Tufts Cove 6 - Revised

WASTE HEAT RECOVERY PROJECT

REDACTED

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1. Introduction

Synapse Energy Economics was hired by the Nova Scotia Utility and Review Board to review Nova Scotia Power's (NSPI) revised waste heat recovery project for the Tufts Cove generating station and make a recommendation on whether to approve the work order based on new data made available by NSPI.

2. Revisions to Original Filing

NSPI provided additional information and updates to the Tufts Cove project in its revised filing. The capital cost estimates were increased from a project total of $66M to $84M, including the duct firing which increased from $11M to $13.5M. These updates were reflected in the economic analysis provided by NSPI as well. NSPI also provided the results of a modeling analysis (the "Hatch study") that quantified the benefits of the duct firing. This data was previously unavailable and helped to provide a better idea of the benefit estimates that could be achieved through the addition of duct firing to the combined cycle.

In response to Synapse's recommendation of pursuing a stand-alone combustion turbine (CT) as an alternative to duct firing, NSPI provided its results for a call for expressions of interest in fast response peaking power. Three responses were received from generation hardware suppliers, all of which quoted prices that were more expensive than the cost of duct firing quoted by NSPI.

3. Combined Cycle

Based on an analysis of the revised application with updated cost estimates and benefits, Synapse has found the combined cycle portion of the project to again be well justified. The capital costs have increased significantly, however this is offset by the increase in fuel prices as well. Since the plant will be burning fuel more efficiently at higher capacity factors, while also displacing less efficient plants, Synapse is convinced that the combined cycle portion will be economic.

4. Duct Firing

The Company's revised proposal has added evidence supporting the inclusion of duct firing to the project which would add 24MW of net capacity at an incremental capital cost of $13.5 million, up from $11 million in the original filing. Despite the new quantitative duct firing analysis provided by NSPI, Synapse has identified a number of issues with the Company's analysis. NSPI's analysis of the duct firing is unconvincing and we do not support UARB approval of the duct firing portion of the project.

A. Capital Cost Allocation

In its filing, NSPI claims the project capital cost is broken down as shown in Table 4.1 below.

CC without Duct Firing	CC with Duct Firing	Incremental Cost of DF	$/kW (24.3MW)
$70.8 million	$84.3 million	$13.5 million	$555.6

Table 4.1 **– Updated capital cost estimates from NSPI. $ CAD.**

Synapse asked NSPI for further detail on how these costs and allocations were calculated. NSPI provided a spreadsheet showing the cost break-down for individual hardware components, indirect costs, and other estimated expenses for the project. Shown below are several costs that Synapse believes should be split between the CC and DF project costs, however in the Company's allocation of costs they are put 100% into the cost of the CC. The only exception is the "…" cost, in which 98.5% has been put into the CC portion.

Item	Total Cost with Duct Firing	Total Cost without Duct Firing

Table 4.2 **– Examples of project costs that have been allocated completely to the CC portion of the project. $ CAD.**

Additionally, … and … costs are the same in both cases, even though the size of the systems will be double in the combined cycle with duct firing case. These are not large cost items but it is an indication that only indirect costs that are clearly dependant on the purchased equipment cost are prorated. As shown in the table above, some large indirect costs are assumed by the Company to be the same despite the increased complexity, size, and commissioning requirements of the combined cycle with duct firing relative to the unfired combined cycle. These costs represent over $x million of the project budget and clearly some of this should be allocated to the duct firing to account for the increased complexity. For example, the duct firing version will be … 150MW versus 125MW, so we are skeptical that the cost of … would be the same between the two cases.

The indirect costs that are prorated are done so on the total equipment cost difference. As a result, if the equipment cost difference is now on the low side, which it appears to be, then all the indirect costs that are prorated based on the total equipment cost difference are also on the low side. Examples of these are "…" and "…." The … charge to duct firing is $... out of a total of $..., or around 16%, the same percent that NSPI is quoting for the duct firing portion of the project.

NSPI also provided its estimates for contingency costs. The contingency costs used in the previous application from Fall 2007 showed … percentage of project cost for both the CC portion and the DF portion. However, in the revised cost estimates, NSPI used an average contingency of …% for the unfired CC and …% for the CC with DF. If the contingency percentage …, it would … to the CC with DF capital cost.

Synapse hired IEA Energy in Portland Maine to run a series of GTPro/PEACE model runs. These model runs were intended to give us a better idea of the relative capital cost differences between the two portions of this project. IEA Energy was asked to run three scenarios, the first was two LM6000 CTs, the second was a CC conversion of the two CTs without duct firing for 25MW additional capacity, and the third case was a CC conversion with duct firing for 50MW additional capacity. The capital cost output from the PEACE model is summarized below.

CC No DF ($ million)	CC With DF ($ million)	Incremental DF Cost ($ million)	$/kW for DF
$179.0	$197.2	$18.2	$749

Table 4.3 **– Total owner's cost output from GTPro/PEACE modeling of 2 LM6000 units converted to a combined cycle, with and without duct firing. Totals include cost of the original LM6000 CTs. Converted to $CAD using conversion of $1 USD = $1.0342 CAD.**

These results show a more balanced cost allocation, with the duct firing portion taking a larger percentage of total project costs than NSPI has claimed and should be taken into account when looking at the economics of the project.

