial Analysis

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

5. THE PROPOSAL

Results to be delivered

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

Project Management

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

Project Execution Outage Schedule

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

6. QUALITATIVE FACTORS

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

7. RISK ANALYSIS

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

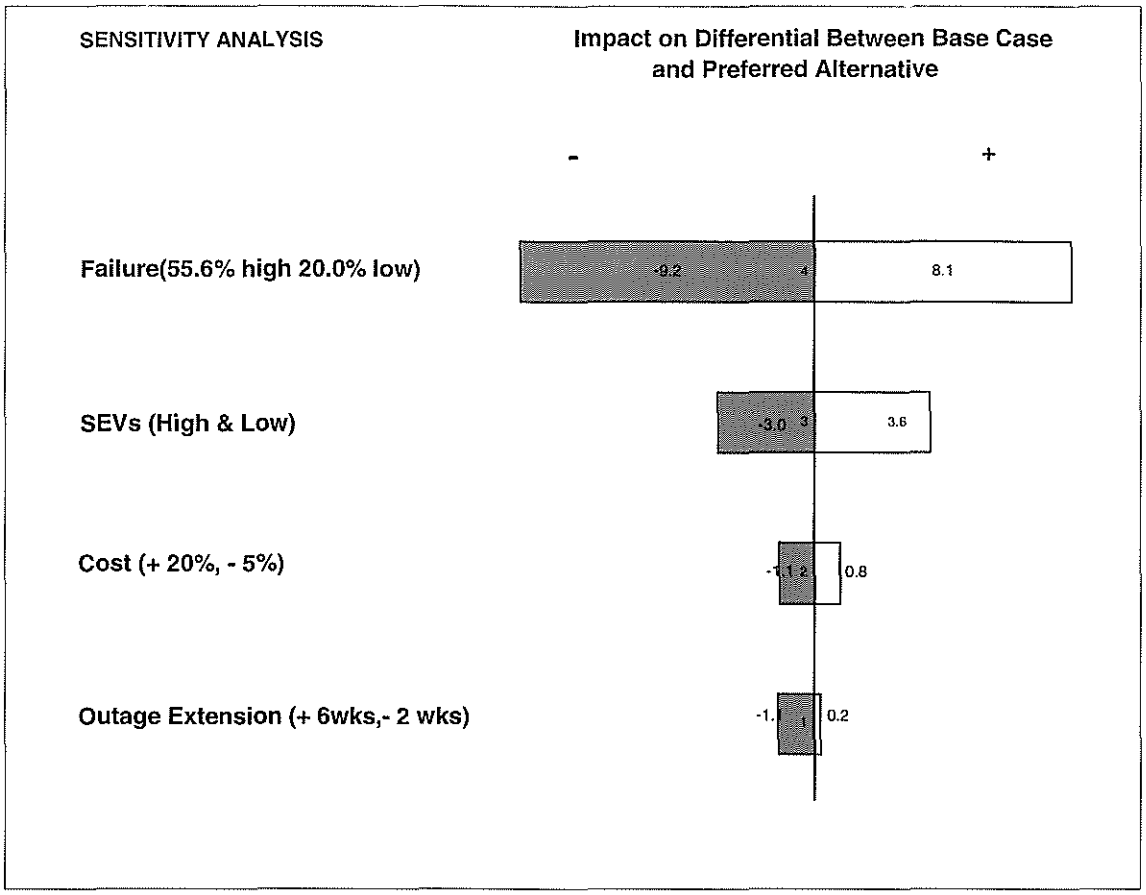
will not meet expected performance or reliability standards. 2. Insufficient scope of work.	2. Future outages required to complete additional scope items.	2. M	the Transformer specification. Technical data and standards will be measured during factory acceptance and in-service testing. 2. Numerous Stakeholder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

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

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

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

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



8. POST IMPLEMENTATION REVIEWS

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

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

ONTARIO POWER GENERATION

HYDROELECTRIC
Summary of Estimate CAPITAL

Date	Dec. 2007
Project #	DESJ0031

Facility name: Des Joachims GS

Project Title: Replace Main Output Transformers

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

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

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

BUSINESS CASE SUMMARY

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

1. RECOMMENDATION

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

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

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

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

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

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

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

2. SIGNATURES

Submitted by:

Apr 26/06
Plant Group Manager – OSPG date

Recommended by:

May 3/06
EVP – Hydro date

Finance Approval:

SVP & Chief Financial Officer date

Line Approval per OAR 1.1.2:

May 13/06.
President & CEO date

3. BACKGROUND & ISSUES

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

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

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

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

4. ALTERNATIVES & ECONOMIC ANALYSIS

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

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

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

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

Financial Analysis

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

5. THE PROPOSAL

Results to be delivered

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

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

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

Project Management

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

6. QUALITATIVE FACTORS

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

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

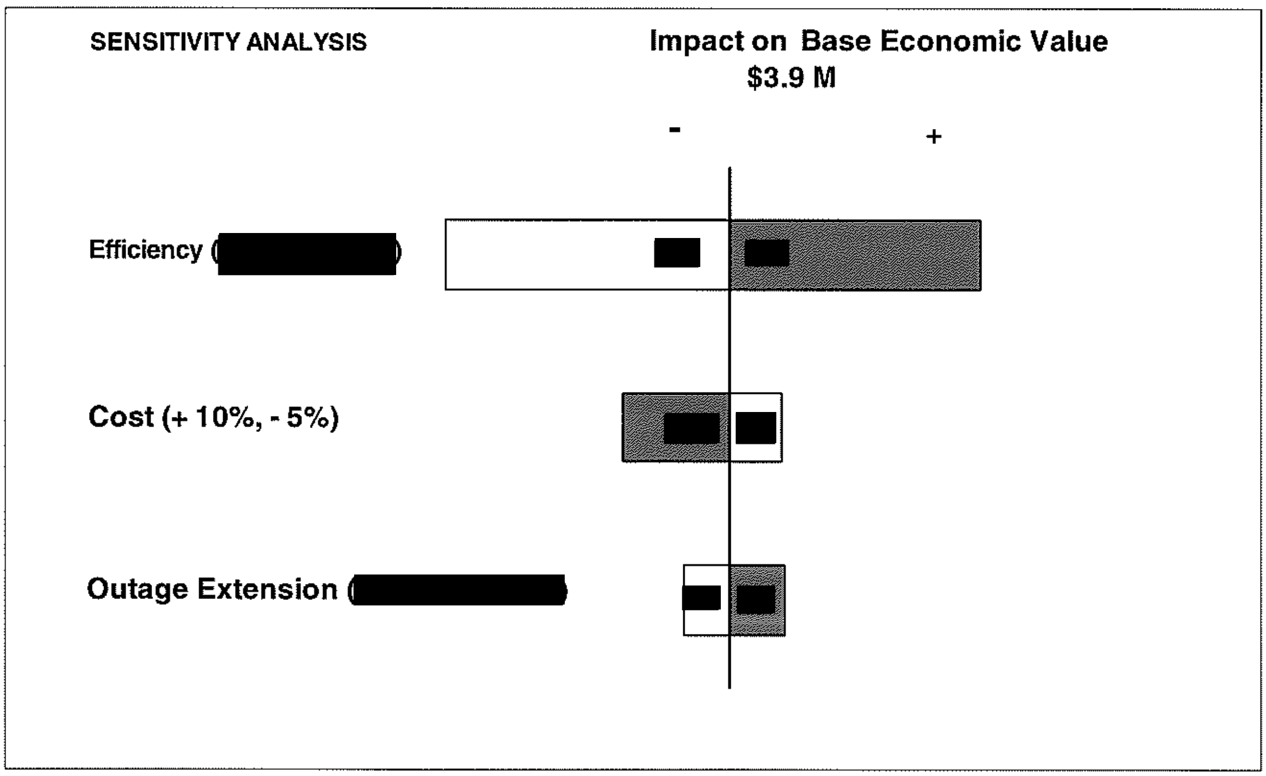
7. RISK ANALYSIS

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

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

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

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



8. POST IMPLEMENTATION PLAN:

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

ONTARIO POWER GENERATION

HYDROELECTRIC Summary of Estimate

Date	April 2006
Project #	**DESJ 0016**

Facility name: Des Joachims Generating Station

Project Title: Turbine Runners – Replace runners

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

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

Prepared by: R. Gorell	Approved by: [signature]
Project Engineer Ron Gorell	Project Manager
Date: April 11/06	Date: April 25/06

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

1. RECOMMENDATION

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

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

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

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

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

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

2. SIGNATURES

Submitted by:

15 Oct 2008
EVP - Hydro — date

Recommended by:

Dec 3/08
EVP & COO — date

Finance Approval by:

Nov /08
SVP & CFO — date

Approved by:

Dec 4/08
President & CEO — date

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

3. BACKGROUND & ISSUES

Plant:

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

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

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

Issues:

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

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

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

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

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

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

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

4. ALTERNATIVES & ECONOMIC ANALYSIS

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

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

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

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

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

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

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

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

This is the recommended alternative.

Financial Analysis

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

5. THE PROPOSAL

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

Year 2009

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

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

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

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

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

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

6. QUALITATIVE FACTORS

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

7. RISK ANALYSIS

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

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

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

8. POST IMPLEMENTATION REVIEWS

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

ONTARIO POWER GENERATION

HYDROELECTRIC
Summary of Estimate - Capital

Date	September 10, 2008
Project #	OTTO0021

Facility name: Otto Holden G.S.

Project Title: Replace Sluicegates & Rehabilitate Sluicegates System

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

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

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

3 Includes removal costs of: $457k

4 Includes Definition Phase Cost of: $194k

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

ONTARIOPOWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0075-R003*

Type 2 Business Case Summary

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

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

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

Business Need:

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

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

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

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

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

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

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

Base Case: Status Quo – No Project

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

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

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

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

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

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

Alternative 4: Refurbish headgates and rehabilitate gains and hoists

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

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

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

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

Part B: Project Cash Flows

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

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

Additional Information on Project Cash Flows (optional):

Part C: Financial Evaluation

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

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

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

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

Part E: Post Implementation Review (PIR) Plan				
Type of PIR		Target Project In Service Date	Target PIR Completion Date	
Simplified		2014-10-31	2014-12-31	
Measurable Parameter	**Current Baseline**	**Target Result**	**How will it be measured?**	**Who will measure it? (person/group)**
Improve headgate performance for emergency closure and maintenance isolation when dewatering the unit. Reduced leakage on first unit completed.	Current leakage has not been measured but was observed (visually) in the investigation and described as significant.	Leakage reduced as per requirements listed in the technical specification.	Leakage will be measured during commissioning and established as a new baseline.	Production, Project Management
Develop firm scope of work and costs for remaining units.	Current scope and costs based on estimates from vendor for replacement and assumed condition of embedded components.	Firm scope and execution phase costs estimates for remaining units.	Updated Project Scope documented in the Full Execution Phase Release Project Charter. Release Quality Estimate developed based on revised scope.	Asset Management & Technical Services - Programming
Scope	The scope for this Partial Release is outlined in the Project Definition Charter	Execute scope detailed in Project Charter.	Project officer to confirm the approved scope was completed as per the Charter.	Asset Management & Technical Services - Programming
Cost	The cost estimates for this phase of the project are included in the cash flow table of this BCS.	Execute the scope within the approved funding.	Actual costs to be compared to approved funds in this release.	Asset Management & Technical Services - Programming

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

ONTARIO POWER GENERATION

Project Summary of Estimate

Date: August 29, 2012

Project #: OTTO0039

Facility name: Otto Holden GS

Project Title: Replace Headgates and Rehabilitate Gains

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

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

Notes: 1 Schedule: Start Date: October 2012

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

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

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

4 Includes Removal Costs of: $150k

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

Ranney Falls GS G3 Project (Project Number HDEV0024)

1 Recommendation

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

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

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

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

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

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

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

2 Signatures

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

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

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

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

3 Background and Issues

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

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

3.1 Description of Existing Ranney Falls Generating Station

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

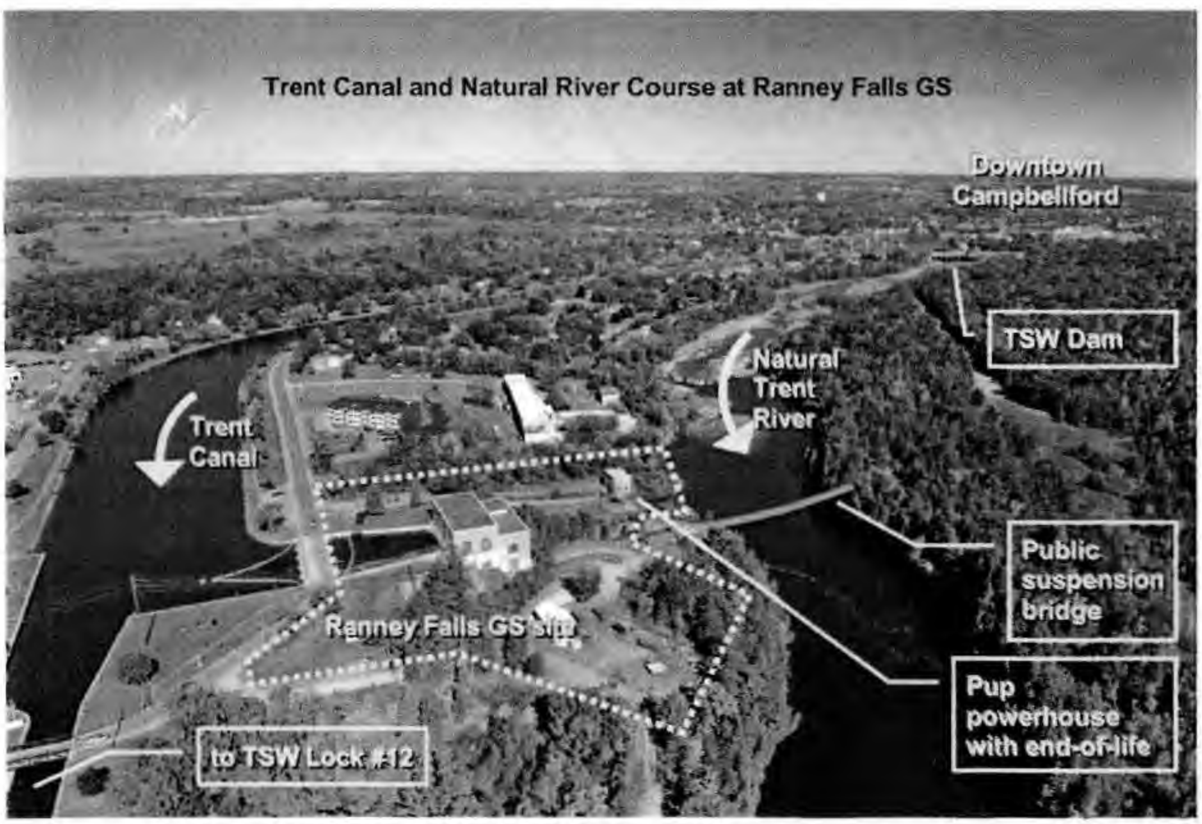


Figure 3-1 Existing Ranney Falls Generating Station – Aerial View

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

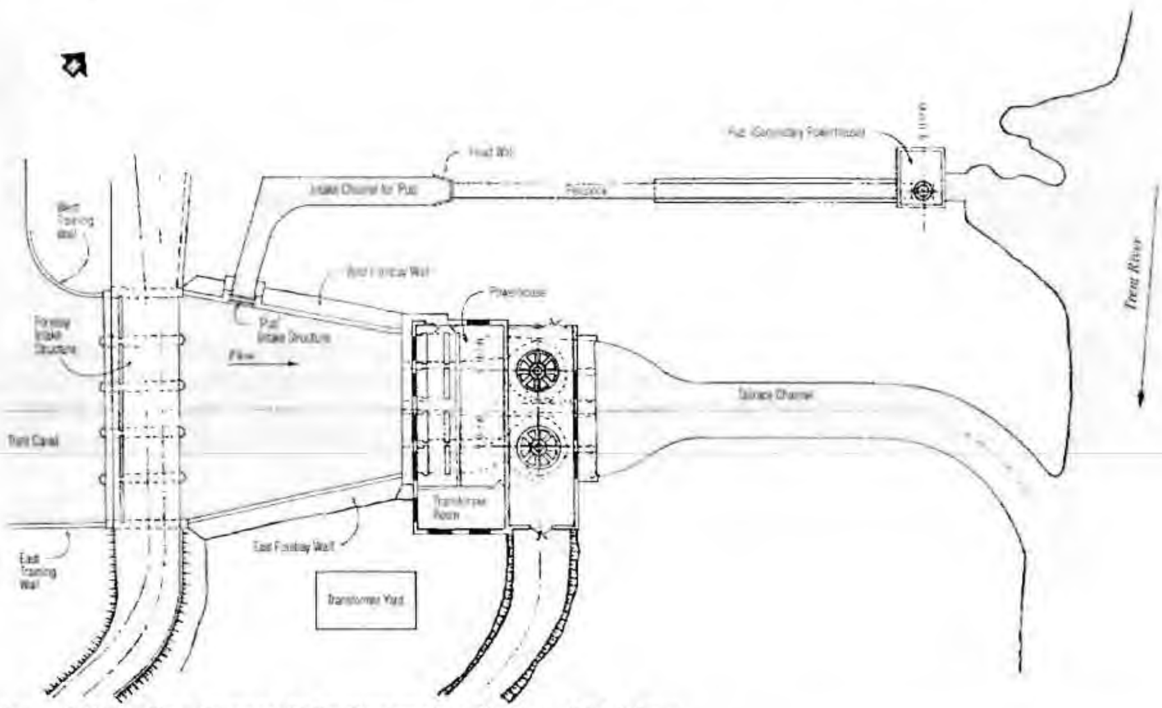


Figure 3-2 Existing Ranney Falls Generating Station - Plan View

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

3.2 First Concept Study by KST Hydroelectric Engineers

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

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

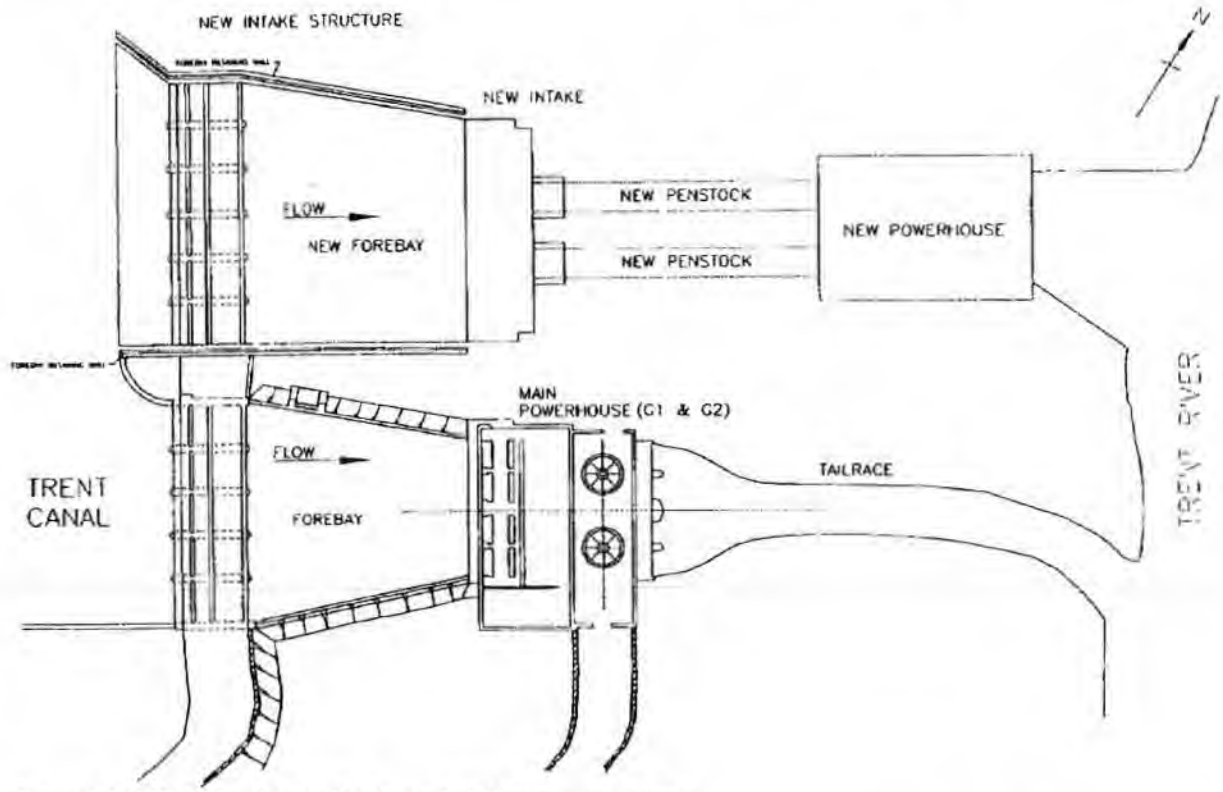


Figure 3-3 KST Hydroelectric Engineers' 1992 recommendation

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

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

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

3.3 Second Concept Study by Hatch Acres International

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

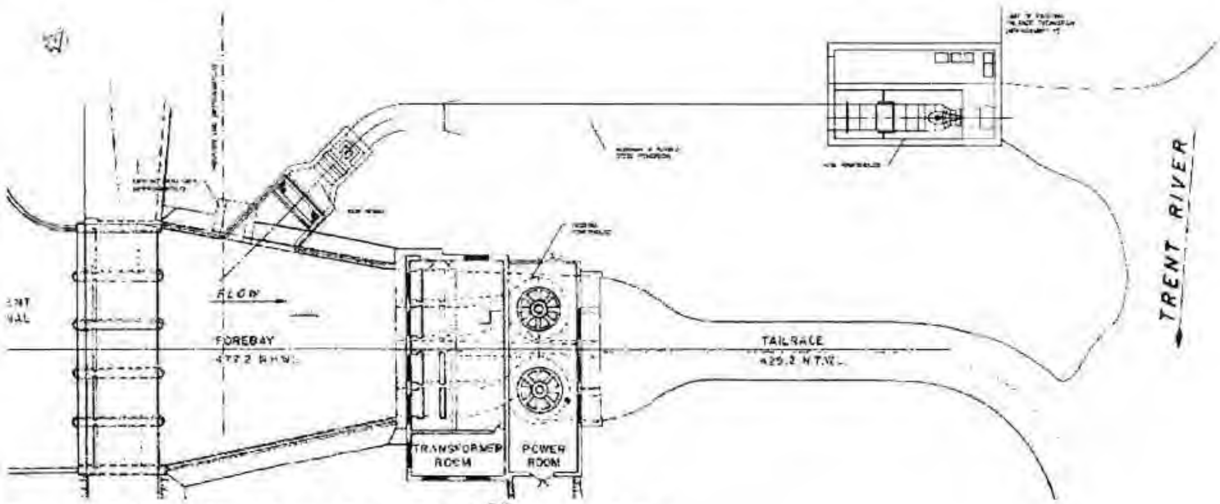


Figure 3-4 Hatch Acres International's 2006 recommendation

3.4 Third Concept Study by OPG Hydro Engineering

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

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

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

The differences between the three schemes are described as follows:

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

4 Alternatives and Economic Analysis

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

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

Table 4-1 Economic and sensitivity analysis

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

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

4.1 Alternative 1: Status Quo

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

4.1.1 Lost Opportunity

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

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

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

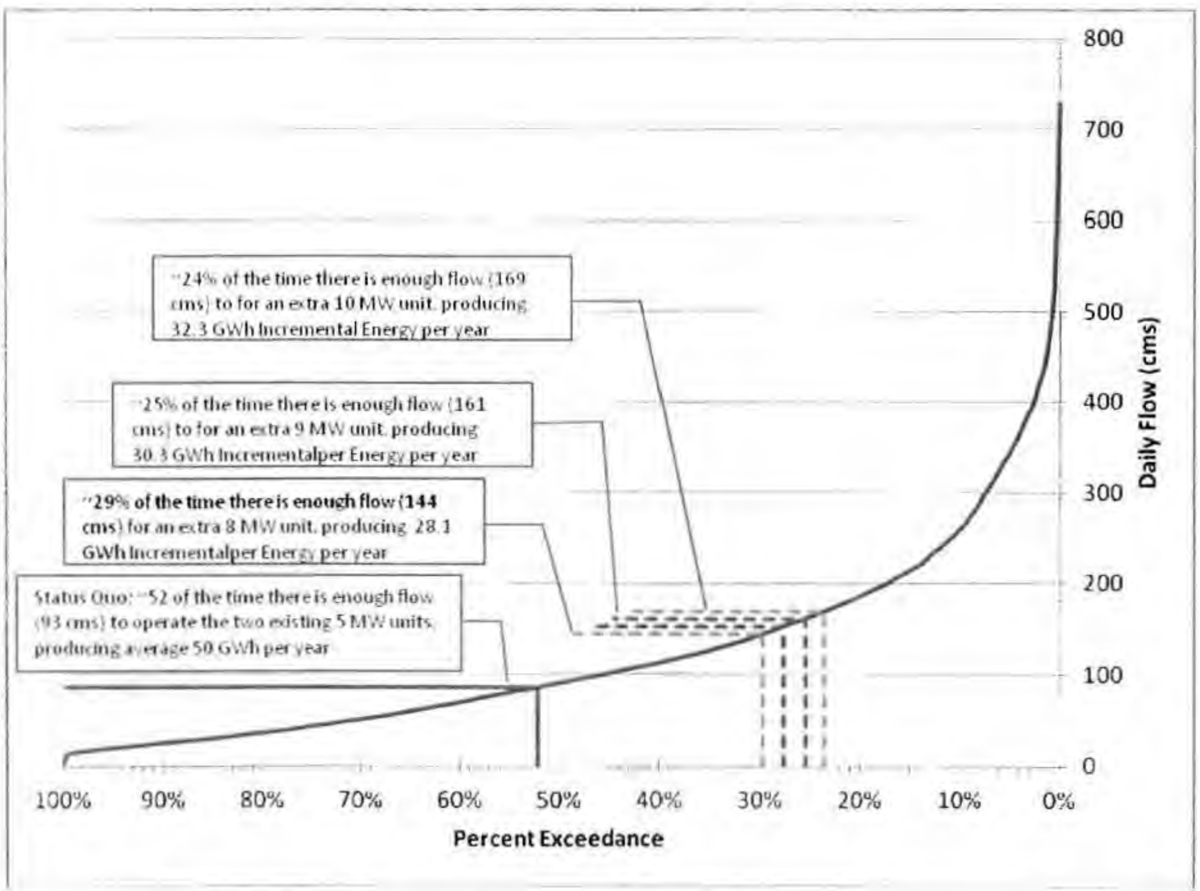


Figure 4-1 Comparison of Unit Size and Incremental Energy

4.1.2 Continued Exposure to Flooding Risk

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

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

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

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

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

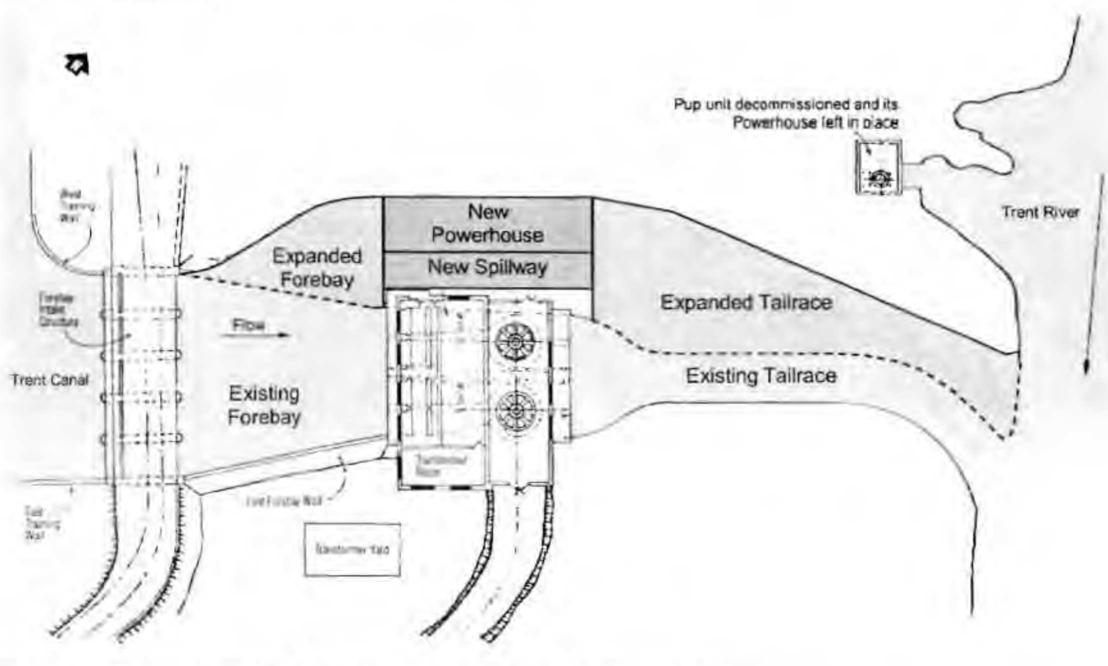


Figure 4-2 Ranney Falls G3 Project with no penstock and long tailrace

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

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

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

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

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

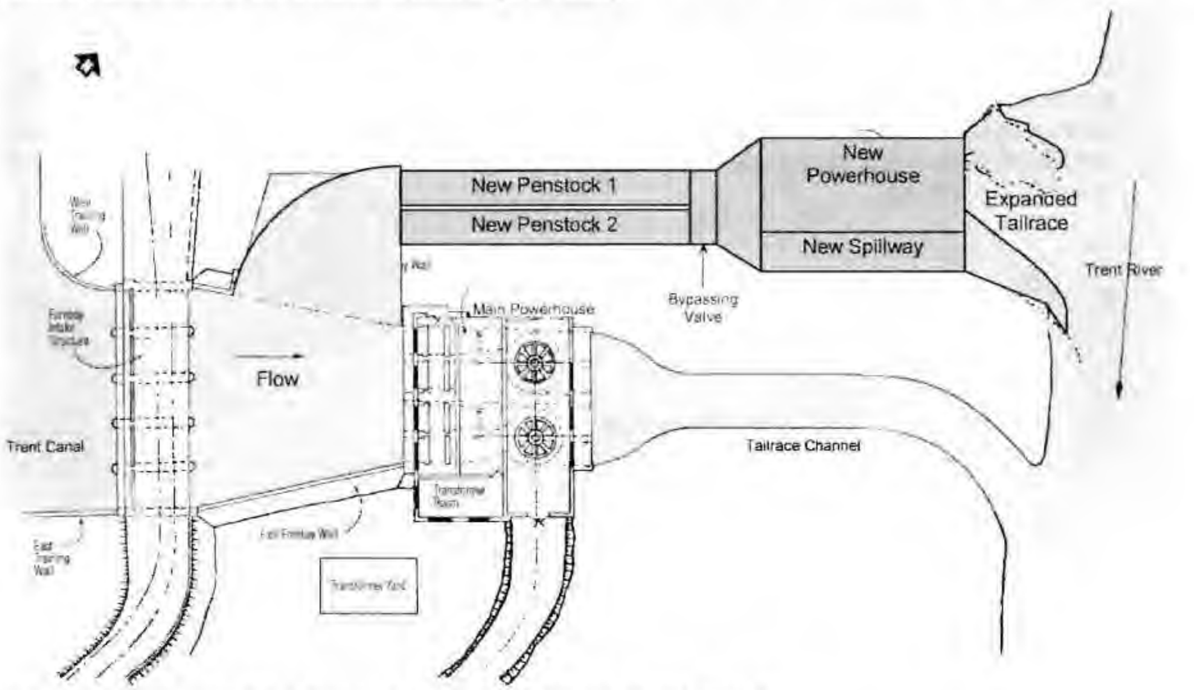


Figure 4-3 Ranney Falls G3 Proposal with penstocks and short tailrace

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

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

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

5 The Proposal

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

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

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

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

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

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

6 Qualitative Factors

The Preferred Alternative will:

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

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

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

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

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

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

- Enables OPG to meet its mandate from the Government of Ontario to expand hydroelectric generation on existing sites. This Project also aligns with OPA direction as an opportunity to redevelop existing infrastructure for longer term.

- Have limited environmental impact as the Project does not involve new inundation that is often seen in other hydroelectric development projects. In-stream construction is limited in scope and poses minimal concerns that will be fully addressed by the project. A coordinated federal-provincial environmental assessment will be completed. The Project requires only screening level assessments..

- Boost local economic activity during construction. About hundred man-year jobs are expected to be created during the three year duration of this project.

- Have limited Employee/Public Safety risks with any potential risks being assessed and addressed through a site and project-specific Public Safety Risk Assessment and Action Plan.

7 Risks

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

Table 7-1 Summary of Risks

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

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

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

8 Post Implementation Review (PIR) Plan

Type of PIR: Simplified

Target Project In-Service Date: Q4, 2015

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

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

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

9 Appendix B – Glossary

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

10 Appendix C – Cost Variances from Business Plan

	2010 & prior	2011	2012	2013	2014	2015	2016 & beyond	Total
Previously Released	**584**	**873**						**1,457**
Spent Life-to-Date (up to month-end August, 2011)	584	700						1,284
Remaining to Spend		173						173
Previously Released	584	873						1,457
Request Now			3,839	2,262				6,101
Future Request				21,160	14,039	5,900		41,099
Superseding Release								
Revised Project Total	**584**	**873**	**3,839**	**23,422**	**14,039**	**5,900**		**48,657**
OM&A	584	873						1,457
Capital			3,839	23,422	14,039	5,900		47,200
Revised Project Total	**584**	**873**	**3,839**	**23,422**	**14,039**	**5,900**		**48,657**

11 APPENDIX D – Summary of Estimate for Definition Phase

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

12 APPENDIX E – Financial Analysis and Assumptions

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 sp]are parts could be identified. Project costs in both cases were also consistent with our current estimates, [how]ever 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 Sustaining		Class Capital		NPV or IEV		IRR		Discounted Payback	

Submitted By:

15 Dec 2006

M. Arnone — Date:
Director, Projects and Modifications

Finance Approval:

Dec 14, 2006

R. Leavitt — Date:
Director Investment Management

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

15 Dec 2006

S. Seedhouse — Date:
Director, Station Engineering

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 to 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.

[illegible]milar problems were encountered with the Darlington Emergency Power Generators (EPGs) and the Pickering B [illegible]s. In both cases the control systems were completely replaced (Ref D-PIR-49200-10001 and NK30-BCS-[illegible]4600-00011-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	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:

ONTARIOPOWER GENERATION

BUSINESS CASE SUMMARY

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	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
Contract - Software & HFE	[redacted]								
	[redacted]								
	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Spending	[redacted]								
Committed Cost	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
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:

ONTARIOPOWER GENERATION

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	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Spending	[redacted]				-
Committed Cost	[redacted]				
Project Costs (excl contingency)	[redacted]				-
General Contingency	[redacted]				
Specific Contingency	[redacted]				
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

ONTARIOPOWER GENERATION

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 ([redacted] 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 ~~19 May 2006.~~ 2 Jun 2006.

$000's Capital		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Full (Phase 1)	6,060	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:		[redacted]
IRR:			N/A	Contingency % on Remaining Release:		

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 modem 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 modem 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 modem 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
[illegible]				
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.!	**Medium**
[illegible]				
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**
[illegible]				
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**
[illegible]				
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**

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resources familiar with annunciation.			if necessary.	
[illegible]				
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
[illegible]				
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**
[illegible]				
No risks identified.				
[illegible]				
No risks identified.				
[illegible]				
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**

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Attachment 1 Tab 4

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

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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	[illegible]	5,560	4,133	4,261	3,214	492		22,034
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)	2,234	[illegible]	308			-	[illegible]

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 11/06
Date:

Approved By:

R Hohendorf
Eng & Mods Manager (Strat IV)
May 12, 2006
Date:

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ENGINEERING & MODIFICATIONS BUSINESS CASE SUMMARY	

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				
Contract - Design				
Contract - Installation				
Contract - Other				
Interest (Capital Project Only)				
Sub Total (excl Contingency)				
Contingency				
Grand Total	14,819	22,058	7,238	

Weld Overlay Project 10 - 62568 Capital 10 - 62435 OM&A
Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

1/ RECOMMENDATION:

Approval is requested for the Full Release of $53.2M Capital (including contingency) and $[redacted] OM&A (specific contingency) to proceed with the next stage of the Weld Overlay Project which will design and manufacture weld overlay tooling for those Darlington outlet feeders that are life-limited by pipe wall thinning caused by Flow Accelerated Corrosion (FAC). This brings the total costs to $71M.

The business objective of this project is to reduce the cost of managing life-limiting feeder thinning by developing a repair alternative to the current exclusive use of Cut and Weld tooling for replacing thinned feeders. It is estimated that using weld overlay repair technology in conjunction with Cut & Weld tooling (as necessary), will provide a financial benefit in the range of approximately $38M - $143M (NPV) with a 19% – 45% IRR. (See Alternative Section for details). This estimate is based primarily on the assumptions:

- Less overall time required to repair a feeder during a Darlington outage
- Lower execution costs per feeder repair

To date, there has been four partial releases for Weld Overlay under project # 62435 (OM&A): $1.5M in 2005-2006 for the Definition stage (Proof-of-Concept); $700K in 2006-2007 for the Pre-Tool Development phase, $3.7M in 2007 for Stage I (Preliminary Design of Tool and process) and; $10.6M in 2008 to complete Stage I which is in progress. The project is currently managing Stage I Preliminary Design contracts with two separate vendors in an effort to maximize the probability of project success.

A 2011 Darlington Spring Outage In-service date for this process and tool significantly increases its economic benefits, which necessitates seamless transition into Stage II of the Weld Overlay Project. For this reason, this request for Capital funding approval is being made prior to the completion of Stage I, and prior to estimates being provided by the vendors. The budgetary estimates included in this request are based on costing experience with the similar Cut and Weld tooling, and are considered conservative. Also, a large amount of contingency has been assigned in this BCS to account for the uncertainty.

At the end of Stage I, a revised BCS will be prepared with updated project costs within the value of this release request, and updated risks to reflect the work completed in Stage I. The project team will present the technical and business case as a formal recommendation in a decision meeting, chaired by the CNE (see Attachment D). This revised BCS will be presented for signature during this decision meeting with the CNE, and follow up meetings with the CNO, COO, and CEO. If approved, only the value in the revised BCS will be released. At this time, outage savings will be quantified for 2010 - 2014 business planning - P.Hodgkin.

1000's (incl contingency)	Funding	Type	LTD 2008	2009	2010	2011	2012	Later	Total
Currently Released	Partial	OM&A	3,647	12,887					16,534
		Capital							-
Requested Now	Full	OM&A			1,000				1,000
		Capital		5,050	45,060	3,084			53,194
Future Funding Req'd	N/A	OM&A							-
		Capital							-
Total Project Costs			3,647	17,937	46,060	3,084	-	-	70,728
Other Costs									-
Ongoing Costs									-
Grand Total			3,647	17,937	46,060	3,084	-	-	70,728

Investment Type	Class	NPV	IRR	Discounted Payback
Value Enhancing	Capital & OM&A	38M - 143.4M	19% - 45.5%	5 - 3 Years

Submitted By:

T. Mitchell
Chief Nuclear Officer
Date:

Finance Approval:

D. Hanbidge
S.V.P. & Chief Financial Officer
Date:

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

J. Hankinson
President & Chief Executive Officer
Date: May 15/09

2/ BACKGROUND & ISSUES

Degradation of primary heat transport system feeders by flow-accelerated corrosion (FAC) is a significant life-limiting threat to OPG Nuclear plants. Cut and weld methods currently used for replacement of thinned feeder sections requires a number of preparatory activities (including channel defuelling, isolation and draining) that cannot be completed in parallel. As the number of feeders to be replaced increases, the time required to complete the repairs has a more significant impact on the duration of planned outages.

Another approach to feeder repair is to build up the feeder wall thickness by weld overlay, which deposits a layer of weld metal on the exterior of the pipe work. Advantages of this method include elimination of the need to defuel and drain the channel, a potential reduction in the time required for repairing each feeder, as well as an anticipated reduction in worker radiation dose and the amount of loose contamination and radioactive waste produced.

Weld overlay is a demonstrated technology that has been used successfully in both nuclear and non-nuclear repair applications. This current proposed application of the technology is considered a first of a kind due to the specific conditions of the repair. These include, that it is to be performed on thin wall, carbon-steel nuclear class 1 piping with specific material property requirements; it is to be applied with very tight clearances making tooling design difficult, and the pipe will be full of water during the application. In the original proof of concept study, weld overlay was demonstrated as being feasible for these specific conditions, however residual technical risks were identified. These risks include material properties (hydrogen, hardness, and residual stress), and miniaturization of the tooling.

During Stage I Preliminary Engineering (currently in-progress), the residual risks identified during the proof of concept work are being addressed. Weld processes are being developed to enhance favourable material properties, inspection techniques are being developed for pre and post overlay requirements, and a conceptual tool design will be provided based on tooling requirements and available clearances at the feeder hub to pipe weld area. Two vendors are currently contracted in competitive, parallel efforts to successfully complete Stage I in order to maximize the probability of project success.

A 2011 Darlington Spring Outage in-service date for this process and tool significantly increases its economic benefits, which necessitates a seamless transition into Stage II of the Weld Overlay Project. For this reason, this request for Capital funding approval is being made prior to the completion of Stage I, and prior to estimates being provided by the vendors. The budgetary estimates provided in this request are based on costing experience with the similar Cut and Weld tooling, and are considered conservative. Also, a [redacted]% contingency has been assigned in this BCS to account for the uncertainty.

At the conclusion of Stage I, an updated economic analysis and revised BCS will be prepared using vendor provided budgetary estimates for Stage II, and a formal decision meeting will be held to determine whether to recommend proceeding with weld overlay tool detailed design and manufacture. The basis for the decision meeting may be found in Attachment D. If a recommendation to proceed is decided, a second decision meeting will be held with the CNO to present the case and obtain his acceptance. The CNO will then take the recommendation to the COO and then to the President for approval and final release.

The Weld Overlay Project is being executed in two stages as detailed in the table below. This staged funding release and execution is being used to minimize the financial risk, and provide adequate assurance that the repair technique and tooling is technically acceptable.

Stage 1 (OM&A) consists of: Proof of Concept (complete); Pre-Tool Development (complete); and Preliminary Engineering (in progress). To date, the concept of weld overlay has been demonstrated as a feasible repair technology and residual technical risks have been identified. The Preliminary Engineering phase will resolve the technical risks which involve primarily material property issues, and will provide a conceptual tool design.

Stage 2 (Capital) consists of three distinct phases: Detailed Design & Prototype Fabrication; Fabrication & Mock Up Testing; and Commissioning. At the end of this stage of the project, the tool sets will be declared as Available For Service, Regulatory approval will have been granted, and multiple tool sets ([redacted] currently projected) will be available for use at Darlington.

ONTARIOPOWER GENERATION

BUSINESS CASE SUMMARY

Stage / Cost Type	Phase	Cost Area	Cost Item	Estimated Cost (K$ CND) Includes Contingency							
				2005	2006	2007	2008	2009	2010	2011	Total
1 OM&A	1	Proof-Of-Concept	Develop Concept and identify major risks	1,275	145						1,420
		Pre-Tool Development	Development of tool requirements		260	370					630
		Preliminary Engineering (Currently in Progress)	Material Property Issue Resolution, Preliminary Design - Tool / Process			127	1,470	12,887	.		14,484
2 Capital	2	Detailed Design & Prototype Fabrication	Tool Development & Commissioning								
	3	Fabrication & Mock Up Testing						[redacted]	[redacted]	[redacted]	[redacted]
	4	Commissioning									
2 OM&A	(OM&A Specific Contingency)								[redacted]	[redacted]	[redacted]
				1,275	405	497	1,470	17,937	46,060	3,084	70,728

A total of $53.2M Capital (including contingency) and $[redacted]M OM&A (specific contingency) is requested to perform Stage II of the Weld Overlay project. This release request Includes a $[redacted]M specific contingency to cover uncertainties regarding applicability of PST which is dependent on Tool ownership (title) by OPG or entry of a non-OPG owned tool into Ontario which may be built in the USA. Applicability of PST will not be known until the successful completion of Stage I; therefore, [redacted]% of tool development costs have been reserved in a specific contingency. This funding will only be released if PST is required.

This release request also includes a specific contingency of $[redacted]M OM&A to deal with uncertainties regarding on-reactor commissioning in 2010. If the feeder is repaired and left in-service, it is Project OM&A; if it is repaired and cut out it is Project Capital. At this point in the project, it has not been decided whether the feeder will be left in service or cut out.

This full release business case summary and the associated economic analysis ("Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002", N-REP-30751-10007) considers only the weld overlay candidates at Darlington based on the latest feeder replacement schedule. The analysis assumes that weld overlay repair will be performed on the feeder repair candidates from 2011 onward.

Since the original Economic Analysis assessment in 2007, the 6 probe inspection results at Darlington have shown an increased number of feeders that have life limiting thinning in the Grayloc area (as projected in N-BCS-30751-100000-R000) which considerably strengthens the economic viability of this project with the additional funding requested. As well, 6 probe inspections for all Darlington units are not yet complete and may reveal additional life limited thinned feeders.

This project includes only the costs associated with developing, delivering and commissioning the Weld Overlay tooling. Weld Overlay field application costs will be addressed outside this project; however, these projected (listing estimates) costs have been included in the NPV calculations.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

The economic benefit of introducing weld overlay tooling is presented in this BCS as a potential NPV range. This approach was taken for the following reason:

The actual number of feeders scheduled for repair in any given outage (until Unit end-of-life) can vary because of new inspection results and emergent repair requirements. There are currently two methods used for determining feeder repair candidates (Reference NK38-CALC-33160-10044):

1. **Current Assessment:** The current case provides the remaining life of feeders with the current assessed wall thinning rates as determined by the *rate from initial* methodology for feeders limited adjacent to the Grayloc weld. It is commonly assumed that the feeder pipe adjacent to the Grayloc weld began life at a wall thickness lower than that of nominal pipe thickness. Thus, the methodology is assumed to provide conservative estimates of the wall thinning rate.
2. **Risk Informed:** The risk informed method incorporates all the information that is available for each feeder. As described, the formal feeder thinning assessment utilizes a single thinning rate to ensure conservatism in estimating remaining life. However, for replacement planning purposes it is recognized that over conservatism puts a strain on long term planning practices.

The Risk Informed method allows for a more realistic approach to determining which feeders require replacement, however, by reducing some of the conservatism, there is an inherent risk of under estimating thinning rates, which could result in emergent replacements. Because of this risk, and the risk of emergent replacement requirements coming from future inspections, two (2) separate economic analyses were conducted, using a set of feeder repair candidates derived from each estimating method. The result of each analysis (NPVs) represents the potential range of economic benefits/losses of introducing weld overlay tooling.

Risk Informed Scenario

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay Project (1 Year)	Alt 3	Alt 4	Alt 5
Revenue	(265,956)	(145,853)	(145,853)	(157,929)			
OM&A	(170,802)	(125,618)	(121,971)	(126,299)			
Capital	0	(51,205)	(51,205)	(51,205)			
Present Value (PV)	(201,308)	(165,731)	(163,233)	(170,893)			
Net Present Value (NPV)	**N/A**	**35,576**	**38,074**	**30,414**			
Internal Rate of Return (IRR) %	N/A	17.7%	19.1%	17.7%			
Discounted Payback (Yrs)	N/A	8.2	8.1	8.3			

Current Assessment Scenario

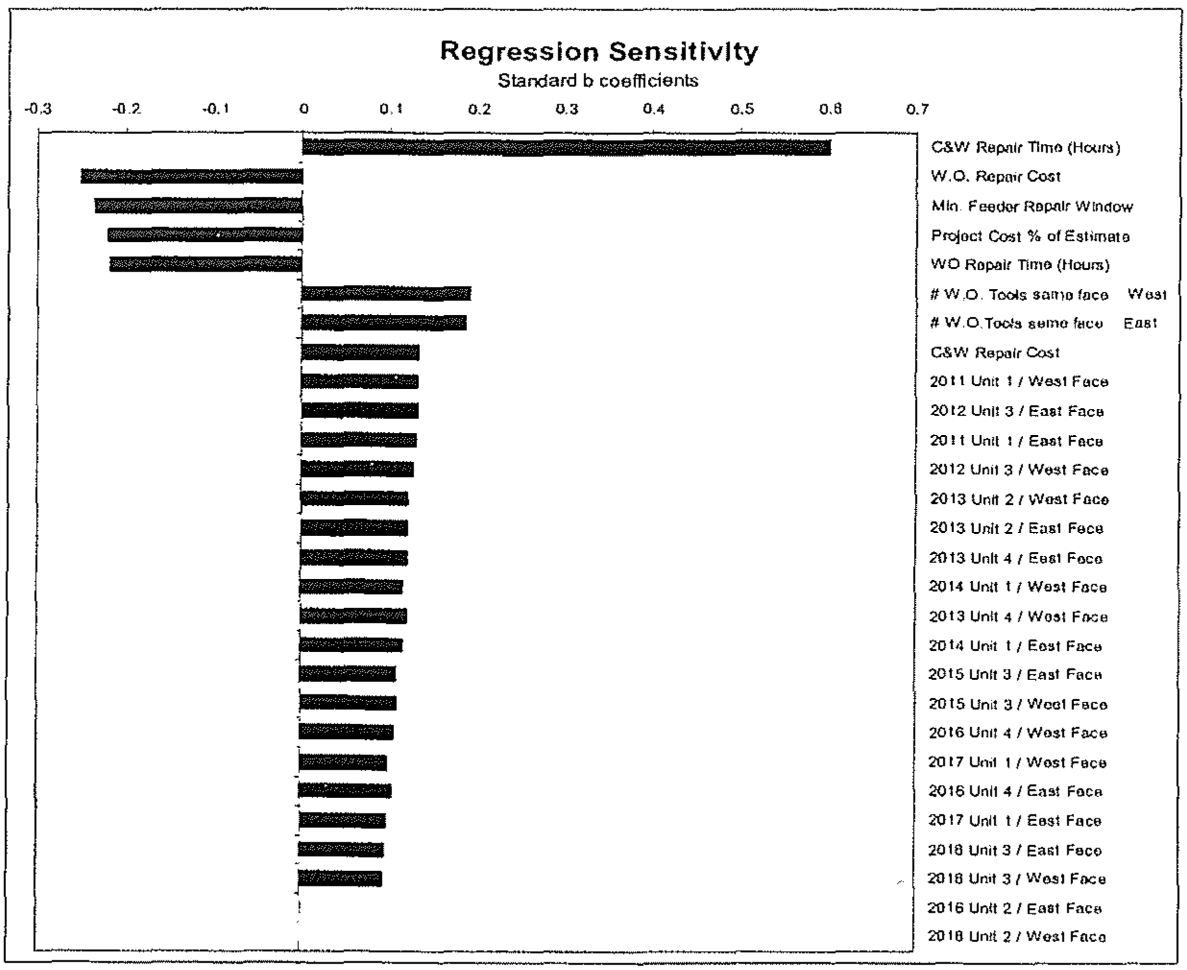
$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay Project (1 Year)	Alt 3	Alt 4	Alt 5
Revenue	(573,891)	(311,812)	(311,812)	(335,964)			
OM&A	(370,833)	(252,997)	(249,350)	(258,266)			
Capital	0	(51,205)	(51,205)	(51,205)			
Present Value (PV)	(451,016)	(310,114)	(307,616)	(325,336)			
Net Present Value (NPV)	**N/A**	**140,903**	**143,401**	**125,680**			
Internal Rate of Return (IRR) %	N/A	42.5%	45.5%	44.4%			
Discounted Payback (Yrs)	N/A	5.1	5.0	5.3			

Monte Carlo Simulation

The purpose of the analysis is to demonstrate the viability of Weld Overlay within the parameters of uncertainty that currently exist, before Stage 1 is complete. This was accomplished by completing a Monte Carlo simulation of the impact of Weld Overlay (versus Cut and Weld) using 28 variables that were identified as having the greatest impact on economic viability of the project.

Two Hundred Thousand (200,000) iterations were completed using @Risk software. The 28 variables were chosen randomly (for each iteration), within our best estimate of the parameters for each variable. The Monte Carlo analysis produced the following results:

Mean NPV = $72 Million
Maximum NPV = $233 Million
Minimum NPV = - $39 Million
There is a 90% confidence that the NPV will fall between $20 Million and $ 130 Million
The analysis produced 1,564 negative results
The analysis produced a tornado diagram ranking variable sensitivity. See below.



Refer to N-REP-30751-10007, "*Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002*" for detailed financial model assumptions used in the development of this business case.

Base Case: Not Recommended - Stop the project
This is not recommended, as the exclusive use of Cut and Weld tools will result in lengthy outages during the peak replacement years that could jeopardize the Darlington Business Plan and the Darlington target of 38-day outages.

Alt. 1: Recommended - Proceed with Stage II of the Weld Overlay project

It is recommended to proceed with the release of $53.2M Capital (including contingency) and $[redacted]M OM&A (specific contingency) to award and execute a contract for Stage II of the Weld Overlay project. This technology will provide an alternative feeder repair option for repairing thinned areas, with an expected reduction in:

- Overall time required to repair a feeder
- Execution cost of feeder repair
- Production and safety risks associated with breaking the pressure boundary (See Qualitative factors)

It is estimated that using Weld Overlay tools in conjunction with Cut and Weld tools (as required) starting in 2011 will provide a financial benefit of approximately $38M - $143M (NPV). At the conclusion of Stage I, an updated economic analysis will be prepared using vendor provided budgetary estimates for Stage II and a formal decision meeting will be held to determine whether to proceed with weld overlay tool development, therefore, limiting sunk costs should this project not prove beneficial.

This alternative includes a specific contingency of $[redacted]M capital to cover uncertainties regarding applicability of PST, as well as a specific contingency of $[redacted]M OM&A to deal with uncertainties regarding on-reactor commissioning in 2010.

Details of the proposal are presented in Section 4.

Alt. 2: Not Recommended - Delay project for 1 year

This alternative is not recommended because delaying the project will:

- Reduce the overall financial benefit by ~ $8M - $18M (NPV) if tooling is available for 2012 vs. 2011
- Increases the risk that, due to unforeseen issues in this R&D project, the tooling will not be ready when feeder repairs are most needed.
- Risk losing experienced team members and vendors to support tool development.

Alt. 3: Not Recommended - Include Pickering A and Pickering B
This is not recommended because:

- Pickering B has very few feeders that are candidates for weld overlay before end of life.
  Pickering A feeders may not benefit from grayloc-area overlay, as they have concerns with life-limiting thinning further downstream. The extent of downstream thinning and the potential benefit of grayloc-area overlay will become more apparent after further inspection programs are completed at Pick A. It would be advantageous to first develop the tooling for Darlington, and adapt the tooling for Pickering A later, as required.
- Both Pickering A and Pickering B have tighter clearances around the feeders, making tool design more challenging.

The NPV has not been shown for this alternative because of the uncertainty indicated above.

4/ THE PROPOSAL

Upon successful completion of Stage I (currently in-progress), a formal decision meeting will be conducted to determine whether to proceed with weld overlay tool development based on Stage I results and up to date Stage II budgetary estimates.

If tool development does not present a positive economic case or if Stage I was not able to resolve outstanding areas of technical risk, the project will likely be cancelled; otherwise, a revised BCS, within the value of this BCS, will be submitted for approval and used to award a contract for Stage II of the weld overlay tooling and processes development project for Darlington. Stage II will be executed in three (3) phases:

1. Detailed Design and Prototype Fabrication
   In this Phase, detailed documentation and drawings for the weld overlay tool and process will be prepared based on the parameters identified in Stage I.

   A prototype tool will be built and tested on a mock-up which will simulate real feeder configurations, feeder clearances and shutdown conditions.

   CNSC acceptance will be obtained for the weld overlay processes, analyses and inspections; as well as support for joint registration of the weld procedure with TSSA.

2. Fabrication and Mock-up Testing
   In this Phase, the Production Tools (up to [redacted] sets) will be manufactured and the application of the weld overlay and weld defect repair will be further tested and demonstrated.

3. Commissioning
   In this Phase, commissioning tests and available for service declaration will occur, with likely one commissioning trial at a Darlington unit in 2010.

5/ QUALITATIVE FACTORS

Using Weld overlay technology in combination with the Cut & Weld method (as required) potentially offers the following qualitative benefits:

- Eliminates the need for isolating, draining, removal and replacement of feeders experiencing thinning in the area adjacent to the Grayloc hub, thereby reducing production and safety areas of risk inherent in breaking the pressure boundary.
- Reduces exposure time, thereby achieving an overall reduction in radiation dose uptake.
- Reduces both the potential for loose contamination release and the production of high level active waste associated with Cut & Weld activities.

As well, this repair technology may be considered for providing a potential repair technique for pipe thinning problems in other systems or at other OPG stations.

6/ RISKS (see Attachment D for details)

	Low = 1 to 3	Medium = 4 to 9	High = 10 to 25		
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
The vendor's proposed cost of Stage 2 scope (Tool Design and Commissioning) is significantly higher than current estimates. Impact: Higher than estimated capital costs; lower NPV; delay to project resulting from the requirement for a superseding BCS approval.	▪ Conservative estimates based on Cut and Weld tooling development experiences have been used. ▪ A [redacted]% general contingency has been established for this project phase. ▪ A competitive atmosphere for award of Stage II has been set up with two vendors performing Stage I activities. ▪ A firm price contract will be negotiated.	12	15							15	6	8							8
The scope of work may increase based on unresolved technical issues, or discovery of new issues, or Regulatory requirements. Impact: Increased costs, schedule extension and increased complexity	▪ A [redacted]% general contingency has been established for this project phase. ▪ The proof of concept phase disclosed significant technical risks. ▪ Experienced vendors have been contracted.	16	20		8					20	6	15		6					15
The schedule necessary to meet the DNGD 2011 outage may not be achievable resulting in repair of feeders solely with cut and weld tooling during this outage. Impact: An estimated decreased	▪ Experienced vendors are being used. ▪ A competitive atmosphere between vendors has been established to increase their motivation. ▪ Capital funding release is being	20	25							25	16	20							20

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
		Impact			
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
savings of approximately $10M-$20M (NPV).	sought in order that Stage II award is not delayed.																		
Availability of long lead parts/tools (e.g. feeder mock-up) may delay tool development (Stage 2) and subsequent tool AFS resulting in repair of feeders solely with cut and weld tooling during the 2011 Darlington outage. Impact: An estimated decreased savings of approximately $10M - $20M (NPV).	▪ Plan to include Mock-up in vendor's deliverables for early Stage II. ▪ Use of existing mock-ups if available.	20	25							25	16	20							20
Lack of experienced OPG support resources for this project may lead to delays in reviews of deliverables or inadequate reviews. Impact: A delay in completion of this project due to schedule delays or due to rework.	▪ Appropriate engineering and project support resources will be identified and recruited to the project. ▪ Interface agreements will be obtained with required resource/interfacing teams. ▪ Managed task contracts will be set-up with external vendor experts.	8	16	12						16	6	9	6						9
Tool design and miniaturization may not be able to achieve all feeder configurations that will require repair. Impact: A continued need for cut and weld in inaccessible locations.	▪ The configurations with the most feeders to repair have been identified in the technical specification, and are the demonstration configurations in Stage I. ▪ The specification for the area of damage has been reduced	20								20	12								12

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Attachment 1 Tab 10

Low = 1 to 3	Medium = 4 to 9	High = 10 to 25				
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact									After Mitigation: Probability x Impact								
		Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	by half since the proof of concept, thus reducing the overlay area required. ▪ Vendors will have to disclose known limitations at the end of Stage I so that this may be accounted for in the final economic evaluation before proceeding with Stage II.																		
The "As-Built" clearances at the grayloc area of some feeders may be more restrictive than the designed feeder clearances, resulting in the tooling not being able to fit those Weld Overlay feeder candidates. Impact: The cost of unplanned Cut and Weld repairs; Weld Overlay tool having less value than originally projected.	▪ A sample of actual field measurements will be performed during the spring 2009 DNGS outage to assess the magnitude of the difference. ▪ Actual field measurements of all candidate feeders will be recommended as they are available in lead-up outages to avoid unplanned replacement activities. ▪ Methods will be explored to increase feeder clearances, such as end-fitting jacking techniques.	20		16						20	12		9						12
Post Weld Overlay material properties (Residual Stress, Hydrogen Ingress and Hardness) may not be fully resolved after Stage I. Impact: Schedule delays and cost overrun for additional work	▪ Post Stage I decision meeting to cancel project if risk is too high going into Stage II. ▪ Removed DNGS feeders (artifacts) have been set aside for weld overlay testing purposes (if required).	15	15							15	6	6							6

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Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
		Impact			
	1	2	3	4	5
Probability 5	5	10	15	20	25
Probability 4	4	8	12	16	20
Probability 3	3	6	9	12	15
Probability 2	2	4	6	8	10
Probability 1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
required. At worst, cancellation of the weld overlay project would result in sunk costs of approximately $16.5M OM&A (includes contingency) and any Stage II expenditures (Capital Release).	▪ Experienced vendors are being used.																		
Weld Overlay repair may not be feasible with fuel in the channel. <u>Impact</u>: Channel will be refueled for the weld overlay repair, increasing time and cost of the repair.	▪ Currently Cut and Weld requires the channel to be defueled therefore the cost of fuel would be the same under both Cut & Weld and Weld Overlay scenarios should this risk materialize. The cost of fuel has not been included in the economic analysis. (If included, the case for Weld Overlay is made stronger).	4								4	2								2
Regulatory approval sought in Stage II may be delayed or rejected. <u>Impact:</u> Schedule delays and cost overrun for additional work required. At worst, cancellation of the weld overlay project would result in sunk costs of approximately $16.5M OM&A (includes contingency) and any Stage II expenditures (Capital Release).	▪ A Regulatory plan has been prepared and an initial meeting held early in the project. ▪ During Stage I, at least one update meeting will be held with the CNSC ▪ Technical experts with knowledge in Code/Regulatory issues will be contracted for this work and will support Regulatory discussions and submissions. ▪ Nuclear Weld Overlay experience from utilities will be	12	15			9				15	6	8			4				8

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Low = 1 to 3	Medium = 4 to 9	High = 10 to 25				
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	sought. ▪ Removed DNGS feeders (artifacts) have been set aside for weld overlay testing purposes (if required).																		
The Regulator may require a 48 hour wait prior to Ultrasonic Inspection of the overlaid area. This wait may be deemed necessary to allow crack initiation for hydrogen. <u>Impact:</u> The benefits of Weld Overlay will be reduced by the net additional time required for inspection.	▪ Stage I development includes significant effort to determine and minimize hydrogen ingress during weld overlay. Based on successful development in this area, the 48 hour period should not be required. ▪ Industry OPEX of weld overlay will be used to present a case that hydrogen induced cracking is not an issue.	16								16	12								12
The number of candidate weld overlay feeder repairs is reduced due to the approval of lower pipe thickness limits or adjustments to the rate of thinning calculations. Impact: Less return on investment. At worst, sunk costs could reach *$16.5M* OM&A (Including contingency) and any Stage II expenditures (Capital Release)	▪ Maintain communication with Feeder experts and stakeholders to quickly respond to changes in feeder condition or assessments. ▪ At the conclusion of Stage I, the economic benefits will be re-assessed prior to proceeding with Stage II; the minimum thickness limits will be reconfirmed at this time.	15								15	10								10
There may be a requirement for a Cut and Weld crew on standby as contingency during weld overlay. This standby charge	Supply chain to negotiate if required.	3								3	3								3

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Attachment 1 Tab 10

Low = 1 to 3	Medium = 4 to 9	High = 10 to 25			
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
may be significant. Impact: Less return on investment.																			
The efficiency (time required) or the application cost per feeder of weld overlay is greater than that for cut and weld. Impact: Less return on investments. At worst, sunk costs could reach $16.5M OM&A (Including contingency) and any Stage II expenditures (Capital Release)	• At the conclusion of Stage I, the economic benefits will be re-assessed prior to proceeding with Stage II	8								8	8								8
The value of the Canadian dollar drops to a value for a sustained period of time that may significantly increase costs should a vendor from the U.S. be contracted for this job (<$0.8 USD). Impact: Higher cost of development and/or application	• Request proposals in Canadian funds. • [redacted]% contingency has been added to conservative estimates.	12								12	6								6
The vendor's QA program is not approved for stage II work and/or implementation Impact: That vendor's bid is not acceptable.	• OPG Supply chain is engaged in reviewing and auditing the vendor's QA program. • Two vendors are contracted for stage I work.	8	15							15	8	10							10
Opportunity - Another utility with	• Senior Management to									4									8

Low = 1 to 3	Medium = 4 to 9	High = 10 to 25			
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
similar grayloc thinning issues may join OPG as a partner in the Weld Overlay Project. This would result in reduced weld overlay project costs by a significant amount.	continue discussions with interested utility.	4									8								
Opportunity – Process and tooling may be used for other Stations or systems.	•	9								9	9								9
Opportunity – Introduction of an alternate vendor for feeder repair may lead to more competitive quotes for future work.		6								6	6								6

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7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Comprehensive	Jun 2011	Dec 2012	VP Science & Technology Development

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Time to perform a single repair	Cut & Weld	<25 hours	Use outage reporting data	Performance Engineering
2.	Dose per repair	Cut & Weld	< cut and weld	mRem/Feeder Dose reporting system.	Reactor Maintenance
3.	Number of feeders that require cut and weld replacement per 100 feeders requiring repair.	Cut & Weld	< 10	Use outage reporting data	Major Components/ Feeders
4.	Weld overlay in-service repair failures.	N/A	0	SCRs	Major Components/ Feeders
5.	Number of pipe 'blow-thru' events	N/A	0	SCRs	Reactor Maintenance
6.	Cost per repair average.	Cut & Weld	< 500k in first 3 years	Negotiated cost per repair	Supply Chain

- A Comprehensive Post Implementation Review (CPIR) will be carried out at the conclusion of Stage 1 of the project to capture the lessons and make recommendations for the next stage. If a CPIR is found not appropriate at the end of Stage 1, it will be conducted within one year of the project in service (by December 2012), consistent with the corporate PIR Procedure.

- 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 effectiveness of the weld overlay repair technology in conjunction with Cut & Weld tooling over the previous cut and weld method alone

    ii. The measurement of project targets specified in the table above

- Review project intent, 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

• The Comprehensive PIR will be conducted by Independent Team with the Team Leader appointed by the Project Approval Authority

• Key Lessons-Learned on the technology development, contracting and planning will be captured in addition to the project execution lessons.

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

- Acronyms etc are spelled out in the text.

Appendix "B" Project Funding History

$ 000's Capital Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values Year	2009	2010	2011	2012	2013	2014	2015	Later	Total
Full	May	2009	5,050	45,060	3,084						53,194
											0
											0
											0
											0
											0
											0
											0
LTD Spent	Feb	2009	0								0

$ 000's OM&A Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values Year	2005	2006	2007	2008	2009	2010	2011	Later	Total
Developmental	Feb	2005	200								200
Partial	Jun	2005	1,500								1,500
Partial	Jul	2006	1,273	686							1,959
Partial	Aug	2007	1,273	407	670	3,560					5,910
Partial	Oct	2008	1,273	407	497	3,867	10,490				16,534
Full	May	2009	1,273	407	497	3,867	10,490	1,000			17,534
											0
											0
LTD Spent	Feb	2009	1,273	407	497	1,470	260				3,907

Comments:

ONTARIOPOWER GENERATION

Appendix "C" Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	2%	SR & D Opportunity	Yes
Progress Payments	Yes	Foreign Currency	See Comments	Retainer Fee	No
Income Tax Rate	Generation	PST	See Comments	Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Office, Misc Equipment 20%	Leasing	No	Indexed Priced Contract	No

Comments:

[redacted]% of tool development costs (~$[redacted]M) has been reserved in a specific contingency to cover uncertainties regarding applicability of PST which will not be resolved until the successful completion of Stage I.
Any Stage II foreign exchange issues will be covered by the [redacted]% general contingency requested in this release.

Project Cost Estimate:

Design Complete	Zero to Minimal	Quality of Estimate	Conceptual + 60% to - 25%	3rd Party Estimate	Yes
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote(s)	No	First Unit Actual Used	N/A
Cost Sharing	No	Contracts in place	No	Competitive Bid	Yes
Fixed Price Contract	Yes	Fee for Service	No	Firm Vendor Proposal	No

Comments:

Refer to N-REP-30751-10007, "*Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002*" for detailed financial model assumptions used in the development of this business case.

Rationale for Cost Classification:

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	N/A	N/A	N/A	N/A							
	4	N/A	N/A									
Pickering B	5	N/A	N/A	N/A	N/A							
	6	N/A	N/A									
	7	N/A	N/A									
	8	N/A	N/A									
Darlington	1	Sep	2018	935	88%	D1111	D1411	D1711				
	2	May	2016			D1021	D1321					
	3	Mar	2020			D1231	D1531	D1831				
	4	Mar	2021			D1341	D1641					

Comments:

D1021 is included as target commissioning outage.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Risk Informed Scenario

Impact on Revenue

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH	58.36	52.98	54.58	54.58	56.23	56.23	57.93	57.93		
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	0.0
Other	0.0	0.0	(8.6)	(23.0)	(3.0)	(23.7)	(34.2)	(22.0)	(151.5)	(266.0)
Base Case	**0.0**	**0.0**	(8.6)	(23.0)	(3.0)	(23.7)	(34.2)	(22.0)	(151.5)	(266.0)
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	0.0
Other	0.0	0.0	(8.6)	(10.9)	(1.2)	(11.3)	(18.3)	(12.2)	(83.3)	(145.8)
Recommendation	**0.0**	**0.0**	(8.6)	(10.9)	(1.2)	(11.3)	(18.3)	(12.2)	(83.3)	(145.8)
Net Impact	0.0	0.0	0.0	12.1	1.8	12.4	15.9	9.8	68.2	120.2

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage OM&A	0.0	0.0	(2.7)	(11.7)	(1.8)	(13.1)	(25.9)	(10.7)	(104.8)	(170.7)
Project OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Case	**0.0**	**0.0**	(2.7)	(11.7)	(1.8)	(13.1)	(25.9)	(10.7)	(104.8)	(170.7)
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Outage OM&A	0.0	0.0	(2.7)	(7.4)	(1.3)	(8.6)	(16.0)	(6.9)	(65.2)	(108)
Project OM&A	0.0	(12.9)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	(13.9)
Recommendation	**0.0**	(12.9)	(3.7)	(7.4)	(1.3)	(8.6)	(16.0)	(6.9)	(65.2)	(122.0)
Net Impact	0.0	(12.9)	(1.0)	4.3	0.5	4.5	9.9	3.8	39.6	48.7

Comments:

See NPV Calculations for Details and Summary

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Current Assessment Scenario

Impact on Revenue

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH	58.36	52.98	54.58	54.58	56.23	56.23	57.93	57.93		
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(17.3)	(43.1)	(17.8)	(53.2)	(151.4)	(61.0)	(230.0)	(573.8)
Base Case	**0.0**	**0.0**	(17.3)	(43.1)	(17.8)	(53.2)	(151.4)	(61.0)	(230.0)	(573.8)
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(17.3)	(19.0)	(8.9)	(23.1)	(83.0)	(34.2)	(126.4)	(311.9)
Recommendation	**0.0**	**0.0**	(17.3)	(19.0)	(8.9)	(23.1)	(83.0)	(34.2)	(126.4)	(311.9)
Net Impact	**0.0**	**0.0**	**0.0**	**24.1**	**8.9**	**30.1**	**68.4**	**26.8**	**103.6**	**261.9**

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage OM&A	0.0	0.0	(10.6)	(23.5)	(7.4)	(29.1)	(101.5)	(37.1)	(161.6)	(370.8)
Project OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Case	**0.0**	**0.0**	(10.6)	(23.5)	(7.4)	(29.1)	(101.5)	(37.1)	(161.6)	(370.8)
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage OM&A	0.0	0.0	(10.6)	(14.6)	(4.9)	(17.8)	(62.9)	(23.3)	(101.4)	(235.5)
Project OM&A	0.0	(12.9)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	(13.9)
Recommendation	**0.0**	(12.9)	(11.6)	(14.6)	(4.9)	(17.8)	(62.9)	(23.3)	(101.4)	(249.4)
Net Impact	**0.0**	(12.9)	(1.0)	**8.9**	**2.5**	**11.3**	**38.6**	**13.8**	**60.2**	**121.4**

Comments:

See NPV Calculations for Details and Summary

ONTARIOPOWER GENERATION

OPG Confidential	Page: 23 of 29
BUSINESS CASE SUMMARY	

Weld Overlay Project 10 - 62568 Capital 10 - 62435 OM&A
Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

Attachment "A" **Project Cost Summary**

	$000's OM&A	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support									-
	Engineering									-
	Procurement									-
	Construction									-
	Other									-
	Project Management (OPG)	708	470							1,178
	Engineering & Drafting (OPG)	202	315							517
	Material	[redacted]								
	Contract - Other									
	Interest (Capital Project Only)									-
	Project Costs	[redacted]								
	General Contingency									
	Specific Contingency									
	Project Costs	3,647	12,887	1,000	-	-	-	-	-	17,534
Cash	Adjust to Cash Basis + / -	-	-	-					-	-
	Project Costs	3,647	12,887	1,000	-	-	-	-	-	17,534
Funding	Currently Released	3,647	12,887							16,534
	This Release			1,000						1,000
	Future Release								-	-
	Project Funding	3,647	12,887	1,000	-	-	-	-	-	17,534

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Budget	2009-2013 Business Plan	2,893	4,240							7,133
	Variance to Business Plan	754	8,423	-	-	-	-	-	-	7,177
Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

ONTARIOPOWER GENERATION

Weld Overlay Project 10 – 62435 OM&A
Full Release Business Case Summary N-BCS- 30751-10001-R000
Project Cost Summary

Attachment "A"

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnl & Support									-
	Engineering									-
	Procurement									-
	Construction									-
	Other									-
	Project Management (OPG)		166	507	166					839
	Engineering & Draftting (OPG)		108	108	108					324
	Material		[redacted]							
	Contract - Other									
	Interest (Capital Project Only)		46	1,183	760					1,989
	Project Costs	-	[redacted]							
	General Contingency									
	Specific Contingency									
	Project Costs	-	5,050	45,060	3,084	-	-	-	-	53,194
Cash	**Adjust to Cash Basis + / -**								-	-
	Project Costs	-	5,050	45,060	3,084	-	-	-	-	53,194
Funding	**Currently Released**									-
	This Release		4,995	43,905	3,060					51,960
	Future Release								1,234	1,234
	Project Funding	-	4,995	43,905	3,060	-	-	-	1,234	53,194

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Budget	2009-2013 Business Plan		11,000	12,500	1,000					24,500
	Variance to Business Plan	-	(7,120)	21,948	1,387	-	-	-	-	16,215
Other	Removal Costs Included above									-
	Inventory to be written off									-
	Spare Parts In Inventory									-

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **is not required**

Reviewed By:
Name
Carol Gregoris

April 15/09
Date:

Approved By:
Allan Lew
Eng & Mods Strat IV Manager

15 APR 2009
Date:

Project Name 10 - 62568 Capital 10 - 62435 OM&A
Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

Attachment "B" Project Variance Analysis

	Capital & OM&A	LTD Feb 2009	Total Project: Last BCS Oct 2008	Total Project: This BCS Feb 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support				0	
	Engineering				0	
	Procurement				0	
	Construction				0	
	Other				0	
	Project Management (OPG)		2,095	2,017	-78	
	Engineering & Drafting (OPG)		626	841	215	
	Material		[redacted]	[redacted]	[redacted]	Mock-Up. Addt'l feeder samples
	Contract - Other		[redacted]	[redacted]	[redacted]	Addt'l costs for WO design, Qualification and commissioning.
	Interest (Capital Project Only)		1,000	1,989	989	
	Project Costs (Scores Basis)	0	[redacted]	[redacted]	[redacted]	
	General Contingency		[redacted]	[redacted]	[redacted]	
	Specific Contingency		[redacted]	[redacted]	[redacted]	PST Applicability, Commisioning
	Project Costs (Scores Basis)	0	47,533	70,728	23,195	

Other	Removal Costs included above	-	-	-	0	
	Inventory to be written off	-	-	-	0	
	Spare Parts in Inventory	-	-	-	0	

Comments:

Attachment "C" Milestones and In Service Declarations

Key Milestones

Completion Date			Description
Day	Mth	Yr	
30	09	2009	Award Stage II Contract
30	11	2010	Commissioning Complete
30	06	2011	AFS

A Project Execution Plan (PEP) **will be approved by Dec 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
July	2011	In Service	40,500	100
Dec	2011	Project Closure	200	

Attachment D **Decision Map**

1. **Recommendation to CNO**
(Process to follow guidelines of Engineering Decision Making N-Guid-01900-10001; Type 3 Decision)

Purpose: To provide a recommendation of either proceeding with Stage II, or canceling the project based on the technical results of Stage I and an updated economic analysis for Stage II. This recommendation will be documented and presented to the CNO, for acceptance.

Chair/Sponsor: Paul Spekkens, VP Science & Technology Development

Attendees:

(1) CNE *
(2) Darlington Director of Engineering *
(3) At least one other Station Engineering Director * (Contrarian Role)
(4) Senior Manager Plant Design Darlington *
(5) Director Engineering Services *
(6) Manager Feeder Integrity Project
(7) Manager Performance Engineering Darlington
(8) Director Nuclear Finance
(9) Manager Nuclear Finance
(10) Manager Darlington Maintenance
(11) Weld Overlay Team Representatives

Format:

Presentation:
- Project Team to present the results of Stage I and an updated risk table based on these results.
- Project Team to present an assessment of the regulatory risk.
- Project Team/Nuclear Finance to present an updated economic analysis incorporating updated:
  1. Costs (vendor proposal in-hand),
  2. Schedule, and
  3. Assumptions.
     - Feeder repair numbers (based on Spring 2009 inspections)
     - Tool limitations (based on clearances vs. conceptual design)
     - Time to apply repair (estimated)
     - Cost of application (budgetary)
     - Monte Carlo analysis results
  4. Other alternatives considered (including lower minimum thickness requirements)

Discussion:
Open discussion and questions

Decision:
CNE makes the decision. Dissenting opinions are to be noted.

Criteria for a decision to proceed should include the following:
- Revised BCS updated economic analysis continues to have a positive NPV.
- Technical risks low; limited medium technical risks may be accepted.
- Regulatory Risk low.

Minutes:

- Presentations, major discussion items, decision, and dissenting opinions are to be recorded.
- Actions with dates should be captured and A/Rs created as appropriate.

- The Recommendation is to be documented and the revised BCS presented for signature by the CNE.

2. CNO acceptance meeting

- CNO acceptance or rejection of the recommendation is to be documented and the revised BCS presented for signature.
- Attendees: CNE
  VP Science & Technology Dev (Project Sponsor)
  SVP Darlington (or delegate)
  Director Station Engineering, Darlington
  VP Nuclear Finance
  Manager, Feeder Integrity Projects
  Project Manager – Weld Overlay Project

- Any actions should be captured and A/Rs created as appropriate
- CNO to take the recommendation and revised BCS to the COO for approval.

3. COO acceptance meeting

- COO acceptance or rejection of the recommendation is to be documented and the revised BCS presented for signature.
- Attendees: CNO
  CNE
  VP Science & Technology Dev (Project Sponsor)
  SVP Darlington (or delegate)
  VP Corporate Investment Planning

4. President Approval of Revised BCS

Attachment "E"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages OR Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

Filed: 2013-09-27
EB-2013-0321
Ex. D2-1-3
Attachment 1 Tab 10

Pickering A Fuel Handling SPV Reliability Improvement 13 - 46634 (Capital) 13 - 46635 (OM&A)
Full Release Business Case Summary NA44 - BCS - 35300 - 00004 - R000

Name / Title / Phone	Location	Action	Signature	Date
Nahil Rahman Director - Pickering Projects 701-4053	P72-1	Review BCS	[signature]	13 Feb 2012
Sean Granville Director Operations & Maintenance - Pickering 701-2099	PO5-A2	Review BCS	[signature]	2012/2/24
Dwight Zerkee Manager Investment Management 702-5058	P82-3	Review BCS	[signature]	2 Mar 12
Randy Leavitt Vice President – Nuclear Finance 702-5177	P82-3	Review BCS	R Leavitt	Mar 8, 2012
Stephen Rogers Director - Asset Planning & Integration 400-3993	H07-E5	Review BCS	M. Stephen Rogers	March 19/2012
Don Power Vice President - Corporate Investment 400-7172	H07-G05	Review BCS	[signature]	March 26/12
Glenn Jager Senior Vice President – Pickering 701-3260	P42-E3	Submit BCS	[signature]	30 MAR 2012
Wayne Robbins Chief Nuclear Officer 702-5294	P82-6	Review BCS	[signature]	2012-04-02
Donn Hanbidge SVP & Chief Financial Officer 400-2395	H19-F27	Approve BCS	[signature]	2012-04-27
Tom Mitchell President & CEO 400-2121	H19-A24	Approve BCS	[signature]	2012-06-06
Carolyn Sicard Nuclear Investment Management 702-4082	P82-3B6.2	Return for Distribution		

OFFICE OF THE
PRESIDENT & CEO
APR 30 2012

Pickering A Fuel Handling SPV Reliability Improvement 13 - 46634 (Capital) 13 - 46635 (OM&A)
Full Release Business Case Summary NA44 - BCS - 35300 - 00004 - R000

1/ RECOMMENDATION:

We recommend a **Full** Release of an **additional $23.088** Million ($16.136 Million **Capital** and $ 6.952 Million **OM&A**) to fund **completion of all modification, commissioning and closeout** for this project. Approval of this request will bring the total to date funding to **$34.262** Million including a contingency of [redacted] Million. The total project is estimated to cost **$ 34.262** Million with an estimated completion date of 12/30/2014.

The Business Objective of this **Sustaining** project is to improve the performance and reliability of the Pickering A Fuel Handling (FH) System to address the following issues:

- Pickering A FH System is a significant contributor to production loss from forced outages and Unit deratings
- Component obsolescence is becoming a major issue with the Fuel Handling System reaching its end of life
- Fuelling unavailability often disrupts outage critical path and station Integrated Operating Plan (IOP) schedules

In addition, during fuel handling equipment or systems failure, there is an employee and public safety risk when irradiated fuel cannot be transferred to the appropriate location where adequate cooling is maintained.

This project will replace, refurbish or overhaul the key system components that have aged past their design end of life. Specifically, the focus will be on components classified as Single Points of Vulnerability (SPV) equipment that have a zero tolerance of unplanned failures. Replacing these components will improve the FH system performance and reliability until the Station end of life.

Installation activities in Unit 4 during the 2011 planned outage were completed, for the most part, under the current funding release. Some work (Electrical Catenaries, Rolling Shield Gear Box and Y-Drive Mitre Box) could not be completed due to unavailability of materials at that time. Funds requested in this Full Release BCS are to complete design and installation activities for Unit 1, the remaining work for Unit 4 and project close out. Execution is planned during P1211 outage in Sep 2012 and during P1341 outage in Sep 2013 (for the remaining Unit 4 work).

$000's (incl contingency)	Funding	Type	LTD Dec 2011	2012	2013	2014	2015	2016	Later	Total
Currently Released	Partial	OM&A	200							200
		Capital	10,700	3,900						14,600
Adjustments to Current Release	Adjustments	OM&A	(146)							(146)
		Capital	(3,480)							(3,480)
Requested Now	Full	OM&A		6,952						6,952
		Capital		8,036	7,890	210				16,136
Future Funding Req'd	None	OM&A								-
		Capital								-
Total Project Costs		OM&A	54	6,952	-	-	-	-	-	7,006
Total Project Costs		Capital	7,220	11,936	7,890	210	-	-	-	27,256
Total Project Costs		Total	7,274	18,888	7,890	210	-	-	-	34,262
Other Costs										-

Investment Type	Class	NPV	IRR	Discounted Payback
Sustaining	Multi Class	24,652	20.3	5.2

Submitted By: (Date) 30 MAR 2012
Glenn Jager
Senior Vice President – Pickering Nuclear

Financial Approval By: April 27/12 (Date)
Donn Hanbidge
SVP & Chief Financial Officer

(OAR Element 1.1 Project in Budget)
Line Approval By: 2012-05-06 (Date)
Tom Mitchell
President & CEO

2/ BACKGROUND & ISSUES:

During the Pickering A Return to Service project, new safety requirements required conversion of adjuster rods to shutoff rods to increase total shut off rod reactivity worth. Following the changeover, adjuster rods cannot be retracted to compensate when fuel handling is unavailable. As a result, the system is required to be available to fuel at least every 33 hours or the reactor Units will de-rate. The original design requirement for the FH system availability was 70%, whereas the availability target is now 92%. Since the Pickering A FH systems are 35 to 40 years into their 40 year design life, component obsolescence and end of life issues present significant challenges in meeting the availability targets.

This project is an immediate priority due to continued FH system deterioration, known end of life components, and limited outage window availability to accommodate work without extending outage durations in the future. Since the Return to Service Project, Pickering A FH has seen its highest contributions to Forced Loss Rate (FLR):

- 36.2 days in 2008
- 0.5 days in 2009
- 17 days in 2010
- 6.7 days in 2011

With aging components and major obsolescence issues, this trend is estimated to increase and thereby pose a significant threat to the current Business Plan FLR targets of 42.4 days for 2012, 43.5 days for 2013 and 43.7 days for 2014.

As well as being a major contributor to units FLR, poor fuel handling system reliability also impacts station performance objectives. Unplanned fuelling unavailability disrupts scheduled maintenance. When fuel handling capability is restored, priority is given to fuel the unit for full power operation. As a result, scheduled maintenance is deferred, particularly channelized maintenance and testing.

Outage critical path schedule adherence is also affected by poor fuel handling reliability. Fuel handling supports outage execution by providing a platform for reactor inspection and maintenance activities as well as delivery of inspection tools. Fuel handling system unavailability has a direct and negative impact on critical path during these outages.

Furthermore, when irradiated fuel is stranded in the fuel handling systems as a result of breakdowns, the required repairs pose a significant radiological safety risk to our employees and an increase in public safety risk.

A review of the fuel handling systems based on INPO AP-913 (Equipment Reliability Process) was conducted to determine the scope of work required to achieve acceptable levels of reliability for the Pickering A Fuel Handling systems. The review identified equipment that are Single Points of Vulnerability (SPV) or equipment with a zero tolerance of unplanned failures. Any FH SPV equipment failures (within the scope of this project) would result in Unit shutdown(s) and/or de-rating(s).

The project scope focuses on the replacement, refurbishment and overhaul of SPV equipment of the Pickering A Fuel Handling System. Improvements to maintenance capabilities and routine maintenance (i.e. component replacements) will also be performed to ensure maximum gains in system availability and reliability until the end of station life.

The following activities have been completed using the Partial Release funding:

- Purchase order issued for major equipment/component procurement for Units 1 and 4 (except U1 Ball Nuts as no OEM vendor was available to supply these nuts at that time)
- Unit 4 and Unit 1 work plan preparation and assessment completed

- Unit 4 Installation activities completed, except for the following:
  - Electrical Catenaries – due to material unavailability
  - Rolling Shield Gear Box – Obsolete part (spare gear box has now been obtained from Unit 3)
  - Y-drive Mitre box - due to material unavailability
- Return For Service (RFS) after Unit 4 SPVs replacement

The Partial Release was not fully spent due to the following:

- Some material was not available and could not be installed in P1141
- Labour cost less than estimated (reduced scope in P1141)
- Contingency not used

The P1141 OPEX has been incorporated into the remaining work scope. Some major OPEX includes:

- Thrust bearing – Use of manlifts to reduce time and dose.
- Configuration Issues on Y Drive alignment and elevator chain
- New Gear box rotation checks during installation
- FM Catenary Hoses – Alignment/Twists

3/ ALTERNATIVES & ECONOMIC ANALYSIS:

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3	Alt 4	Alt 5
Revenue	(93,744)	(8,573)	(8,179)	(18,335)			
Base OM&A	0	0	0	0			
Outage OM&A				0			
Project OM&A	0	(7,006)	(6,952)	(7,006)			
Total OM&A	0	(7,006)	(6,952)	(7,006)	0	0	0
Provision							
Capital		(25,689)	(18,533)	(27,328)			
Present Value (PV)	(50,559)	(32,425)	(25,907)	(37,471)			
Net Present Value (NPV)	N/A	18,134	24,652	13,088			
Internal Rate of Return (IRR) %	N/A	11.0	20.3	10.3			
Discounted Payback (Yrs)	N/A	6.2	5.2	7.0			

Base Case: × *Not Recommended* - **Stop the Project**

Maintaining the status quo is not an acceptable option for the following reasons:

- FH Systems will continue to be a main contributor to Unit de-ratings and forced outages and result in large financial losses. The consequences include:
  - De-rating 10% of both Units 1 and 4 for two weeks per year due to unavailability of SPV parts in the FH systems.
  - 10% probability of one unit shut down for one month per year because of FH SPV equipment failures and spare parts unavailable.
  - 50% probability of one unit shut down for three weeks per year because of FH SPV equipment failures.
- Considering component obsolescence and unavailability of spare parts, the probability of equipment failure will continue to increase within the intended station life
- Failures will continue to disrupt Outage critical path and IOP scheduled activities
- With fuel handling equipment or system failures, there is an employee and public safety risk if irradiated fuel cannot be transferred to the appropriate location where adequate cooling is maintained

Alternative 1: ✓ *Recommended* - **Replace/Refurbish/Overhaul SPV equipment**

The recommended alternative focuses on replacing the Single Point of Vulnerability (SPV) items identified by the Equipment Reliability Analysis Program as per AP-913 guidelines. This includes the development of Engineering Changes, procurement of long lead material and replacement and overhauling of life-expired FH equipment.

This option is recommended because:

- All business objectives are achieved
- It is in alignment with the Equipment Reliability Restoration Program (ERRP)
- It will help ensure current station FLR objectives and priorities are met
- It will contribute towards achieving FH equipment availability rate of 92%
- The P1211 and P1341 planned outages have sufficient windows for carrying out all installation work for Unit 1 and outstanding installation work for Unit 4

The following assumptions were made with regard to Unit deratings/outages until the modifications are completed:

- De-rating 10% of Unit 1for two weeks and Unit 4 for 1 week due to unavailability of SPV parts in the FH systems.
- 10% probability of Unit 1 shut down for one month and Unit 4 for 15 days per year because of FH SPV equipment failures and spare parts unavailable.
- 50% probability of one Unit 1 shut down for three weeks and Unit 4 for 10 days per year because of FH SPV equipment failures

The breakeven point for this alternative is 5.5 days FLR days per unit per year.

Alternative 2: × *Not Recommended* - **Delay for 2 Years**

Although this alternative satisfies all objectives of the project, it is not recommended because:

- Delaying the project will impact key business production objectives due to the high probability of existing Fuel Handling system equipment failure
- Any cost savings would be offset by the increased risk and consequence of forced outages due to equipment failure
- The delay period has a negative impact on the probability of aging equipment failure
- P1441 and P1511 outage windows may not be adequate for completing all installation activities which may result in an outage extension

4/ THE PROPOSAL

The following are the objectives and expected results (deliverables) for this Full Release BCS:

- Project Management Support
- Engineering Support
- Modification - SPV equipment replacement for Unit 1 and remaining work for Unit 4
- Stress Assessments
- Project Close Out

The following activities will be completed using the Full Release Funding:

- Capital Activities
    - Purchase order issued for U1 Ball Nuts (deferred from partial release)
    - Design and procurement activities for TM Rotor Bearing Tooling and Replacement of U1 & U4
    - Unit 1 Installation activities during P1211
    - Unit 4 remaining work (Electrical Catenaries, Rolling Shield Gear Box, and Y-drive Mitre Box) during P1341 (deferred from 2011 outage)
    - Operations acceptance/RFS for Unit 1 and remaining work for Unit 4
    - Unit 1& 4 Design Close Out
    - Project Close Out

- OM&A Activities:
    - Ball Screw Stress Assessment
    - FM Pressure Boundary Stress Assessment
    - FM Carriage/Trolley Structure Stress Assessment

Please refer to Attachment "E" for detailed scope of the project.

Note:
The scope of the project is limited to SPVs (as listed in Attachment 'E') that have been determined to pose the greatest risk or have uncertainty that requires further assessment. Any additional equipment/component will be addressed under the FH/Station maintenance program. Ball screw and pressure boundary component analyses are included in the project scope; however if replacements are required a separate project will be initiated to complete the required work.

TM Overhaul (SPV 895) – The TM Rotor bearing replacement in U1 and U4 will be executed if it is determined that the condition of the bearings in U2 or U3 indicates the need for replacement.
In situ inspection of the bearing in running units will result in high doses and high hazard work. Tooling will be developed to carry out in situ inspection in U2/U3. Based on the observed condition of the TM rotor bearing with similar service life in U2/U3, the decision will be made for the path forward for U1/U4. Specific contingency money is allocated if the TM Rotor bearings cannot be replaced in situ resulting the need to remove the TM from the unit. The plan is to develop tooling to replace bearings "in situ", practice on U2/U3 and execute in U1 and U4.

5/ QUALITATIVE FACTORS

1. Improve FH System health and reliability by replacing SPV components.
2. Reduce risk of radiological dose to public and employees until end of station life.
3. Avoid disruption to Outage critical path and IOP schedule activities.

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6/ RISKS ANALYSIS (See Attachment D for details)

Low 1 to 3	Medium 4 to 9	High 10 to 25			
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Probability X Impact

Risk Description	Mitigating Activities	Mitigation	Specific Cont'ncy $000's	Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environmental	Nuclear Safety	Risk Rating (1 to 25)
Cost a) The Project Charter identifies Fuel Transfer Mechanism Overhaul (SPV 875) as part of the scope. It is not conclusive if a complete overhaul is necessary to replace the TM Rotor Bearings. Additional funds will be required, if work to remove and/or overhaul the TM is to be completed.	1. Allocate specific contingency for Fuel Transfer Mechanism Overhaul (SPV 875) should it be required to remove it from the unit. 2. Develop tooling early so assessments can be performed ASAP to determine extent of work required for FTM.	Before	5,000	9	9							9
		After		4	4							4
b) Estimate is based on similar projects, first unit installation and consultations with other work groups involved. There is no OPEX available for some major works such as trolley bearings, electrical catenaries. Assessment cost estimates are of conceptual quality and may be conservative.	1. Use OPEX from first unit construction. 2. Allocate contingency to address over expenditures. 3. Monitor project costs on a weekly basis to avoid cost over runs.	Before		9	6							9
		After		4	4							4
Scope: Scope of work is fairly well defined but there may be discovery issues during installation, such as unforeseen radiological hazards e.g. Hot particles and high dose situations. Discovery work may also require additional Design and Installation contract efforts.	1. Ensure Fuel Handling personnel reviews scope and assesses work to be completed. 2. Allocate contingency to address issues that may arise. 3. Obtain Radiation Protection input when preparing and assessing work plans to minimize/reduce radiation hazards. 4. Have all stakeholders perform walkdowns and conduct comprehensive Pre-job briefings. 5. OPEX	Before		3	9				6			9
		After		2	4				2			4

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Schedule Ability to complete the required prerequisite work at risk within the outage window. Above risks may result in outage extension or deferring of some work. Conflicting projects (i.e. ECI vs. FH SPV) will impact outage schedule and may result in outage extension or deferring of some work. Ability to complete the work is at risk due to critical material availability like Ball Nuts. OPEX from U4 modification, - changes in outage schedule, insufficient time allowed for FH to conduct testing, configuration issues, discovery work, legacy issues. All these can impact schedule (and cost).	1. Work closely with the Outage group and Fuel Handling to coordinate activities. 2. Engage Supply Chain to ensure all materials (including ball nuts) required for installation are available and ready for use. 3. Close coordination and field walkdowns. 4. General contingency added to address these risks. 5. OPEX from U4	**Before**		6	9							9
		After		4	4							4
Resources Possibility of a change in personnel working on this project such that knowledge and experience from previous installation will not be fully applied. Station resources may be pulled to complete higher priority work during outages. OPEX from U4 modification – Maintenance Techs required to support troubleshooting, are not always available readily, causing delay.	1. Obtain early commitment from OPG resources i.e. Design, Field Eng and Station. 2. Fuel Handling Technical and Assessing units will assist and be consulted by projects group to help build expertise. 3. Use augmented staff or have additional budget to complete work. 4. Contractor Engaged	**Before**		3	9	9						9
		After		2	4	2						4

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Quality Quality of design and manufacturing of ball nuts being installed may lead to "new" failure modes which may not show up during testing or commissioning. There is a possibility that new components may not be compatible with existing system. There will be a major schedule impact if issues with the components arise. OPEX from U4 modification – some quality issues with the new material	1. Use qualified and experienced vendors (on ASL) with access to quality manufacturing facilities. Engage OEM supplier for critical components. Request Supply Chain inspections at various stages in the production process. 2. Use OPEX from previous U4 FH maintenance/work. 3. Use lessons learned from previous Unit installation. Work plans updated with OPEX from U4 4. Employ strict quality control and testing of new components. 5. Save the old components, in case it is to be reused.	**Before**		3	9	9						9
		After		2	6	4						6
Technical a) Hot spot in Unit 1 tensioning tower may affect conveyor cart overhaul work. Work will require additional Radiation Protection consideration and extra rigor.	1. Engage Radiation Protection and ALARA in advance to come up with strategy to complete work. 2. Consult Radiation Protection for preparation of work plans.	**Before**		6	9				6			9
		After		3	6				3			6
b) Configuration Issues	1. OPEX from U4 2. FH Technical Support to address 'as found' 3. General Contingency	**Before**		6	6							6
		After		3	3							3
c) Ball screw and pressure boundary component analysis and assessments will be done in this project There is a very low probability that replacements will be necessary.	Ball screw & Pressure boundary component replacement will be carried out as separate project, if required.	**Before**		8	10							10
		After		2	4							4

7/ POST IMPLEMENTATION REVIEW

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date	PIR Responsibility (Sponsor Title)
Comprehensive	31-Dec-13	30-Jun-14	Fuel Handling Manager

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure Person / Group?
1.	Forced Loss Rate due to Fuel Handling	FLR 3% (2010) and trending upward	FLR <2%	FLR attributed to SPV failure	Fuel Handling Manager
2.	Replace/Refurbish/Overhaul SPV equipment identified in Project Charter	Equipment is at the end of design life	No SPV component failures leading to unit outage/ de-rating	Outages/De-rating contributed by SPV failures.	Fuel Handling Manager
3.	Availability of Fuel Transfer mechanism	Equipment is at the end of design life. Condition of bearings unknown.	Assessment completed and suitable actions taken to mitigate the risk.	FLR attributed to SPV failure	Fuel Handling Manager
4.	Life expectancy of Ball screws	Near end of design life. Remaining life expectancy unknown.	Assessment completed and remaining life expectancy known.	Assessment completion	Fuel Handling Manager
5.	Health of PB components and load bearing structures.	Near end of design life. Remaining life expectancy unknown.	Assessment completed and remaining life expectancy known.	Assessment completion	Fuel Handling Manager

APPENDIX "A' GLOSSARY (acronyms, codes, technical terms)

AFS	Available for Service
ALARA	As Low As Reasonably Achievable
BCS	Business Case Summary
CMO	Contract Management Office
CNSC	Canadian Nuclear Safety Commission
COMS	Constructability, Operability, Maintenance, Safety
ECC	Engineering Change Control
EOL	End of Life
ERRP	Equipment Reliability Restoration Program
FH	Fuel Handling
FLR	Forced Loss Rate
FM	Fuelling Machine
FTM	Fuel Transfer Mechanism
INPO	Institute of Nuclear Power Operations
IOP	Integrated Operating Plan
IRR	Internal rate of return
NICR	Non-Identical Component Replacement
NPV	Net Present Value
OAR	Organizational Authority Register
OEM`	Original equipment manufacturer
OM&A	Operation, Maintenance and Administration
OPEX	Operational Experience
OPG	Ontario Power Generation
PB	Pressure Boundary
PEP	Project Execution Plan
PIR	Project Implementation Review
REIS	Report of Equipment In Service
RFS	Return For Service
SCR	Station Condition Record
SPV	Single Point of Vulnerability

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APPENDIX "B"

Comparison of Total Project Estimates

$ 000's			This Appendix compares the Total Project Estimate for each BCS									Total Project
			Total Project Estimate (by Year incl Contingency)									
BCS Type	Class	Mth	Yr	2011	2012	2013	2014	2015	2016	2017	Later	Est
Developmental	Capital	Jan	2011	8,000	14,500	500						23,000
Partial	Capital	Feb	2011	10,700	15,500	750						26,950
Partial	OM&A	Feb	2011	200	7,990							8,190
Full	Capital	Jan	2012	7,220	11,936	7,890	210					27,256
Full	OM&A	Jan	2012	54	6,952							7,006
												0

LTD Spent	Capital	Dec	2011	7,220								7,220
LTD Spent	OM&A	Dec	2011	54								54
LTD Spent												0

Comments:

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APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

Financial Assumptions:

Discount Rate:	7%	Cost Escalation (Yr)	3%	SR&D Opportunity	No
Progress Payments	No	Foreign Currency	No	Retainer Fee	No
Depreciation Rate (Capital)	Generating Equip 8%	PST	No	Interest Rate (Capital)	6%
Revenue Rate	Corp SEV	Leasing	No	Indexed Priced Contract	No

Comments:
Major assumptions about contribution of the FH system to unit de-rates/shutdowns used in the financial evaluation for the base case and Alternative 1 are listed in Section 3 "Alternative and Economic Analysis". These assumptions are based on available FLR data and OPEX from FH department.

Project Cost Estimate:

Design Complete:	100%	Fixed Price Contract	No	3rd Party Estimate	No
Quality of Estimate	Budget +30% to -15%	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote	Yes	First Unit Actual Used	Yes
Firm Vendor Proposal	No	Cost Sharing	No	Competitive Bid	Yes
Reviewed by Sponsor	Yes	Fee for Service	No	Contracts in place	Yes

Comments:
Project cost estimate is based on man-hour commitment provided by various contributing groups such as Projects, Design, Field Engineering, Station resources, Contract Management Office and Project Management Office. The project estimate for remaining installation work is based on the first unit construction costs. There is no OPEX for some major work such as FT magazine bearing, electrical catenaries and assessments. No contracts are in place for stress assessment/analysis and quality of estimates is conceptual.

Rationale for Capital Cost Classification:

As per FIN-PROC-PA-003, this project qualifies for Capital funding since it involves the upgrade/replacement of a system that will contribute to extending the life of the asset.

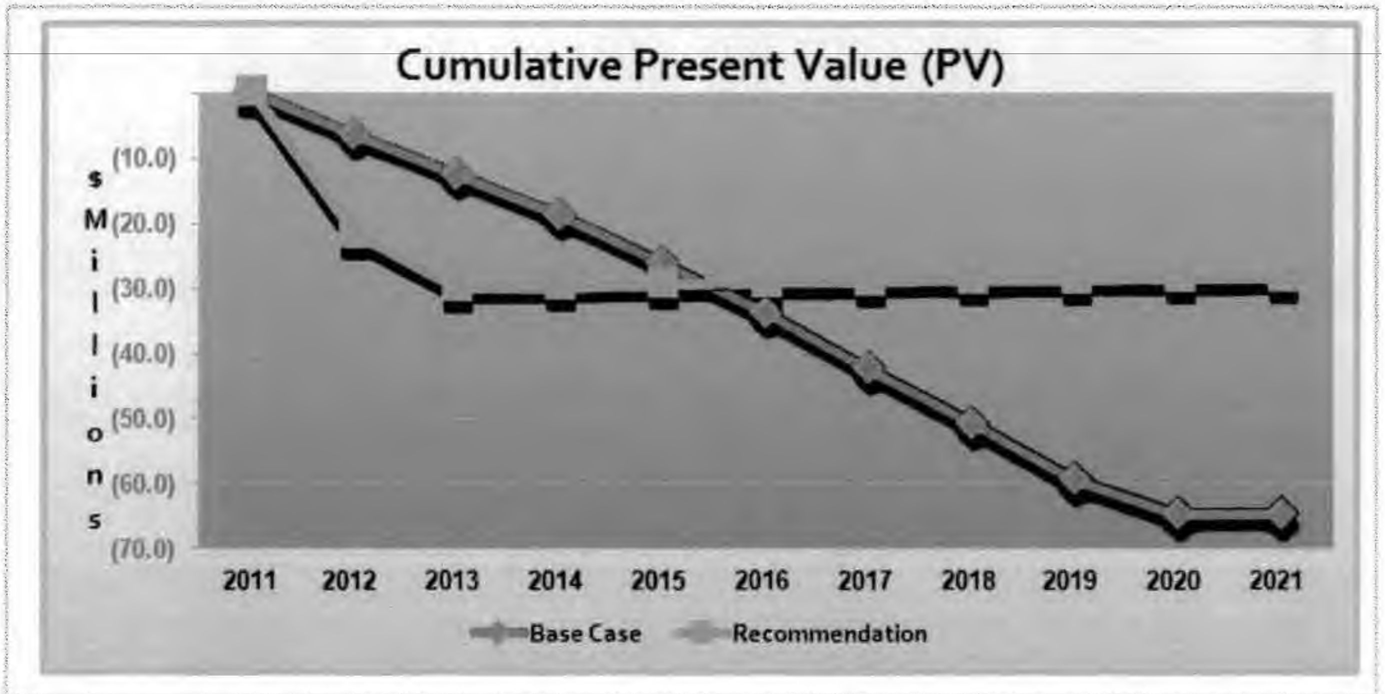
Generation Plan Assumptions:

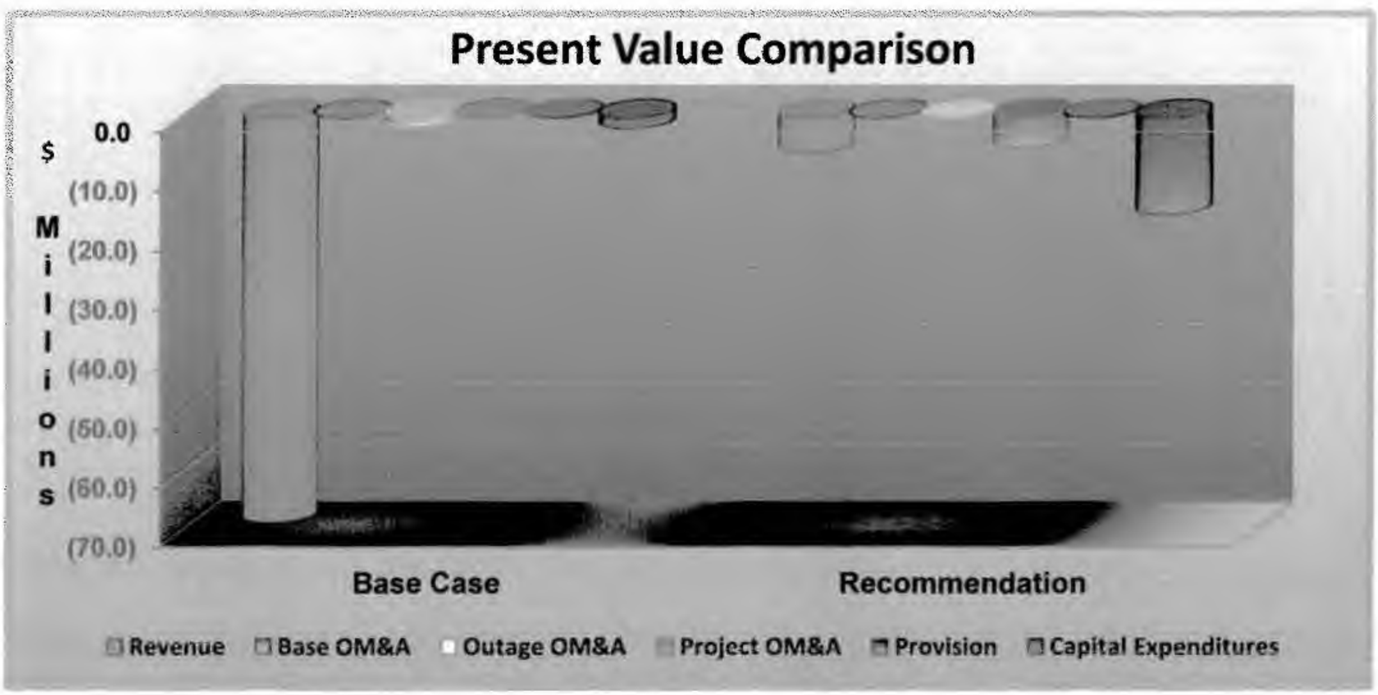
Station	Unit	EOL or Refurb	MW	Planned Outages for Project Work						
Pickering A	1	Jun-20	515	P1211						
	4	Jun-20	515	P1141	P1341					
Pickering B	5	Nov-18	516							
	6	Nov-18	516							
	7	Jun-20	516							
	8	Jun-20	516							
Darlington	1	Sep-16	878							
	2	Feb-18	878							
	3	Sep-19	878							
	4	Jan-21	878							

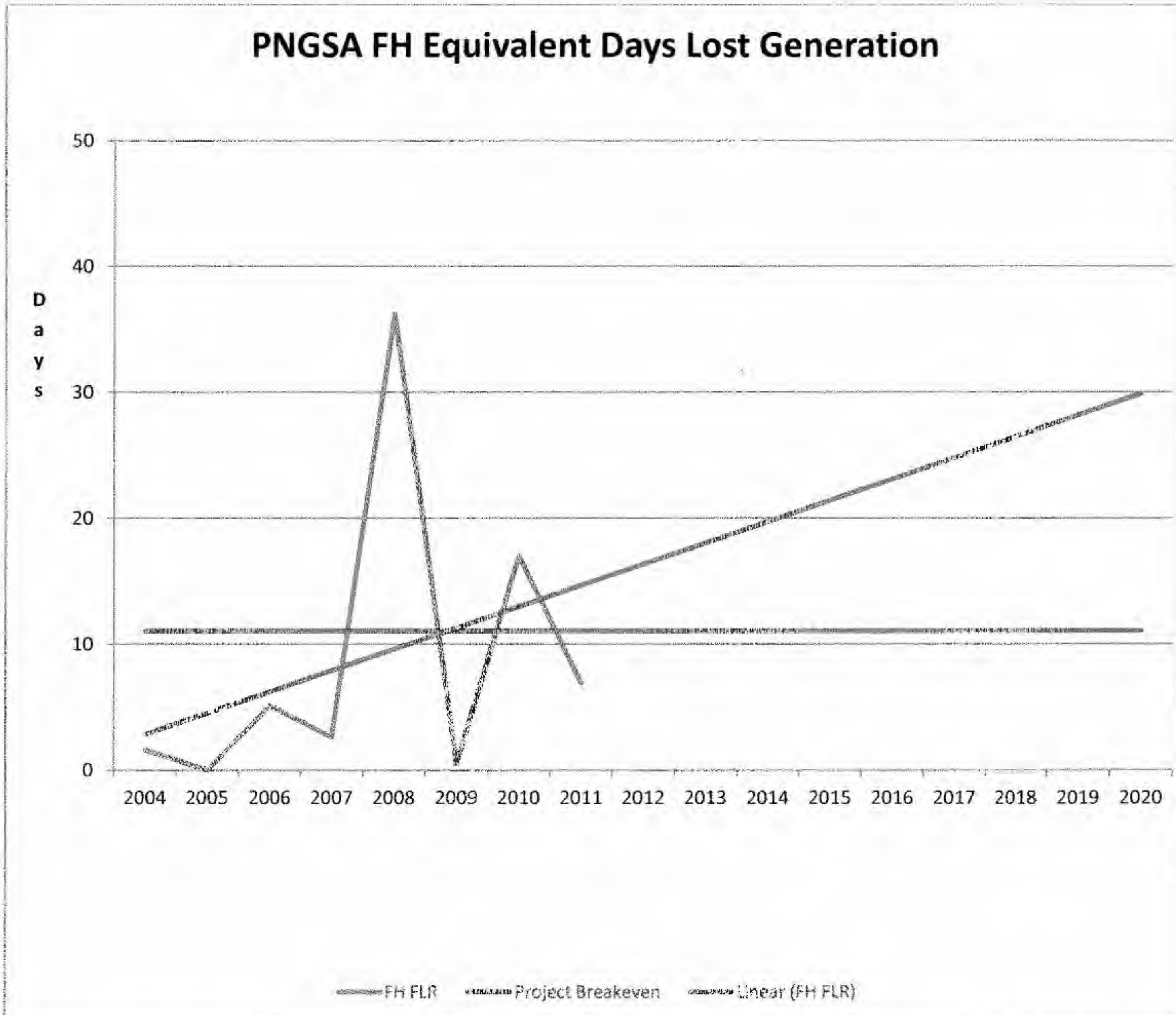
Comments:
If TM Rotor Bearing cannot be replaced in situ, then FT Mechanism replacement will need to be scheduled in a future outage.

APPENDIX "D"

FINANCIAL MODEL – ASSUMPTIONS
Impact on Operations







The number of days lost due to PNGSA fuel handling failures has been trending upwards since re-start in 2004. While some of the lost generation is due to failures other than SPV equipment, it is assumed that SPV equipment failures will be the predominant failure mode going forward. The breakeven point for this $35M project is 11 days equivalent of lost generation due to fuel handling failures (or 5.5 days per unit).

APPENDIX "E"

PROJECT DELIVERABLES
For this Release

Description	Item	Cost ($000's)
Provide Project Mangement Support	Design Projects and Project Controls	1,185
	Project Close Out	67
Provide Engineering Support	Design and Drafting Support	564
	Design Agency Support	200
	Field Eng. Support	877
	EC Close Outs (U1 and U4)	87
Procurement	Unit 4 Materials	500
Construction	Installation of SPVs for Unit 1	[redacted]
	TM Rotor Bearing Tooling Development	
	Installation of remaining SPVs for Unit 4	
	CMO, Rad Protection, ALARA	
Stress Assessments (OM&A)	Ball Screw	
	FM Pressure Boundary	
	FM Carriage Trolley Structure	
Interest	Capital Project	
Contingencies	General Contingency	
	Specific Contingency	
		23,088

PROJECT DELIVERABLES
From Partial Release (Jan 2012 – Mar 2012)

Description	Item	Cost ($000's)
Provide Project Mangement Support	Design Projects and Project Controls, CMO, Rad Protection, Field Engineering	441
Provide Engineering Support	Design and Drafting Support	114
Procurement	Unit 1 Materials	2,263
Interest	Capital Project	[redacted]
Contingencies	General Contingency	
		3,918

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ATTACHMENT "A" **PROJECT COST SUMMARY - 13-46634 (Capital)**

	$ 000's Capital	LTD Dec 2011	2012	2013	2014	2015	2016	2017	Later	Total
Accounting Basis	Project Mgmnt & Support	2,127	1,087	272	131					3,617
	Engineering	441	1,269	394	44					2,148
	Procurement	1,909	2,263	500						4,672
	Construction	[redacted]								
	Other									
										-
										-
										-
	Interest (Capital Project)	[redacted]								
	Project Costs									
	General Contingency									
	Specific Contingency									
	Project Costs	7,220	11,936	7,890	210	-	-	-	-	27,256

	$ 000's Capital		LTD Dec 2011	2012	2013	2014	2015	2016	2017	Later	Total
Funding Basis	**Current Release**	Project Costs	[redacted]								
		Contingency									
		Total									
	Adj to Current Release	Project Costs									
		Contingency									
		Total									
	This Release	Project Costs									
		Contingency									
		Total									
	TTD Released	Project Costs									
		Contingency									
		Total	7,220	11,936	7,890	210	-	-	-	-	27,256
	Future Releases	Project Costs								-	-
		Contingency								(0)	(0)
		Total	-	-	-	-	-	-	-	(0)	(0)
	Project Funding		[redacted]								
	Contingency Funding										
	Total Funding		7,220	11,936	7,890	210	-	-	-	(0)	27,256

		LTD Dec 2011	2012	2013	2014	2015	2016	2017	Later	Total
Budget	2011 - 2015 Business Plan	7,220	8,100	600						15,920
	Variance to Budget	0	1,847	1,808	175	0	0	0	0	3,830
Other	**Removal Costs (above)**									-
	Inventory W / O									-
	Spare Parts in Invent									-

Reviewed by:	**(Date)**	**Approved by:**	**(Date)**
Craig Verwey Project Manager	FEB 10/12	Nahil Rahman Director – Pickering Projects	13Feb2012

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Business Case Summary

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ATTACHMENT "A" PROJECT COST SUMMARY - 13-46635 (OM&A)

	$ 000's Capital	LTD Dec 2011	2012	2013	2014	2015	2016	2017	Later	Total
Accounting Basis	Project Mgmt & Support	34	184							218
	Engineering	20	136							156
	Procurement									-
	Construction									-
	Other									-
	Assessments		[redacted]							
	Interest (Capital Project)									
	Project Costs									
	General Contingency									
	Specific Contingency									-
	Project Costs	54	6,952	-	-	-	-	-	-	7,006

		$ 000's Capital	LTD Dec 2011	2012	2013	2014	2015	2016	2017	Later	Total
Funding Basis	Current Release	Project Costs		[redacted]							
		Contingency									
		Total									
	Adj to Current Release	Project Costs									
		Contingency									
		Total									
	This Release	Project Costs									
		Contingency									
		Total									
	TTD Released	Project Costs									
		Contingency									
		Total	54	6,952	-	-	-	-	-	-	7,006
	Future Releases	Project Costs								-	-
		Contingency								-	-
		Total	-	-	-	-	-	-	-	-	-
	Project Funding			[redacted]							
	Contingency Funding										
	Total Funding		54	6,952	-	-	-	-	-	-	7,006
Budget	2011 - 2015 Business Plan		54	6,150							6,204
	Variance to Budget		0	170	0	0	0	0	0	0	170
Other	Removal Costs (above)										-
	Inventory W / O										-
	Spare Parts in Invent										-

Reviewed by: (Date)	Approved by: (Date)
FEB 10/12	13 Feb 2012
Craig Verwey Project Manager	Nahil Rahman Director – Pickering Projects

Pickering A Fuel Handling SPV Reliability Improvement 13 - 46634 (Capital) 13 - 46635 (OM&A)
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ATTACHMENT "B" PROJECT VARIANCE ANALYSIS

	$ 000's Capital	LTD Dec 2011	Total Project Last BCS Jan 2011	Total Project This BCS Jan 2012	Variance	Comments
Scores Basis	Project Mgmnt & Support	2,161	2,500	3,835	1,335	See comments below.
	Engineering	461	1,100	2,304	1,204	See comments below.
	Procurement	1,909	6,000	4,672	(1,328)	New estimate based on actual cost per OPEX from Unit 4.
	Construction	[redacted]				
	Other					
	Analysis/Assessments					
					-	
					-	
					-	
	Interest (Capital Project Only)	[redacted]				
	Project Costs (Scores Basis)					
	General Contingency					Less is required due to OPEX from unit 4.
	Specific Contingency					
	Project Costs (Scores Basis)	**7,274**	**35,140**	**34,262**	**(878)**	

Other	**Removal Costs included above**				-	
	Inventory to be written off				-	
	Spare Parts in Inventory				-	

Comments:

PM increase due to:

- Field Eng./Rad. Protection/PM costs under estimated in previous release
- Increase in original Project duration

Engineering increase due to:

- Field Eng./FH Technical Support costs now included here vs. PM support.
- Configuration/Engineering cost greater than original estimate
- Additional engineering work for revision to Non-Identical Component Replacement (NICR) to be completed for Electrical Catenaries due to configuration issues.

Construction increase due to:

- Increase in project duration and TM Rotor Bearing Tooling development
- CMO and Rad. Protection costs now included here vs. PM

Pickering A Fuel Handling SPV Reliability Improvement 13 - 46634 (Capital) 13 - 46635 (OM&A)
Full Release Business Case Summary NA44 - BCS - 35300 - 00004 - R000

ATTACHMENT "C" SCHEDULE

Key Milestones

Completion Date	Description
26-Sep-12	Start of Installation, Unit 1, P1211 - SOI
2-Jan-13	Operations Acceptance/Readiness for Service for Unit 1 - AFS
9-Oct-13	Start of Installation, Unit 4 (remaining SPVs) , P1341 - SOI
30-Dec-13	Operations Acceptance/Readiness for Service for Unit 4 - AFS
30-Dec-14	Project Complete Milestone - PSM

A Project Execution Plan (PEP) will be approved by 29-Feb-12

In Service Declarations: (Capital only)

Date	Description	$000's (Total = Project Cost excl contg)	% In Service (= 100%)
31-Dec-11	SPV's in service in Unit 4 (P1141)	7,298	37
2-Jan-13	SPV's in service in Unit 1 (P1211)	10,426	53
20-Dec-13	Remaining SPV's in service in Unit 4 (P1341)	2,026	10
		19,750	100

Comments:

Pickering A Fuel Handling SPV Reliability Improvement 13 - 46634 (Capital) 13 - 46635 (OM&A)
Full Release Business Case Summary NA44 - BCS - 35300 - 00004 - R000

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 100	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule 12 month	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.:Clean-up costs > $15MCat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages ORMajor degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's OrderCat. A spill (45 - 55 pts)Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact.Minor local damage	Systematic non-compliance with potential for finesORPotential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spillsEmission in exceedance of regulatory or legal limitsField orders or AMP'sPublic complaints with OPG implicationsDanger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project scheduleORPossibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first aid. Complete recovery by worker.	Cat. C spills - reportableAdministrative infractionsPublic Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on qualityRoutine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-complianceORRoutine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker	Administrative, non-reportable eventsCat. C spills non-reportable and spills resulting from Acts of God	

Attachment "E" **Project Scope**

The project scope is divided between two funding classes, Capital and O&MA. Scope of work for each funding class is listed below:

Capital – SPV's Replacement:

I. U1/U4 Fuelling Machine SPV parts Replacement/Refurbish/Overhaul

- Y drive Pillow Block Bearings replacement (SPV#10)
- Y drive Mitre box replacement (SPV20)
- Guide Column Reducing gear box (SPV30)
- Guide Column Ball nuts overhauling and tooling development (SPV35)
- Modification and replacement of wiring harness (SPV 195-515)
- Replacement of Catenaries (SPV 565)

II. U1/U4 FM Vault SPV parts Replacement/Refurbish/Overhaul

- Rolling shield Reducing gear box (SPV40)
- Rolling shield Mitre box (SPV45)
- Rolling shield chains (SPV55)
- Rolling shield Pillow block bearings (SPV56)
- Rolling shield Couplings (SPV50)
- Rolling shield sprockets (SPV57)
- Thrust bearing (SPV610)

III. Fuel Transfer mechanism SPV parts Replacement/Refurbish/Overhaul

- Ferguson drive clutch & brake (SPV145)
- Cable harness (SPV 170-190, 471,472.1,473.1,474.1,476.1,477.1,478.1,479,481,482.1,483.1,484)
- Elevator carriage overhaul (SPV 585)
- Fuel transfer bearing cam follower (SPV590)
- Transfer mechanism Carriage bearing /bushing (SPV 595)
- TM Ferguson drive (SPV 600)
- Fuel Transfer mechanism Overhaul (SPV 875)

- Elevator gear box (SPV 995)
- Elevator carriage (SPV 1000)
- Elevator top housing snout assembly (SPV 1005)
- Elevator top housing intermediate assembly (SPV 1006)
- Elevator top housing Take up assembly (SPV 1007)
- Elevator top housing sprocket (SPV 1010)
- Elevator top housing spherical roller bearing (SPV 1015)
- Roller bearing (SPV 1020)
- Elevator top housing sprocket assembly (SPV 1025)
- Elevator chain (SPV 1030)
- Elevator bottom housing sprocket (SPV 1035) (inspection only)
- 1&4-35230-DM2 (SPV 150)

IV. Irradiated fuel bay SPV parts Replacement/Refurbish/Overhaul

- Conveyor Cart Overhaul and develop tooling (SPV 580)

V. Stress analysis of FM pressure boundary and load bearing components for life extension.

- Carriage/Trolley load bearing structure/welds SPV 130
- FM Pressure Vessel SPV 135

VI. Non SPV oil Catenaries

- Oil Catenaries SPV 956

VII. Non SPV D2O Catenaries

- D2O Catenaries SP V957

OM&A – Assessments:

I. Ball Screw Stress Assessment

II. FM Pressure Boundary Stress Assessment

III. FM Carriage Trolley Stress Assessment

ONTARIO POWER GENERATION

Recommendation for Submission to the Board of Directors

November 15, 2012

DARLINGTON REFURBISHMENT PROJECT
DETAILED PLANNING - 2013 DEFINITION PHASE - PARTIAL RELEASE

EXECUTIVE SUMMARY:

The purpose of this memorandum is to provide an update on the status on the Darlington Refurbishment Project and to request an incremental release to continue detailed planning within the Definition Phase of the project.

Life to Date actual cost, as of September 30, is $295M on a plan of $347M with a CPI of 1.14. Cumulative Definition Phase spend, at year end 2012, is forecast to be $380M on a plan of $436M. The overall program SPI is 0.96 and all program milestones within the Definition Phase are on or ahead of plan, with one exception. The Level 3 Definition Phase schedule planned for completion by October 15th will be completed by December 15th.

The CNSC public environmental assessment hearing is scheduled for December 3rd to 6th. OPG continues to respond to CNSC questions on the Integrated Safety Review (ISR) code review reports and safety factor reports.

The Re-tube and Feeder Replacement (R&FR) project remains on plan and detailed reviews of the contractor's definition phase Level 3 schedule and cost estimate are ongoing. Turbine/Generator contract negotiations with the original equipment manufacturer have concluded without being able to reach a satisfactory agreement. Management is executing "Plan B" which consists of separating the scope into Original Equipment Manufacturer (OEM) only scope and other scope. The project is evaluating alternate vendors and contract strategies for the other scope and has started discussions with Alstom for the OEM only scope. Management has also commenced contract planning for the reactor defueling work program.

The Darlington Energy Complex, which will house a full-scale reactor mock-up as well as warehouse facilities and offices, is ahead of schedule with the potential for an early occupancy around mid 2013.

Scope definition to the system level is progressing well for all projects. Management is continuing to develop its overall project plan and estimate based on results of the scoping process. Further details on the project status are provided in the attached 'Darlington Refurbishment Program Status Report' for the period ending September 30, 2012.

As provided in Appendix 1, the Darlington Refurbishment overall project cost estimate remains less than $10B (2009$) or $10.8B (2012$), excluding interest and escalation. Management continues to have a high confidence that the refurbishment of the Darlington units will result in a Levelized Unit Energy Cost (LUEC) of less than 8.0¢/kWh (2009$) or 8.6¢/kWh (2012$). The economics of Darlington Refurbishment are comparable with Combined Cycle Gas Turbines (CCGT). The continued uncertainty in long term price of gas, the cost of a CO_2 adder and the future of shale gas makes the refurbishment of Darlington an attractive option for Ontario.

Management is seeking incremental release of $492M to complete 2013 detailed planning deliverables within the Definition Phase, resulting in a total cumulative release of $928M for the project. Details of this release request are provided in Appendix 2.

Included in this request is the incremental release for Facility and Infrastructure projects to support the Darlington Refurbishment Project and extended operations of the Darlington station for an additional 30 years, including 2013 release for a new Auxiliary Heating System Facility, West Security, Office and Lunchroom / Change Room Facility, R&FR Island Support Annex, and Refurbishment of the Operations Support Building. These projects will be managed within the overall program using the internal gating/release process. Management will continue to provide quarterly status reports on the progress of these projects.

A recommendation to the Board on OEFC - Darlington Refurbishment Definition Phase Financing is being separately submitted.

RECOMMENDATION

That the Board of Directors:

- Approve a release of $492M for 2013 detailed planning deliverables (including 2013 funding for Facilities and Infrastructure projects), for a total cumulative release of $928M for the Definition Phase.

Recommended By:	**Approved for Submission to the Board of Directors**
"Original signed by:"	*"Original signed by Donn Hanbidge on behalf of :"*
Albert Sweetnam Executive Vice President, Nuclear Projects	Tom Mitchell President and Chief Executive Officer

This Board memorandum was reviewed and approved for submission to the Board of Directors by the Nuclear Oversight Committee on November 13, 2012.

APPENDIX 1 - UPDATE ON THE DARLINGTON REFURBISHMENT PROJECT ECONOMICS

The Darlington Refurbishment Project has been assessed against other feasible generation projects which OPG might consider, including new Combined Cycle Gas Turbines (CCGT). The following is a summary of the economic assessment.

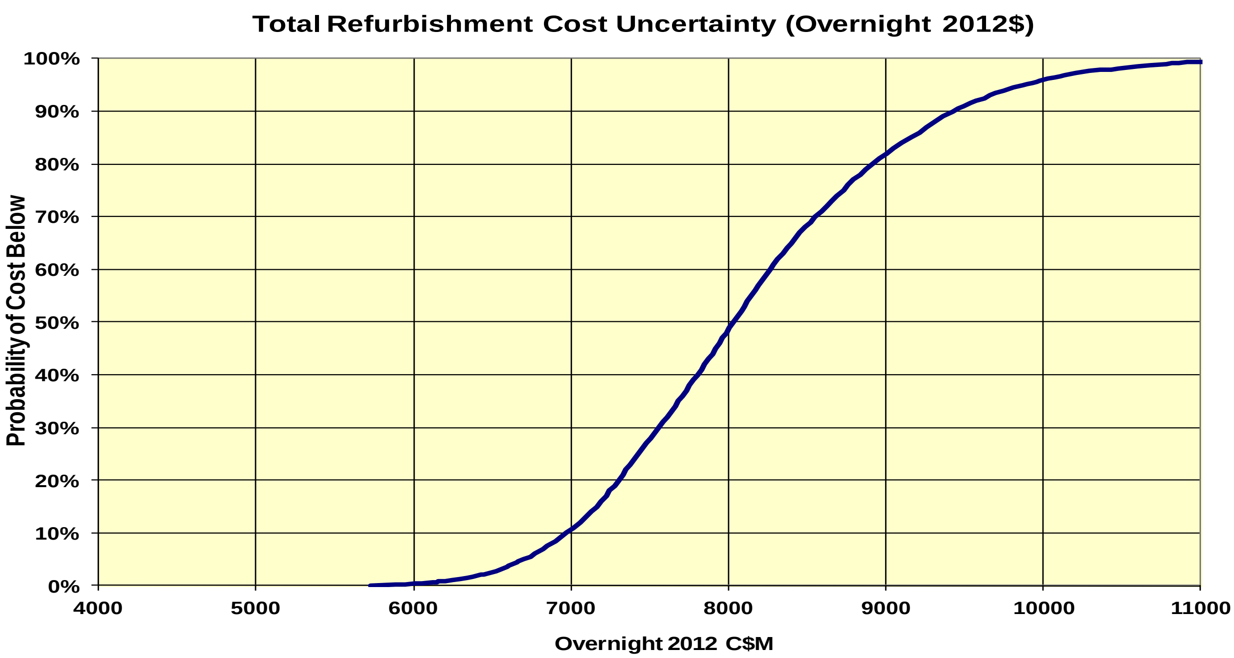
Summary of the Economic Assessment

The Darlington Refurbishment Screening Level Economic Assessment was prepared and was endorsed by the Darlington Management Advisory Committee on September 29, 2008 and subsequently reported to the Nuclear Generation Projects Committee of the Board on November 19, 2008. In November 2009, based on the economics of the project as documented in the Preliminary Business Case, the OPG Board of Directors approved the overall timeline and release strategy for the refurbishment, and released funds to complete the Preliminary Planning within the Definition Phase of the Darlington Refurbishment Project, and commence development of the required infrastructure. In November 2011, the OPG Board of Directors released additional funds to commence the Detailed Planning work in the Definition Phase.

The economic assessment has been updated to reflect current knowledge and understanding of the Darlington Refurbishment Project and to reflect additional experience from other refurbishment projects.

As shown in Figure 1 below, the Darlington Refurbishment Project overall costs estimate remains less than $10B (2009$) or $10.8B (2012$) which is consistent with the Preliminary Business Case of November 2009. This amount includes contingency and excludes interest and escalation.

Figure 1: Darlington Refurbishment Project Cost Confidence Ranges



The current expectation on schedule duration remains an average of 36 months per unit, with a total duration of 88 months assuming 19 and 17 month overlaps between units.

The future operating costs and performance of Darlington are a significant aspect of the economic assessment. An updated analysis has been completed of past performance in order to forecast the expected capability factor for the Darlington units in the post-refurbishment period. The following table summarizes the refurbishment and key post-refurbishment costs and performance assumptions used in the economic assessment.

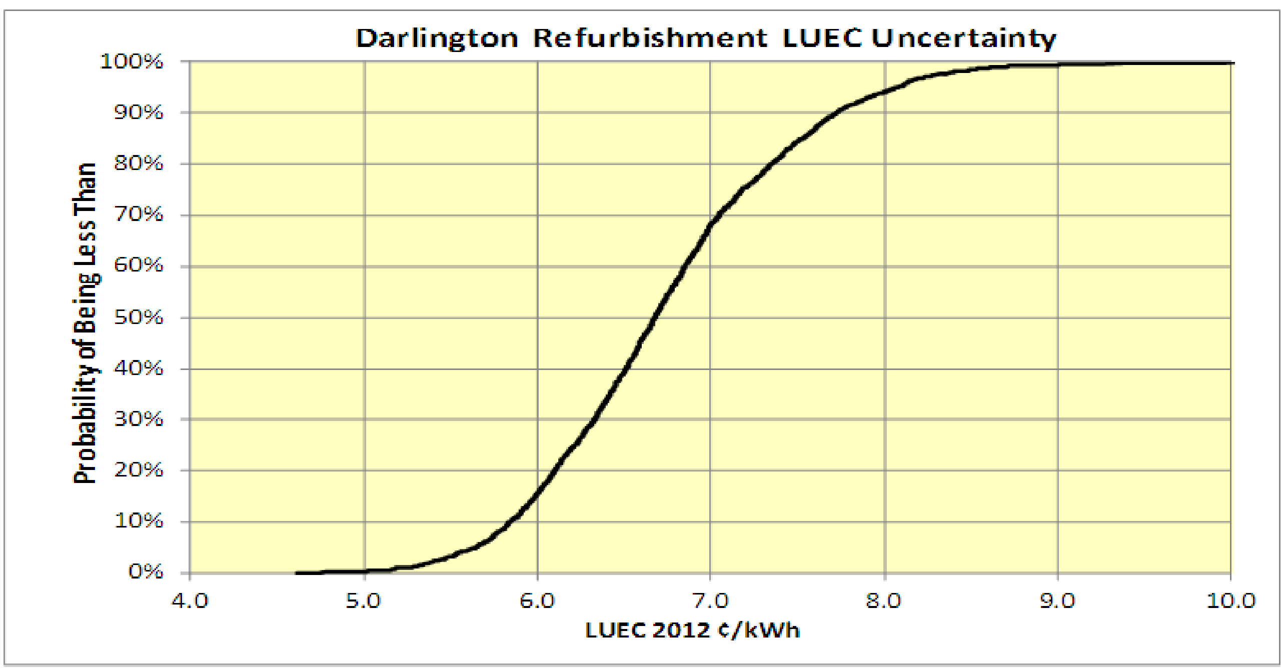
Table 1: Current Darlington Refurbishment/Post-Refurbishment Costs and Performance Forecasts

	Low Confidence (10%)	Medium Confidence (50%)	High Confidence (90%)	Opportunity
Refurbishment Cost ($B) Overnight Costs (2012$) Total Cost – 4 units [1] Avg. Cost per Unit	[redacted]	[redacted]	[redacted]	Lower overall project costs by applying lessons learned, effective planning and control of scope, and execution excellence and exploiting economies of scale
Post Refurbishment Capability Factor	93%	88%	83%	Replacing equipment in refurbishment that allows increased unit reliability
Post Refurbishment Annual Costs [2] (2012$M/yr)	[redacted]	[redacted]	[redacted]	Through business transformation continue to lower the direct and indirect costs of operations

Notes:
(1) Total Cost includes Interest and Escalation.
(2) Includes Station Base (OM&A), Outages (OM&A), and Projects (Capital and OM&A) and Nuclear and Corporate Support; excludes Fuel & Fuel Related

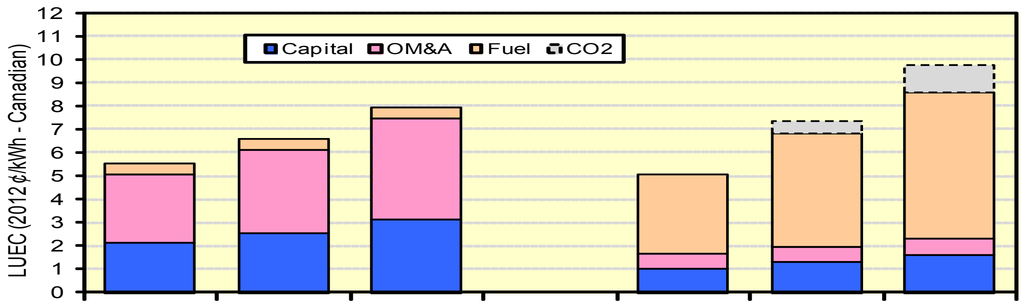
As shown in Figure 2 below, OPG continues to have high confidence that the refurbishment of Darlington will result in a LUEC of <8.0 ¢/kWh (2009$) or <8.6 ¢/KWh (2012$), which is consistent with the LUEC reported by OPG in 2009.

Figure 2: Darlington Refurbishment Levelized Unit Energy Cost Confidence Ranges



The economics of Darlington Refurbishment are comparable with Combined Cycle Gas Turbines (CCGT); however, there is uncertainty in gas plant power costs including the cost of CO_2 and the future of shale gas, as shown in Figure 3 below.

Figure 3: Levelized Unit Energy Costs for Darlington Refurbishment and Comparators



Assumptions:	Darlington Refurb				New CCGT		
	Low	Median	High		Low	Median	High
Overnight capital (C$B)	[redacted]				[redacted]		
Overnight capital (C$/kW)							
Annual Capacity Factor (%)	93%	88%	83%		93%	88%	83%
Gas Price (C$/mmBtu @ Henry Hub)					4	6	8
CO_2 Offset Cost (C$/tonne)					0	15	30

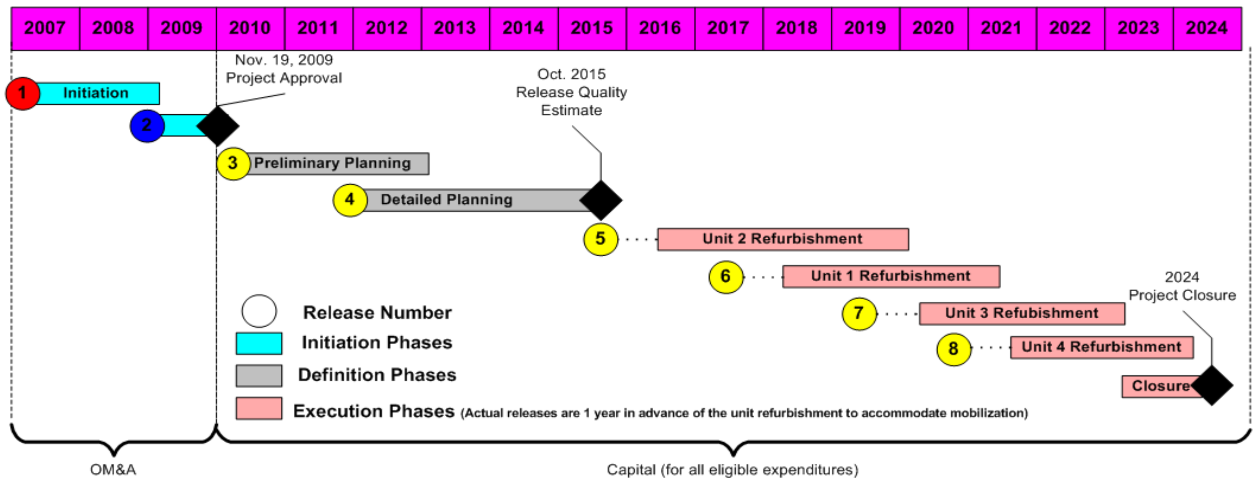
Recommendation

On the basis of this updated analysis which continues to show that the refurbishment of Darlington is economic relative to other generation options, Management recommends proceeding with further detailed planning expenditures in the Definition Phase of the Darlington Refurbishment Project.

APPENDIX 2 – DEFINITION PHASE RELEASE, RELEASE 4B – 2013 DETAILED PLANNING

In accordance with the approved release strategy (Figure 1), funding in the amount of $548M is required to complete 2013 deliverables of the Definition Phase; including $56M already released. The incremental release amount for 2013 Detailed Planning deliverables (Release "4b") is $492M.

Figure 1: Darlington Refurbishment Release Strategy



Summary of Detailed Planning Release Request

2013 deliverables for the Definition Phase include:

- Environmental Assessment approval
- Preparation and submission of the Global Assessment and Integrated Improvement Plan to the CNSC
- Negotiation of major contracts, e.g. Turbine/Generator, Fuel Handling and Steam Generator Primary Side Clean
- Completion of first refurbishment unit modification design requirements, and commencement of detailed engineering
- Detailed design for Safety Improvements, e.g. 3rd Emergency Power Generator, Containment Filtered Venting System, Powerhouse Steam Venting System
- Identification of long lead materials and initiation of procurement
- Completion of the Darlington Energy Complex
- Execution of approved Facilities and Infrastructure projects (D2O Storage and Drum Handling Facility, Water and Sewer Mains, Site Electrical Power Distribution System Upgrade, West Security, Office and Lunchroom / Change Room Facility, R&FR Island Support Annex, Operations Support Building, Auxiliary Heating System Facility)
- Construction of the reactor mock-up
- Design and fabrication of R&FR tooling
- Execution of pre-refurbishment 2013 online and unit outage work orders
- Development of site transition plans, e.g. for programs, staff, processes, etc. transitioning between the Darlington station and Refurbishment
- Training of additional authorized and licensed staff

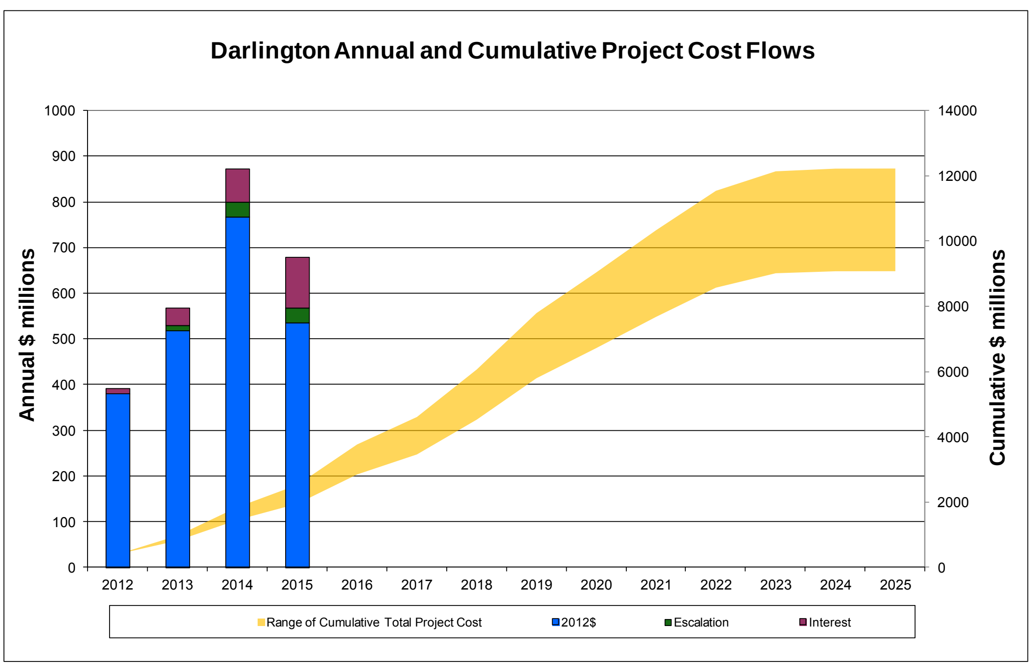
The following table provides a summary, by major category and year, of the planned definition phase funding requests.

Table 1: Darlington Refurbishment Definition Phase Estimate Overview

		Categories	Description of Work	Definition Phase					Definition Phase vs Release 4a		
				LTD 2012	2013 Release 4b	2014 Release 4c	2015 Release 4d	Total	Nov'11 (2011$)	PoP	Variance
	Direct Work	Major Contracts (RFR, Fuel Handling, Steam Generators, Turbine Generators)	Contract award, tooling & mock up, engineering, long lead materials	75	221	363	200	860	761	99	Cashflows updated based on contract award in 2012.
	Direct Work	Balance of Plant	Pre requisite work, Safety Improvement Opportunities, Islanding, Eng Projects	5	39	96	84	224	153	71	Scope rationalization ongoing, offest by maintenance cooling project
	Direct Work	Operations/Maintenance Support	Programs, cyclical outage work, system shutdown	6	12	16	31	65	86	(20)	
	Direct Work	Infrastructure Projects	Infrastructure requirements for NR (inside/outside station) , Station 2nd Life Projects, D20, Holt Road	110	89	151	63	414	359	55	New Holt Rd Interchange; advanced Facilities from execution phase
				196	362	627	378	1,563	1,358	205	
	Support	Program Support and Oversight	Program oversight and project management; includes engineering, project controls, supply chain, quality management, infrastructure and facility costs.	132	86	89	94	401	406	68	Improved understanding of program oversight requirements including external oversight.
	Support	Regulatory	Nuclear Safety ISR/ IIP/ GA, CNSC, EA, Licensing Support	38	15	13	8	73			
				170	100	102	102	474	406	68	
	Reserve	Contingency	Includes F&IP	[redacted]							Contingency allocated to R&FR contract as a result of fixed firm price contracts for tooling and mock-up and Fuel Handling based on scope confirmation.
$ of Year	Financial	Interest									
$ of Year	Financial	Escalation	Mgmt Reserve not escalated								
Subtotal Request to BoD (NR Program)				380	548	857	650	2,434	2,311	123	

Figure 2 shows the ccumulative project expenditures for the high confidence estimate, including interest and escalation, which upon completion of the Release Quality Estimate in 2015 will be approximately $2.4B.

Figure 2: Darlington Refurbishment Release Strategy



Financing for the Definition Phase

Refer to OEFC - Darlington Refurbishment Definition Phase Financing recommendation for submission to the Board of Directors, dated November 15, 2012.

Summary of Overall Project Estimate

The project estimate and resulting cash flows continue to be fine-tuned as part of the Definition Phase work and will be finalized at RQE in 2015.

The project estimate is based on the following assumptions.

- First unit refurbishment start date – October 2016
- Duration of refurbishment (4 units) – 36 months each, 88 months total
- Estimate is in overnight $2012M (excluding interest and escalation)
- Estimate is based on scope approved by the Scope Review Board, assumed contractor costs, and detailed OPG costs. As contracts are awarded and contractor estimates are refined, the project estimate will be updated.
- Contingency is based on an assessment of estimate uncertainty (price, quantity, productivity) as well as an assessment of discrete project risks.
- The refurbishment project organization will perform oversight of EPC vendors and will operate the unit during the refurbishment period.

As noted in Appendix 1, the Darlington Refurbishment Project overall costs estimate remains less than $10B (2009$) or $10.8B (2012$), excluding interest and escalation, which is consistent with the Preliminary Business Case of November 2009.

Table 3 provides the estimate both with and without interest and escalation. Table 3 also provides a breakdown by major scope category including core refurbishment scope, scope related to operating and maintaining the plant during refurbishment, as well as value enhancing scope which will improve plant performance post refurbishment. Further, Table 3 provides, separately, estimates for facility and infrastructure projects related to the extended operations of the Darlington station for an additional 30 years (including refurbishment of the Operations Support Building and a new Auxiliary Heating System Facility) and provision funded amounts for interim waste storage including reactor waste canisters (“RWC”) and an interim storage facility.

Table 3: Darlington Refurbishment Overall Project Estimate

		Categories	Program Estimate: Nov '12	Program Estimate: Nov'11	Program Estimate: PoP ('12 - '11)	Program Estimate: Explanation	Nov'12 Estimate: Refurb (Core)	Nov'12 Estimate: Ops & Mtce Support (OM&A)	Nov'12 Estimate: Value Enhancing	Nov'12 Estimate: Total
In 2012$s	Direct Work	Major Contracts (RFR, Fuel Handling, Steam Generators, Turbine Generators)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Direct Work	Balance of Plant	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Direct Work	Operations/Maintenance Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Direct Work	Waste Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Direct Work	New Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Direct Work	Infrastructure Projects	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Direct Work		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Support	Program Support and Oversight	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Support	Regulatory	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Support		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Cont'gy	Contingency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s	Cont'gy		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In 2012$s			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$ of Year	Fin'l	Interest	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$ of Year	Fin'l	Escalation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$ of Year			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$ of Year	**Subtotal (NR Program - excl. Provision, F&IP CS)**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prvsn.		Retube Waste Containers/ RWSB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prvsn.			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prvsn.	**Subtotal (including Provision)**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
F&IP CS		Infrastructure Projects - Station - CS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
F&IP CS		Contingency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
F&IP CS		Interest	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
F&IP CS		Escalation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
F&IP CS		Subtotal F&IP CS Projects	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
F&IP CS	**Grand Total (including Provision & F&IP CS)**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

OPG continues to benchmark its cost and schedule assumptions and plans against other Candu refurbishments. OPG's refurbishment schedule is based on the Wolsong refurbishment actual duration, pro-rated to account for Darlington's larger unit size (480 fuel channels in a Darlington unit vs. 380 fuel channels in a Candu 6 design). OPG costs have economy of scale advantages (4 units vs. 1 unit) when compared to Candu 6 single unit refurbishments. Table 4 provides a comparative assessment, based on publicly available information, of the current cost and schedule of the Darlington Refurbishment as compared to other existing refurbishments.

Table 4: Darlington Refurbishment Comparison to Other Refurbishments

Station (Per Unit)	Start Date	Planned /Actual Duration (Months)	Planned /Actual Cost	Comments
Darlington	OCT 2016	36/TBD	[redacted]	Based on current estimate, net of provision, including interest and escalation; [redacted]
Pt. Lepreau	MAR 2008	[redacted]	[redacted]	Schedule delay largely due to Calandria Tube leak.
Wolsong	APR 2009	[redacted]	Not Available	Cost information is not available for Wolsong.
Bruce A Units 1 & 2	OCT 2005	[redacted]	[redacted]	Scope includes replacement of Steam Generators as well as large Balance of Plant scope due to fact that units were in a lay-up state prior to refurbishment. Actual Duration assumes generator issue at Unit 2 will be resolved before the end of November 2012. [redacted]
Gentilly 2	Was APR 2014	[redacted]	[redacted]	[redacted]

Recommendation

On the basis that the refurbishment of Darlington is economic relative to other generation options, Management recommends the release of $492M, for 2013 detailed planning deliverables for a total cumulative release of $928M for the Definition Phase.

ONTARIOPOWER GENERATION

Report

OPG Confidential Commercially Sensitive	
Document Number: NK38-REP-09701-10021	Usage Classification: N/A
Sheet Number: N/A	Revision: R000

Title:
CONTRACTING STRATEGY FOR TURBINE GENERATORS

Contracting Strategy For Turbine Generators

NK38-REP-09701-10021

2012-08-31

Order Number: N/A
Other Reference Number:

OPG Confidential
Commercially Sensitive

Recommended by: Oct 5, 2012
Todd Josifovski, Date
Project Director, Turbine Generators
Refurbishment Execution

Concurred by: Stephen Mills Oct. 5, 2012
Stephen Mills, Date
VP, Nuclear Commercial Development

Approved by: Oct 5, 2012
Dietmar Reiner, Date
SVP, Nuclear Refurbishment

Revision Summary

Revision Number	Date	Comments
R000	2012-08-31	Initial issue

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1.0 EXECUTIVE SUMMARY

The Darlington Refurbishment ("**DR**") Commercial Strategy identified a need to establish separate contracting strategies for each of the major projects under the DR Program. The recommended contracting strategy is based on the business drivers and commercial principles set out in the DR Program Commercial Strategy and specific contracting considerations relevant to the Turbine Generator ("**TG**") Project ("**Project**").

The Darlington TG sets were custom designed and are unique to Darlington Nuclear Generating Station ("**DNGS**"). The Project under the DR Program is a combination of piecemeal retrofits, repairs of hardware, hydraulics and full controls upgrades. Successful planning and execution of this work will need a large amount of technical integration and accurate interfacing. The contracting strategy for the Project thereby recommends bundling the following work into one package for contracting purpose as the most preferred option:

- Turbine High Pressure, Low Pressure, and Auxiliaries repairs/replacements
- Generator Rotor, Stator, and Auxiliaries repairs/replacements
- Moisture Separator Reheater repairs/replacements
- Turbine Controls Upgrade
- Generator Controls Upgrade

Bundling the work in this manner allows work to be efficiently scoped, planned, scheduled, and managed in accordance with the DR Program schedule.

Having considered various contracting and sourcing models, the TG Project Team concluded the nature of the TG work will fit well into the procurement model for an Engineering, Procurement and Construction ("**EPC**") contract. The recommended approach is to negotiate acceptable contract terms with the Original Equipment Manufacturer ("**OEM**") as the primary option while in parallel continue to perform the preparatory work that would allow OPG to pursue, in whole or in part, a competitive bidding process as a backup option. This approach will allow OPG to minimize impact on the DR Program schedule, if OPG decides to cancel the negotiations with the OEM for any reason (including for reasons of not being able to achieve the negotiation objectives within a specified time frame) and continue pursuing other sourcing alternatives.

Various pricing models were considered by the Project Team. The recommended pricing models vary based on the nature of the work and have been determined based on operational knowledge/experience.

The approach recommended in this contracting strategy is expected to allow OPG to achieve the DR Program and Project objectives, as well as post-refurbishment goals within acceptable risk thresholds and value for money considerations.

2.0 INTRODUCTION

2.1 Background Information

The Project is one of the major projects within the DR Program. The goal of the Project is to complete a major overhaul and upgrade of the turbine generator sets and their control systems to extend the life of the equipment for an additional 25 to 30 years. Five separate and distinct phases have been identified, presented to the DR Scope Review Board ("**SRB**")[1] and approved at Project Gate 0 on May 5, 2011:

(a) Steam Turbines and Turbine Auxiliaries: inspections, repairs, and/or replacements of High Pressure ("**HP**") and Low Pressure ("**LP**") turbine components and a number of turbine auxiliaries;

(b) Generator and Generator Auxiliaries: inspections, repairs, and/or replacements of generator components (including generator stator rewind) and a number of generator auxiliaries,

(c) Moisture Separator Reheater ("**MSR**"): inspection, overhaul, and/or replacements of MSR internals and auxiliaries (e.g. strainers, valves);

(d) Turbine Control Upgrade: replacement of the obsolete analogue Steam Turbine Electronic Control ("**STEC**") System, includes entire Turbine Supervisory System with modern design (digital system); and

(e) Generator Excitation Upgrade: replacement of the obsolete Generator Excitation system controls with modern design (digital system) and a set of additional Generator Excitation and Protection equipment to resolve obsolescence.

Based on the Class 5 estimates[2] developed in 2011 for the above work, the total estimated value for the Project is around $510 M, of which around [redacted] is the

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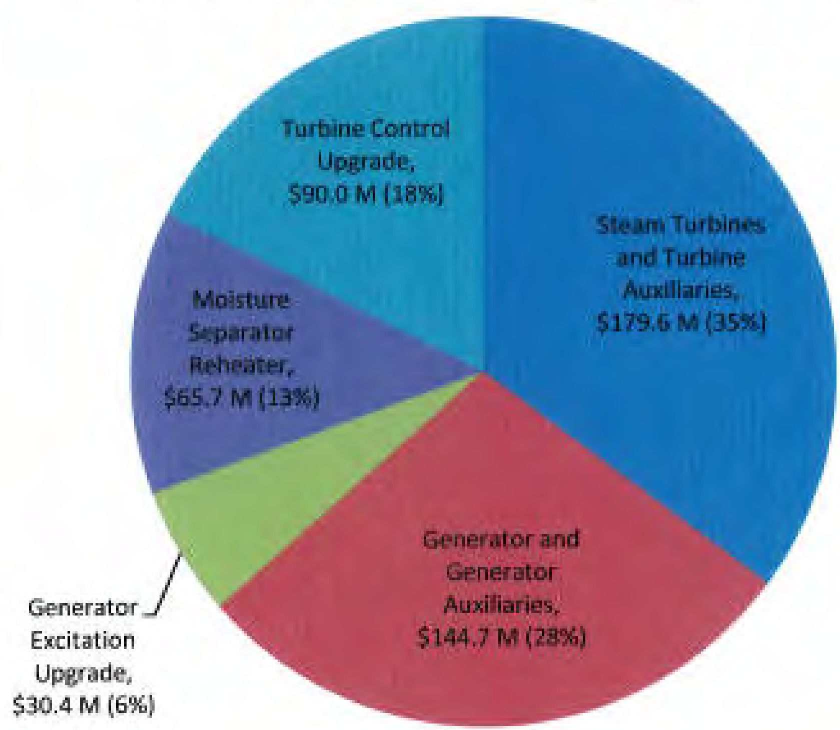
[1] *The purpose of the SRB is to:*
- *challenge the proposed refurbishment work scope to ensure work is necessary for the successful refurbishment of Darlington;*
- *align the scope with the objectives of maintaining/improving reliability and lowering production costs; and*
- *ensure investments in refurbishment deliver value for money.*

[2] *Cost Estimate Classification System from the Association for the Advancement of Cost Engineering (AACE) which maps the phases and stages of project cost estimating together with a generic maturity and quality matrix. The Project Class 5 estimates are based on current Darlington Scope Request (DSR) forms, prepared at the initial stages of project definition based on limited information.*

confirmed scope and [redacted] is classified as the contingency scope.[3] The contingency scope is the work that has been identified as "potentially required". A set of contingency items are listed for the Steam Turbine and Turbine Auxiliaries, Generator and Generator Auxiliaries and MSR phases. Once inspections and analyses are complete, recommendations will be made as to whether this scope of work is required.

Although some of the work can be done as part of Darlington's project portfolio for inspection and maintenance, the whole work is planned to be executed during the refurbishment outage for efficiency to minimize outage schedule. The breakdown of work sub-packages by estimated $ value (and % value) is presented below. These estimates may change over time as the project definition phase progresses and will be updated.

Figure 1: Cost Breakdown by Scope of Work



[3] *In addition to the above estimates, approximately $60 M of turbine related operations & maintenance ("OM&A") cyclical work (e.g. regular equipment maintenance activities, removal and installation of the HP casings, etc.) are also planned for execution during this Project.*

The Darlington TGs were originally designed, manufactured and installed by Brown Boveri Canada Inc. ("**BBC**"). BBC, the OEM has since undergone a number of changes as a business entity – BBC was bought out by Asea Brown Boveri ("**ABB**") and subsequently ABB's TG business segment was bought out by Alstom Power ("**Alstom**"). Currently, Alstom is the OEM on record and has been providing technical, engineering, maintenance and outage support services for the Darlington TG units. These TG sets are considered specialized products, unique in North America as they were custom designed specifically for Darlington.

2.2 Objectives and Scope of Strategy

The key purpose of this document is to set out the overall contracting strategy for delivery of the Project scope of work. This document will:

(a) Identify the contracting alternatives suitable for the Project;

(b) Document evaluation considerations; and

(c) Recommend a contracting strategy (including strategy around sourcing and pricing).

A Contracting Strategy Summary for Turbine Generators (NK38-REP-09701-10030-R000) was prepared to provide an overview and key drivers for the proposed contracting strategy. That document was reviewed and approved by the EVP, Nuclear Projects on March 9, 2012. As the Project Team progresses with the recommended path forward, this document was created to provide a more in-depth analysis of the main alternatives and key factors considered by the Project Team in the process of developing the proposed contracting strategy.

2.3 Development Process

The Project Team was established in early March 2011 with representation from Engineering, Execution, Supply Chain and Commercial Strategy (renamed Nuclear Commercial Development in June 2012). This core Project Team commenced the strategy development work through understanding the scope of work with the review and analyses of background information available from OPG's 2010 Darlington Steam Turbine Electronics Controls Project (DN STEC Upgrade Project 16-33973), relevant internal and external operating experience ("**OPEX**") and results from comprehensive Component Condition Assessments ("**CCA**"). The Project Team identified and analyzed potential options around work packaging, contracting approaches/models and pricing options. Inputs were also solicited from other key stakeholders within the company and external sources.

Figure 2: TG Project Team involved in the contracting strategy analysis

3.0 STAKEHOLDER ANALYSIS

In addition to the Project Team engaged in strategy development, key stakeholders groups who provided input included representatives from Law (internal and external counsel from Blake, Cassels & Graydon, LLP), Finance, DR Planning & Control and Hydro Supply Chain. The recommended strategy was also communicated to the Chief Supply Officer ("**CSO**") and the following committees:

- DR Program Level Cross-Functional Sourcing Team ("**CFST**")
- Refurbishment Project Executive Team ("**RPET**")
- Nuclear Executive Committee ("**NEC**")
- Executive Advisory Committee ("**EAC**")
- Nuclear Oversight Committee ("**NOC**") of OPG's Board of Directors

4.0 CONTRACTING CONSIDERATIONS

In developing the contracting strategy for the Project, the Project Team took into consideration the need to ensure the achievement of OPG's business objectives and the DR Program and Project objectives while keeping with Guiding Commercial Principles as outlined in the DR Program Commercial Strategy (NK38-REP-00150-10001).

The following business drivers have also been considered in evaluating the contracting strategy for this Project:

- OPG's future business direction: The principal objective is to enable operations at the Darlington units for an additional 25 to 30 years, or more, post refurbishment. Maintaining or enhancing TG reliability is an important element for OPG's long-term goals and business direction (i.e. smaller fleet, smaller staff, different long term inspection and maintenance strategy).

- Number of vendors: The scope of work in this Project requires a large amount of technical integration and it is important to minimize the number of vendor interfaces/hand-offs. Based on OPG's past experience with similar projects and industry OPEX on TG work, the importance of having a single point of accountability for project execution is recognized.

- Long-lead considerations: Certain materials and work required for the Project are considered long lead items (12 to 48 months). These can include specific parts for the turbine and generator auxiliaries to design and engineering work.

- Quality considerations: Industry OPEX indicates that transition from analogue to digital systems in an operating facility is a complex project with high regulatory scrutiny. Quality management is a critical element required for the TG work.

- Downstream activities: Regarding the TG Controls replacement, minimizing impact on simulator changes will decrease the level of downstream changes required around operating documents, training, regulatory authorization requirements etc. There is also a need to minimize impact on normal operating conditions and unit response.

- Operational Reliability: TG units are critical components for nuclear generation. Any problem requiring an unexpected shutdown of the main turbine is likely to cause a significant unplanned outage, potentially resulting in millions of dollars of downtime costs. The DGNS have approximately 870,000 KWh of generation capacity per unit and costs associated with unplanned outages can amount to $1.25 M per day for one unit. Operational reliability is a critical consideration for this Project.

5.0 VENDOR/MARKETPLACE CAPABILITIES, RESTRICTIONS

Based on market intelligence, the Project Team identified the following vendors as capable of undertaking the whole or parts of the scope of work ("**SOW**"):

(a) Turbines, Generators, and Auxiliaries: Siemens, General Electric ("**GE**"), Alstom;

(b) Moisture Separator Reheaters: Siemens, GE, Alstom, Babcock & Wilcox; and

(c) Turbine, Generator and Excitation Controls (includes Excitation power component upgrades): Siemens, GE, Alstom, ABB. Invensys can only perform turbine and general controls.

The Project Team has also identified that some off-shore Japanese and Korean TG manufacturers such as Toshiba, and Mitsubishi who may be in a position to offer some alternative options for this work. However, additional OPEX will need to be sought out on their performance in similar projects. Additionally, it will be important to seek out information on these companies performance as a support organisation for longer term maintenance requirements. These companies will be considered in any competitive bidding options.

Based on the 2010 Vendor Assessment Report from the DN STEC Upgrade Project (NK38-REP-64100-10002-R000) which evaluated five vendors (GE, Siemens, ABB, Alstom, Invensys), each is identified as capable of supplying a functional turbine control system. While the general hardware and software architectures for all systems were very similar, the key variations between vendors existed in the types of redundancy, ability to interface with existing systems, Human Machine Interface ("**HMI**") offerings, installation and commissioning capabilities, hardware and software support periods, and simulator integration support.

Alstom, as the OEM has been providing technical support to OPG to address life cycle management issues and technical expertise during Darlington's planned outages for the last 15 years, working with the design basis of Darlington's TG set. In the TG industry, Alstom currently holds the dominant position in the nuclear generation refurbishment market winning more than half of the available world refurbishment market since 2004. Next to Alstom, Siemens and GE are second and third in terms of installed base of nuclear turbines globally[3]. Of these three vendors, only Siemens and Alstom have retrofitted equipment on other manufacturers' steam TG's. Most retrofits are performed by the OEM.[4]

Siemens is currently the OEM for OPG's turbine units at Pickering Nuclear Generating Station ("PNGS"), providing on-going maintenance and technical support. [redacted]

[3] *2011 industry data indicates Alstom has a market share of 30%, Siemens 23%, and GE 15%.*

[4] *Electric Power Research Institute (EPRI), 2010 Technical Report on Large Steam Turbine Component Retrofits and Replacements: Lessons Learned*

6.0 CONTRACTING ALTERNATIVES ANALYSIS

6.1 Work Packaging for Contracting Purpose

The Project Team considered the following two work packaging options for contracting purposes:

- Option 1: Unbundle the total SOW by scope (i.e. equipment/component or labour and materials) or type of work (i.e. Engineering, Procurement or Construction); and

- Option 2: Bundle all TG work as one package.

A summary of the analysis completed are included in Appendix A. Under Option 1, based on the nature of the vendor, the Project Team determined that the lowest level of unbundling technically feasible is to divide the Project by equipment/component into the five phases identified in Section 2.1. Although Option 1 provides the opportunity for OPG to increase the number of potential vendors to bid on the separate scope items with more leverage for OPG to obtain better contract terms and prices, it introduces substantial risks in several key areas which may prevent OPG from meeting the Project and DR objectives, increased technical and project management challenges. These include extensive in-house integration and monitoring efforts (i.e. coordination, scheduling, contract management, etc.), significant increase in equipment compatibility issues and overall inefficiencies with the lack of a single point of accountability.

The Project Team recommends proceeding with Option 2. Contracting all TG work as one package under Option 2 not only minimizes the work effort required for OPG, it provides greater confidence of seamless integration of equipment with overall vendor quality management and sharing of risks with the single point of accountability which will be essential given the expected regulatory scrutiny that the Project would likely be subject to.

Work packaging under Option 2 is also supported by industry research prepared by the DN STEC Upgrade Project team in 2010 (OPEX Report NK38-REP-64000-10001: DNGS Steam Turbine Controls Retrofit). The research, based on a review of a number of Electric Power Research Institute Reports and direct OPEX enquiries from eight utilities in Canada and the US, which completed similar controls retrofits stated: "The strategy during the planning stage of such a complex project should be to use the same vendor for turbine, generator, and electro hydraulic governor if possible to facilitate easy interface and reduce risks. If not, the interfaces have to be very well-defined and understood prior to design and implementation."

6.2 Contracting Model

To maintain alignment with the overall contracting framework that has been adopted for the DR Program, the Project Team examined the following contracting models for this Project:

- Option 1: Traditional Design-Bid-Build
- Option 2: Design-Build or EPC
- Option 3: Turnkey

Based on analysis of these contracting models as summarized in Appendix B, the Project Team recommends proceeding with Option 2. Under Option 2, an EPC contract would facilitate efficient scoping, planning, and execution, consistent with timing and scheduling considerations for the DR Program. This model minimizes the number of vendor interfaces and hand-offs while assigning a "single point of accountability" for Project execution. The other two options were not considered viable because of the extensive integration efforts required in this Project.

6.3 Sourcing Strategy

The next decision point is around the sourcing approach to be adopted for this Project. Other vendors have no design basis knowledge of the Darlington TG sets. A 2006 competitive process for replacement of the last state of turbine blades at Darlington did not yield a viable proposal from a non-OEM vendor due to limitations in critical/key machine boundary conditions only known to the OEM. The non-OEM vendor had to make significant assumptions and factor in a number of technical constraints. To consider non-OEM vendors, OPG would need to obtain Intellectual Property ("**IP**") rights from OEM Alstom to make the information available to the other vendors or the other vendors will need to either reverse engineer, or completely re-design the components in order to complete all the repairs, replacements and controls upgrades. The table below provides a summary provided by Faithful+Gould Inc. ("**F&G**"), an engineering consultant hired by OPG, in respect of the potential additional costs associated with obtaining the design basis information to facilitate a competitive sourcing strategy.

Figure 3: Additional Estimated Costs Associated with Obtaining Design Basis Information for Competition[5]	
Obtaining IP Rights for Design Basis information from OEM:	
• Restricted[6]	\$22.9 M to \$39.1 M
• Unrestricted (allows for manufacturing and sale of components)	\$40.5 M to \$62.1 M
Reverse Engineering[7]:	
• Additional work to allow Reverse Engineering	\$11.7 M to \$39.0 M (min. for 1 unit to max. for 4 units)
• Reverse Engineering – including Controls (vendor costs only, excludes OPG internal costs)	\$14.6 M to \$22.5 M

The report identified that although most components can now be reverse engineered, OEM specific work areas for the Turbine, Generator and Excitation Controls SOW include controls logic, hydraulics, and system integration where extensive work technical specification and engineering work with a high level of complexity is required. Empirical evidence in F&G's analysis suggests that success to first-time-right quality remains limited which may result in higher potential risks, additional costs and delays in the Project schedule. The Koeburg Nuclear Power Station is an example of a turbine reverse engineering activity which resulted in dependability problems; the unit was in service for ten months before the failure occurred and investigation identified shortcomings in the reverse engineering process and material receiving process.

[redacted]

5 *F&G, OPG Darlington Refurbishment IP and Reverse Engineering Report (February 2012)*

6 *Restricted IP Rights are limited to provision of outline Operating and Maintenance drawings showing general arrangements of equipment and exploded views but not material specifications, detailed clearances and technical specifications.*

7 *Reverse Engineering describes the practice of determining material make-up and dimensions of an existing part and using that information to design and manufacture a replacement part.*

Based on the above cost estimates, a competitive sourcing strategy may add approximately 5% - 12% additional costs to the overall Project to obtain the necessary design basis information. There may also be additional increase in internal costs and efforts which have not been quantified. Given the value for money considerations and DR Program objective to minimize the impact on existing units, the Project Team decided that the best sourcing strategy is to initially approach Alstom with the full SOW and endeavour to negotiate appropriate contract terms, while in parallel embarking on preparatory activities respecting other sourcing alternatives. With this approach, if negotiations with Alstom are unsuccessful, OPG will be able to minimize impact on the Project schedule and continue pursuing other sourcing alternatives, including engaging other vendors in a competitive process.

7.0 RECOMMENDED CONTRACTING STRATEGY

Based on the Contracting Alternatives Analyses in Section 6.0, the Project Team recommends the following contracting strategy:

Plan A – Initial Negotiations with OEM

As an initial step, OPG will bundle the whole TG work into one package and engage OEM Alstom in negotiations for an EPC contract. As evidenced in the information provided in Section 6.0 above, this approach appears to be the most optimal approach that allows OPG to obtain value for money based on the lowest operational risk and lowest project cost. This approach also appears to best align with the DR program objectives of long-term reliability and maintainability of the equipment, with reliable performance and lower production costs. The basis of selection for the Plan A is also validated through in a facilitated workshop using the Kepner-Tregoe ("**KT**") Decision Analysis[8] tool as outlined in Appendix C. In summary:

- Bundling of the whole TG work into one package for contracting purposes offers the best opportunity for a successful project from cost, schedule, and quality perspectives given the high level of integration required between the various work phases for this Project. It is assessed qualitatively that the potential benefits from bundling will outweigh the potential cost savings that may be derived from piecemealing the work for contracting purposes. This approach is also recommended by industry OPEX.

- The Design-Build (EPC) contracting model offers the most balanced approach for the whole TG work with the best opportunity for a successful project from cost,

[8] *Kepner Tregoe Decision Analysis tool is a structured methodology for gathering information and prioritizing and evaluating it. It was developed by Charles H. Kepner and Benjamin B. Tregoe in the 1960s. This is a rational model that is well respected in business management circles. An important aspect of Kepner-Tregoe decision making is the assessment and prioritizing of risk.*

schedule, and quality perspectives with a single point of accountability and sharing of risks.

- Engaging the OEM as an Initial Step is a prudent decision from a value for money, Project and operational risks perspectives given the additional costs associated with obtaining the design basis information to facilitate competition, increased internal resource commitments and the potential equipment compatibility issues. Alstom as the OEM for OPG's TG sets at Darlington will have the ability to manufacture required parts in a reasonable time frame and OPG will be able to obtain spare parts with no extra-stocking or quality requalification requirements. Alstom has a good track record of field execution with OPG Nuclear and the nuclear industry, with significant experience in this type of work and presence in more than half of the world refurbishment market. The other two vendors under consideration for a bundled EPC contract should OPG engage in a competitive process would include GE and Siemens. GE has [redacted]

The negotiations strategy with Alstom will include a pre-defined set of negotiation objectives and key success factors, building on the key principles of accountability, transparency and value for money. This is outlined in the Darlington Refurbishment Turbine Generator Project Negotiations Plan (NK38-PLAN-09701-10096). OPG will maintain appropriate leverage in the negotiations with a defined timeline to complete negotiations and full disclosure of OPG's plans to engage in a competitive process if negotiations are unsuccessful.

In preparation for negotiations, the Project Team gathered available commercial OPEX for Alstom through discussions with internal OPG stakeholders across the organization that had past experience of negotiations and experience working with Alstom. Such stakeholder feedback provided the Project Team with an understanding of the key commercial terms that Alstom had provided or agreed to in previous competitive processes or single source purchases. OPG intends to negotiate a new agreement for the Project that will be comparable to an agreement successfully negotiated with Alstom in the past as a result of a competitive process and build in any lessons learnt from OPG's past experience with Alstom.

Negotiations are not a commitment to enter into an agreement. For OPG to engage Alstom in an EPC contract for the entire SOW, the proposed contract must achieve the pre-determined negotiation objectives including being commercially viable (i.e. value for money, transparency, appropriate allocation of risks, appropriate commercial terms, etc.). Should OPG contract the services of Alstom under Plan A, it would require a full single source justification in accordance with OPG-PROC-0058: Procurement Activities, and the appropriate levels of approvals mandated by OPG-STD-0017: Organizational Authority Register ("**OAR**"). The proposed timelines, key deliverables and due diligence associated with the proposed negotiation activities are outlined in Appendix D.

Plan B – Competitive Sourcing

The Plan B option involves OPG engaging in an alternate procurement process which involves competitive sourcing. This option will be invoked under the following possible scenarios in Plan A:

i. OPG is unsuccessful in achieving the desired negotiation objectives and goals;

ii. Either OPG or Alstom decides to cancel negotiations for any reason; or

iii. OPG's senior management does not approve the single source contract when negotiations are completed.

Under this plan, OPG will issue an Expression of Interest ("**EOI**") to potential vendors and will develop technical requirements/specifications for the Request for Proposals (**RFP**"). OPG plans to consider the available options in respect of procuring materials, equipment and services regarding the Project, and the intent of the EOI is to assist OPG to assess the market for such materials, equipment and services taking into consideration Project risks related to the scope, cost and schedule. OPG will use the information submitted by potential vendors in response to the EOI to prepare a proponents list and the RFP, review scope risk related to non-OEM vendors and determine if the OEM needs to be engaged for specific activities and/or supply of equipment on a selective single source basis. Vendors may express interest in the entire scope of the Project, or individual work scopes (i.e. any of the 5 scopes of work) that are suited to their experience, expertise or interest.

The Project Team will initiate activities associated with Plan B in parallel with Plan A. Work will continue to assess which equipment/component will require design basis or other information from OEM to unbundle the TG work to re-evaluate the SOW packaging for contracting purposes. These additional planning activities and adherence to the requirements in engaging in a transparent and fair competitive process in Plan B are expected to require 18 months of work effort. Details of the key deliverables and the TG Project schedule will be reassessed when Plan B is invoked to incorporate the timelines as outlined in Appendix E. Plan B is not expected to impact the critical path for the overall DR Program.

8.0 CHOICE OF PRICING MODEL

The Project Team recommends that the pricing models be different for the confirmed scope of the work [redacted] and the contingency scope of work [redacted]

For the confirmed scope, it is recommended that:

(a) The materials for the TG and Auxiliaries (including skids) and MSR to be done on a fixed price basis since the work will be essentially completed on the vendor's premises.

(b) If any interface engineering (e.g. Engineering Change Control ("ECC") type integration work) is required for the above work, then it should be managed through a cost reimbursable plus fixed-fee model. Another option may be to ask the vendor to provide a fixed price (based on the estimated work effort (in hours) × hourly labour rate) for the ECC integration work based on the various existing interface agreements that will be provided to the vendor.

(c) The inspection, analysis, and repair/overhaul work for TG and Auxiliaries at site to be based on a cost reimbursable, with a target price plus fixed fee model. The target price should be arrived at through an open book pricing approach.

(d) The engineering and supply portion of the Turbine Controls and Generator Excitation Upgrades to be done on a fixed price basis. The installation and testing work at site should be based on a cost reimbursable, with a target price plus fixed fee model. The target price should be arrived through an open book pricing approach.

(e) All types of commissioning support work to be priced on a cost reimbursable basis, as the level of uncertainty in scope is maximum for this portion of the work in the Project definition phase.

For the contingency scope of work, the Project Team recommends that any work accepted as confirmed scope from this bucket during Project execution should be package under fixed price and fixed schedule model. To achieve transparency and value for money, OPG should pursue an open-book contract with the vendor for full disclosure, cost transparency and build-in incentive/disincentive mechanisms around target costs to promote risk sharing. An open-book contract will allow OPG to work with the vendor to obtain visibility into each major cost item to reach a target price that reflects an appropriate risk profile for each party. This also provides OPG with an audit trail to mitigate regulatory risks associated with rate applications and the ability to retain information in planning future projects.

9.0 PROCUREMENT PROCESS PREREQUISITES/CONSIDERATIONS

The procurement process and negotiation strategy needs to effectively executed in order to obtain value for money and appropriate commercial terms. Approvals to enter into a contract will not be obtained unless value for money can be demonstrated.

The process includes the following stages:

- Stage I – Prepare for Negotiations
- Stage II – Conduct Negotiations
- Stage III – Complete the Commercial Agreement
- Stage IV – Obtain Approvals and Execute Agreement

Stage I - Prepare for Negotiations

The objective of Stage I is to prepare OPG to enter into negotiations with the OEM. At the end of this stage, OPG will be prepared to negotiate with Alstom and, in the event negotiations fail to achieve the desired objectives, to have a preliminary preparation/plan to initiate a competitive process. This stage will comprise of a number of activities largely executed in parallel.

Stage II - Conduct Negotiations

The objective of Stage II is to conduct the negotiations and arrive at a commercially acceptable agreement with appropriate commercial terms and pricing which meets technical requirements. The core activity will be the actual conduct of negotiations.

Stage III - Complete the Commercial Agreement

(Refer to Stage V if Stage II is unsuccessful)

On completion of successful negotiations, as measured against the negotiation objectives, the actual agreement will be completed and finalized. This stage will include OPG internal stakeholder reviews of the draft agreement to assess whether value for money has been obtained.

Stage IV - Obtain Approvals and Execute Agreement

OPG will prepare/complete required documents for review and approval in accordance with OPG-PROC-0058: Procurement Activities. The key documents will include:

- "Single Source Justification" Form
- "Major Contract Memorandum"
- "Recommendation for Submission to the Board of Directors Memorandum" (with supporting information)

Stage V - Subsequent Phase (if Stage II is unsuccessful)

If the negotiations do not succeed within the specified time frame, OPG will terminate the negotiations and pursue other procurement alternatives (i.e. re-package and issue RFP). An alternate procurement approach has the potential to considerably delay the Project schedule due to the associated engineering and technical requirements, and, as well, negatively impact multiple Project objectives identified earlier in this Report. The possible options and other positions that OPG may take, including off-ramps during negotiations, will be further developed and executed during this stage.

10.0 INTERFACE OR INTEGRATION ISSUES WITH OTHER CONTRACTING STRATEGIES/MAJOR CONTRACTS FOR THE DARLINGTON REFURBISHMENT WORK

A bundled EPC approach to the TG work can be performed mostly in a stand-alone manner due to the following:

(a) The islanding approach plans to create a "fence inside the fence" for the TG machines;

(b) The areas can be easily geographically segregated; and

(c) Well defined termination points will be developed to define the limits of all the geographic segregation.

As the definition phase progresses further for all other DR Program projects, including for the Balance of Plant, integration issues will be reassessed.

11.0 KEY RISKS AND PROPOSED MITIGATION

Some of the key risks and proposed mitigation are:

(a) [redacted] In the event negotiations break off or become stalled, there is a significant risk to the TG Project in terms of schedule. The contract negotiations have to be carefully planned and managed. To focus the negotiation efforts, OPG has developed a Negotiation Plan (NK38-PLAN-09701-10096) which outlines the negotiation objectives in advance.

(b) [redacted] OPG has the final decision authority for scope and plans to implement a strict scope review and control process for deciding any additional scope inclusion from this group of work. OPG has knowledgeable people who can assess recommendations and determine work to be done prior to work proceeding.

(c) Engineering has confirmed that if the work goes to the OEM, it will only need functional specifications compared to the detailed technical specifications that will be required for a competitive scenario. Scope definition and technical requirements are expected to be further refined through discussions with Alstom under Plan A, which may reduce the incremental engineering work required if OPG has to engage in a competitive process under Plan B.

(d) Due to engineering and material lead times, the contract(s) need to be executed in early 2013 to meet an October 2016 start date for the Project. OPG will have to engage Alstom in active negotiations with a target date of completion that will allow sufficient time for OPG to pursue a competitive process if negotiations are unsuccessful with Alstom to minimize the impact to the Project schedule. At this time, it is estimated that Plan B would require 15-18 months to accommodate the additional planning activities associated with reassessment of work packaging, technical engineering work and the competitive process. Depending on when Plan B is invoked, OPG may have to reassess the sequence of the DR Program project portfolio to delay the TG work to accommodate the additional efforts. The more the Project is delayed; the greater the impact on the level of scheduling contingency available for unexpected work for this Project. Also, OPG will have reduced leverage when negotiating a contract with other vendors given the time constraints.

(e) Under Plan B, successful proponents will be expected to work with the Alstom equipment. There is a risk that potential vendors may be unwilling to participate in the competitive process due to reluctance to work with a competitor or utilize a competitor's products. OPG will consider leveraging any existing master agreements and will need to proactively manage the relationships with the vendors involved to mitigate this risk.

(f) Lack of project resources for the TG work to execute the contracting strategy – this lack of resources spans across Engineering (impacting preparation of specifications/SOW required for issuing RFP), and Execution. There is a high probability that this will have a direct impact on the contract award timeline.

12.0 SUCCESS CRITERIA/KEY PERFORMANCE INDICATORS

The following are the criteria of success for the proposed contracting strategy: (i) OPG successfully awards appropriate terms and for the SOW; (ii) the awarded terms and conditions incorporate OPG's core business values of accountability, transparency and value for money, taking into account the overall DR Program objectives to maintain OPG control, minimize impact on existing units, achievable schedule and budget and the appropriate allocation of risks as outlined in the DR Program Commercial Strategy (NK38-REP-00150-10001).

13.0 IMPLEMENTATION PLAN

The implementation plan has been incorporated into Section 9.0 of this document.

REFERENCES

[R-1] EPRI 2010 Technical Report, "Large Steam Turbine Component Retrofits and Replacements: Lessons Learned

[R-2] Project Charter: Steam Turbine Electronic Controls Upgrades dated July 10, 2008

[R-3] Project Charter: Main Generator Excitation Controls Replacement dated March 7, 2007

[R-4] Project Business Case Summary: Steam Turbine Electronic Controls Upgrades dated January 26, 2009

[R-5] TG Controls Upgrade: Overview of Level 1 logic/schedule dated September 9, 2010

[R-6] Draft Basis of Estimate: Turbine Generator Controls Upgrade dated March 2, 2010

[R-7] DNGS Turbine Generator Controls Upgrade Project Vendor Assessment Report dated January 27, 2010

[R-8] DNGS Steam Turbine Controls Retrofit OPEX Report dated December 7, 2009

[R-9] Turbine Generator Controls Upgrade Value Engineering Study Report dated March 26, 2010

[R-10] Darlington Scope Request Forms for Turbine Generator dated May 5, 2011-06-24

[R-11] White Paper – Turbine Generator Refurbishment Strategy dated April 7, 2011 (NK38-REP-09701-10017)

[R-12] White Paper – Refurbishment Island Strategy dated February 10, 2011 (NK38-REP-09701-10005)

[R-13] White Paper – Shutdown, Layup, Commissioning, and Startup Strategy dated March 11, 2011 (NK38-REP-09701-10015)

[R-14] Various internal meeting minutes and OPEX reports

[R-15] Turbine Generator Lessons Learned items and attachments from DR DOLLAR database

[R-16] Darlington Refurbishment Turbine Generator Project Negotiations Plan (NK38-PLAN-09701-10096)

[R-17] OPEX, COG Screened Events Database no. 41053, WANO MER ATL 07-297, "Generator Cooler Bellows Failure Causes Unit Turbine Trip", Koeburg, 2007-07-17.

Appendix A: Analysis of Work Packaging for Contracting Purpose

The Project Team considered two work packaging options in the TG Project for contracting purposes:

- **Option 1:** Unbundle the total SOW
- **Option 2:** Bundle all TG work as one package

Under Option 1, the scope of work can be unbundled by equipment/component, labour and materials, or type of work. Based on the nature of the vendor market, the Project Team determined that the lowest level of unbundling technically or practically feasible is to divide the Project by equipment/ component as per the five phases identified in Section 2.1.

- Separating by type of work for this SOW does not seem ultimately beneficial from a contracting perspective. For example, there are a number of vendors in the market able to do inspections but the majority of the inspections work can only be carried out during refurbishment (i.e. with machines dismantled). The cost/complexity of bringing in multiple vendors to work on the same equipment at the same time may outweigh the perceived benefit from the independence of accountabilities for the inspection vs. repair/replace parts of the SOW.

- Unbundling by labour and materials may introduce the option to award contracts to vendors with core expertise in the respective labour areas (e.g. firms specializing in design/engineering can be awarded that piece of work, firms expert in installation can be awarded that piece of work etc). This approach may also enable OPG to have flexibility in the materials procurement strategy e.g. conduct procurement directly from the OEM for the most critical components and explore the market for the best pricing and availability for other parts. However, the Project Team determined that this is not the most preferred option to unbundle the SOW as it would transfer a large burden of project management and scheduling risks to OPG.

Legend:	Increased risks to achieving objectives 	Decreased risks to achieving objectives 

Details of the analysis for the two work packaging options are outlined in the table below:

Project Objectives[9]	Option 1 Unbundle the total SOW by equipment/component	Option 2 Bundle all TG work as one package	Supporting Information
Minimize risks to project execution and scheduling:			Unbundling will result in increased risks in the following: • Unbundling may result in multiple contracts with different vendors, with many interfaces which will increase complexity around management of the overall TG Project. • Technical integration with different vendors for hardware and controls. • Compatibility for turbine-generator and excitation controls which interfaces with a large number of field devices, components within hydraulic system, and excitation power system. Configuration management and corresponding level of effort needed to mitigate this risk usually increases with increasing number of vendors for an equipment group like TG.
Maximize value for money			Bundling will result in fewer potential bidders with less opportunity to drive more competitive costs through rates and burdens whereas unbundling will introduce the opportunity for innovation, especially for Controls.
Minimize risk to ongoing operability after refurbishment			Unbundling will result in more interfaces, technical and process differences between vendors, increasing the risk of equipment compatibility and reliability issues. TG's are critical components for nuclear generation and unplanned outages can cost OPG up to $52 K in lost generation per hour.
Ensure accountabilities for deliverables is clear			Unbundling will increase the number of interfaces and integration issues with the lack of a single point of accountability. Under a bundled approach, the accountability for scheduling, integration and coordination are largely transferred to the vendor who can be held responsible for the overall deliverable.
Allows OPG to maintain oversight			Unbundling increases OPG's effort level in contract and project management to monitor vendor quality and compliance with multiple contracts, different quality programs, etc.

9 *Results of the assessment highlighted if the option would result in an increased/decreased risk associated with the achievement of the desired objectives.*

Title:
CONTRACTING STRATEGY FOR TURBINE GENERATORS

Project Objectives*	Option 1 Unbundle the total SOW by equipment/component	Option 2 Bundle all TG work as one package	Supporting Information
Maximize transfer of risk to vendor	↑	↓	Unbundling may result in several contracts with potential EPC variations. Integration issues may also transfer additional risks back to OPG. Under the bundled approach, the vendor will be responsible for interface, integration, scheduling and coordination. As such, the vendor can be largely held accountable for the overall quality of the project deliverables. This is important given the expected increased regulatory scrutiny associated with the complexity of this Project.
Minimize changes to maintenance, training practices post refurbishment	↑	↓	Unbundling may result in multiple contracts with different vendors. There will be variations between the vendors in the integration and configuration of the TG components which may require increased training efforts and significant changes to maintenance and training practices post refurbishment
Minimize level of resources (staff) required by OPG	↑	↓	Unbundling increases OPG effort level in contract and project management to monitor vendor quality and compliance with multiple contracts, different quality programs, etc.

<u>Recommended Work Packaging Approach</u>: Based on the analysis, the Project Team concluded that the best approach for packaging the scope of work for contracting purposes is Option 2, to "Bundle all the TG work as one package".

Appendix B: Contract Model Analysis

	PROS	CONS
OPTION 1: Traditional Design-Bid-Build ➢ Serial sequence of design and construction phases ➢ Procurement begins with construction ➢ OPG contracts separately with designer and constructor; retains overall project management responsibility, including project oversight	▪ Ability to leverage the competitive bid process with an increased supply base for each phase of work ▪ Ability to leverage vendor capabilities (e.g. vendors expert in installation may be considered only as the pool for the installation work) ▪ Lower direct cost contracting option, with OPG responsible for the quality control and quality assurance functions	▪ It is difficult to separate detailed design/engineering and manufacturing phases because of large inherent design risk. There is limited ability to address constructability issues in the design. In this approach, the entire design risk is retained by OPG ▪ Does not support exploring the potential of long-term maintenance arrangements with any one vendor ▪ Maximizes numbers of interfaces and number of contracts which potentially nullifies the benefits expected from bundling of the work for contracting purposes ▪ Inability to have a reliable cost and schedule estimate upfront; maximum schedule requirement with potential escalation of costs due to long schedule ▪ Procurement approach may directly impact timely availability of long-lead items ▪ For the Controls upgrade part, detailed technical specifications instead of functional specifications will be required for establishing separate construction contracts ▪ As OPG retains most of the risks (i.e. quality, costs and schedule), additional contingency and resources must be put in place due to the complexity in the nature of the work when dealing with multiple vendors

	PROS	CONS
Option 2: Design-Build or EPC ➢ Overlapped sequence of design and construction phases ➢ Procurement begins during design ➢ OPG to enter into one contract with a contractor for overall project (i.e. coordination, detailed design and engineering, manufacture and supply or selection and procurement of equipment/components, installation, testing and commissioning or commissioning support)	▪ Shortest schedule because of concurrent design and construction activities ▪ Greater potential for up-front cost certainty ▪ Ability to transfer risks around cost (and to some extent, schedule) to contractor ▪ Provides maximum flexibility in terms of initiating procurement of long lead items in a timely manner ▪ Minimizes internal staffing requirements for monitoring and due diligence ▪ Facilitates the quality management aspect with single point of accountability	▪ Higher cost because of risk transfer and contingencies carried by the contractor ▪ Failure to properly prepare specifications may leave OPG exposed to increased costs associated with "extras" (e.g. engineering changes midstream). ▪ Level of OPG involvement in design must be clearly specified in details and managed accordingly.
Option 3: Turnkey ➢ Overlapped sequence of design and construction phases ➢ Procurement begins during design ➢ OPG provides performance specifications and the contractor has a wide discretion as to how to it can satisfy the requirements. There is no design review	This option was not analysed in detail because: ▪ As OPG is the General Contractor, it does not make logical sense to have pieces under the Program set up as Turnkey. ▪ Anticipated transition challenges as highlighted in OPEX Report NK38-REP-84000-10001 R000: Efforts by Operators to issue Turnkey contracts have resulted in significant problems for Controls Upgrade Projects (large risk of a "black box" transferred to OPG resulting in undesired learning curve events with significant economic losses). Experiences tend to support that involvement of in house staff from the start to finish side-by-side OEM/vendor was considered crucial to the success of the projects.	

<u>Recommended Contracting Model</u>: Based on the analysis, Option 2 – EPC Model is selected as the best approach for the TG Project.

Appendix C: KT Analysis

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Decision Analysis Executive Summary Report

Select the best contracting option to implement (engineer, procure and construct) the Turbine Generator Refurbishment Project identified scope of work.

Decision Background

As part of the Refurbishment Project at Darlington there will be number of work packages prepared and executed to ensure that the turbine generator sets (TG) operate efficiently and effectively until end of life (additional 30 years). The original company is no longer servicing the industry but the original design basis information and associated intellectual property has passed through an intermediary company and is now resident with a single vendor which currently provides engineering and maintenance support to Darlington.

Decision Analysis Team

Name	Company	Team Member Role	Team Member Expertise
neill allen	KT	Facilitator	Commercial Strategy
Chatterjee, Deepa		Content expert	Commercial Strategy
Craig, Dale		Content expert	Engineering
Jocubovski, Todd		Owner	Project Manager
Woodward, Marry		Content expert	Commercial Strategy
Nelson, Andrew		Content expert	Supply Chain
Smara, Silvia		Content expert	Supply Chain
Prokopelva, Evgenia		Content expert	Legal Issues
Chatterton, Ron		Content expert	Ops and Maintenance
Allen, Neill		Facilitator	Commercial Strategy

Decision Statement

Select the best contracting option to implement (engineer, procure, construct) the identified scope of work for the Darlington turbine generator sets.

Must Objectives	Measures
Must not compromise current OPG policy for procurement	Meet OPG governance
Meet Technical Requirements	As per OPG approved technical specifications
Meet Quality Requirements	As per PO (tech specs plus source surveillance etc. to satisfy that vendor application of their Quality Program satisfies OPG requirements for permanent plant components. Vendor must be (or capable of qualifying) on OPG Approved Supplier List.

Title: **CONTRACTING STRATEGY FOR TURBINE GENERATORS**

think

Decision Analysis Executive Summary Report

Select the best contracting option to implement (engineer, procure and construct) the Turbine Generator Refurbishment Project identified scope of work.

Want Objectives	Measures	Weights
Minimize risk to project execution and schedule(three phases of engineering, procurement and manufacturing and field execution and commissioning)	Development of engineering requirements Duration of procurement process Complexity of execution phase Ability to integrate with other work	10
Maximize value for money (cost element)	Total cost for refurbishment to OPG (internal and external expenditures)	9
Make decision transparent	Demonstrate open and fair process	8
Minimize risk to ongoing operability after refurbishment	Vendor ability to minimize manage changes	7
Ensure accountability for deliverables is clear (risk element)	Minimize number of hand offs and interfaces	7
Enable contractor procurement	Remove any impediments from contractor process	6
Allows OPG to maintain oversight	By monitoring quality program, project task completion	5
Maximize transfer of risk to vendor	Clarity on EPC accountabilities	5
Maximize value for money (pre refurb outages impact for inspection by non OEM)	Pre refurbishment outage impact for additional inspections and preparations due to lack of access to original design information	4
Minimize changes to maintenance, training practices post refurbishment	Vendor ability to minimize manage changes	4
Demonstrate open process for selection of vendors	Provides sufficient records, documents to support an audit	3
Minimize future dependency on single sourcing	Develops alternative supply sources	3
Minimize level of resources (staff) required by OPG	Number of interface points in processes and deliverables	2

Alternatives Considered

Unbundled scope (5 packages), competitive bid process.
Bundled scope, sole source process (OEM)
Bundled scope, competitive bid process
Unbundled scope, selective sole source and competitive processes

Recommended (or Selected) Alternative

Bundled scope, sole source process (OEM)

think

Decision Analysis Executive Summary Report

Select the best contracting option to implement (engineer, procure and construct) the Turbine Generator Refurbishment Project identified scope of work.

Risks Associated with the Recommended (or Selected) Alternative(s)

Alternative: Bundled scope, sole source process (OEM).

Risks (If...)	Probability	Adverse Consequences (Then...)	Seriousness
The single source vendor goes out of business	L	Delay to project while new procurement process is entered into. Possible higher costs	H
OPG cannot negotiate an acceptable contract with vendor	L	Delays to award of contract and project schedule. Potential to have to repeat procurement process with new vendors. There would be some internal cost increases and potential project cost issues if work has to be expedited.	H
Risks (If...)	**Probability**	**Adverse Consequences (Then...)**	**Seriousness**
The vendor refuses to transfer intellectual property	H	Future maintenance and modification options are limited unless OPG future needs are captured in contract terms and conditions	M
We do not use a competitive bid process then there could be a challenge to OPG's contracting strategy by external stakeholders (supply chain process challenged)	M	There could be delays to award of contract if process review requested	M
The vendor increases the contingency scope (due to their influence over the entire project)	L	Schedule and cost increase above estimate	M
Risks (If...)	**Probability**	**Adverse Consequences (Then...)**	**Seriousness**
We do not use a competitive bid process then there could be a challenge to OPG's contracting strategy by external stakeholders (cost recovery allowance challenged)	H	Rate approval and full cost recovery may be denied at a future date	L
OPG's reputation for open and fair treatment of vendors is challenged	L	Increased scrutiny of OPG Supply Chain processes	L

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Decision Analysis Executive Summary Report

Select the best contracting option to implement (engineer, procure and construct) the Turbine Generator Refurbishment Project identified scope of work.

Actions and their Status

Best Choice Alternative: Bundled scope, sole source process (OEM).

Action	Who	By When	Status	Notes
Prepare recommendation cover letter to go with Contracting Strategy and KT analysis to executive team	Woodward, Nancy	2/29/12	In Progress	

Summary

Record Name

Select the best contracting option to implement (engineer, procure and construct) the Turbine Generator Refurbishment Project identified scope of work.

Knowledge Management Code

OPG

Record Created

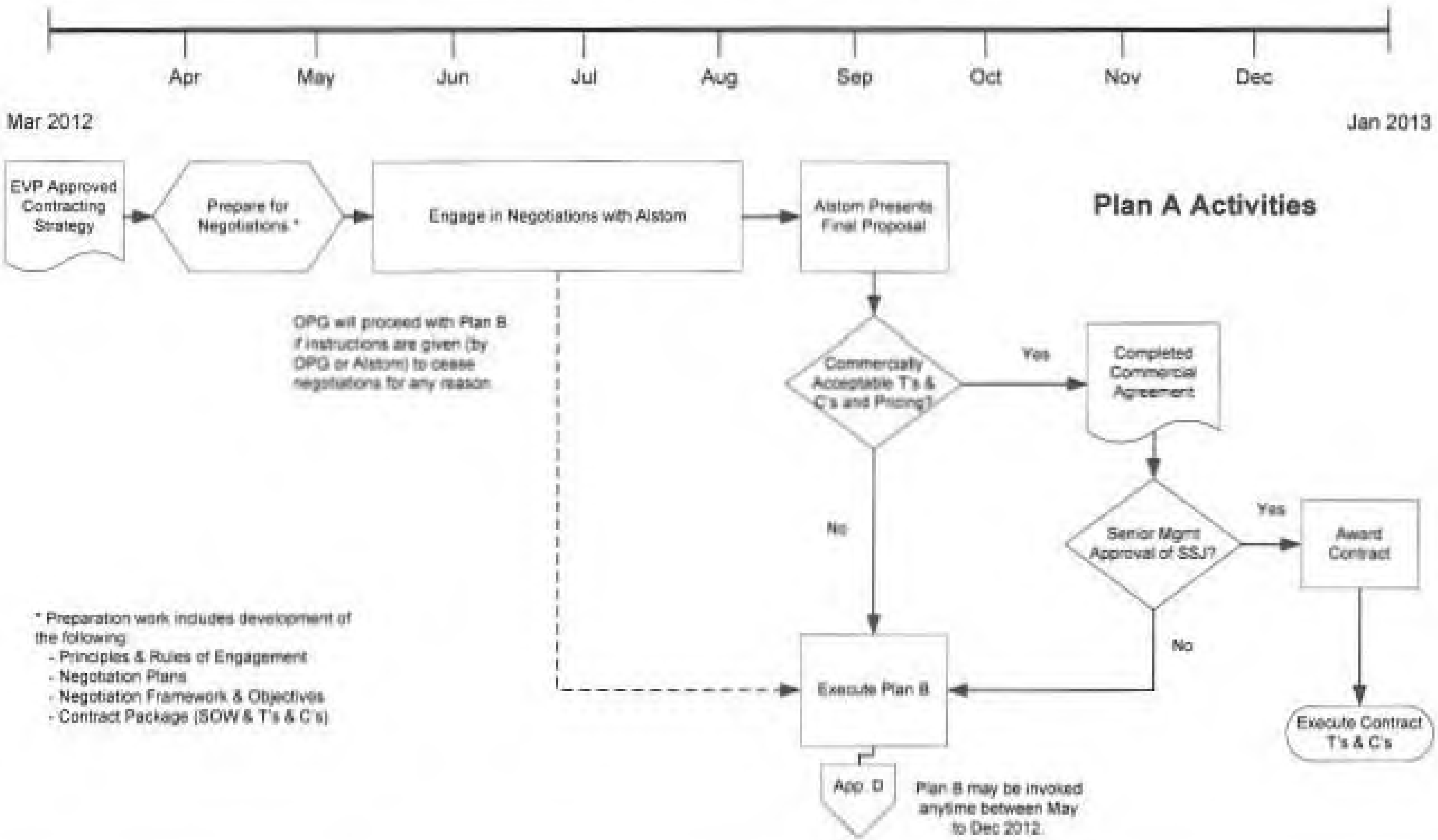
02/02/2012

Benefits

Lessons Learned

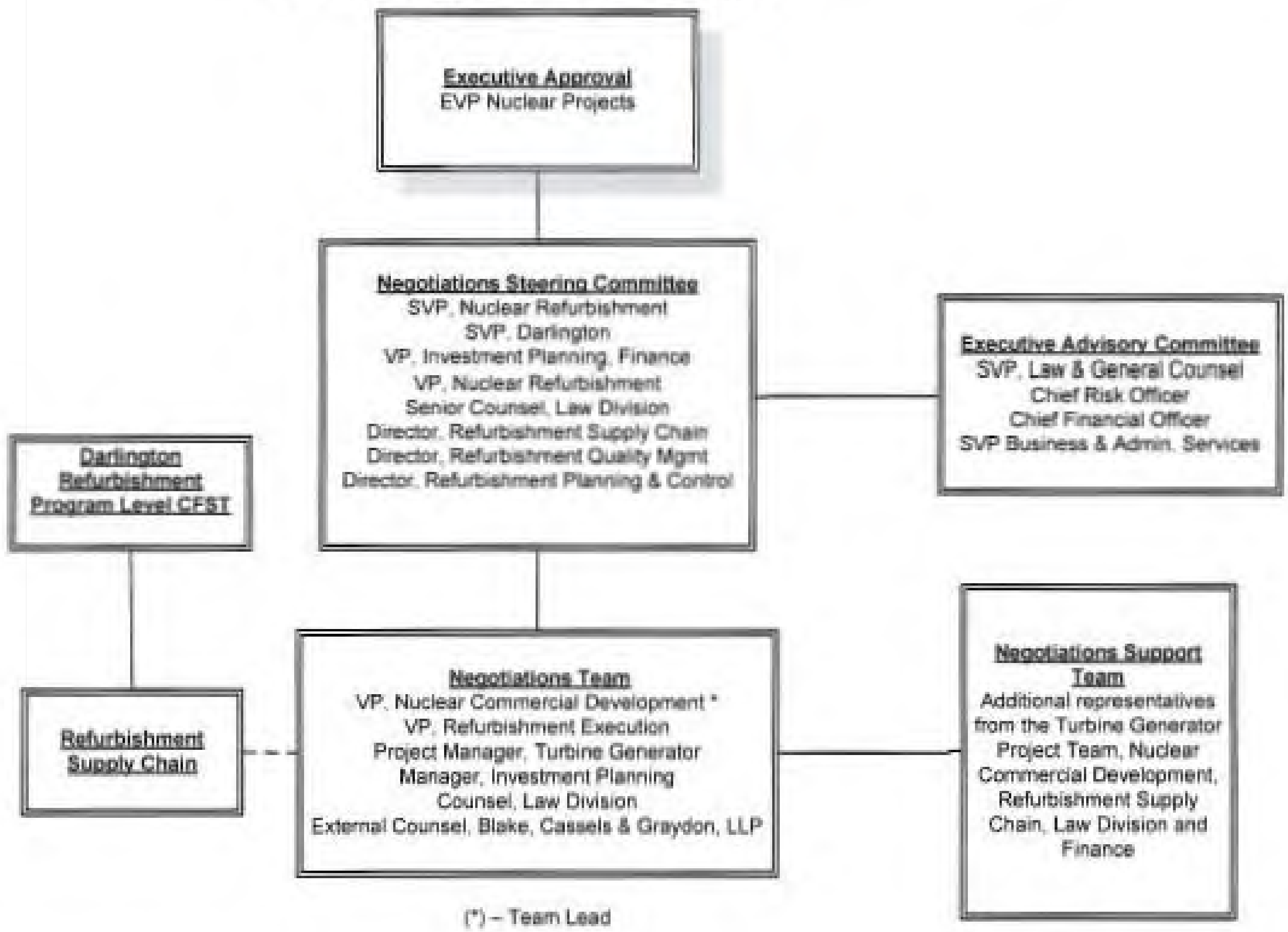
Closeout Notes

Appendix D: Plan A – Initial Negotiations with OEM



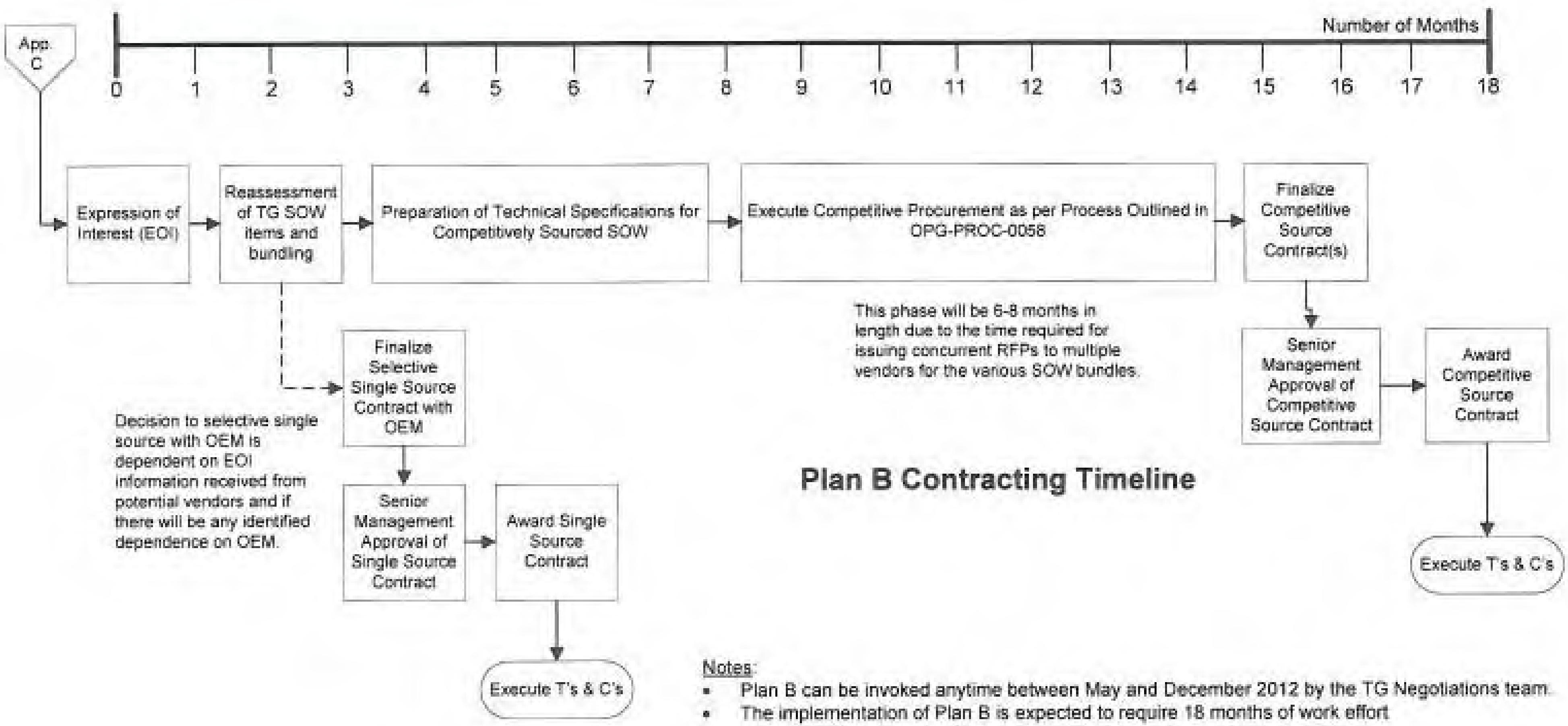
* Preparation work includes development of the following:
- Principles & Rules of Engagement
- Negotiation Plans
- Negotiation Framework & Objectives
- Contract Package (SOW & T's & C's)

Plan A – Negotiation Team Structure



(*) – Team Lead

Appendix E: Plan B – Competitive Sourcing



Plan B Contracting Timeline

Notes:
- Plan B can be invoked anytime between May and December 2012 by the TG Negotiations team.
- The implementation of Plan B is expected to require 18 months of work effort

ONTARIOPOWER GENERATION

Report

OPG Confidential	
Document Number: NK38-REP-09701-10020	Usage Classification: N/A
Sheet Number: N/A	Revision: R000

Title:
CONTRACTING STRATEGY FOR FUEL HANDLING - DEFUELLING

Contracting Strategy For Fuel Handling - Defuelling

NK38-REP-09701-10020-R000
2012-10-02

Order Number: N/A
Other Reference Number:

OPG Confidential
Commercially Sensitive

Recommended by: OCT 02, 2012
Sorin Marinescu — Date
Project Manager
Nuclear Refurbishment

Concurred by: Stephen Mills Oct. 2, 2012
Stephen Mills — Date
Vice President
Nuclear Commercial Development

Approved by: Oct 4, 2012
Dietmar Reiner — Date
Senior Vice President
Nuclear Refurbishment

Revision Summary

Revision Number	Date	Comments
R000	2012-10-02	Initial issue.

Table of Contents

1.0 EXECUTIVE SUMMARY

The Darlington Refurbishment ("**DR**") Program Commercial Strategy identifies a need to establish separate contracting strategies for each of the major projects under the DR Program (each a "**Contracting Strategy**"). This document sets out the Contracting Strategy for the defuelling portion of the Fuel Handling ("**FH**") Project. This Contracting Strategy is based on the business drivers and commercial principles set out in the DR Program Commercial Strategy.

After considering bundling and unbundling work packaging options, the FH team (the "**Team**") determined that the preferred approach for the FH Project (the "**Project**") is to bundle the contracts by scope of work:[1]

a) Defuelling of the reactors ("**Defuelling Work**") prior to retube and feeder replacement ("**RFR**") [~$25M]; and
b) Refurbishment of the FH equipment ("**Refurbishment Work**") [~$170M].[2]

Unbundling the Project work by scope allows DR to:

- source and move forward with critical path defuelling work while preparations for scoping and sourcing for the refurbishment work continue in parallel;
- mitigate risks associated with a non-integrated approach to the Defuelling Work (i.e., engineering, procurement, and technical support during execution); and
- maximize competitive sourcing potential for the overall Project (up to ~$170M).

This Contracting Strategy, therefore, recommends the following sourcing approaches for the Defuelling Work:

a) ***Plan A***: Engage in discussions with GE-Hitachi Nuclear Energy Canada Inc. ("**GHNEC**") (the Original Equipment Manufacturer ("**OEM**") of the FH equipment) for the engineering, supply of hardware, and technical support for the Defuelling Work. Provided that negotiations result in an acceptable agreement with GHNEC, approval to single source the Defuelling Work will be required. This option ensures the lowest risk to the overall DR Program schedule and the lowest technical risk due to equipment and design integration issues. The field execution of the Defuelling Work will be performed by OPG FH Operations personnel with GHNEC providing technical support.

b) ***Plan B***: Competitively procure the Defuelling Work. The composition of the competitive field for this work may include Candu Energy Inc. ("**CEI**", formerly AECL), Extended Services Master Services Agreement ("**ESMSA**") vendors, and/or other vendors. This may require engaging GHNEC as a subcontractor for some of the activities.

This Contracting Strategy deals with the Defuelling Work only. The Contracting Strategy for the Refurbishment Work is found in NK38-REP-09701-10130.

[1] Rationale for bundling by scope as the preferred alternative is set out in Appendix B.

[2] Refurbishment Work is refurbishment of Fuel Handling equipment installed on individual units, common equipment installed on East and West Fuelling Facilities Areas, and equipment in the Central Service Area. The work includes pre-refurbishment work, refurbishment work and post-refurbishment work.

2.0 INTRODUCTION

2.1 Background Information

The objective of the Defuelling Work is to remove all the irradiated fuel from the reactor core (as each unit starts its refurbishment outage) in order to allow the downstream DR activities, including RFR, to be executed.

2.2 Pre-Refurbishment

OPG engaged GHNEC to provide preliminary engineering (design and engineering), including pre-refurbishment engineering projects (studies, modification outlines and scoping determinations). This preliminary engineering work was awarded to GHNEC in April 2011 under an existing purchase order ("**PO**") (PO No. 205047), which was created under the terms of the existing FH Services Agreement with GHNEC. In 2012, OPG has spent $2.2M under this PO for preliminary engineering for both the Defuelling Work and the Refurbishment Work. The work related to the Defuelling Work is expected to be complete in Q4 2012.

2.3 Defuelling Work

The Defuelling Work consists of defuelling of the four (4) reactors for subsequent RFR activities. The contract for Defuelling Work includes design engineering, manufacturing procurement, and commissioning of all the components and equipment, followed by technical and operational support during the actual defuelling activities. The actual defuelling activities will be provided by OPG.

The Defuelling Work is required prior to starting major reactor refurbishment work, including RFR work for all units. The Defuelling Work will be a critical path activity and needs to be completed in the shortest practical timeframe.

As part of the pre-refurbishment work, GHNEC was engaged to complete a study (NK38-REP-35000-10004) to determine the most effective method to defuel the reactor core in order to perform the RFR work. "Flow Defuel" is the method that is being recommended to execute the Defuelling Work. Flow Defuel uses the flow of the Primary Heat Transfer ("**PHT**") system to push the fuel into the downstream fuelling machine assisted by Flow Restricting Outlet Bundles ("**FROBS**") and other components in the FH system. In the case where Flow Defuel is not able to defuel a channel, dummy fuel bundles will be used to displace the irradiated fuel into a fuelling machine.

Details of the scope of work for the Defuelling Work can be found in NK38-SOW-35000-10002. Based on the current schedule, OPG needs to execute an agreement or agreements for the Defuelling Work by early Q2 2013 to meet the DR Program milestones.

3.0 PROJECT OBJECTIVES

The key objective of the DR Program is to extend the life of the plant for 30 years. DR activities must be focused on ensuring reliability and improving performance and maintainability. Investments in refurbishment must deliver value for money and be aimed at improving reliability while lowering production costs.

In addition to the objectives for the DR Program, specific objectives were identified for the Defuelling Work. These include:

(a) Eliminate any nuclear and safety related risk related to defuelling;

(b) Defuel the reactor within the allotted schedule to allow downstream refurbishment work to commence;

(c) Seamlessly integrate defuelling activities with existing FH activities to minimize disruption to the fuelling of running units;

(d) Maintain or enhance the reliability of the FH equipment and system to meet performance objectives post-refurbishment, particularly Forced Loss Rate ("**FLR**");

(e) Ensure compatibility of parts with existing FH equipment;

(f) Ensure compliance with the technical and quality assurance requirements;

(g) Minimize impact on Operations and Maintenance staff; and,

(h) Complete the Defuelling Work within the approved funding limits.

A Kepner-Tregoe ("**KT**") analysis was performed for the Defuelling Work. The results are attached in Appendix D and include additional commercial objectives for the contracting strategy.

3.1 Purpose

The purpose of this document is to set out the overall Contracting Strategy proposed for delivery of the Defuelling Work under the DR Program. This document will:

- Identify the contracting alternatives suitable for the Defuelling Work;
- Document evaluation considerations; and
- Recommend a Contracting Strategy (includes strategy around sourcing and pricing models).

3.2 Development Process

The Team was initially established in February 2011 with support provided as required by Faithful+Gould Inc. and OPG's Law Division. A smaller working group was established which included Project Management, Refurb Supply Chain and Commercial Strategy (now Nuclear Commercial Development). The Team then identified and analyzed potential options around work packaging, contracting approaches/models and pricing options.

As the scope of work became understood, the decision was made in August 2012 to focus on the Defuelling Work ahead of the Refurbishment Work because the two scopes of work are mutually independent and are driven by different DR project execution timelines.

3.3 Stakeholder Identification

A list of stakeholder groups is listed below.

- Darlington Refurbishment Execution (Sorin Marinescu, David Train)
- Darlington Refurbishment Engineering (Catalin Butoi)
- Darlington Station Engineering (Jai Sanasi)
- Darlington Refurbishment Supply Chain (Gary Paterson, Mike Vacariu, Shirley McTeer, Andy Nelson)
- Darlington Refurbishment Commercial Strategy/Nuclear Commercial Development (Nancy Woodward, Kent Scherm, Pam Hendrix)
- Darlington Operations and Maintenance (Frank Guglielmi)
- Darlington Refurbishment Planning and Controls (Sunil Ingle)
- Darlington Refurbishment Program level Cross Functional Sourcing Team ("**CFST**") members (Law: Evguenia Prokopieva, Matt Thorpe; Treasury; Tax; Risk Services; Controllership)
- Refurbishment Program Executive Team ("**RPET**")
- Previous supporting members (Steve Ilott, Omair Naeem, John Cho, Silviu Stancu)

Each of the stakeholders identified was either on the Team or was consulted by the Team because of his or her role within the DR Program.

4.0 CONTRACTING CONSIDERATIONS

In developing the Contracting Strategy for the Defuelling Work, OPG must consider how the work will be executed and contracted in order to ensure the achievement of OPG's core business objectives and values of: safety, including nuclear safety, accountability, fairness, transparency and value creation.

(a) Defuelling Risks

Defuelling is a highly operations-oriented critical path work activity which will have significant impact on the entire DR Program. No refurbishment activities can be undertaken until the reactor is defueled.

(i) OPG has never defueled an entire reactor on critical path with the final goal of restarting the unit;

(ii) If the reactor cannot be partially or completely defueled by flow defuel method (the recommended method per previous studies), OPG will use dummy fuel bundles to push irradiated fuel out of the channel (as approved in an Engineering Decision Meeting ("**EDM**") ref.: NK38-REP-01000-0435734);

(iii) It is possible that varying lengths of dummy fuel bundles may be required due to channel creep and sag. The design of the dummy fuel bundle is critical because the dummy fuel bundles must mimic the dimensions of real fuel bundles in the existing fuelling machines ("**FM**") and be strong enough to safely push irradiated fuel out of the channel;

(iv) The dummy fuel bundles and FROBS must also be designed to enable them to be crushed and properly disposed of as part of the RFR work.

While it is expected that there will be some iterations during commissioning with the FROBs flow hole size and dummy fuel bundle lengths, problems during defuelling such as: dummy fuel bundles interference in the FMs, FROBS or fuel carriers fail to meet the requirements for defuelling, etc. may impact on nuclear safety and will very likely result in delays to the RFR work and the entire DR critical path schedule.

(b) Business Drivers:

(i) There is a preference for minimal number of parties to be accountable for the delivery of the Defuelling Work. A single point of accountability for the execution of the Defuelling Work is preferred to ensure proper oversight coordination, integration and flexibility of implementation.

(ii) Cost and schedule related considerations:

- Completion of the full scope of work[3] within the approved and released original budget for the Defuelling Work.
- Completion of the full scope of work within the original schedule.

(c) Commercial Principles

The Guiding Commercial Principles from the DR Commercial Strategy were considered in developing and evaluating the contracting options. A list of the principles considered is contained in Appendix A. A review of the applicability of these principles will be performed prior to negotiations and design of the contracts.

4.1 Vendor/Marketplace Capabilities, Restrictions

Key capabilities and restrictions in the vendor marketplace have been assessed for the Defuelling Work. Labour required to defuel the reactor (i.e., field execution for defuelling) will be performed by OPG operators and PWU maintenance staff. This is due to licensing and regulatory constraints – the unit is considered operational with fuel in the reactor and therefore must be operated (and therefore defueled) by trained staff of the license holder (OPG).

Four potential suppliers, CEI, GHNEC, Promation and Numet were identified as potentially capable of performing design and engineering work, designing and manufacturing FROBS, dummy fuel bundles and fuel carriers, performing software changes and any other modifications required for the Defuelling Work. All of these suppliers are on OPG's Approved Supplier List ("**ASL**"). The required details of the QA requirements are included in the Scope of Work document: NK38-SOW-35000-10002.

4.1.1 GE-Hitachi Nuclear Energy Canada Inc. (GHNEC)

GHNEC is the OEM of the Darlington FH system and the original design agency responsible for FH under the Design Agency Interface Agreement ("**DAIA**"). GHNEC is in the ASL and has provided services to OPG for a period of 30 years plus. Over this period, OPG has awarded numerous POs to GHNEC. The majority of the POs were for Darlington FH systems and very few for Pickering FH systems.

GHNEC maintains in-house design expertise to manage and modify the FH hardware, software and controls and to maintain FH specialized equipment including the test facility. GHNEC provides configuration management, systems engineering, as well as material and troubleshooting support. All source documents are maintained by GHNEC. OPG does have some in-house capability to develop software and hardware changes; however, there is still a link back to GHNEC to update and maintain the source documents and to maintain the test facility.

[3] Full scope of work in this context means all work approved by the Scope Review Board.

GHNEC could engineer, design and manufacture FROBS, fuel carriers and dummy fuel bundles. They could also lead and execute the required scope of work including: the analysis required to integrate the defuelling equipment with the existing equipment; the software changes which mitigates the risks of incompatibility; adapting the existing equipment for any mitigation strategies that arise (i.e. grappling in a sagging channel) and provide advice for the entire FH system during the actual defuelling activities conducted by OPG.

4.1.2 Candu Energy Inc. (CEI)

Although CEI (formerly AECL) is the designer of the Pickering, Gentilly and Pt. Lepreau FH systems, and has experience in fuel handling in general. [redacted] CEI has subcontracted to GHNEC for engineering and manufacturing of FH systems of some CANDU plants outside Canada (China, Korea). CEI has potential capability to design FROBS, fuel bundles and fuel carriers.

CEI would need to get access to source documentation (from GHNEC) and then take the time to become knowledgeable in trolley-based fuelling. CEI could provide hardware changes but any software changes would have to be validated by GHNEC. [redacted]

CEI is on the ASL and has provided services to OPG for a period of 30 years plus. Over this period, OPG has awarded numerous POs to CEI. However, the majority of CEI's OPG FH experience is with Pickering systems.

4.1.3 Promation and Numet

The Team determined that having experience and a proven track record in FH systems design is critical to providing the Defuelling Work. [redacted]

Promation (Promation Nuclear Ltd.) is on the ASL (since 2011) and OPG has awarded very few POs. Numet (former Rolls-Royce Civil Nuclear Canada Ltd.) is on the ASL and OPG has awarded relatively very few POs. None of these POs have been with FH systems.

4.2 Contracting Alternatives Analysis

4.2.1 Bundling of Work

The Team looked at each of the FH work packages and identified potential options for bundling of the work and contracting models. These included, (i) bundling all the work together, (ii) bundling by type of work, and (iii) bundling by scope of work. Full details of the options considered can be found in Appendix B.

4.2.2 Contracting Models

Various contracting models were considered in developing and evaluating the contracting options. A list of the pros and cons of all the contracting models considered is contained in Appendix C. None of the contracting models fit the Defuelling Work which includes buying a piece (or pieces) of engineered equipment and some related technical support services.

4.2.3 Work Packaging and Vendor Fit

The Defuelling Work includes:

(a) Engineering work that could be provided by CEI or GHNEC;

(b) Design and supply of dummy fuel bundles, fuel carriers and FROBS that could be provided by CEI, GHNEC, Numet or Promation; and

(c) Software changes which must be provided by GHNEC due to their source code knowledge and highest level of understanding of the impact of code changes on FH operations.

While the design and manufacture of the dummy fuel bundles, fuel carriers and FROBS could be procured on a competitive basis (CEI, GHNEC, Numet, or Promation (for design and manufacture)):

- GHNEC is the only supplier with trolley mounted FH system design and engineering experience and has a proven track record;
- GHNEC has been retained by OPG for over 30 years as the Design Agency for Darlington's FH system and has unique knowledge and expertise;
- GHNEC has experience with similar flow defuelling of reactors, having completed the *defuelling* work for Bruce Power LP;
- GHNEC is in the best position to advise OPG on defuelling the reactor. As the designer and manufacturer of fuel bundles and FH components, GHNEC has unique knowledge of the FH system that can be expected to minimize the risks during the design and manufacture of the FROBS, dummy fuel bundles and fuel carriers; and
- In the event design changes or modifications are required to the FROBS, dummy fuel bundles or fuel carriers during defuelling, GHNEC as the designer and manufacturer of the FH system is in the best position to ensure that the required changes or modifications are compatible with the existing system and to integrate the changes or modifications to the station FH systems and/or software required.

Due to the Defuelling Work being the first project executed on critical path, the entire DR schedule is at risk if a vendor with an untested and unproven track record and no previous knowledge of trolley based FH systems is awarded the contract.

The scope of the Defuelling Work has been prepared based on GHNEC providing the engineering studies and preliminary scoping engineering support. Additional work will be required in order to procure the work on a competitive basis.

4.3 Decision Options and Constraints

Initial development of this Contracting Strategy focused largely on contracting the entire FH scope (Defuelling Work and Refurbishment Work) to GHNEC or to GHNEC with a partner (for the Refurbishment Work). In the event that negotiations were not successful in that scenario, an alternative plan was developed which sought to minimize the scope that was required to be performed by GHNEC. This alternative which limits the scope that was to be sourced to GHNEC (i.e. the Defuelling Work), was preferred by both the Team and management, and it is the recommended approach.

The probability of success of the Defuelling Work is maximized with participation from GHNEC because GHNEC is the designer of the FH equipment and OPG does not have the internal design capability to perform the engineering work for FH. Provided that negotiations result in an acceptable agreement with GHNEC, approval to single source the Defuelling Work will be required.

How the Defuelling Work negotiations progress with GHNEC may shape GHNEC's involvement in the Refurbishment Work.

5.0 RECOMMENDED CONTRACTING STRATEGY

This Contracting Strategy recommends the following sourcing approach for the Defuelling Work:

(a) ***Plan A (preferred):*** Engage in discussions with GHNEC for the engineering, supply of hardware, and technical support for the Defuelling Work. Provided that negotiations result in an acceptable agreement with GHNEC, approval to single source the Defuelling Work will be required. This option ensures the lowest risk to the overall DR Program schedule and the lowest technical risk due to equipment integration issues. The field execution of the Defuelling Work will be performed by OPG FH Operations personnel with GHNEC providing technical support.

(b) ***Plan B:*** Engage in a competitive process with CEI, ESMSA, and/or other vendors. Plan B may result in better commercial terms (i.e. risk acceptance); however, engaging in a competitive process will require the scope of work to be re-written and will require additional planning activities. A competitive process may negatively impact on the overall cost of the Defuelling Work and schedule, and the benefits of a competitive process will likely be outweighed by the additional risk exposure. It may be difficult, given GHNEC's historical involvement with Darlington FH activities, to reasonably run a fair competitive process. As the Defuelling Work is the critical path activity prior to starting all major reactor refurbishment work, including RFR work, the entire DR schedule is hinged on the success of the Defuelling Work of each unit. Further development of Plan B will be undertaken in parallel with Plan A activities.

NOTE: The Negotiations Plan for the Defuelling Work can be found in NK38-PLAN-09701-10099.

6.0 CHOICE OF PRICING MODEL

Description	Unit 2	Unit 1	Unit 3	Unit 4	Comments
Engineering	Fixed Price				Detailed engineering is for all four units
Procurement	Fixed Price + Fixed Unit Price	Firm Price + Firm Unit Price	Firm Price + Firm Unit Price	Firm Price + Firm Unit Price	Procurement will include component manufacturing and delivery
Technical Support	Cost reimbursable + fixed fee	Cost reimbursable + fixed fee	Cost reimbursable + fixed fee	Cost reimbursable + fixed fee	Ongoing engineering support when defuelling performed by OPG personnel

7.0 INTERFACE OR INTEGRATION ISSUES WITH OTHER CONTRACTING STRATEGIES/ MAJOR CONTRACTS FOR THE DARLINGTON REFURBISHMENT WORK

At this point in time, the following interface or integration issues have been identified:

(a) Defuelling Work must be completed upstream of RFR; and

(b) Defuelling and Refurbishment Work will have some interface with resources and equipment supporting the running units.

This area will be continually assessed as the definition phase progresses further for all other DR Projects including the FH Project.

8.0 KEY RISKS AND PROPOSED MITIGATION

Key risks and proposed mitigation are contained in the Risk Register.

Commercial risks for Plan A include:

- [redacted]
- [redacted]
- [redacted] By establishing negotiations timelines as found in the Negotiations Plan (ref.: NK38-PLAN-09701-10099), a finite amount of time is allocated for negotiations to be completed. If negotiations are not complete within the allocated timeline, OPG will move forward with Plan B.

Key risks associated with Plan B were included in the KT analysis (Appendix D), and identified several that were assessed as having both a high probability, and a high consequence level. These included:

- Vendor not fully understanding the Defuelling Work's scope;
- Significant increase of interfaces introducing the need for additional OPG oversight; and
- Increased risk of integration issues having high negative impact in the Defuelling Work.

The above risks were identified with the alternative competitive sourcing options, and would be mitigated if the Defuelling Work is single sourced to GHNEC.

9.0 SUCCESS CRITERIA/PERFORMANCE INDICATORS

The key success criterion is successful negotiations with GHNEC for the Defuelling Work as outlined in the Negotiations Plan (ref.: NK38-PLAN-09701-10099).

Other critical success factors include:

(a) Meet Regulatory Requirements: meet all required standards for safety, environmental compliance and the CNSC/other applicable quality standards

(b) Maintain OPG Control: OPG has ultimate accountability for delivering the DR Program as the Program Manager

(c) Minimize Impact on Existing Units: minimize disruption to operating units where safety of the units is involved and where production is potentially disrupted

(d) Achievable Schedule and Budget: Schedule and budget are to be realistic and achievable. Cost recovery and financing methods must be in place.

(e) Demonstrate Success: Demonstrate to the public and shareholder that the Program is a success. The RPET have defined success through the following program critical success factors:

   (i) Sustain current plant performance and support, where feasible, initiatives to achieve top decile performance post refurbishment;

   (ii) Program implemented on budget, on schedule (measured against release quality estimate baseline); and

   (iii) Return plant and people back to Darlington.

10.0 IMPLEMENTATION PLAN

Details of the Implementation Plan can be found in the Darlington Refurbishment Fuel Handling – Defuelling Project Negotiations Plan (ref.: NK38-PLAN-09701-10099).

Appendix A: Commercial Principles

Principle	Comments
Early Communication with OPG Stakeholders	There were open and active discussions with senior management and other important stakeholders (e.g. Law, DR Program Level CFST etc.) to make them aware of the Defuelling Work and obtain their input on the Team's recommended Contracting Strategy.
Early Engagement for Market Due Diligence	The Team drew from review of past & present FH projects and commercial agreements, OPG ASL database, OPEX around FH work primarily within Darlington, and the Team's knowledge base to gather market intelligence for FH work.
Competition	The Team's approach was that competition is the preferred method of procurement and benefits of competition must be considered. The option of sourcing via competition was incorporated in packaging the scope of work, the analysis of the contracting approach and the overall sourcing strategy.
Acceptance by Marketplace	A review of the marketplace for vendors experienced in FH system work, specifically, trolley-based FH system work as found at Darlington & Bruce was completed and reviewed by the Team.
Compliance with Applicable Internal Policies and Procedures	The Team's view is that the proposed Contracting Strategy complies with the requirements in applicable OPG's internal policies and procedures.
Scope Definition and Work Packaging	The strategy development considers optimal bundling of the scope of work taking into account acceptable risk thresholds associated with integration activities.
Timing of Contract Award	Consideration for cost and schedule when deciding the contract award timing, in particular for the Defuelling Work. Timing of engaging any third party will be decided in the context of OPG's and DR's objectives and priorities. Consideration is also given to pre-refurbishment work and long lead items.

Principle	Comments
Risk Sharing vs. Risk Premium	The objectives and key risk areas associated with the Defuelling Work were identified from analysis of the available options. These were considered to determine the best Contracting Strategy to achieve the DR and the Defuelling Work's objectives and post-refurbishment goals within acceptable risk thresholds taking into account inherent risks around transparency and value for money.
Working Approach/Philosophy between OPG and Vendors	Partnership approaches with appropriate monitoring and oversight by OPG was considered. 'Open book' contracts will be pursued to permit OPG to have a good understanding of the vendor's cost structure. OPG will leverage vendor capabilities and execution methodologies and work together to cooperatively resolve issues.
Use of OPG Knowledgebase	The Team gathered OPG OPEX for FH work from contracting and commercial perspectives through review of past projects and discussion with knowledgeable stakeholders across OPG.
Linkages to Other DR Strategies	OPG will avoid developing internal skills that will not be required post-refurbishment. Internal OPG resources will provide project oversight during planning and execution of the FH work to ensure effective integration with other DR strategies. Where required due to licensing and/or regulatory issues, internal OPG staff will be utilized.

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Appendix B: Bundling of Work

Option 1	Bundle All Work Together	The first option considered was bundling of all of the FH work (Defuelling and Refurbishment). Bundling all the work together and contracting with one vendor including GHNEC using an EPC model is the least complicated approach for procuring the work and is an approach consistent with many of the business drivers and commercial principles (i.e. minimizing the number of parties being accountable for Project delivery, mitigating risks on long-lead items, reducing the number of interfaces, and taking advantage of vendor capabilities). Based on the vendor/marketplace capabilities, bundling of all the work together would require contracting of all the work to GHNEC. Given that some of the work can be done by others, this option does not appear to be the best option. Bundling of all of the work together could negatively impact on OPG's ability to manage cost, integrate with the DR work schedule and OPG's ability to demonstrate value for money.
Option 2	Unbundle the Work by Type of Work	The second option considered was a complete unbundling of all of the FH work. This option would allow each of the CCA work packages to be dealt with individually or broken down by type of work (i.e. engineering, procurement and construction or labour and materials). Labour and materials could be further broken down and bundled based on the type of labour (i.e. design, inspection, construction, etc.) or type of material (i.e. original equipment manufacturer). Unbundling of the work allows for each work package to be carefully assessed and opportunities identified to procure from competitive sources. While this approach may enable competition for some materials and may reduce the price of some items, managing multiple work packages, suppliers and contracts would be time consuming and require additional resources. This approach is not consistent with the DR Program philosophy, business drivers and guiding commercial principles. The risks associated with this approach have the potential to significantly outweigh any potential cost savings (i.e. compatibility issues between hardware and software). The impact on schedule could be significant. Configuration management risk and corresponding level of effort needed to mitigate this risk usually increases with the number of suppliers. It may also be difficult to achieve the schedule, integrate work provided by multiple suppliers, and seamlessly plan and execute the work.
Option 3	Bundle by Scope of Work	The third option considered was bundling the work by scope as follows: • Defuelling Work • Refurbishment Work The Defuelling Work is by nature a completely separate type of work than the Refurbishment Work and therefore it doesn't make sense to bundle the scopes together. In effect, until the reactor has been defueled, the unit is still considered to be operational. Specifically: • The timing of the work and contract award is different for Defuelling Work and Refurbishment Work. Defuelling Work must be done long before the Refurbishment Work is done. • Defuelling Work is critical path and risks associated with Defuelling Work are very different from the risks in the Refurbishment (see section 4.0(a)). The commercial terms will need to mitigate (as much as commercially possible) these risks. • The potential suppliers for the Defuelling Work are different from the potential suppliers for the Refurbishment Work. The potential suppliers for the Defuelling Work (noted in section 4.1) are designers, engineering services and manufacturers of defuelling components including FH components. The potential suppliers for the Refurbishment Work will include contractors who will install FH components into the FH system. Bundling by scope of work would allow OPG to source to the most appropriate vendor and better ensures alignment between vendor/marketplace capabilities and the work that needs to be done. It is a better option than bundling of all work together because it enables OPG to select the best sourcing option for each of the work scopes. Bundling by scope is less complicated than complete unbundling and the approach is consistent with many of the business drivers and commercial principles (i.e., minimizing the number of parties being accountable for Project delivery, mitigating risks related to schedule, reducing the number of interfaces, and taking advantage of vendor capabilities). Bundling by scope of work and alignment of scope with vendor capability will positively impact on OPG's ability to manage the work. Given that and utilize competitive bidding which enables OPG to demonstrate value for money.

B.1.0 DEFUELLING WORK

For the Defuelling Work, in order to ensure integration, the Team determined that bundling the engineering, supply of hardware, and technical support together would reduce the schedule and technical risk due to equipment and design integration issues. Due to licensing requirements, the field execution of the Defuelling Work can only be performed by OPG FH Operations personnel. Unbundling of the Defuelling Work and competitive bidding would introduce risks (These other risks are contained in section 4.2.3 of this Contracting Strategy and the KT Analysis contained in Appendix D).

Appendix C: Contracting Models

Contracting Model	Description	Pros	Cons
Self Perform	The Self Perform model would mean that OPG would perform all of engineering, procurement, and construction activities for the Project. This option was briefly examined with the Team identifying the following pros and cons.	• Possibly cheaper (only if resources could be dedicated – see cons); • More control overall; • Schedule management totally in OPG's control; • Easier control of inage and pre-refurb outage scope if required.	• Limited resources / resources not available [eng/supply/trades]; • No infrastructure to support this approach; • Lack of FH engineering expertise internally; • Limited trades staff; • Not in alignment with OPG's strategic direction; • Time required to hire additional resources, train, etc., would cause delays; • OPG retains all risk.
Design, Bid, Build (DBB)[4]	Historically the way OPG has done business, the DBB model has OPG contract with separate entities to provide the design and to install. Procurement can be handled by a contracted party or by OPG supply chain.	• Less OPG resources than self perform; • OPG has more influence & can ensure OPG convention (i.e., historically this is the OPG way of doing things); • OPG can maintain input & control through reviews & design acceptance.	• Separate contracts require increased OPG resources to oversee and manage; • Extends schedule by requiring engineering to be complete prior to procurement & construction (unless procurement done at risk); • Process tends to be serial with limited ability to compress timelines; • Responsibilities are split; • Increased risk on OPG to manage interfaces i.e., finger pointing between design & build; • Increased difficulty in maintaining schedule & cost control; • Not in alignment with OPG's strategic direction.
Engineer, Procure, Construct (EPC)[5]	The EPC model would have OPG contracting with a single entity to provide the design, procure the material, and installation (and/or field technical support in the field as may the case with Defuel). It requires careful up-front development of specifications to ensure the EPC supplier has the required information.	• Fewest OPG resources required to oversee and manage (single interface, single contract); • Maximizes risk transfer to supplier (see cons for cost aspect); • Single accountability for contract, schedule, design, procurement, construction; • Potential cost savings due to better rates negotiated with supplier getting a larger overall piece of the overall program; • Seen as best opportunity at achieving schedule and cost targets when managed correctly; • In alignment with OPG's strategic direction.	• Difficult for OPG culture to 'let go' & lack of OPG experience managing EPC; • Transfer of risk to supplier can drive up cost to OPG; • Requires complete and accurate specifications to be produced by OPG up front; • OPG may have reduced ability to select subcontractors; • Larger overall impact if supplier under-performs.

[4] Note: Design, Bid, Build is not a relevant contracting model for the Defuelling Work as we are essentially buying a piece (or pieces) of engineered equipment and some related technical support services.
[5] Note: EPC is not a relevant contracting model for the Defuelling Work as we are essentially buying a piece (or pieces) of engineered equipment and some related technical support services

Appendix D: Kepner-Tregoe Analysis

Decision Analysis Worksheet Report

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FH Defuelling Strategy

Decision Analysis Background

As part of Darlington Refurbishment there are two major fuel handling projects. The first is the defueling of the reactors and the second is the rehabilitation and upgrade of the fuel handling system. This analysis is specific to the defueling phase of the refurbishment work. GE Hitachi currently acts as the OEM for Darlington fuel handling systems. A decision needs to be made as to the best option for OPG regarding the provision of engineering products (software, drawings and documentation) and procurement of hardware associated with the defueling project. It should be noted that execution of the field work will be performed by OPG operators so a full EPC contract cannot be considered for this case however technical field support for execution will be required.

Decision Analysis Team

Name	Company	Team Member Role	Team Member Expertise
neill allen	KT		
Hendrix, Pam			
Nelson, Andrew			
Scherm, Kent			
Marinescu, Sorin			
Vacariu, Mike			
Woodward, Nancy			
Diening, Jos			

Decision Statement

Select the best contract sourcing strategy for the provision of engineering (design) products, hardware procurement and field execution technical support for the defueling project.

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FH Defuelling Strategy

Objectives and Measures

Objectives	Measures	Classification
Meet OPG's current policy for procurement.	Satisfy OPG governance as concurred by Supply Chain management.	Must
Products and deliverables must meet quality requirements	As captured in the technical specifications or functional requirements certain CSA standards must be met. CSA N 286-05 for the design QA program.	Must
Minimize potential for changes to existing system. (OPG desire to maintain optimal configuation among all fuel handling systems.)	Demonstrated understanding of Darlington type fuel handling systems	Want
Vendor company must be sustainable financially	As assessed by Supply Chain	Want
Have knowledgable resources retained throughout the project	Evaluation of company technical capability	Want
Minimize risk to project execution	By evaluating the integrated capability of providing an integrated solution to the product and any mitigation plan. (Teams evaluation of the vendor overall capability relative to quality, schedule, cost, experience and technical expertise.)	Want
Demonstrate open, fair, transparent process for selection of suppliers	Auditable documentation trail	Want
Minimize the number of interfaces in the design/procure process	Number of hand-offs of deliverables.	Want
Meet existing Refurbishment milestones	As defined in current PIMS critical path.	Want
Minimize risk to nuclear safety	Demonstrated quality of previous deliverables and resources.	Want
Maximize value for money to OPG.	Cost element of value for money definition.	Want
Minimize the required OPG resources.	OPG resources involved across all departments	Want
Transfer of risk to vendors.	Clarity on vendor accountabilities and assumed risk.	Want
Allows OPG to maintain oversight	Ability to monitor the vendors quality program and project task completion.	Want

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FH Defuelling Strategy

Weight of Want Objectives

Want Objectives	Measures	Weights
Minimize risk to nuclear safety	Demonstrated quality of previous deliverables and resources.	10
Minimize risk to project execution.	By evaluating the integrated capability of providing an integrated solution to the product and any mitigation plan. (Teams evaluation of the vendor overall capability relative to quality, schedule, cost, experience and technical expertise.)	9
Minimize potential for changes to existing system. (OPG desire to maintain optimal configuation among all fuel handling systems.)	Demonstrated understanding of Darlington type fuel handling systems	9
Have knowledgable resources retained throughout the project	Evaluation of company technical capability.	8
Maximize value for money to OPG.	Cost element of value for money definition.	7
Meet existing Refurbishment milestones	As defined in current PIMS critical path.	7
Demonstrate open, fair, transparent process for selection of suppliers	Auditable documentation trail	6
Minimize the number of interfaces in the design/procure process	Number of hand-offs of deliverables.	5
Vendor company must be sustainable financially	As assessed by Supply Chain	5
Allows OPG to maintain oversight.	Ability to monitor the vendors quality program and project task completion.	4
Minimize the required OPG resources.	OPG resources involved across all departments	4
Transfer of risk to vendors.	Clarity on vendor accountabilities and assumed risk.	3

Alternatives

Bundled defuelling scope, single sourced to OEM

Bundled defuelling scope competitively bid

Unbundled defuelling scope with mixed procurement via single source and competitive bid elements

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FH Defuelling Strategy

Alternatives Screened through Must Objectives

Must Objective and Measure	Bundled defuelling scope, single sourced to OEM		Bundled defuelling scope competitively bid		Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	
	Supporting Data	Go/No Go	Supporting Data	Go/No Go	Supporting Data	Go/No Go
Products and deliverables must meet quality requirements As captured in the technical specifications or functional requirements certain CSA standards must be met. CSA N 286-05 for the design QA program.	OEM is on the ASL	Go	All vendors must be on ASL	Go	All vendors will be on or capable of meeting ASL requirements	Go
Meet OPG's current policy for procurement. Satisfy OPG governance as concurred by Supply Chain management.	Yes, with appropriate justification and approval	Go	Yes	Go	Yes	Go

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Decision Analysis Worksheet Report

FH Defuelling Strategy

Alternatives Scored Against Want Objectives

Objective:	Measure:	Weight:
Minimize risk to nuclear safety	Demonstrated quality of previous deliverables and resources.	10

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	OPEX from many previous projects	10
Bundled defuelling scope competitively bid	New approach, some companies have more knowledge/experience in some areas of the scope but not all areas	5
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Allows OPG to tailor the best suppliers but introduces some integration risk	7

Objective:	Measure:	Weight:
Minimize risk to project execution.	By evaluating the integrated capability of providing an integrated solution to the product and any mitigation plan. (Teams evaluation of the vendor overall capability relative to quality, schedule, cost, experience and technical expertise.)	9

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Minimises integration risk	10
Bundled defuelling scope competitively bid	Minimises integration risk but less experience and more potential re-work.	7
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Introduces intregration risk but allows for best supplier for some elements. OPG would have to provide more technical and project management integration	4

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Decision Analysis Worksheet Report

FH Defuelling Strategy

Minimize potential for changes to existing system. (OPG desire to maintain optimal configuration among all fuel handling systems.)	Demonstrated understanding of Darlington type fuel handling systems	9

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Greatest understanding	10
Bundled defuelling scope competitively bid	Reduced understanding, some learning curve.	8
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Same as above	8

Objective:	Measure:	Weight:
Have knowledgable resources retained throughout the project	Evaluation of company technical capability.	8

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Currently available, supporting continued operation of other units.	10
Bundled defuelling scope competitively bid	Would be assessed as having knowledge for award of contract but depth and sustainability may be questionable	7
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Better assurance for each element but not necessarily for project management and integration.	5

Objective:	Measure:	Weight:
Maximize value for money to OPG	Cost element of value for money definition.	7

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Most likely most expensive	5
Bundled defuelling scope competitively bid	Most likely least expensive	10

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Decision Analysis Worksheet Report

FH Defuelling Strategy

Objective:	Measure:	Weight:
Maximize value for money to OPG.	Cost element of value for money definition.	7

Alternative	Supporting Data	Score
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	In between as it may incur additional costs for oversight and additional project management	8

Objective:	Measure:	Weight:
Meet existing Refurbishment milestones	As defined in current PIMS critical path.	7

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	most likely	10
Bundled defuelling scope competitively bid	somewhat at risk	7
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	most risk due to the porcesses involved	5

Objective:	Measure:	Weight:
Demonstrate open, fair, transparent process for selection of suppliers	Auditable documentation trail	6

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Least transparent (note all will have supporting documentation)	5
Bundled defuelling scope competitively bid	Most transparent	10
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	In between	8

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Decision Analysis Worksheet Report

FH Defuelling Strategy

Objective:	Measure:	Weight:
Minimize the number of interfaces in the design/procure process	Number of hand-offs of deliverables.	5

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Least	10
Bundled defuelling scope competitively bid	Middle (some OEM/OPG interfaces are required)	8
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Most	3

Objective:	Measure:	Weight:
Vendor company must be sustainable financially	As assessed by Supply Chain	5

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Part of a bigger suite of projects to OEM	10
Bundled defuelling scope competitively bid	We would have to evaluate this so some small risk	8
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Similar to item 2	8

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Decision Analysis Worksheet Report

FH Defuelling Strategy

Objective:	Measure:	Weight:
Allows OPG to maintain oversight.	Ability to monitor the vendors quality program and project task completion.	4

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Requires least amount of oversight, existing OPG process in place (Important for permanent plant)	10
Bundled defuelling scope competitively bid	Requires more oversight	8
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Requires most oversight	6

Objective:	Measure:	Weight:
Minimize the required OPG resources.	OPG resources involved across all departments	4

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Least	10
Bundled defuelling scope competitively bid	More	8
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Most, supply chain, engineering and project management.	5

Objective:	Measure:	Weight:
Transfer of risk to vendors.	Clarity on vendor accountabilities and assumed risk.	3

Alternative	Supporting Data	Score
Bundled defuelling scope, single sourced to OEM	Difficult starting position	8

Decision Analysis Worksheet Report

FH Defuelling Strategy

Objective:	Measure:	Weight:
Transfer of risk to vendors.	Clarity on vendor accountabilities and assumed risk.	3

Alternative	Supporting Data	Score
Bundled defuelling scope competitively bid	Risk transfer can be part of negotiation	10
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	Some risk transfer but introduces integration risk back to OPG	7

Total Weighted Scores for Alternatives

Alternative	Total Weighted Score
Bundled defuelling scope, single sourced to OEM	699
Bundled defuelling scope competitively bid	594
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	477

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Decision Analysis Worksheet Report

FH Defuelling Strategy

Making the Decision

Tentative Choice	Total Score	Best Choice?	Risks	P	Adverse Consequences	S
Bundled defuelling scope, single sourced to OEM	699	☐	Operations require support for emerging issues reducing project priority at the OEM	H	Some schedule delay.	L
			If negotiation over commercial terms are not successful	M+	Cost increase, schedule delay.	M
			Less opportunity for innovation or rigourous cost challenge	M	Cost increase missed opportunity for schedule improvement	L
			If GE Peterborough plant is closed	L	Delay project.	H
Bundled defuelling scope competitively bid	594	☐	If the new vendor does not fully understand scope of projects	H	Schedule, cost impacts.	H
			If the vendor requires a steep learning curve to understand interfaces	H	Schedule, cost impacts.	M
			If new vendor does not have staff with field experience then support during the execution phase will be limited.	H	Schedule impact.	M
			If new vendor then commercial contract will take time to negotiate	M	Schedule impact and potential exception claims throughout project	L
			If not OEM then a relationship will need to be established.	M	Cost increase to OEM sourced elements	L

e think

Decision Analysis Worksheet Report

FH Defuelling Strategy

Tentative Choice	Total Score	Best Choice?	Risks	P	Adverse Consequences	S
Unbundled defuelling scope with mixed procurement via single source and competitive bid elements	477	☐	Significant increase of interfaces introduces need for a lot of OPG oversight	H	Technical and schedule problems	H
			Introduces threat of integration mistakes	H	Technical, cost schedule problems	H
			Accumulated effect of multiple delays by each player	M	Technical, cost, schedule problems	M

ONTARIOPOWER GENERATION

Report

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Title:
CONTRACTING STRATEGY FOR STEAM GENERATORS

Contracting Strategy For STEAM GENERATORS

NK38-REP-09701-10024-
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TABLE OF CONTENTS

Revision Summary

Revision Number	Date	Comments
R000	2011-08-10	Initial Release

1.0 EXECUTIVE SUMMARY

The Darlington Refurbishment (DR) Commercial Strategy identified a need to establish separate contracting strategies for each of the major projects under the DR Program. This strategy is the first version of the contracting strategy for the Steam Generator (SG) Project.

The recommended contracting strategy is based on the business drivers and commercial principles set out in the DR Program Commercial Strategy and specific contracting considerations relevant to the SG Project.

The Darlington Steam Generators Refurbishment Scope includes the following:

(a) Primary Side Clean (PSC)

(b) Waterlancing, or Secondary Side Clean (SSC)

(c) Access Port Installation

(d) SG Inspections and Maintenance

(e) Divider Plate Leakage Measurements

(f) Lay-up

A fair and competitive bidding process for award of the above scope is desired, and as such an Expression of Interest (EOI) approach has been adopted to determine Vendor interest and capability prior to Request for Proposal (RFP).

Various contracting models were considered by the SG Team. The nature of the SG work is assessed to fit well into the procurement model where an Engineering, Procurement and Construction (EPC) contract is negotiated.

The SG Team has examined a number of work packaging options, and following an analysis that included evaluating advantages and disadvantages to each, recommends pursuing a bundled approach to packaging this work. Bundling the work in this manner will allow work to be efficiently scoped, planned, scheduled, and managed in accordance with the DR schedule.

Various pricing models were also considered by the SG Team, tailored for the scopes of work and expected conditions. It is recommended that the contract be a combination of fixed and firm price (sum of the fixed and firm prices for the applicable sub projects), and target price (covering all the sub projects).

The timing of contract award will consider the overall DR Program schedule that will get better defined with the progress of the definition phase. The DR Program execution start date may further evolve. Contracting milestone dates for the SG Project will be evaluated against the overall DR Program execution timeframe and specifically the SG Project execution window to ensure the timing of contract award maximizes OPG's commercial leverage without impacting the Project schedule.

As further information becomes available, the contracting strategy will be updated if and as needed.

2.0 INTRODUCTION

2.1 Background Information

Major inspections and maintenance work of the steam generator sets at Darlington to address degradation and extend their life for an additional 25 to 30 years has been identified as a major Project that needs to be planned and executed under the DR Program.

The core scope of work for this Project has been approved by the DR Scope Review Board in March 2011 under Darlington Scope Request (DSR) Form TS0050: Darlington Steam Generators (SG) and can be summarized as below:

(a) SG PSC that can be broadly described as mechanical cleaning of the inside of the tubes (inner diameter). As per presentation made to the OPG Executive Committee on April 14, 2009, it was recommended to continue pursuing PSC as the method of restoring Reactor Inlet Header Temperature (RIHT), flow, and Neutron Over Power (NOP) margin while keeping the existing SG's through end of second Pressure Tube life.

(b) Inspection and Maintenance work as per Life Cycle Management Plan (LCMP): An augmented inspection and repairs scope for refurbishment has been established.

(c) SG Primary Side Divider Plate Leakage Measurements: Measure leakage using Acoustic Leakage Inspection System (ALIS) and/or equivalent to compare measurements conducted in previous outages.

(d) SG SSC (i.e. cleaning outer diameter of tubes, tubesheet and possibly upper support plates): Waterlance each SG using a combination of high pressure intertube lancing and intertube/annulus flushing with visual inspections.

(e) Installation of Access Ports to allow additional incremental visual inspection of SG internals during and post refurbishment, ability to clean upper support plates through water lancing, future chemical cleaning opportunities, remote inspection of U bend region of tube bundle and foreign material removal.

(f) Lay-up work.

Based on the Class 5 estimates as available from the current DSR's, the work sub-packages by estimated $ value is presented as below:

- PSC: $ 114.0 M
- Inspection and Maintenance work: $ 50.1 M
- SG Primary Side Divider Plate Leakage Measurements: $ 2.0 M
- SSC: $ 8.0 M
- Access Ports: $ 25.0 M
- Lay-up: $ 0.9 M

For additional details on SG work scope, please refer to Appendix B.

2.2 Objectives and Scope of Strategy

The key purpose of this document is to set out the overall contracting strategy proposed for delivery of the above scope of work (or, as further modified) under the DR Program. This document will:

- Identify the contracting alternatives suitable for the SG Project
- Document evaluation considerations
- Recommend a contracting strategy (includes strategy around sourcing and pricing)

At the outset, a draft strategy will be prepared for consultation with and review by the key project stakeholders. Following stakeholder reviews, Revision 0 of the document will be issued (TCD: August 30, 2011). As the procurement process progresses thereafter, the strategy document will be updated if and as required.

2.3 Development Process

In late March 2011, a core SG Project Team was established. These Team members included members from Engineering, Execution, Supply Chain and Commercial Strategy. This core Team commenced the strategy development work through understanding the scope of work through review of scope documents and collection and analyses of relevant internal and external operating experience (OPEX). The Team then identified and analyzed potential options around work packaging and contracting approaches/models.

As of July 2011, consultations, meetings, and brainstorming sessions have happened within this Team, supplemented with review of relevant background documentation as noted in the Bibliography Section (Appendix A) of this report to arrive at this stage of the strategy development. Discussions will continue further with the current Project Team as additional information regarding vendor market, OPEX, and risks become available.

3.0 STAKEHOLDER ANALYSIS

A preliminary list of stakeholder groups is noted below, together with their level of involvement in the strategy development to date.

The core SG Project Team included:

- Darlington Station Engineering: Components and Equipment (SG SPOC: Junaid Khan)
- DR SG Engineering (David Krupjuweit, Tahir Iqbal, Mario Pieries)
- DR SG Execution (Todd Josifovski, Pejman Asgaripour, Clare Robinson)
- DR SG Supply Chain (Peter Kukk)
- DR SG Commercial Strategy (Deepa Chatterjee, Kent Scherm)
- DR SG Planning and Controls (Sharyn Donnelly)

Law has reviewed the EOI, the EOI Scope of Work and draft EOI Evaluation Criteria. Law has also reviewed the draft Contracting Strategy.

4.0 CONTRACTING CONSIDERATIONS `

4.1 Business Drivers

The following business drivers have been considered in evaluation of the contracting strategy at this point in time:

(a) OPG's future business direction:

- o Smaller fleet, smaller staff, different labour and contracting strategies, different long-term inspection and maintenance strategy, different outage strategy (longer periods between subsequent outages, make others capable of supporting standard inspection and maintenance needs).

- OPG does not want to own any design and/or tools and hence will not invest further in design and/or tool development (to be noted that OPG has invested around $ 10 M already in PSC equipment).

(b) Cost and schedule related considerations:

- Need for reliable release quality estimate (RQE)
- Completion of the contract within the original budget (against RQE)
- Completion of the scope of work within the original schedule (against RQE)
- As per the current draft Level 1 Overview Schedule for Unit 2, the PSC work is assessed to be on the critical path, driven solely by space availability in the vault. Efforts by the Project Team to identify ways of removing PSC from critical path are being made. This could prove to be a driver for choosing a PSC technology that allows setup outside of the R&FR vault space constraints in order to move PSC off of critical path. This may have to be balanced against a requirement to develop & install containment penetration inserts to utilize such a process system.
- The team noted that the current unit overlap plan (19 months) may have an impact on the PSC work in terms of cost impact from increased tooling and resource requirements, in particular if PSC remains on the critical path.
- It is to be noted that the timing and sequencing of all the elements of the SG work within the overall refurb window needs to be critically assessed and finalized so that all schedule constraints are fully identified and assessed.
- The team also recognizes that execution efficiencies can be gained and/or optimized by careful sequencing of the SG work.

(c) Long-lead considerations:

- PSC: In 2004, OPG used the Framatome ANP PSC Process, called Sivablast for D411. In 2009, OPG completed the qualification and effectiveness testing of CANDUclean process but did not execute any PSC utilizing that process. Both of these processes are thus qualified but will require further optimization as noted under Appendix B to address tube wall wear. The optimization and design acceptance phase of PSC is currently estimated to take around one year. All the balance work required to reach the "execution ready" phase (e.g. detailed engineering, design, fabrication, testing, site preparation and documentation) is also estimated to take another year, although this will vary with the type of technology and process used. So, a total lead time of 2 years is estimated for the PSC process if OPG uses either of the two existing technologies.

- In the event that a new PSC technology is chosen for DR, a detailed development and/or qualification plan will be required as part of the RFP process to mitigate, to the greatest extent possible, reliance on an unproven technology, and aggressively target and track to the pre-execution project milestones. A greater effort from OPG project personnel to track (and potentially drive) the development/qualification work would be required. The risk of this approach would need to be weighed against any perceived contractual benefits.

(d) Quality considerations:

- The contractor is required to carry out all engineering, procurement and construction management activities under its approved Quality Assurance Program for Nuclear Activities which meets the requirements of CSA Z299.1 and CSA N286-05, applicable elements for Design, Procurement and Construction and the applicable elements of N286.7 as a minimum, for the duration of the project. In addition, the contractor will need to establish and maintain a quality program that meets as a minimum the Electrical Power Research Institute (EPRI) guidelines to ensure the prevention and detection of counterfeit, fraudulent or substandard items ("CFSI").

- OPG wants simplified model for requalification of the PSC process. It may be noted that both the existing processes are capable of effectively removing outer porous layer of magnetite from tube ID surface. There is room for increasing the effectiveness of both the processes to improve removal of the inner hard and dense adhering magnetite layer.

4.2 Commercial Principles

The Guiding Commercial Principles as outlined in NK38-REP-00150-10001 R000: DR Program Commercial Strategy has been considered for developing and evaluating the contracting options, and to arrive at a recommendation. The SG team's applications of these Principles are placed in Appendix C.

The timing of contract award [Appendix C Item (f)] will require careful consideration. Confidence in the overall DR Program execution start date (i.e. 2015 vs. 2016) and the specific execution schedule for the SG work need to be increased prior to finalizing the SG project RFP and contract award schedule. The Program and Project constraints in terms of cost, schedule, scope, and quality would need to be balanced against the opportunity to maximize OPG's commercial leverage through prudent timing of the contract award. Optimizing Project's pre-execution workload would assist OPG in this decision. As the overall DR Program start date evolves, the Project's contracting milestone dates will be evaluated accordingly.

5.0 VENDOR/MARKETPLACE CAPABILITIES, RESTRICTIONS

As per OPG's current knowledge of the vendor marketplace, there are limited potential suppliers who can support the scope of work under consideration:

- Primary Side Clean: AECL and Areva

  [redacted]

- Inspections and Maintenance: Areva and Babcock and Wilcox (B&W) (historically, 100% SG inspections have been done by OPG IMS).

- SG Primary Side Divider Plate Leakage Inspection: Historically, the only method used at OPG has been the ALIS technology, operated by Kinectrics. Ownership of the Intellectual Property (I/P) and status of equipment to be investigated by Project Team.

- Secondary Side Clean: Areva and B&W

  B&W performed a total of six waterlancing campaigns in Darlington SGs between 1995 and 2003. [redacted] the competitive bidding process was used in 2003 and Areva was awarded the contract for D341 campaign. [redacted] Waterlancing contracts for subsequent campaigns at Darlington were awarded to Areva through single sourcing.

  B&W have been performing waterlancing at the Pickering A and B SGs (Pickering work have also been historically awarded through a combination of competitive and single sourcing processes).

- Access Ports: Areva and B&W.

  B&W is the Original Equipment Manufacturer (OEM) for SGs and OEM support is essential for the Access Ports work. Formal request will need to be made to B&W for releasing the drawings and documents required to complete this modification.

OPG-wide spends for the period 1996 to 2009 for AECL, Areva, and B&W are attached in Appendix E.

Westinghouse supplies a full range of SG services in the United States. Based on initial assessment of the SG EOI responses, it may be the case that they do not currently have PSC tooling developed for the unique requirements of a CANDU unit, and will be required to develop and qualify new types of tooling, technologies and/or processes accordingly. This may result in a firm/fixed price from Westinghouse being higher than the other prospective proponents and/or a schedule that does not meet the needs of the DR project. These elements will be evaluated in more detail during the RFP phase.

[redacted]

The SG Team assessed that there is opportunity to obtain additional information regarding vendor capabilities in the market through initiating the EOI process.

6.0 CONTRACTING ALTERNATIVES ANALYSIS

6.1 Work Packaging

Option 1: Unbundled Steam Generator Work Packages

- Unbundle the Scope of Work (SOW) for contracting purposes. Logically, the lowest level of feasible bundling is to separate the scope into five broad buckets based on the fundamental nature of the work, OPG's historical practices and the nature of the vendor market: a) PSC b) All Inspections and Maintenance work except SSC c) SSC, d) SG Primary Side Divider Plate Leakage Measurement, and e) Access Ports. The lay-up work should be combined with the PSC work, being the most logical and practical combination from the execution aspect.

Pros:

- Unbundling will keep the option open to retain known and/or proven expertise and/or suppliers for the different pieces of the work (e.g. Inspection & Maintenance Services (IMS) for inspections, Areva for waterlancing, Kinectrics for Divider Plate Leakage Measurements etc.).

- Unbundling keeps the option open to OPG to use known technology and processes for the various pieces of the work, if supported by the sourcing approach (e.g. deployment of previously used Sivablast technology will require sole sourcing the PSC work to Areva). This lowers the technical risks, as use of new technologies/processes usually comes with "unknowns".

- May facilitate OPG getting better leverage in negotiations and eventually better contract terms and lower contract prices, when dealing with different vendors for different components of the work.

- Allows OPG to easily examine alternatives for a specific part of the SG project in subsequent units if desired results are not achieved from the first unit.

Cons:

- The scope of work requires a high level of integration and co-ordination and hence it is important to minimize the number of vendor interfaces/hand-offs and have fewer (preferably one) point(s) of accountability for Project execution. As all work packages will be performed on the same equipment, allowing multiple vendors will increase the integration and interface risk. OPG will need to manage majority of this risk as the Owner and General Contractor.

- With the exception of the divider plate leakage measurements (executed historically by Kinectrics using ALIS), it is not believed that an unbundled approach will increase the number of potential vendors that can bid on the work packages.

- Splitting the work packages and allowing multiple suppliers to work on one major component may lead to difficulty in assigning ownership to project planning, coordination between different work groups and/or execution risks and issues as they arise.

- There is a strong possibility that this approach will enhance the level of effort required around project management (including scheduling integration and coordination).

- OPG will absorb more training and in processing cost as resources will not be shared between various sub-projects.

<u>Option 2: Bundled Steam Generator Work Packages</u>

- Bundle all work as one package for contracting purpose

Pros:

- The geographical nature of the equipment on which the work will be performed (one equipment, one man-way) lends itself well to assigning one vendor point of accountability for full Project execution. This will limit hand-off, and coordination risks.

- This approach is assessed to better support the specific cost and schedule related considerations stated under Section 4.1 above. As integration, and coordination risks, including scheduling integration and coordination risks, are largely transferred to the contractor under a bundled approach, it is assessed that the contractor can be made largely accountable for generating a good quality RQE within the timeline required by OPG.

- This approach is assessed to facilitate a more "partnership type" working relationship with one vendor as outlined under Appendix C (i.e. high estimated contract value and the vendor having a stake at the outset of the process for overall project delivery will facilitate this relationship).
- Bundling increases the potential contract value, and hence increases the probability that vendors/ consortia of vendors will be willing and able to invest in development and qualification of tooling and processes. This willingness will be further enhanced if OPG considers building a longer term inspection and maintenance arrangement, given OPG's future business direction noted under Section 4.1 above.
- There will be savings to OPG for training and in processing as one vendor can share resources among different projects.

Cons:

- Bundling will not enable retaining any parts of the overall SOW in-house with OPG, although OPG has current ability to plan and execute the Inspections and Maintenance and Primary Side Divider Plate Leakage Measurement work.
- Bundling may not enable utilization of existing and known technologies/processes for PSC and other (e.g. Primary Side Divider Plate Leakage Measurements) work as these technologies/processes usually vary from supplier to supplier. For PSC, OPG has already invested around $ 10 M. Bundling may lead to a situation where OPG may (or, may not) be able to utilize either of these technologies. If not, then OPG may need to provide a detailed cost-benefit type explanation around the chosen technology and process.
- Concentrating all work packages with one vendor presents the risk that acceptable work performed on some sections of scope may be offset by less than expected quality on another (in terms of quality, schedule, or budget).
- Concentrating all work packages with one vendor may expose OPG to increased risk that an unforeseen commercial event (i.e., bankruptcy) could place undue risk on the DR execution.

6.2 Contracting Model

To maintain alignment with the overall contracting framework that has been adopted for the DR Program (ref. NK38-REP-00150-10001 R000: DR Program Commercial Strategy), the following contracting models were chosen for further examination:

Option 1: Self-Perform:

In-house capability does not exist to self-perform the full scope. There is capability to complete the SG Inspections and Primary Side Divider Plate Leakage Measurement work in-house.

Pros:

- Utilizing proven experience for the inspections and maintenance work
- Provides OPG the greatest flexibility to adjust the scope and schedule of the work, if retained in-house; OPG will have maximum control.

Cons:

- Does not support the first contracting consideration stated under Section 4.1 above – this is not in alignment with OPG's future business direction.
- This may lead to a situation where OPG staff and vendors need to work on the same equipment location at the same time, thereby making the integration and coordination of the work complex and difficult to manage.

Option 2: Traditional Design-Bid-Build:

Serial sequence of design and construction phases; procurement of materials usually commences with the construction phase; Owner/General Contractor (OPG at this point in time) contracts separately with designer and constructor and retains overall project management responsibility, including project oversight. [Under this model, procurement can be combined with the construction contract, or a modified version can be separate contracts for supply of materials only].

Pros:

- Potential for lowest cost contracting option.
- May leverage the competitive bid process with an increased supply base (multiple and/or different contractors for each of the design and construction contracts).
- May also leverage vendor capabilities utilization (e.g. vendors expert in construction may be considered only as the pool for the construction work).

- May facilitate better control of the quality aspect (if Owner retains quality control and quality assurance functions).

- May maximize the fixed price component of the work, if construction work is being bid to fully completed design specification.

Cons:

- Does not support minimizing interfaces and hand-offs (rather, maximizes numbers of interfaces and number of contracts) – potentially nullifies the benefits expected from bundling of the work for contracting purposes.

- Maximum schedule requirement, escalation costs greatest due to long schedule.

- Procurement approach may directly impact timely availability of long-lead items, or this approach may result in separate OPG procurement of long-lead items thereby creating another set of hand-offs.

- Design, development, and use of tools for work of this nature is usually approached through an integrated solution by the vendors in the market i.e. it is difficult to separate detailed design/engineering, tool manufacturing and execution phases. There is limited ability to address constructability issues during design phase. In the DBB approach, the entire design risk is retained by the Owner.

- Overall, as Owner retains most control, Owner retains most risks (and hence may need to carry additional contingency beyond what is typical for DBB contract due to the volume of the work). Previous experience with DBB approach (not for this specific SOW, but in general) indicates there are often significant difficulties requiring the contractor to perform rework/warranty work because the contractors try to blame OPG or other contractors for the problems.

Option 3: Design-Build or EPC:

Overlapped sequence of design and construction phases; procurement begins during design; Owner contracts with Design-Build (or EPC) contractor. OPG to enter into one contract with a DB contractor for overall project coordination, detailed design and engineering, manufacture and supply or selection and procurement of equipment/components, and execution.

Further developments and variations around the basic EPC approach may be further developed contingent on the sourcing model being pursued and better understanding about the phases of this work including timing of execution windows, ability to create construction islands, cost and schedule implications of phasing/staging the work, vendor's ability to deliver improved execution and cost, degree of Owner's involvement and oversight required.

Pros:

- In alignment with preference for limited number of accountable parties for Project delivery (single point accountability).
- Potential for the shortest schedule with concurrent E/P/C activities, and minimizes risks arising from multiple hand-offs and communication channels.
- Supports vendor capability development and early start of long-lead work.
- Greater up-front cost certainty.
- Risks around cost (and to some extent, schedule) can be largely transferred to contractor.
- May help to leverage vendor capabilities better (e.g. OPG may place more reliance on vendors to develop and deploy more efficient and optimum technologies and processes for executing the work).
- Streamlines Project organization and communication models.
- Aligns with Construction Industry Institute's (CII's) Project Delivery and Contract Strategy (PDCS) model (see Appendix H).

Cons:

- Higher cost because of risk transfer and contingencies carried by the contractor, although OPG will require correspondingly less contingency.
- Less Owner involvement in design (In essence, this is more of an advantage here as OPG does not want to own the design and following OPG's Engineering Change Control (ECC) process is not required for all work – Quality Development Plan (QDP) will be followed for Tooling).
- Failure to properly prepare functional specifications may leave OPG exposed to "extras".
- Rigours effort required in conducting audits on vendors' QA program as OPG will heavily rely on contractors' quality records prior to starting up the units.

Option 4: Turnkey:

Overlapped sequence of design and construction phases; procurement begins during design; Owner contracts with Turnkey contractor.

This was considered as a starting option but not further evaluated at this stage because:

- Approach not in alignment with the overall contracting approach for the DR Program (as OPG is the General Contractor, it does not make logical sense to have pieces under the Program set up as pure Turnkey)
- A certain degree of OPG's involvement and oversight is essential for this type of work which is largely concentrated on inspection and maintenance.

6.3 Related Internal and External OPEX

The SGs at Darlington and Pickering (A and B) sites are physically different and have different sludge issues. Hence, the SG Project team primarily collected and analysed OPG's internal OPEX on PSC and SSC from Darlington as summarized in Appendix D. These points are deemed important for planning and executing future PSC campaigns, and designing RFPs and agreements for this work.

The SG Team also gathered relevant external OPEX as noted under Appendix D.

7.0 RECOMMENDED CONTRACTING STRATEGY

Work packaging - After evaluating the related contracting considerations, and the Pros and Cons as noted under 6.1 above, <u>it is recommended at this stage that the whole SG work be bundled into one package</u> for contracting purpose. This approach offers the best opportunity for a successful project from cost, schedule, and quality perspectives. It is assessed qualitatively that the potential benefits from bundling will outweigh the potential cost savings that may be derived from piece-mealing the work for execution purposes. However, if the vendor market capability cannot support this approach, the Project Team will revisit the bundling strategy. At this point, the SOW for EOI has been prepared in separate modules, so that if an unbundled approach needs to be taken at a later date, that doesn't delay the next steps in the procurement process.

The request for EOI was issued on June 15, 2011. Initial assessment of the EOI submissions indicates no prospective proponent exceptions to the bundled approach, and the expectation is that the process can continue in a fair, competitive manner with the current strategy. If the vendors are unable to support the bundled work packaging strategy, preliminary thought has been given to breaking the scope if required, possibly into a primary side/secondary side split. This would serve to limit workforce handoffs and access coordination at the job face during execution to a minimum. Further detailed evaluation of work package combinations will not be performed by the team until (if required) after the EOI responses are fully evaluated. In addition, the contracting requirements for the Inspection and Maintenance work bundle/package may be amended to align with DR labour strategy discussions and requirements.

Contracting Model - After evaluating the related contracting considerations, and the Pros and Cons as noted under 6.2 above, it is recommended that the Design-Build (EPC) approach be pursued as it offers the most balanced approach. This approach offers the best opportunity for a successful project from cost, schedule, and quality perspectives.

8.0 CHOICE OF PRICING MODEL

Team discussions with respect to pricing models have determined that the SG scope is adequately defined and known to consider fixed and/or firm pricing where appropriate (where "firm" is a "fixed" price with economic price adjustments over a prolonged execution window). In general, development phase work that will be performed once and early in the project will be recommended as fixed, while execution elements that will be spread over a number of years will be recommended as firm.

Where scope is less certain or where OPG interference is expected, target pricing based on defined reimbursable costs plus a fixed fee for Overhead + Profit (O/H+P), with capped incentives/disincentives for cost and schedule over/under runs will be considered.

It is recommended that the contract fixed price be the sum of fixed and firm prices of the applicable sub projects and the contract target price be a lump sum covering all the sub projects.

The project team performed the following analysis for the pricing models:

(a) For PSC work, the definition phase (i.e. pre-execution) work that includes tooling, mock-up, and pre-execution engineering including ECC integration should be done on a fixed price basis. This work can be scoped out in detail and the majority of this work will be performed at the vendor's facility.

The field execution portion of PSC is recommended to be firm price, provided the equipment setup does not conflict with R&FR (i.e., in the vault) and/or critical path.

If the vendor cannot be given full control of the execution area or is at risk of impacting critical path, a target price model should be considered for execution.

(b) The Inspection and Maintenance work has been historically executed by OPG IMS, essentially on a time and materials type of arrangement. However, OPG has detailed past history of this work and hence the ability to scope it out in detail. Pre-execution tooling development and qualification (including ALIS), if and as required, should be fixed price.

The execution should be firm price for the Inspection and Maintenance work provided the vendor has full control over the worksite and is able to provide their own support services.

If the vendor cannot be given full control of the execution area a target price model should be considered for execution.

For the maintenance/repair work that would primarily include tube plugging and tube pulling, the work can be priced on a firm unit price basis.

(c) The confirmed scope for the SSC (waterlancing) work is best suited for the firm price model. This decision is based on OPEX, known base scope, and familiarity with the work scope from many successful previous outages. For any incremental scope (contingent on eddy current inspection data), consideration may be given to a fixed, firm, or cost reimbursable with fee adjustment pricing model, or deferred to subsequent outages (preferred).

(d) For Access Ports, tooling development, mock-up and ECC integration work should be fixed price. This work can be scoped out in detail and performed at the vendor's facility.

Access Port field execution is recommended to be firm price.

If the vendor cannot be given full control of the execution area, a target price model should be considered for execution.

(e) For Lay-up, there is currently no SOW or Technical Spec prepared for SG primary or secondary sides. The Team is unable to recommend a pricing model at this time.

The team also identified additional factors related to project scheduling and vendor support services which may have an impact on the pricing models. These items, as known at this time, are contained in Appendix F: Pricing Model Options Analysis.

9.0 PROCUREMENT PROCESS PREREQUISITES/CONSIDERATIONS

At this point in time, the initial intent is to contract out the whole SG work as one bundle in an EPC model. In the past, however, a mix of different vendors and in-house resources were utilized by OPG to complete similar type of work. So, it is not clearly known at this point whether vendor capabilities in the market can/will support the above contracting approach. To test the market capability, it is recommended that the procurement commences with an EOI:

The nature of this work also lends itself well to an EOI process due to the following:

- Scope is reasonably well known and defined as none of the scope item is totally new work to OPG (each item has been done before; there is a reasonable level of internal OPEX and knowledgebase).

- The above facilitates analysis and good understanding of "discovery" elements at an early phase of the Project.

- The terminal points are well defined.

- There is an expectation that the estimated value of the work and the long-term nature of the Project may encourage formation of partnerships/consortia in the market prior to the RFP stage.

In mid June, a Request for EOI was issued to the vendors identified as having in-house capability and/or potential to develop strategic ties to perform the bundled scope currently identified: AECL, B&W Canada, Areva NP Canada Ltd, and Westinghouse Electric Company. Evaluation of the returned EOI's will be performed and documented by the Project Team. Further development and revision to this document will depend in large part on the proponent responses.

Post EOI, the procurement process is expected to follow the usual competitive process as outlined in OPG-PROC-0058: Procurement Activities.

On a case by case basis as determined by the Project, where specific expertise, tools or materials are required for the Project but not furnished by the vendor, they should be procured under a separate PO by OPG. Business and Project requirements will be considered to determine the preferred approach for supplying specific resources and expertise through either an external vendor or specialized internal workgroup. Specific requirements will be identified and confirmed prior to contract award, however a change order could be used post contract award if needed to meet changing business and Project needs.

10.0 INTERFACE OR INTEGRATION ISSUES WITH OTHER CONTRACTING STRATEGIES/ MAJOR CONTRACTS FOR THE DARLINGTON REFURBISHMENT WORK

It is anticipated that the Project can be performed mostly in a stand-alone manner, due to the bundled approach of the SG scope and also the following:

- The islanding approach plans to create a "fence inside the fence" for the SG work.

- The SGs themselves are well suited to the geographically isolated work that takes place within their confines, both primary and secondary sides.

- Primary and secondary side work may be able to proceed in parallel, given the different isolation boundaries and the physical separation of the worksites by the bellows containment structure.

Some Project interface issues that will require mitigation. Interfacing with other DR Projects that will require mitigation include:

- Coordination of PSC scheduling and execution activities with R&FR, in particular if the work is on critical path.
- If SG work is to be performed prior to or during defueling activities, consideration will have to be given for the required use of the SGs as heat sinks for the fuelled reactor.
- Layup activities and strategies require further development to align with other plant work and Projects.

If the bundled approach of contracting the work scope does not prove to be viable, a great deal more interfacing work will be required to ensure concise hand-offs between contracting workgroups. This aspect may require further expansion in later revisions of this strategy document if need arises.

11.0 KEY RISKS AND PROPOSED MITIGATION

Some of the key risks to the contracting strategy and proposed mitigations identified at this time are included in Appendix G.

Further development of the Project's risk register will be a result of continued risk workshop meetings held by the Team. Future revisions to this document will include the relevant risks identified in those workshops.

12.0 SUCCESS CRITERIA/KEY PERFORMANCE INDICATORS

Critical Success Factors in the DR Commercial Strategy (NK38-REP-00150-10001 R000):

- Meet Regulatory Requirements: meet all required standards for safety, environmental compliance and the CNSC/other applicable quality standards.
- Maintain OPG Control: OPG has ultimate accountability for delivering the DR Program as the Program Manager.
- Minimize Impact on Existing Units: minimize disruption to operating units where safety of the units is involved and where production is potentially disrupted.

- Achievable Schedule and Budget: schedule and budget are to be realistic and achievable. Cost recovery and financing methods must be in place.

- Demonstrate Success: demonstrate to the public and shareholder that the Program is a success. The RPET have defined success through the Program Critical Success Factors outlined in the above document.

Critical Success Factors and Key Performance Indicators specific to the SG Project:

- To be finalised with Project Team inputs during development of project schedule and deliverables throughout EOI and RFP phases.

13.0 IMPLEMENTATION PLAN

This is included under Section 9.0.

Appendix A: Bibliography

- OPG-PROC-0058; Procurement Activities
- NK38-REP-00150-10001; Darlington Refurbishment Program Commercial Strategy
- NK38-SOW-33110-10012; DARLINGTON REFURBISHMENT UNITS 1-4 SG SECONDARY SIDE TUBESHEET WATERLANCE
- NK38-SOW-33110-10014; SCOPE OF WORK DOCUMENT - DNGS UNITS 1-4 SGS PRIMARY SIDE CLEANING
- NK38-SOW-33110-10016; DARLINGTON REFURBISHMENT - UNITS 1-4 STEAM GENERATOR INSPECTION AND REPAIRS
- NK38-SOW-33110-10017; DARLINGTON REFURBISHMENT - UNITS 1-4 STEAM GENERATOR ACCESS PORT INSTALLATION
- NK38-REP-33000-10003 R002; Darlington Heat Transport Aging Report
- NK38-REP-33110-10031 R00; D411 Unit 1 Spring 2004 Outage Primary Side Clean (PSC) Lessons Learned Report
- NK38-REP-33110-0047600; Darlington Unit 4 Boiler Divider Plate Inspection using 'ALIS' Technique
- NK38-REP-33110-0000458; Darlington Unit 2 Boiler Divider Plate Inspection using 'ALIS' Technique
- D-LLD-33110-10013 R00; DNGS Unit 1 (D811) Steam Generator Waterlancing Lessons Learned
- D-LLD-33110-10016 R00; DNGS Unit 3 (D931) Steam Generator Waterlancing Lessons Learned
- D-LLD-33110-10020 R00; DNGS Unit 2 (D1021) Steam Generator Waterlancing Lessons Learned
- D-LLD-33110-10018 R00; D1041 Steam Generator Primary Side Open/Close and Secondary Side U-Bend Inspection Lessons Learned
- NK30-LLD-36340-00008 R00; P1072 Steam Generator Waterlancing – Lessons Learned Report

Appendix A (Continued)

- NK30-LLD-36340-00007 R00; Unit 6 (P961) Steam Generator Waterlancing Lessons Learned Report

- Construction Industry Institute (CII) www.construction-institute.org; Owner's Tool for Project Delivery and Contract Strategy Selection (PDCS)

Appendix B: Steam Generator Scope of Work

The core scope of work for this Project has been approved by the DR Scope Review Board in March 2011 under Darlington Scope Request (DSR) Form TS0050: Darlington Steam Generators (SG) and can be summarized as below:

(a) SG PSC that can be broadly described as mechanical cleaning of the inside of the tubes (inner diameter). As per presentation made to the OPG Executive Committee on April 14, 2009, it was recommended to continue pursuing PSC as the method of restoring Reactor Inlet Header Temperature (RIHT), flow, and Neutron Over Power (NOP) margin while keeping the existing SG's through end of second Pressure Tube life. This includes:

- Optimization of the PSC process to address the tube wall wear and to provide the relation of wear to the process operating parameters.
- Obtaining design acceptance of PSC process from OPG including revised tube design spec. to address tube wall wear, prior to obtaining implementation acceptance for the PSC process.
- Performing detailed Engineering, design, fabrication, testing and qualification (if required) of PSC tooling. Perform Detailed Engineering of PSC Support (Waste Magnetite Handling, Vault Penetration Insert).
- Performing Site Execution of PSC during refurbishment.
- Performing post execution preventive maintenance and have the equipment ready to execute PSC on next unit

(b) Inspection and Maintenance work as per Life Cycle Management Plan (LCMP): An augmented inspection and repairs scope for refurbishment has been established. This scope includes:

- Tube Inspections and Monitoring: primary side open/close on each of the 16 SGs, bobbin probe eddy current inspection for 60% of tubes in each of 4 SGs, ultrasonic testing of 50 tubes over 4 SGs, Tube crack detection (SCC) using X probes (100% of tubes) in each of 4 SGs, one primary side tube removal for each SG, tube plug weld inspections in each of 4 SGs, and required PIP inspections.
- SG Internal Inspections and Monitoring: secondary side support visual inspections in each of 4 SGs, feedwater nozzle thickness measurement via UT in 1 SG, primary head divider plate visual inspections on the cold and hot leg, tube sheet secondary side visual inspection in each of 4 SG's, retrieval of any retrievable foreign material (if required), Feed-

Appendix B (Continued)

water thermal sleeve/ring ID visual inspection in 1 SG and Primary and Secondary separators visual inspection in each of 4 SG's.

- SG Maintenance and Repair: Tube plugging, tube sheet plugging, and tube removal (contingency item as required based on inspection results and/or PSC). Also, removal of deposits at the tube support plates and above the preheater, if found to exist through inspection, is included as a contingency item.
- Reporting: Provide OPG daily and preliminary inspection results to permit fitness for service assessments conducted by OPG. Compile and submit to OPG final inspection and maintenance reports for submission to the Canadian Nuclear Safety Commission (CNSC).

(c) SG Primary Side Divider Plate Leakage Measurements: Measure leakage using Acoustic Leakage Inspection System (ALIS) and/or equivalent to compare measurements conducted in previous outages. The scope includes:

- The refurbishment or remanufacture of ALIS measurement hardware and/or equivalent.
- Conducting and executing inspections on all 16 SGs.
- Developing a contingency repair strategy if measurements suggest that leakage results are unacceptable.
- Providing OPG with a final report with a summary of test results.

(d) SG SSC (i.e. cleaning outer diameter of tubes, tubesheet and possibly upper support plates): Waterlance each SG using a combination of high pressure intertube lancing and intertube/annulus flushing with visual inspections. The scope includes:

- Hand hole opening and closing
- Initial pre-waterlancing inspections
- Initial sludge sampling
- On-boiler setup, commissioning and operation of static lancing/annular flushing system, drainage system and IBL lancing to remove both hard and loose sludge deposits

Appendix B (Continued)

- Preliminary and final inspections to ensure that lancing and flushing meet the acceptance criteria
- Post execution equipment maintenance

(e) Installation of Access Ports to allow additional incremental visual inspection of SG internals during and post refurbishment, ability to clean upper support plates through water lancing, future chemical cleaning opportunities, remote inspection of U bend region of tube bundle and foreign material removal. This includes:

- Install 7 additional access ports per SG along the Upper Cone (1), Tube Support Plate (4) and Preheater (2).
- Spare access port components
- Engineering Analysis including preparation of engineering change packages, technical specifications, design report, drawings and registration.
- Installation services including supply of equipment, consumables, procedures, training for machining ports.
- Inspection of port components to demonstrate code compliance and to verify that no foreign material was added to the SG and that no damage to the SG internals was caused during installation of the inspection ports.
- Demonstration of functional access for future inspections and waterlancing campaigns.

(f) Lay-up work. This includes:

- Dosed wet-layup with recirculation and nitrogen cover gas for the lay-up of the secondary side. Assess isolation method to allow use of nitrogen cover gas.

The lay-up of the primary side will involve circulation of dry, dehumidified air once the Primary Heat Transport (PHT) system is drained and vacuum-dried.

Appendix C: Guiding Commercial Principles for SG Contracting Strategy

The Guiding Commercial Principles as outlined in NK38-REP-00150-10001 R000: DR Program Commercial Strategy has been considered for developing and evaluating the contracting options, and arrive at a recommendation. The SG team's applications of these Principles are illustrated below:

a) Early Communication with OPG Stakeholders: Open and active discussions have either commenced or are being planned with senior management and other important stakeholders (e.g. Law, DR Program Level CFST etc.) to make them aware of the SG Project and the team's recommended contracting strategy.

b) Early engagement for Market Due Diligence: The SG Project has issued an EOI to gather current market intelligence on the potential suppliers for the 6 SOWs under consideration. The team has also drawn from review of OPG's past experience with PSC and SSC, and OPEX from other CANDU units in Ontario.

c) Competition: The team understands that competition is clearly the preferred method of procurement and benefits of competition should never be underestimated. Competition should be used where contractors have a reasonable likelihood of being awarded the contract and completing it successfully to meet OPG's post-refurbishment goals within an acceptable risk threshold. The team recommends that the procurement process for SG Project should follow the competitive approach.

d) Acceptance by Marketplace: The team identified no market constraints at this time that would impact the proposed contracting strategy. EOI process is utilized to have additional information in this area.

e) Scope Definition and Work Packaging: The strategy development has considered optimal bundling of the Scope of Work (SOW). It is understood by the team that the SOW must be clearly defined to establish appropriate commercial relationship and work grouping should allow for efficient scoping, planning, scheduling and execution. As the EOI responses are received and evaluated, the work packaging aspect will be re-evaluated, if and as necessary.

f) Timing of Contract Award. Cost and schedule related considerations are currently being considered for deciding the contract award timing. Timing of engaging any third party will be finally decided in the context of OPG's and DR's objectives and priorities. Consideration must be given to the critical path work and associated long lead items. Timing of contract award must ensure completion of work on schedule and on budget.

g) Specific considerations for designing contracts: The Principles outlined in NK38-REP-00150-10001 R000 regarding Risk Allocation, Commercial Structure, and

Appendix C (Continued)

Vendor Team will be factored into the negotiation approach and design of contracts

h) Project Objectives: The SG Project objectives and associated delivery strategy need to be fully aligned with the DR Program objectives as outlined in NK38-REP-00150-10001 R000. Briefly, these are, meet regulatory requirements, maintain OPG control as the overall Project Manager, minimize impact on operating units, achieve schedule and budget - schedule and budget are to be realistic and achievable, and demonstrate to the public and shareholder that the project is a success.

i) Working approach/philosophy between OPG and vendors. Partnership approaches with appropriate monitoring and oversight by OPG will be considered. OPG will leverage vendor capabilities and execution methodologies and work together to cooperatively resolve issues.

j) Use of OPG knowledgebase: The SG team is gathering OPG OPEX and OPEX from other CANDU units for similar work, including from contracting and commercial perspective. Summary of the observations available to date have been presented under Section 6.0 below.

k) Linkages to other DR Strategies – OPG will avoid developing internal skills that will not be required post-refurbishment. Internal OPG resources will be available to provide project oversight during planning and execution of the SG work. Heavy reliance will be placed on contractors to successfully perform the work.

Appendix D: Related External and Internal OPEX

Internal OPEX:

The SGs at Darlington and Pickering (A and B) sites are physically different and have different sludge issues. Hence, the SG Project team primarily collected and analysed OPG's internal OPEX on PSC and SSC from Darlington as noted below.

Primary Side Clean:

Darlington completed one PSC campaign to date in Unit 1 (Spring 2004 outage) using Sivablast technology. The contracted work included PSC equipment, mock-ups, effectiveness and qualification testing, waste handling, bungs and Foreign Material Exclusion (FME) barriers and field execution. [redacted]

The following key points have been summarized from review of a number of lessons learned reports from this work and are deemed important for planning and executing future PSC campaigns, and designing RFPs and agreements for this work:

- Recommended that future PSC carry out optimization of the process, specific to Darlington SG, and demonstrate effectiveness
- Any future requalification of the PSC process should be done to a simplified approach that addresses solely the tube wall wear and provides the relation of wear with respect to the process operating parameters, instead of meeting an acceptance criterion.
- [redacted]
- Improvements to drying techniques of the SGs prior to PSC are recommended

Post Implementation Review Report of Qualification testing completed for the CANDUclean process (AECL) for Darlington steam generators in 2009 (reference D-PIR-33110-10004) also recommended:

- Any future requalification of the process should be done to a simplified approach that addresses solely the tube wall wear and provides the relation of wear with respect to the process operating parameters, instead of meeting an acceptance criterion.

Appendix D (Continued)

Waterlancing:

As noted under Section 5.0 above, waterlancing at Darlington has been historically performed by both B&W (1995 to 2003) and Areva (2004 to present). The contractor has been responsible for design and registration, lance qualifications, lancing documentation, training of personnel and site execution.

The following key points have been summarized from review of a number of lessons learned reports for applying as lessons learned in future SSC campaigns:

- Recommended that future contracts include a performance cleanliness clause.
- Revisit the recommendation to lance tube sheets at current intervals based on lancing results from this and previous campaigns.
- Training requirements need to better defined and clearly stated in contract and Project Kick-off Meeting.
- Refurbishment of the lancing tools was recommended prior to the next outage

Access Port Installation:

In addition, the team also collected and analysed internal OPEX re: Access Ports installation at Pickering A. The key points noted from this review for future reference are:

- The contract was awarded through competitive bidding to B&W.
- [redacted]
- Most of the delays were due to OPG regarding non-conformances and changes requiring approval by OPG, including Design.
- Full mock-ups with training in plastic suits are suggested to resolve and reduce field issues. Special nozzle training for welders also suggested.
- Contingency planning around FME Prevention and foreign material recovery plan is also suggested as these caused problems during the past nozzle work.
- OPG needs to rely on vendor's expertise and may consider that vendor should handle the field change control items.

Appendix D (Continued)

External OPEX:

The SG team also gathered relevant external OPEX. The SG SOW for Pt. Lepreau was very similar to the one planned for DR. The key points noted for future reference through discussion with Pt. Lepreau representative are as below:

- PLNGS had an existing co-op agreement with B&W and awarded their full SG Inspection and Maintenance work to B&W as OEM sole source. The PSC work was bundled with the R&FR work (added as an addendum to the R&FR work) and awarded to AECL. This was a unique situation for PLNGS. AECL already had lots of support personnel at site for the retube activities and PLNGS was able to utilize some of that support for the PSC work.

- A combination of fixed price and time and materials arrangements were utilized for the contracts.

- For the Inspection and Maintenance work, an inventory of PLNGS tooling was given to B&W during the planning stage and they were responsible for bringing any tooling above and beyond that. All specialized tooling was B&W's accountability. AECL was responsible for 100% of their tooling.

- A combination of mock-ups at the vendors' facilities and PLNGS were utilized for the work.

Vendors were not accountable for compiling the final inspection reports for submission to the CNSC, although PLNGS often sent the post-inspection Results Assessment (prepared by B&W) to the CNSC as supplementary information to PLNGS' letter.

Appendix E: Vendor Spends

[redacted]

Appendix F: Pricing Model Options Analysis

The recommended pricing models for each sub-project can be found in Section 8.0.

Item	Condition / Element	Alternative Considerations	Recommended Pricing Model Options
1	Restriction on vault access for PSC. (Prerequisite to RFP is a high-quality level 1 refurb schedule indicating accurate PSC ties to R&FR activities)	A. Execute PSC on critical path. B. Choose the vendor who can set up equipment outside of vault. C. Negotiate an access window with R&FR. D. Sole source PSC to the vendor who can setup outside of vault (not preferred, strategy recommends a bundled approach of various SG work packages).	Primary driver is ability to set up PSC process system outside of vault to mitigate potential conflicts with R&FR: 1. FIRM PRICE: If PSC setup performed outside vault. 2. If PSC setup performed inside vault, then pricing model is FIRM if off critical path, or TARGET if risk of critical path is high.
2	PSC tooling development / qualification.	A. Inform all proponents at RFP about OPG owned tooling and OPG restrictions on making the tools available to vendors other than original manufacturer B. Inform all that 2 systems are qualified for DNGS. C. Only issue RFP to vendors who have process/waste collection tooling for PSC. D. Issue RFP to all 3 proponents without disclosing the tooling availability.	FIXED PRICE for all alternatives: Plant modification, tool development/modification, process qualification/optimization, preventive maintenance, storage.

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3	Vendor Support Services during execution (Rad protection, confined space, HoR, etc.). (Prerequisite to RFP is for Program to determine how support services will be managed)	A. OPG to provide limited support services to EPC contractor (this includes separate PO's to other vendors to render common services). B. Include support services into EPC contract.	1. TARGET PRICE (cost reimbursement plus incentive/disincentive) for all field execution elements if vendor is not self-sufficient. 2. FIRM PRICE for field execution elements if vendor self-sufficient. Note: in either case cost vs. benefit needs to be analyzed.
4	Field Execution Schedule fluidity: 1. Inter project ties are known (i.e., work scopes within SG project) Seamless SG execution in series. 2. Inter project ties are not known. Downtime in between SG work.	A. Keep trades employed and utilize them on different projects in the event of SG project downtime to save training/in processing costs (note that this is a Program level consideration) B. Negotiate a special rate with the vendor for downtime and explore the option of sharing BTU trades with other refurb projects if execution is TARGET based on other conditions.	1. For case with inter project ties are known or serial execution is assured, FIRM PRICE option is preferred, but should be TARGET PRICE if option 1 (vendor not self sufficient) of Vendor Support Services (item 3 above) is selected. 2. If uncertainty exists for the serial execution of SG sub-projects, TARGET PRICE model for all field execution elements regardless of which support services option is selected.
5	Access port installation.	A. Bundle this work with the other SG sub-projects. (preferred and recommended) B. Sole source to OEM.	1. FIXED PRICE: for all ECC work (i.e equipment modification, configuration management, tooling development). 2. FIRM PRICE for field execution if option 2 (vendor self sufficient) of Vendor Support Services is selected (item 3 above). 3. TARGET PRICE for field execution if option 1 (vendor not self sufficient) of Vendor Support Services is selected (item 3 above).
6	Water Lancing.	A. Inform all proponents at RFP that 2 systems have been qualified at DNGS (at RFP phase) B. Keep it bundled with other SG sub-	FIRM PRICE for tooling development / qualification AND field execution regardless of contracting strategy. Decision based on OPEX, known scope, and familiarity of work scope

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		projects (preferred and recommended). C. Sole source lancing to the existing lancing contractor in DNGS.	execution at DNGS. This work has been done multiple times in planned outages and the risk of any incremental cost to OPG as a result of owners not fulfilling its contractual obligations is low.
7	Inspection & Maintenance.	A. Keep bundled with other SG sub-project scope (preferred and recommended). B. Execute inspections in-house, with separate contract for maintenance portions, i.e., tube plugging/pulling. C. Contingency repair scope due to discovery work (for example, divider plate ALIS leakage measurements) is an unknown, and will need to be addressed during execution on a case by case basis, with repair deferral to subsequent planned outages as a consideration.	1. FIXED PRICE: for any required ECC work (i.e. equipment modification, configuration management, tooling development). 2. FIRM PRICE for field execution if option 2 (vendor self-sufficient) of Vendor Support Services is selected (item 3 above). * 3. TARGET PRICE for field execution if option 1 (vendor not self-sufficient) of Vendor Support Services is selected (item 3 above). 4. Tube plugging and tube pulling can be priced on a firm unit price basis. 5. Contingency repair scope discovered by the inspection program is not known and should not be part of the fixed price package, but may be performed on a unit or target price basis. (*) note that team discussions included the option of target pricing as this will be a first-of-kind for having an external vendor provide this service.
8	Layup.	A. Include it in EPC contract. B. Have a separate specialty contractor to support multiple layup activities.	Note: This cannot be evaluated in detail at this stage due to lack of schedule and project inter ties information at the present time.

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Appendix G: Key Risks & Proposed Mitigation

Item	Contracting Risk	Mitigation Strategies	Mapping to Project Risk Register
(1)	PSC on critical path of refurb schedule – due to vault space allocation limits. This could drive selection of a PSC technology that allows setup outside of vault.	Team evaluation of PSC technologies and their process system footprint. Weigh technology risk vs. schedule risk (in RFP evaluation?) and potential for additional modifications to plant (i.e., penetration inserts)	TBD
(2)	Long Lead time - Risk to project schedule if new PSC technology chosen – will require development/qualification – mitigate by early negotiations of milestones in RFP process and track – what mitigations in place in case of qualification failure? Quality of process failure?	Related to (1) above. Selection of new technology PSC would require tightly defined scope and milestones at RFP stage with strong OPG oversight to mitigate schedule and budget risks.	TBD
(3)	SOW level of completeness? No SOW for layup. Lack of SOW or spec makes determining portions of E/C/P and recommending pricing strategy difficult.	Meet SOW and tech spec milestone dates.	TBD
(4)	Risk that late removal of scope may have negative impact on preferred approach to contracting strategy. I.e., if EOI submissions indicate an inability to perform the bundled scope, said work scope will be repackaged prior to moving to RFP stage. If that element of work is subsequently removed, its early presence will have had a negative impact on the bundled approach (which in this case may have been acceptable with the initial removal.	Keep SOWs separate to enable easier repackaging. Meet scope definition milestones.	TBD

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(5)	Risk that EOI will indicate that vendors are unable to support the bundled approach to work packaging – will require further evaluation of repackaging work scope – advantage that SOWs are separate and won't also breakup (although ALIS is now being placed into the SOW for inspection/maintenance) and layup does not yet have a SOW or tech spec for either primary or secondary side	Keep SOWs separate to enable easier repackaging. Re-evaluate strategy following EOI submissions	TBD
(6)	Risk of contractor having full work scope and becoming unviable prior to project completion (bankruptcy, dissolution of consortium, other)	RFP evaluation criteria to address.	TBD
(7)	Risk of fitness for service issues due to unknown scope expansion triggers during refurb – mitigate by defining the known unknowns up front – what are the scope expansion triggers and criteria – what are the expected boundaries to the expanded scope – are strategies being planned to mitigate?	Meet SOW and tech spec milestone dates. Ensure SOW contains correct scope, with defined expansion criteria (i.e., what triggers expansion), along with the boundaries of the expansion (i.e., what does the expanded scope now include). Define the known unknowns / eliminate the unknown unknowns in scope documents.	TBD
(8)	Risk to use of the ALIS technique for assessing divider plate leakage; Ownership of the technology and equipment need to be addressed. Current location and status of equipment need to be addressed.	Management to address. Is technology/equipment the IP of Kinectrics? Transfer implications?	TBD
(9)	Schedule risk – ensuring quality SOW's are issued by project milestone date	Management to address.	TBD
(10)	Schedule risk – ensuring RFP issued by project milestone date	Management to address.	TBD

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(11)	Schedule risk – ensuring contact awarded by project milestone date (negotiations)	Management to address.	TBD
(12)	Concentrating all work packages with one vendor presents the risk that acceptable work performed on some sections of scope may be offset by less than expected quality on another (in terms of quality, schedule, or budget).	Consideration will need to be given to building in contractual 'off-ramps' for individual elements of the work scope for subsequent unit refurb outages (i.e., during DR execution) to mitigate this risk.	TBD

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Appendix H: Project Delivery and Contract Strategy (PDCS) Contract Model Selection

Table A - 1: Analyze

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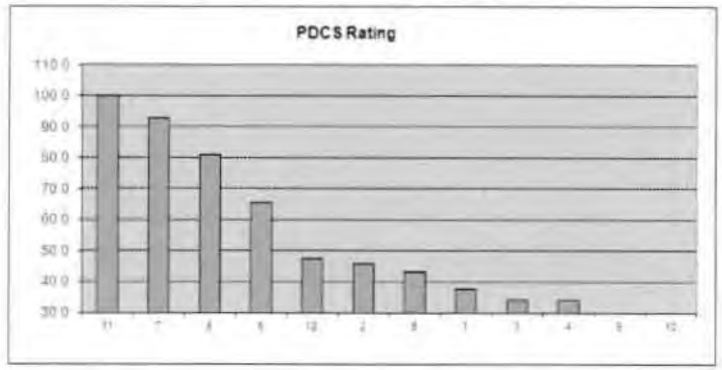
	Factor #	Selection Factor Action Statement (see table FO-1)	Rank	Preference Score	Relative Weighting
Cost Related Factors	1	Control cost growth	1	100	22%
	2	Ensure lowest cost			
	3	Delay or minimize expenditure rate			
	4	Facilitate early cost estimates			
	5	Reduce risks or transfer risks to contractor(s)	3	80	18%
Schedule Related Factors	6	Control time growth	2	90	20%
	7	Ensure shortest schedule			
	8	Promote early procurement	5	60	13%
Other Factors	9	Ease change incorporation			
	10	Capitalize on expected low levels of changes			
	11	Protect confidentiality			
	12	Capitalize on familiar project conditions			
	13	Maximize Owner's controlling role			
	14	Minimize Owner's controlling role			
	15	Maximize Owner's involvement			
	16	Minimize Owner's involvement	6	50	11%
	17	Capitalize on well defined scope	4	75	16%
	18	Efficiently utilize poorly defined scope			
	19	Minimize number of contracted parties			
	20	Efficiently coordinate project complexity or innovation			

Sort Results

Sort, then View Results Here

PDCS #	Rating	PDCS	Designer	Constructor	CM - Agent	PM - Agent	Contractor	Supplier
			Default Compensation Approach					
11	100.0	**Turnkey**					**Competitive Lump Sum**	
7	93.0	**Design-Build or EPC**					**Competitive Lump Sum**	
8	81.0	Multiple Design-Build or EPC					Competitive Lump Sum	
6	65.7	CM@Risk	Firm Price	GMP				
12	47.7	Fast Track	Cost+Fee	Cost+Fee				
2	45.9	Traditional (DBB) with Early Procurement	Cost+Fee	Competitive Lump Sum				Competitive Lump Sum
5	43.4	Traditional (DBB) with Early Procurement and CM	Cost+Fee	Competitive Lump Sum	Cost+Fee			Competitive Lump Sum
1	37.8	Traditional Design-Bid-Build (DBB)	Firm Price	Competitive Lump Sum				
3	34.3	Traditional (DBB) with Project Manager	Firm Price	Negotiated Lump Sum		Negotiated Lump Sum		
4	34.3	Traditional (DBB) with Construction Manager	Negotiated Lump Sum	Competitive Lump Sum	Negotiated Lump Sum			
9	25.5	Parallel Primes	Cost+Fee	Competitive Lump Sum				Competitive Lump Sum
10	24.2	Traditional (DBB) with Staged Development	Competitive Lump Sum	Competitive Lump Sum		Cost+Fee		Competitive Lump Sum



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Report

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Contracting Strategy For Balance of Plant

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Revision Summary

Revision Number	Date	Comments
R000	2013-03-19	Initial issue.

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1.0 EXECUTIVE SUMMARY

The Darlington Refurbishment ("**DR**") Program Commercial Strategy identified the requirement to establish separate contracting strategies for each of the major projects under the Darlington Refurbishment Program (each a "**Contracting Strategy**"). This document is the overall, parent Contracting Strategy for the Balance of Plant ("**BoP**") Project. This Contracting Strategy is based on the business drivers and commercial principles set out in the DR Program Commercial Strategy.

The BoP project team (the "**Team**") determined that the preferred approach for the BoP project (the "**Project**") is to collate as much bulk work as possible to best leverage existing Extended Services Master Service Agreements ("**ESMSA**") and Engineer, Procure, Construct ("**EPC**") concepts, and to separate out specialized work by exception for alternative sourcing strategies.

This approach to the Project work allows DR to:

- Simplify the procurement approach for what is inherently a complex collection of work that doesn't fit well into existing DR projects;
- Maximize the use of both existing ESMSA and EPC concepts; and
- Minimize the risk inherent in OPG integrating a large number of separate but inter-related packages of plant system work.

The Project redefined the earlier structure of the BoP work to more directly align with the station systems. This exercise included workshops to determine preferred alternatives for contracting individual system packages and verifying that objectives & measures used were consistent across all system work. Execution, commissioning and turnover benefits are expected as a result of this realignment, which places an OPEX driven priority on eliminating interfaces during field execution.

This Contracting Strategy recommends that:

1. The bulk BoP system work is grouped into two major EPC packages: i) nuclear side system work and ii) conventional side system work.
2. These EPC packages be sourced with ESMSA vendors using the secondary compete process.

This approach provides the best alignment with OPG's current core values (accountability, transparency and value for money) with the Project's work scope.

In the event that specialized work is identified that does not fit within this recommendation, additional contract(s) may be required for that work with support from additional contracting strategy analysis.

2.0 INTRODUCTION

2.1 Background Information

The BoP Project includes systems in six distinct areas: Pre-refurbishment, Safety & Control Systems, Reactor Component Systems, Conventional Systems, Common Systems and Special Programs. The scope of work has been reviewed by the Darlington Refurbishment Scope Review Board ("**SRB**").[1]

- Pre-engineering scope development work is currently underway with Owner's Support Services ("**OSS**") contractors. BoP Pre-refurbishment scope will be executed by the Projects and Modifications organization on behalf of DR and does not fall within the scope of this contracting discussion.

- Safety & Control Systems includes digital controls & monitoring computer work and associated parts replacement and spares procurement. Shutdown System Computer replacement was originally part of this work, but has been passed on to the Fuel Handling Project via the Gate Review Board and will be covered in an independent Contracting Strategy document..

- Reactor Side Component Systems work includes heavy water and cooling systems, containment, vault vapour recovery, liquid zone and various instrumentation systems.

- Conventional systems work is composed of electrical system work as well as both service and feedwater systems.

- Common Systems include civil structure inspections and rehabilitation, fire protection work and negative pressure containment.

- Special Programs is largely made up of valve and component work spanning multiple systems.

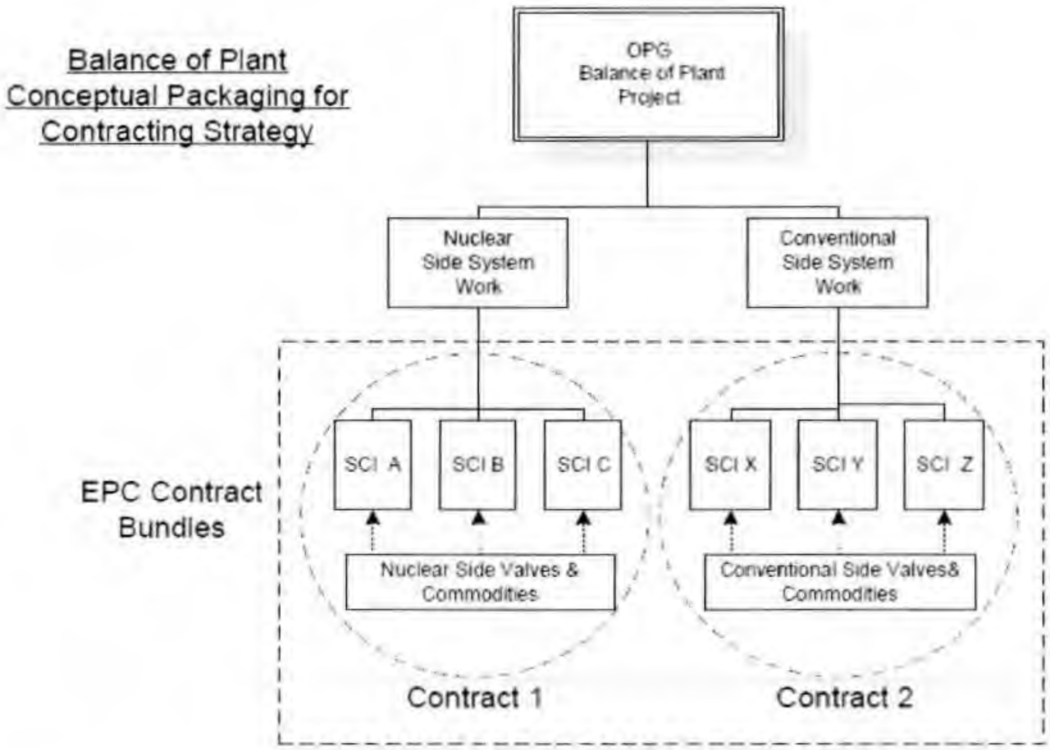
The above scope areas have been further refined to more directly align with the station systems. Execution, commissioning and turnover benefits are expected as a result of this realignment, which places an OPEX driven priority on eliminating interfaces during field execution.

For contracting purposes, a Darlington Scope Request ("**DSR**") line item review was performed by the Project Team to organize the BoP bulk work on a system basis, including a review of the system's geographical plant location. The resulting preliminary system breakout is summarized in Appendix A.

[1] *The purpose of the SRB is to:*

- *challenge the proposed refurbishment work scope to ensure work is necessary for the successful refurbishment of Darlington;*
- *align the scope with the objectives of maintaining/improving reliability and lowering production costs; and*
- *ensure investments in refurbishment deliver value for money.*

Given the work being reorganized into more logical system alignment as a result of this review, a visual representation of the contracting model is provided in the figure below:



Contract 1 – EPC nuclear systems bundle

Contract 2 – EPC conventional systems bundle

Work continues to focus on refining scope and where possible, eliminating scope through cost benefit analysis. In the event that the process identifies specialized work that does not fit within this recommended strategy, additional contract(s) may be required for that work with support from additional contracting strategy analysis.

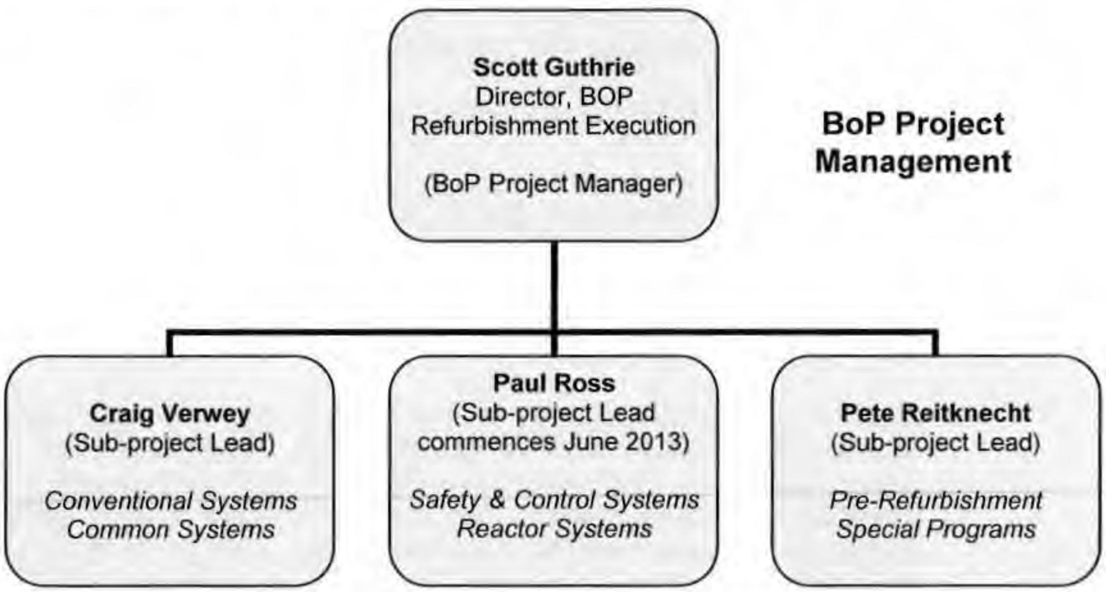
2.2 Objectives and Scope Strategy

The key purpose of this document is to set out the overall contracting strategy proposed for the delivery of the above work. This document will:

- Identify the contracting alternatives that were considered;
- Document contracting considerations taken during assessment of the contracting alternatives; and,
- Recommend a contracting strategy (includes strategy around sourcing and pricing).

2.3 Development Process

The Team was initially formed in mid-2011 and evolved through 2012 with representatives from Refurbishment Engineering, Execution, Supply Chain, Project Controls and Nuclear Commercial Development. With support from Engineering, Operations and Maintenance departments in both Refurbishment and Darlington, the Team began clarifying and rationalizing the project scope to get a better understanding of what is required for refurbishment.



The development process began by familiarizing the BoP team with equipment that needed replacement and work that has to be completed. Members of the team reviewed the DSR and Component Condition Assessment ("**CCA**") records for information on the scope of work which included:

- Work type (e.g., analysis, inspection, obsolescence, replacement, contingency);
- Scheduling time-frame (i.e., pre-refurbishment, refurbishment execution, post-refurbishment);
- Recommended source(s) for engineering, testing and field execution;
- Any long lead items; and
- If any of the work (i) must be performed by the OEM(s); or, (ii) could be performed by others.

Pre-refurbishment work will be handed over to the Projects and Modifications group to be performed on DR's behalf.

As the scope of work and complexity became better understood, the bulk work was realigned to a more consistent system-based approach for packaging.

Operational experience ("**OPEX**") has been and continues to be collected and analyzed. Bundling of work was discussed with the work logically grouped into the identified sub-projects and bundles. Separate project teams are established for each of the sub-projects to manage the planning and execution for the scope of work within each sub-project. The individual project teams are responsible for identifying and analyzing the potential options around work packaging, contracting approaches/models and pricing options. Inputs were also solicited from other key stakeholders within the company and third parties.

Major points from BoP OPEX discussions included:

- Bruce did work by equipment (e.g., valves, motor control centres) without consideration for how these groups interacted & interfaced, with issues only becoming understood during commissioning phase. This led to a number of expensive and onerous rework situations such as having newly installed valves (by contractor A) removed during piping work (by contractor B). Mitigation: consider a system-based work approach.

- Bruce did Engineering Change Control ("**ECC**") integration after install ~$30M – and numerous issues with valves (e.g., code cases) had been lost during interim handovers and were not brought to light until commissioning and Available for Service ("**AFS**"). This required a great deal of firefighting and concession requests from the Canadian Nuclear Safety Commission ("**CNSC**"). Mitigation: valve scope will be clarified down to an equipment code basis by the Project then allocated into the EPC contract(s).

- Field efficiency should drive how the work is ultimately packaged and bid/sourced. Recent OPG experience with PNGS-A Fuel Handling rehabilitation work performed in 2011 with a multidisciplinary contractor showed the advantages of reduced interfaces while performing a large scope of work. Mitigation: limit handoffs and field interferences between different workgroups.

- Personnel involved in the Bruce work recommended considering a breakout of conventional vs. nuclear work as this could segregate contractors using logical physical plant boundaries. This would physically separate workgroups to a large degree, potentially mitigating many interference and handoff issues while making them accountable for more comprehensive packages of scope.

2.4 Stakeholder Identification

Key stakeholders and groups who provided input included representatives from:

- Darlington Refurbishment Execution (Scott Guthrie, Craig Verwey, Vince Palermo, Pete Reitknecht)

- Darlington Refurbishment Engineering (Brian Coulas, Greg Maggs, John McLean, Jennifer Nodwell, Greg Mills)
- Darlington Refurbishment Supply Chain (Yatin Nayak)
- Darlington Refurbishment Operations and Maintenance (Hank Gregory, Alan Cornthwaite)
- Darlington Refurbishment Planning and Controls (Ryan Smith)
- Nuclear Commercial Development (Janice Ding, Neill Allen, Kent Scherm)
- Darlington Refurbishment Cross Functional Sourcing Team ("**CFST**") members
- Refurbishment Program Executive Team ("**RPET**")
- ESMSA Contract Support (Riyaz Habib)
- Previous supporting Project and Supply chain members (Gary Rutledge, Bill Turner, Sean Bagshaw)

3.0 CONTRACTING CONSIDERATIONS

In developing the Contracting Strategy for the Project, OPG must consider how the work required under the Project will be contracted in order to ensure the achievement of OPG's core business objectives and values of safety, including nuclear safety, accountability, fairness, transparency and value for money.

The following business drivers have also been considered in evaluating the contracting strategy:

i) Major modification and refurbishment projects to align as far as possible and practical with the EPC contracting model.

ii) Utilize existing master services agreements as much as possible and practical, insofar as the service provider's skill set matches the services required.

iii) A single point of accountability for each piece of the BoP work execution is preferred to ensure proper oversight, jobsite work coordination and flexibility of implementation

iv) OPG's future business direction:

- Smaller fleet, fewer staff, more strategic labour and contracting strategies, improved long-term inspection and maintenance strategy, different outage strategy (longer periods between subsequent outages), develop vendor capabilities for future services and support.
- Operate in a safe, efficient and cost effective manner, with prudent investments to improve reliability and lower production costs.

- Nuclear Refurbishment to work collaboratively with Darlington station to support its objective of striving toward top global decile performance post refurbishment.

v) Cost and schedule related considerations:

- Completion of the full work scope within the approved and released refurbishment work budget.
- Completion of the full work scope within the approved schedule.

The guiding commercial principals from the DR Commercial Strategy (NK38-REP-00150-10001) were considered in developing and evaluating the contracting options.

3.1 Contracting Alternatives Analysis

3.1.1 Bundling of Work

A number of alternatives were examined by the project team in order to align the Work Breakdown Structure ("**WBS**") with how the team plans to manage the projects. Options examined included:

1) Maintain the six major projects per the initial WBS consisting of Safety and Control Systems, Common Systems, Reactor Systems, Conventional Systems, Pre-Refurb Execution and Special Programs. Each of these projects would then require an assessment for the best alternative contracting option. This was felt to be unmanageable from an execution point of view with too many blurred lines and execution interferences between groups.

2) A single major BoP project, competitively bid as a complete EPC contract (200+ DSRs). This would contain all the modifications and maintenance work considered a part of the BoP scope. A single EPC contract would result in a large (~$500M+) project, failing to develop a larger portion of the vendor community. In the event of poor vendor performance during execution, the lack of immediately available options to pick up required work would pose a risk to the overall program.

3) Redefine the projects to more directly align with the station systems. Advantages to this approach include execution, commissioning and turn-over benefits associated with aligning in this fashion. It would enhance the strong objective of packaging the work to best suit field execution. Station planning, operations support, permitry application and AFS turn-over work is all aligned in this way. While requiring modification to the WBS, this approach was determined to be best aligned with streamlining the field execution elements of the project and was therefore chosen as the realignment model.

An additional benefit to packaging the BoP work by system is the potential for having these projects also define their own shutdown, layup and commissioning requirements.

3.1.2 Work Packaging, Vendor Fit and Contracting Models

In order to determine the preferred sourcing alternative for the Project, a Kepner-Tregoe ("**K-T**") Decision Analysis ("**DA**") was piloted using the SDC system work.

Alternatives examined included:

- Self-perform (included even though it does not really align with the DR principle to move commercial and technical risk away from OPG)
- Open competitive bid using the EPC model
- Sole source using the EPC model
- Separate out E, P and/or C elements (i.e., unbundle functions for bid)
- Secondary compete EPC to the ESMSA vendors

The preferred alternative when scored against the Project's objectives, including a consideration of alternative-specific risks, was determined to be EPC sourcing the system work with the ESMSA via the secondary compete process.

The results of the workshop can be found in Appendix B.

The Team then performed a gap analysis of the objectives and measures used for the SDC package against the remaining system packages. It was verified that all remaining bulk system work required meeting the same objectives identified in the SDC K-T DA, resulting in similar alternative scoring and risks. The conclusion was then drawn that all BoP bulk system work is best sourced with the ESMSA vendor community.

An additional K-T DA workshop was held by the Team to evaluate contracting alternatives for the valve program. [redacted] It was also recognized that opportunities for leveraging commodity buys were lost for components that were common across numerous plant areas and systems.

Alternatives examined for a valve program included:

- Self-perform (included even though it does not really align with the DR principle to move commercial and technical risk away from OPG)
- Competitive bid EPC for all valve program work
- Use ESMSA vendors via EPC and secondary compete
- Contract E and P together, but separate from ESMSA C

- Contract E and P together, but separate from competitive bid for C
- Contract E and P together, with C performed by system upgrade vendor
- Separate bids for each of E, P and C

The preferred alternative was determined to be using the ESMSA vendors using the EPC model.

The results from the valve K-T workshop can be found in Appendix C.

3.2 Decision Options and Constraints

The base workload of the ESMSA vendors needs to be considered while assessing their ability to adequately absorb additional work. This point will require further evaluation at the Program level as additional DR contracts are issued.

Additionally, current ESMSA agreements will need to be assessed for BoP work, in particular the value of the scope, to identify amendments required to conform to warranty, limits of liability, nuclear liability issues, etc. This will be required to ensure consistent commercial elements across all DR contracts.

These issues will require further examination at a DR Program level.

Due to the overall value and amount of work contained within the Project, further consideration must be given to how the work is distributed. Per the previous section, it was determined that the bulk system and valve/commodity work best fits with an EPC model to the ESMSA vendors.

Options for executing this strategy include:

I) Keep all ESMSA work bundled in one mega-package for secondary compete process.

II) Keep all SCI packages separate for secondary compete process.

III) Look for logical breakdown of ESMSA bulk work that both mitigates risks of over-extending a single vendor and keeps the work sufficiently separate geographically and from an isolation/permitry point of view.

A single EPC contract of bulk system work would result in a large (~$500M+) winner-takes-all mega-project. In the event of poor vendor performance or outright failure during execution, a lack of competitive options available to immediately assist if required would pose a very large risk to the program. This option also fails to develop a larger portion of the vendor community, which should be considered given the Project's size.

Conversely, running a secondary competition with the ESMSA vendors for each individual system would largely fail to utilize OPEX concerned with limiting field execution rub points and integration issues. A greater corresponding risk for correctly integrating and scheduling system isolations falls back to OPG, and also results in greater OPG management and oversight requirements.

A logical split of the BoP work destined for the ESMSA vendors is therefore considered beneficial. In the event of vendor performance issues during execution, there will be at least one other vendor currently engaged in similar work, minimizing OPG's risk exposure to the extent possible. This only holds true if different ESMSA vendors win the two EPC contracts. Under the secondary competition process, it is possible that a single vendor can aggressively bid and win both programs. The risks associated with this result will need to be carefully considered in evaluating the respective proposals. In order to mitigate this potential, the major EPC contracts could be bid in series in order to assess vendor capabilities and resources.

In considering these issues, the Team has determined that a split of system work between nuclear side systems and conventional side systems could best meet all Project objectives.

A constraint that requires additional consideration is the status of the Project scope. While many pieces are well understood, the majority of scope definition is not expected to be complete prior to the end of 2013. This includes the ongoing equipment condition inspections and development of Modification Design Requirements ("**MDRs**") and Conceptual Design Requirements ("**CDRs**"). It is not prudent to put these major EPC bundles out for competition until the majority of scope has been adequately defined. In spite of this, there are advantages to begin awarding the work as soon as possible.

It is currently believed by the Team that a ~70% threshold of well defined scope must be met prior to competing the EPC packages. The Request for Proposal ("**RFP**") that is issued must clearly identify that OPG may potentially add scope (i.e., the remaining ~30%) and that the bid evaluation is based on the current defined scope. OPG, at its discretion will request the pricing on the additional scope and validate it with a third party estimate. In the event OPG is not satisfied with the pricing or services provided, OPG should reserve the right to remove the scope and release it to another vendor based on value for money.

4.0 RECOMMENDED CONTRACTING STRATEGY

The bulk BoP system work is recommended to be grouped into two major EPC packages: i) Nuclear side system work and ii) Conventional side system work.

These EPC packages are recommended to be sourced with ESMSA vendors using the secondary compete process. These packages may be bid in series in order to best assess vendor capacity/resources, as scope definition exceeds ~70%. The percentage of scope definition will be tracked using three criteria:

1. Modifications – issuance of MDRs and CDRs;

2. Rehabilitation – completion of Rehabilitation Strategies; and
3. Cost Benefit Analysis – completion to determine if non-core scope will proceed.

Once the combination of the three above areas reaches ~70% of either the Nuclear or Conventional contract scope of work, a secondary compete request for proposal will be issued.

Per the analysis in the previous section, this recommended approach accomplishes the following:

- Aligns with the preferred DR EPC contracting model
- Utilizes existing master services agreements in a manner that is both practical and a good fit
- Reduces interfaces and enforces single point of accountability for each contract
- Develops multiple vendors while providing options to OPG in the event of poor vendor performance or outright failure
- Distributes the work using a logical split that maintains a focus on field execution efficiency, system commissioning and turnover
- Allows for leveraged commodity purchases of items such as valves

5.0 CHOICE OF PRICING MODEL

Due to the expected level of scope definition, the pricing model for the major EPC contracts is expected to be target price per the ESMSA agreement. Further evaluation and validation work will be required prior to RFP.

Contingency scope, as a result of inspections and discovery work during execution, will be cost reimbursable..

6.0 INTERFACE AND INTEGRATION ISSUES

Due to the large volume of plant system work and the continuing development of project scope, the level of interference for this project with other DR projects or their associated contracts has the potential to increase execution risk and will require further evaluation as the project matures. The BoP Project Team will continue to work with other DR projects, in particular those that are planning to utilize the ESMSA's in order to avoid conflicting contracting strategies.

A great deal of effort is already being placed into assessing and executing pre-refurbishment work via Projects and Modifications on behalf of DR.

Further developments in other DR projects (i.e., Shutdown/Layup & Services) may see additional work scope coming into the BoP Project where it is seen to be practical and add value for the Program as a whole. Where other projects may add line items to the BoP ESMSA contract, management of that scope by the BoP Project Team will only be considered on a case by case basis and will otherwise be managed by the original project.

These areas will be continually assessed as the definition phase progresses further for dependencies or integration requirements with other DR Projects.

7.0 KEY RISK AND PROPOSED MITIGATION

Project risks are documented and tracked in the risk register.

Some of the key risks and proposed mitigation associated with the recommended contracting strategy include:

- Project scope development is ongoing and Nuclear/Conventional packages will not be completed prior to the Project's desire to engage the vendors. A plan for bidding the work via ESMSA secondary compete once scope reaches 70% has been developed.
- The Terms & Conditions ("**T's & C's**") in the existing master agreements may not be sufficient to address the needs and risks for the BOP project scope of work to be done during refurbishment execution outage. The Project Team will work with the Contract Managers to review the T's & C's and incorporate any additional requirements in the negotiations when conducting the secondary compete process. A template for contract documents (COIR Deviation list and Work Sheet) is underway with input from Contract Managers for work during refurbishment execution outage.
- The proposed BOP contracting strategy will result in engaging vendors for two major contracts for the scope of work. Additional competent resources may be required to facilitate effective project and contract management which will be essential to mitigate the risks associated with cost and schedule.
- There remains a risk that work of a specialized nature may yet be identified within BoP scope that requires separate contract(s). Additional analysis may be required in order to support alternative contracting strategies for such work.
- Labour relations remain a risk as there are still items subject to CPA decisions.

8.0 SUCCESS CRITERIA & KEY PERFORMANCE INDICATORS

Critical success factors for the proposed contracting strategy include successfully awarding EPC contract(s) for the scope of work in the BoP Project. The contract(s) will incorporate OPG's core business values of Accountability, Transparency and

Value for Money taking into account the overall DR Program objectives to Maintain OPG Control, Minimize Impact on Existing Units, Achievable Schedule and Budget and the Appropriate Allocation of Risks as outlined in the DR Program Commercial Strategy (NK38-REP-00150-10001).

Appendix A: Balance of Plant Preliminary Breakout

Note: This list of Nuclear/Conventional packaging is preliminary, and is subject to further Project review and revision.

Nuclear/Conventional Package	System Description	System SCI
Nuclear	Moderator	32000
	Primary Heat Transport	33000
	Shutdown Cooling	33400
	Liquid Zone Control	34800
	Vapour Recovery	38300
	Active Liquid Waste	79000
	Negative Pressure Containment	34200
	Digital Control & Monitoring Computers	69000
	Reactor Vault Fuelling Duct Atmosphere cooling	73700
	Shutdown Systems	68000
Conventional	Airlocks and Structures	20000 & 21000
	Condensate and Feedwater	43000 & 44000
	Electrical and Cabling	50000 & 51000
	Service Water	72000
	Main Control Room	66100
	Irradiated Fuel Bay	34400
	Main Power Output	51500
	Electrical Penetrations	57000

Appendix B: Kepner-Tregoe Decision Analysis Workshop for SDC

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Decision Analysis Background

The Balance of Plant program for refurbishment consists of a suite of projects. This specific decision analysis is focused on assessing the best strategy for the shut down cooling project.

Decision Analysis Team

Name	Company	Team Member Role	Team Member Expertise
neill allen	KT		
Ding, Janice			
Guthrie, Scott			
Scherm, Kent			
Verwey, Craig			
Cornthwaite, Alan			
Palermo, Vince			
Reitknecht, Pete			
Maggs, Greg			
Nayak, Yatin			
Gregory, Hank			
Smith, Ryan			

Decision Statement

Select the optimum contracting strategy for the Shut Down Cooling project in the BOP program.

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Objectives and Measures

Objectives	Measures	Classification
Satisfy OPG quality requirements.	Vendor is on or can be qualified for the ASL. For approved vendors, OPG Supply Chain can assess quality performance.	Must
Meet OPG defined nuclear/conventional safety requirements.	As reported on CNSC/WSIB or other regulator reports and captured in OPG policy statements and programs.	Must
Support transfer of technical risk to vendors.	Clarity in scope definition and vendors record	Want
Ensure schedule window is maintained.	Opex of previous project/contract schedule performance.	Want
Structure allows OPG to maintain oversight of deliverables.	Demonstrated openness of processes from previous experience.	Want
Make decision transparent, demonstrate open process for vendor selection	Degree of competition Clarity of process.	Want
Maximize value for money to OPG	Total cost for project.	Want
Minimize OPG resource requirements for all aspects of contract.	Number of OPG resources involved in entire process	Want
Minimize interfaces/hand-offs	Assess number of interfaces and hand-off for all aspects of the work.	Want
Supports transfer of commercial risk to vendors.	Clarity of contract in accountability for deliverables and commercial terms. Vendors record of commercial compliance.	Want
Leverage existing agreements/contracts where possible.	Exists or not? Compatiblity of work or commercial terms	Want
Field execution efficiency should be a major driver.	Allows for clarity around the project specific field activities. Minimizes number of interfaces in the execution phase.	Want
Contract structure should be flexible and scalable.	How easy or difficult will it be to add and remove scope to the project.	Want

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Weight of Want Objectives

Want Objectives	Measures	Weights
Maximize value for money to OPG	Total cost for project.	10
Contract structure should be flexible and scalable.	How easy or difficult will it be to add and remove scope to the project.	9
Field execution efficiency should be a major driver.	Allows for clarity around the project specific field activities. Minimizes number of interfaces in the execution phase.	8
Minimize interfaces/hand-offs	Assess number of interfaces and hand-off for all aspects of the work.	7
Ensure schedule window is maintained.	Opex of previous project/contract schedule performance.	7
Leverage existing agreements/contracts where possible.	Exists or not? Compatiblity of work or commercial terms	6
Support transfer of technical risk to vendors	Clarity in scope definition and vendors record	5
Supports transfer of commercial risk to vendors.	Clarity of contract in accountability for deliverables and commercial terms. Vendors record of commercial compliance.	5
Structure allows OPG to maintain oversight of deliverables.	Demonstrated openness of processes from previous experience.	4
Make decision transparent, demonstrate open process for vendor selection	Degree of competition Clarity of process.	3
Minimize OPG resource requirements for all aspects of contract.	Number of OPG resources involved in entire process	2

Alternatives

Self perform. (OPG) (Projects and Modifications but not ESMSA)

Open Competitive Bid with EPC model

Sole source (EPC)

Seperate Elements (unbundle functions) (E and P and C)

ESMSA vendors, EPC (secondary compete process).

Filed: 2013-09-27
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Ex. D2-2-1
Attachment 6-7

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Alternatives Screened through Must Objectives

Must Objective and Measure	Self perform. (OPG) (Projects and Modifications but not ESMSA)		Open Competitive Bid with EPC model		Sole source (EPC)	
	Supporting Data	Go/No Go	Supporting Data	Go/No Go	Supporting Data	Go/No Go
Meet OPG defined nuclear/conventional safety requirements. As reported on CNSC/WSIB or other regulator reports and captured in OPG policy statements and programs.	Yes	Go	Vendors safety records would be screened pre-bid.	Go	Vendor safety record would be screened.	Go
Satisfy OPG quality requirements. Vendor is on or can be qualified for the ASL. For approved vendors, OPG Supply Chain can assess quality performance.	Yes.	Go	Vendors quality program pre-assessed.	Go	Vendor quality program pre-approved.	Go

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Must Objective and Measure	Seperate Elements (unbundle functions) (E and P and C)		ESMSA vendors, EPC (secondary com			
	Supporting Data	Go/No Go	Supporting Data	Go/No Go	Supporting Data	Go/No Go
Meet OPG defined nuclear/conventional safety requirements. As reported on CNSC/WSIB or other regulator reports and captured in OPG policy statements and programs.	Increases risk through number of interfaces but can be achieved.	Go	Already assessed	Go		Go
Satisfy OPG quality requirements. Vendor is on or can be qualified for the ASL. For approved vendors, OPG Supply Chain can assess quality performance.	Quality requirements specified in individual contracts complex but achievable	Go	Existing performance is available.	Go		Go

Decision Analysis Worksheet Report

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Balance of Plant Shut Down Cooling Project

Alternatives Scored Against Want Objectives

Objective:	Measure:	Weight:
Maximize value for money to OPG	Total cost for project.	10

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	OPG internal not available would lead to many staff aug contracts, large turnovers	2
Open Competitive Bid with EPC model	Assumes better terms and conditions can be negotiated than ESMSA	10
Sole source (EPC)	Limited ability to negotiate	5
Seperate Elements (unbundle functions) (E and P and C)	Integration adds a lot of additional costs	3
ESMSA vendors, EPC (secondary compete process).	Competitive Terms and Conditions exist	8

Objective:	Measure:	Weight:
Contract structure should be flexible and scalable.	How easy or difficult will it be to add and remove scope to the project.	9

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)		10
Open Competitive Bid with EPC model	Would need a lot of definition up front to process the contract. Least flexible option.	5
Sole source (EPC)	Contract could be built as scalable and flexible	8
Seperate Elements (unbundle functions) (E and P and C)		6
ESMSA vendors, EPC (secondary compete process).	Process exists, somewhat scaleable	7

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Objective: Field execution efficiency should be a major driver.

Measure: Allows for clarity around the project specific field activities. Minimizes number of interfaces in the execution phase.

Weight: 8

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	We do it every outage.	10
Open Competitive Bid with EPC model		6
Sole source (EPC)	Depends on contractor selected	7
Seperate Elements (unbundle functions) (E and P and C)	Introduces a lot of risk to the execution	5
ESMSA vendors, EPC (secondary compete process).	Interfaces are already in place	8

Objective: Minimize interfaces/hand-offs

Measure: Assess number of interfaces and hand-off for all aspects of the work.

Weight: 7

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	Known existing established interfaces	10
Open Competitive Bid with EPC model	Learning process for field work	6
Sole source (EPC)	Assumes selected based on internal expertise	7
Seperate Elements (unbundle functions) (E and P and C)	Lots of interfaces and hand offs	2
ESMSA vendors, EPC (secondary compete process).	(no less interfaces but better experience to date)	8

e think

Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Objective:	Measure:	Weight:
Ensure schedule window is maintained.	Opex of previous project/contract schedule performance.	7

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	(Too many internal conflicts with other OPG priorities)	5
Open Competitive Bid with EPC model	Focused on this piece of work	10
Sole source (EPC)	Focused on this piece of work, specific skill match	9
Seperate Elements (unbundle functions) (E and P and C)	hand offs will introduce delays	3
ESMSA vendors, EPC (secondary compete process).	Potential for other work conflicts impacting schedule elements	8

Objective:	Measure:	Weight:
Leverage existing agreements/contracts where possible.	Exists or not? Compatiblity of work or commercial terms	6

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	Agreements are in place through PandMods for small projects	10
Open Competitive Bid with EPC model	New contract required if it cannot be added to existing contract (RFR, TG SG etc)	4
Sole source (EPC)	New contract required if it cannot be added to existing contract (RFR, TG, SG etc)	3
Seperate Elements (unbundle functions) (E and P and C)	(OSS for example or OPG does portion)	6
ESMSA vendors, EPC (secondary compete process).	Agreements exist for larger projects	8

e think

Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Objective: Supports transfer of commercial risk to vendors.

Measure: Clarity of contract in accountability for deliverables and commercial terms. Vendors record of commercial compliance.

Weight: 5

Alternative	Supporting Data	Score
Self perform (OPG) (Projects and Modifications but not ESMSA)	No risk transfer	1
Open Competitive Bid with EPC model	Risk transfer captured in contract	10
Sole source (EPC)	Limits leverage.	9
Seperate Elements (unbundle functions) (E and P and C)	OPG is integrator so risk returns to OPG	3
ESMSA vendors, EPC (secondary compete process).	Some limitations due to scale of normal projects with ESMSA	8

Objective: Support transfer of technical risk to vendors

Measure: Clarity in scope definition and vendors record

Weight: 5

Alternative	Supporting Data	Score
Self perform (OPG) (Projects and Modifications but not ESMSA)		1
Open Competitive Bid with EPC model		10
Sole source (EPC)		9
Seperate Elements (unbundle functions) (E and P and C)		2
ESMSA vendors, EPC (secondary compete process).		7

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Objective:	Measure:	Weight:
Structure allows OPG to maintain oversight of deliverables.	Demonstrated openness of processes from previous experience.	4

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	Self monitoring is constant	10
Open Competitive Bid with EPC model	Oversight would be included in terms	5
Sole source (EPC)	Oversight would be included in te	6
Seperate Elements (unbundle functions) (E and P and C)	OPG is integrator	8
ESMSA vendors, EPC (secondary compete process).	Current oversight is through P&M	7

Objective:	Measure:	Weight:
Make decision transparent, demonstrate open process for vendor selection	Degree of competition Clarity of process	3

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	No justification required	10
Open Competitive Bid with EPC model	Open	9
Sole source (EPC)		4
Seperate Elements (unbundle functions) (E and P and C)	Open	8
ESMSA vendors, EPC (secondary compete process).	Secondary compete. original contracts were competitive and open	7

Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Objective:	Measure:	Weight:
Minimize OPG resource requirements for all aspects of contract	Number of OPG resources involved in entire process	2

Alternative	Supporting Data	Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)		2
Open Competitive Bid with EPC model	Supply chain and CFST resources	7
Sole source (EPC)	Supply chain and CFST resource consumption	8
Seperate Elements (unbundle functions) (E and P and C)	Lots of OPG input required	4
ESMSA vendors, EPC (secondary compete process).	Contracts in place. work definition process in place	10

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Total Weighted Scores for Alternatives

Alternative	Total Weighted Score
Self perform. (OPG) (Projects and Modifications but not ESMSA)	439
Open Competitive Bid with EPC model	490
Sole source (EPC)	450
Seperate Elements (unbundle functions) (E and P and C)	284
ESMSA vendors, EPC (secondary compete process).	511

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Making the Decision

Tentative Choice	Total Score	Best Choice?	Risks	P	Adverse Consequences	S
ESMSA vendors, EPC (secondary compete process).	511	☐	We introduce a new (refurb) process to the ESMSA, P&M and Refurb. Outage work versus Refurb	H	Increased errors, costs from increased effort to comply with OPG processes	M
			Terms and Conditions are already established, concerns over liability and incentive clauses.	H	ESMSA contract may need some elements revisited	L
			We give too much work to the ESMSA contractors	M	Schedule, quality of work diminishes, potential cost impacts, increased oversight needed. OPG needs to intervene.	M
			ESMSA contracts renew on a five year cycle. The ESMSA vendor is not renewed.	M	May have impact on vendor deliverables.	H
			ESMSA vendor goes out of business.	L	Significant impact on all aspects of project	H
			ESMSA performance is unacceptable	L	Significant OPG help is required.	M
Open Competitive Bid with EPC model	490	☐	Scope is not well defined at time of RFP.	H	Poor quality bid. Change notices from early in contract	M

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Decision Analysis Worksheet Report

Balance of Plant Shut Down Cooling Project

Tentative Choice	Total Score	Best Choice?	Risks	P	Adverse Consequences	S
			Another new vendor competing for limited resources.	H	Schedule and quality impact. Potential negative impact on other OPG work.	M
			Another new vendor needing additional OPG resources to process bid and contract.	H	Delays in getting contracts in place.	L
			New vendor struggles with interfaces to OPG or other contractors	M	Need for increase oversight and cost and schedule delays	M
			Sucessful bidder has limited OPG experience	L	Rework and therefore schedule and cost impact	M
			Selected vendor goes out of business	L	Not good. Significant delays and cost overruns	H
			Not enough vendor responses	L	Poor quality contract, schedule cost impacts	M

Appendix C: Kepner-Tregoe Decision Analysis Workshop for Valves

e think

Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Decision Analysis Background

The Balance of Plant program captures all the Darlington Refurbishment work outside of the projects on the major equipment sets. The BOP program has accountability for the review and upgrade of the Darlington Station valves. This decision analysis is to select the best contracting strategy to address the Darlington Refurbishment Valve program.

Decision Analysis Team

Name	Company	Team Member Role	Team Member Expertise
neill allen	KT		
Guthrie, Scott			
Scherm, Kent			
Reitknecht, Pete			
Maggs, Greg			
Stewart, Katie			
Cornthwaite, Alan			
Mclean, John			
Nayak, Yatin			

Decision Statement

Select the optimum contracting strategy for the Darlington Refurbishment Valve program.

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objectives and Measures

Objectives	Measures	Classification
Meet OPG defined nuclear/conventional safety requirements	AS captured in OPG policy statements and programs and as reported on CNSC or WSIB or other regulator reports.	Must
Satisfy OPG quality requirements	Vendor is on or can be qualified for the ASL. For approved vendors, OPG Supply Chain can assess quality performance	Must
Maintain plant and paper configuration	Ability to work within the existing processes such as ECC and Passport	Want
Make decision transparent, demonstrate open process for vendor selection	Degree of competition. Clarity of selection process	Want
Field execution efficiency should be a major driver	Allows for clarity around the project specific field activities. Minimises the number of interfaces in the execution phase	Want
Leverage exisiting agreements/contracts where possible	Exists or not? Compatiblity of work or commercial terms	Want
Minimise interfaces and hand offs	Assess number of interfaces and hand offs for all aspects of work. Specifically with other projects.	Want
Minimise OPG resource requirements for all aspects of contract	Number of OPG resources involved in entire process	Want
Structure allows OPG to maintain oversight	Demonstrated openness of processes from previous work. In particular with monitoring code and standard compliance.	Want
Ensure schedule windows are maintained	Opex of previous project/contract schedule performance	Want
Support transfer of technical and commercial risk to vendors	Clarity in scope definition and vendors record of technical and commercial competence	Want
Maximise value for money to OPG	Total cost of all aspects of the project. Ability to optimise commodity purchases.	Want
Contract structure should be scaleable and flexible	How easy or difficult will it be to add or remove scope to the project	Want

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Weight of Want Objectives

Want Objectives	Measures	Weights
Field execution efficiency should be a major driver	Allows for clarity around the project specific field activities. Minimises the number of interfaces in the execution phase	10
Maximise value for money to OPG	Total cost of all aspects of the project. Ability to optimise commodity purchases.	9
Contract structure should be scaleable and flexible	How easy or difficult will it be to add or remove scope to the project.	8
Minimise interfaces and hand offs	Assess number of interfaces and hand offs for all aspects of work. Specifically with other projects.	7
Maintain plant and paper configuration	Ability to work within the existing processes such as ECC and Passport	6
Structure allows OPG to maintain oversight	Demonstrated openness of processes from previous work. In particular with monitoring code and standard compliance	5
Leverage exisiting agreements/contracts where possible	Exists or not? Compatiblity of work or commercial terms	5
Support transfer of technical and commercial risk to vendors	Clarity in scope definition and vendors record of technical and commercial competence	4
Make decision transparent, demonstrate open process for vendor selection	Degree of competition. Clarity of selection process	4
Minimise OPG resource requirements for all aspects of contract	Number of OPG resources involved in entire process	3
Ensure schedule windows are maintained	Opex of previous project/contract schedule performance	2

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Alternatives

OPG Self Perform

Use ESMSA vendors (secondary compete process) EPC

Contract Engineering and Procurement separate from install/construct, ESMSA

Contract Engineering and Procurements separate from competitive bid for bulk installation.

Competitive bid, EPC contract for all valve program work

Separate Engineering and Procurment and Construct/Install functions and contract individually

Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)

e think

Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Alternatives Screened through Must Objectives

Must Objective and Measure	OPG Self Perform		Use ESMSA vendors (secondary compete process) EPC		Contract Engineering and Procurement separate from install/construct, ESMSA	
	Supporting Data	Go/No Go	Supporting Data	Go/No Go	Supporting Data	Go/No Go
Satisfy OPG quality requirements Vendor is on or can be qualified for the ASL. For approved vendors, OPG Supply Chain can assess quality performance.		Go		Go		Go
Meet OPG defined nuclear/conventional safety requirements AS captured in OPG policy statements and programs and as reported on CNSC or WSIB or other regulator reports.		Go		Go		Go

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Must Objective and Measure	Contract Engineering and Procurements separate from competitive bid for bulk installation.		Competitive bid, EPC contract for all valv		Separate Engineering and Procurment a	
	Supporting Data	Go/No Go	Supporting Data	Go/No Go	Supporting Data	Go/No Go
Satisfy OPG quality requirements Vendor is on or can be qualified for the ASL. For approved vendors, OPG Supply Chain can assess quality performance.		Go		Go		Go
Meet OPG defined nuclear/conventional safety requirements AS captured in OPG policy statements and programs and as reported on CNSC or WSIB or other regulator reports.		Go		Go		Go

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Must Objective and Measure	Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)					
	Supporting Data	Go/No Go	Supporting Data	Go/No Go	Supporting Data	Go/No Go
Satisfy OPG quality requirements Vendor is on or can be qualified for the ASL. For approved vendors, OPG Supply Chain can assess quality performance.		Go		Go		Go
Meet OPG defined nuclear/conventional safety requirements AS captured in OPG policy statements and programs and as reported on CNSC or WSIB or other regulator reports.		Go		Go		Go

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Alternatives Scored Against Want Objectives

Objective:	Measure:	Weight:
Field execution efficiency should be a major driver	Allows for clarity around the project specific field activities. Minimises the number of interfaces in the execution phase	10

Alternative	Supporting Data	Score
OPG Self Perform	As performed in every outage	8
Use ESMSA vendors (secondary compete process) EPC	Experience in the plant, continuity through program	7
Contract Engineering and Procurement separate from install/construct, ESMSA	Same as ESMSA EPC for this objective	7
Contract Engineering and Procurements separate from competitive bid for bulk installation	Lots of interfaces	3
Competitive bid, EPC contract for all valve program work	Good continuity but less experience	5
Separate Engineering and Procurment and Construct/Install functions and contract individually	Lots and lots interfaces	3
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Fewest number of execution interfaces	10

Objective:	Measure:	Weight:
Maximise value for money to OPG	Total cost of all aspects of the project. Ability to optimise commodity purchases.	9

Alternative	Supporting Data	Score
OPG Self Perform	Gain on commodity, considered high install costs, big resource availability risk.	3

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Ex. D2-2-1
Attachment 6-7

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objective: Maximise value for money to OPG

Measure: Total cost of all aspects of the project. Ability to optimise commodity purchases.

Weight: 9

Alternative	Supporting Data	Score
Use ESMSA vendors (secondary compete process) EPC	Competitive rates have already been established	9
Contract Engineering and Procurement separate from install/construct, ESMSA	Two contracts and exisiting competitive rates	7
Contract Engineering and Procurements separate from competitive bid for bulk installation.	Two contracts competitively bid	8
Competitive bid, EPC contract for all valve program work	Competitiveness drives for lowest price	10
Separate Engineering and Procurment and Construct/Install functions and contract individually	Does not promote commodity savings due to bulk, more interfaces	2
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Some risk to cost with several vendors involved	4

Objective: Contract structure should be scaleable and flexible

Measure: How easy or difficult will it be to add or remove scope to the project

Weight: 8

Alternative	Supporting Data	Score
OPG Self Perform	Self control the scope and resources issues	10
Use ESMSA vendors (secondary compete process) EPC	Existing process for management of change (assumes worksheets changes can be handled easily)	9
Contract Engineering and Procurement separate from install/construct, ESMSA	Bulk installation improves flexibility	7

think

Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objective: Contract structure should be scaleable and flexible

Measure: How easy or difficult will it be to add or remove scope to the project.

Weight: 8

Alternative	Supporting Data	Score
Contract Engineering and Procurements separate from competitive bid for bulk installation.	Tighter scope definition needed to go to competitive bid for construct	6
Competitive bid, EPC contract for all valve program work	Change can be hard to manage with big EPC assumes weel defined scope	3
Separate Engineering and Procurment and Construct/Install functions and contract individually	Difficult to make changes through 3 separate functions	1
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Could be several different installers	6

Objective: Minimise interfaces and hand offs

Measure: Assess number of interfaces and hand offs for all aspects of work. Specifically with other projects.

Weight: 7

Alternative	Supporting Data	Score
OPG Self Perform	Assumes OPG interfaces and hand-offs are easily managed	10
Use ESMSA vendors (secondary compete process) EPC	Least hand offs but still some interfaces.	9
Contract Engineering and Procurement separate from install/construct, ESMSA	May well have some of the system work too	6
Contract Engineering and Procurements separate from competitive bid for bulk installation.	Major interface between EP and construction	4
Competitive bid, EPC contract for all valve program work	Many interfaces between the valve vendors and other vendors	6

think

Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objective:	Measure:	Weight:
Minimise interfaces and hand offs	Assess number of interfaces and hand offs for all aspects of work. Specifically with other projects.	7

Alternative	Supporting Data	Score
Separate Engineering and Procurment and Construct/Install functions and contract individually	Most interfaces between functions and vendors	2
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Field interfaces would be minimised, but OPG would have interfaces with a lot of vendors	7

Objective:	Measure:	Weight:
Maintain plant and paper configuration	Ability to work within the existing processes such as ECC and Passport	6

Alternative	Supporting Data	Score
OPG Self Perform	Assumes OPG executing its existing process is most efficient	10
Use ESMSA vendors (secondary compete process) EPC	Familiarity with process	9
Contract Engineering and Procurement separate from install/construct, ESMSA	Somewhat familiar with process for installation, learning for EP	8
Contract Engineering and Procurements separate from competitive bid for bulk installation	Potentially new vendors learning OPG process	3
Competitive bid, EPC contract for all valve program work	Would be captured in Ts and Cs , learning curve expected	4
Separate Engineering and Procurment and Construct/Install functions and contract individually	Most potential for "falling between cracks"	2
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	System upgrades will drive use of ECC and passport	5

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objective: Structure allows OPG to maintain oversight

Measure: Demonstrated openness of processes from previous work. In particular with monitoring code and standard compliance.

Weight: 5

Alternative	Supporting Data	Score
OPG Self Perform	Assumes easy compliance to OPG processes by OPG or staff aug staff.	10
Use ESMSA vendors (secondary compete process) EPC	Process in place	8
Contract Engineering and Procurement separate from install/construct, ESMSA	Process in place for install portion	7
Contract Engineering and Procurements separate from competitive bid for bulk installation.	Unknown vendors processes and openness	4
Competitive bid, EPC contract for all valve program work	Single entity to oversee (may be new relationship)	6
Separate Engineering and Procurment and Construct/Install functions and contract individually	To much seperation needing a lot of oversight	2
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Process will be in place for mod developement, will need field oversight	7

Objective: Leverage existing agreements/contracts where possible

Measure: Exists or not? Compatiblity of work or commercial terms

Weight: 5

Alternative	Supporting Data	Score
OPG Self Perform	Assumes existing OPG CBAs and agreements are ok	10
Use ESMSA vendors (secondary compete process) EPC	Agreements in place	9

Decision Analysis Worksheet Report

e think

Valve Program DA on Contracting Strategy

Objective: Leverage existing agreements/contracts where possible

Measure: Exists or not? Compatiblity of work or commercial terms

Weight: 5

Alternative	Supporting Data	Score
Contract Engineering and Procurement separate from install/construct, ESMSA	Agreements in place	8
Contract Engineering and Procurements separate from competitive bid for bulk installation.	Some potential for upfront work to fit existing agreements	5
Competitive bid, EPC contract for all valve program work	Brand new agreement needed	2
Separate Engineering and Procurment and Construct/Install functions and contract individually	A host of new agreements requred	1
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Upgrade vendors wi.ll have agreements in place by then	8

Objective: Support transfer of technical and commercial risk to vendors

Measure: Clarity in scope definition and vendors record of technical and commercial competence

Weight: 4

Alternative	Supporting Data	Score
OPG Self Perform	Absolutely in conflict with this objective	0
Use ESMSA vendors (secondary compete process) EPC	Single point	9
Contract Engineering and Procurement separate from install/construct, ESMSA	Two vendors can promote blame shifting	5
Contract Engineering and Procurements separate from competitive bid for bulk installation.	Two vendors can promote blame shifting	5

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objective: Support transfer of technical and commercial risk to vendors

Measure: Clarity in scope definition and vendors record of technical and commercial competence

Weight: 4

Alternative	Supporting Data	Score
Competitive bid, EPC contract for all valve program work	Captured in new contract	10
Separate Engineering and Procurment and Construct/Install functions and contract individually	OPG becomes the integrator	2
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	As per new contracts	8

Objective: Make decision transparent, demonstrate open process for vendor selection

Measure: Degree of competition. Clarity of selection process

Weight: 4

Alternative	Supporting Data	Score
OPG Self Perform	Closed process, no competition	0
Use ESMSA vendors (secondary compete process) EPC	Perception of less competition (although ESMSA selection was competitive)	5
Contract Engineering and Procurement separate from install/construct, ESMSA	Competition somewhat restricted	6
Contract Engineering and Procurements separate from competitive bid for bulk installation	Competitive elements	7
Competitive bid, EPC contract for all valve program work	Competitve open	8
Separate Engineering and Procurment and Construct/Install functions and contract individually	All elements open	10

e think

Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objective: Make decision transparent, demonstrate open process for vendor selection

Measure: Degree of competition. Clarity of selection process

Weight: 4

Alternative	Supporting Data	Score
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	EP competitive and Installation competitive	6

Objective: Minimise OPG resource requirements for all aspects of contract

Measure: Number of OPG resources involved in entire process

Weight: 3

Alternative	Supporting Data	Score
OPG Self Perform	Direct conflict with this objective	0
Use ESMSA vendors (secondary compete process) EPC	Agreements in place, working practices established	10
Contract Engineering and Procurement separate from install/construct, ESMSA	Initial OPG requirements for support to EP	7
Contract Engineering and Procurements separate from competitive bid for bulk installation	Significant OPG involvement	4
Competitive bid, EPC contract for all valve program work	Limitied OPG involvemnent at front end. One big contract for oversight activities	9
Separate Engineering and Procurment and Construct/Install functions and contract individually	OPG is integrator, many contracts	2
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Will require a lot of agreements	4

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Objective:	Measure:	Weight:
Ensure schedule windows are maintained	Opex of previous project contract schedule performance	2

Alternative	Supporting Data	Score
OPG Self Perform	Too many other priorities, limited resources	2
Use ESMSA vendors (secondary compete process) EPC	Incentives in place some competing priority	9
Contract Engineering and Procurement separate from install/construct, ESMSA	Interfaces may impact scheduling	6
Contract Engineering and Procurements separate from competitive bid for bulk installation	Somewhat unknown given new vendor potential	5
Competitive bid, EPC contract for all valve program work	Incentives in contract single accountability	10
Separate Engineering and Procurment and Construct/Install functions and contract individually	Interfaces and blame allocation	3
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	Best ability to integrate with all aspects of projectbut potential for delays for each phase	8

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Total Weighted Scores for Alternatives

Alternative	Total Weighted Score
OPG Self Perform	421
Use ESMSA vendors (secondary compete process) EPC	529
Contract Engineering and Procurement separate from install/construct, ESMSA	431
Contract Engineering and Procurements separate from competitive bid for bulk installation	311
Competitive bid, EPC contract for all valve program work	389
Separate Engineering and Procurment and Construct/Install functions and contract individually	157
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	422

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Making the Decision

Tentative Choice	Total Score	Best Choice?	Risks	P	Adverse Consequences	S
Use ESMSA vendors (secondary compete process) EPC	529	☐	Conflict between valve work and system work if it is other	H	Schedule and cost impacts	L
			ESMSA vendor or another vendor			
			ESMSA vendor not renewed at life cycle point	M	Schedule and cost impacts	H
			ESMSA vendors become overloaded	M	Sub contracted portions get very high, risk to quality for all aspects	M
			ESMSA may not have sufficient internal valve expertise	M	engineering and procurement problems	L
Contract Engineering and Procurement separate from install/construct, ESMSA	431	☐	Risk for field interference with system modification vendors	H	schedule and cost	L
			Ineffective COMS process	H	quality, rework start up delays	L
			Installation problems need support from EP vendor	H	need to keep EP vendor available for field support or OPG assumes this role	L
			Introduces more complicated oversight	H	additional OPG or contracted oversight	L
			Introduces risk of pass the blame	M	quality, schedule	L

Decision Analysis Worksheet Report

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Valve Program DA on Contracting Strategy

Tentative Choice	Total Score	Best Choice?	Risks	P	Adverse Consequences	S
			OPG does not have history of bundling engineering and procurement to one vendor	M	delay to issuing RFP	L
Contract engineering and procurement separate with installation by system upgrade vendor (ie moderator, service water, etc)	422	☐	Ineffective COMS	H	delays to start up	L
			Requires additional OPG oversight	H	OPG resources	L
			Requires retention of EP function through installation	H	cost	L
			Introduce pass the blame opportunity	M	rework and schedule delays	L
			OPG does not have history of contracting EP separate from C	M	delays to rfp	L
			Difficult to maintain consistent quality and of paperwork and field work	M	quality, cost and schedule	M
Separate Engineering and Procurment and Construct/Install functions and contract individually	157	☐		H		H

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Decision Analysis Worksheet Report

Valve Program DA on Contracting Strategy

Summary

Record Name

Valve Program DA on Contracting Strategy

Knowledge Management Code

Record Created

01/30/2013

Benefits

Lessons Learned

Closeout Notes

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Attachment 6-7