B. Fuel Benefits

The bulk of the economic benefit of duct firing quoted in the Hatch analysis comes from the annual "Fuel Charges" calculation. For instance, in the first year of the analysis (2010), Hatch shows that the addition of duct firing will save NSPI $... million in fuel costs since it will be displacing older, less efficient units that would be burning oil. However, as shown in the comments filed by Synapse previously on December 4, 2007, Tufts Cove Unit 3 will often have available capacity due to the generation from the combined cycle coming online. Therefore, an alternative scenario where generation at Tufts Cove 3 replaces the generation from the addition of duct firing should be considered. In Synapse's analysis of this scenario, it was found that it would be less expensive to run Tufts Cove 3 rather than the duct firing. The table below summarizes these results.

Year	DF Fuel Savings vs TUC3 (MMBtu)	Total Annual DF Fuel Penalty (MMBtu)	Total Fuel Saved vs TUC3 (MMBtu)	Value of Fuel Saved ($MM)	Amortized cost of DF ($MM)	Net value of DF ($MM)

Table 4.4 **– Summary of Synapse analysis comparing generation at Tufts Cove 3 as an alternative to running duct firing at Tufts Cove 6. Discount rate of 6.62%, CRF of 0.0916, HR Penalty of 61 BTU/kWh, NG price of $11.5/MMBTU. $ CAD.**

The first eleven years of operation were analyzed. The fuel saved by running the duct firing rather than TUC3 is not enough to make up for the cost of capital and the heat rate penalty that would be imposed on the CC from the DF. Even using the NSPI capital cost quote of $13.5 million, the DF project ends up over $... million more expensive than generating at Tufts Cove 3. If the GTPro/PEACE estimate of $18.2 million for duct firing is used, the net loss increases to $... million.

TUC3 has the ability to use either natural gas or oil for fuel and for the purpose of this analysis it was assumed that TUC3 would be burning gas. In the event that oil becomes less expensive than gas in the future, then it would likely make sense to run TUC3 with oil and sell the freed up gas to the market. This option would not be available for the duct firing capacity.

Table 1 in Appendix 2 of NSPI's filing to the UARB shows Hatch's summary of the duct firing benefits. The $... million benefit in fuel charges that Hatch calculated in the first year of operation was based on the displaced generation from plants burning HFO and LFO. The change to this benefit should be accounted for as well if the duct firing generation were replaced by running TUC3. Below are the results of this analysis.

Year	HFO ($million)	LFO ($million)	NG ($million)	Net ($million)

Table 4.5 **– Summary of fuel displacement benefits from the addition of duct firing, taken from Vista model output. $ CAD.**

Year	HFO ($million)	LFO ($million)	NG ($million)	Net ($million)

Table 4.6 **– Summary of fuel displacement benefits from using Tufts Cove 3 to replace duct firing generation. $ CAD.**

Using the Vista model outputs, Synapse also considered the issue of hourly constraints on the units, such as hours where TUC3 is already running at full capacity and therefore not able to displace any LFO generation for that hour. These numbers are summarized below for the first full year of operation (2011).

Units	LFO Displaced by DF	TUC3 Available to Replace DF	Additional Hours When TUC3 Available to Displace LFO

***Table 4.7* – Analysis of availability at TUC3 during hours of DF operation to displace LFO generation for 2011. The first column indicates the total hours and generation of LFO units displaced by duct firing. The second column represents the hours from the first column where TUC3 is also available to supply generation. The third column is a count of the hours where LFO units are running while TUC3 has available capacity, representing additional potential savings and benefits.**

The results show that by picking up the duct firing generation with TUC3, the LFO generation can still be displaced, along with a small amount of HFO, to still provide a net savings in fuel costs. The savings are not as large as those estimated to be gained from generating with the duct firing but this scenario has the benefit of lower investment risk since no additional capital costs are required.

C. Environmental Issues

Due to the urban location of the Tufts Cove LM6000 CTs, there are time-of-use constraints on their operation since the noise generated is not allowed during nighttime hours. Synapse was not able to analyze how the duct firing will affect this constraint due to lack of data on the subject, but it should be assumed that the addition of duct firing would likely increase the noise level during operation since they are essentially the power plant equivalent of an afterburner on a jet engine.

D. Alternatives

Shown in the results above, running TUC3 would be a plausible alternative to installing duct firing on the combined cycle. However, if additional generation is required and Tufts Cove 3 cannot make up the capacity for reasons not accounted for in Synapse's analysis, then a standalone combustion turbine would be a viable alternative since it would provide peaking capacity without imposing a heat rate penalty on the existing combined cycle.

NSPI notes in their revised application that 3 responses were received to their call for expressions of interest for 25MW of fast response peaking power and each response was more expensive than duct firing. Synapse agrees with the comments filed by NPB that "This lack of responsiveness is troubling, and suggests that a more expansive approach to the marketplace was warranted."[1]

Many recent reports have quoted combustion turbine costs in the range of $500-$1000 per kW. The table below cites several recent reports and/or articles that show costs in this range.

[1] NewPage Port Hawkesbury Limited and Bowater Mersey Paper Company Limited (NPB)'s comments to the Nova Scotia Utility and Review board regarding NSPI's revised application on Tufts Cove 6. Filed July 4, 2008.

$/kW	Date	Unit	Source
$776	6/23/2008	-	FERC, via Electric Power Daily[2]
$827	6/10/2008	-	NMPRC IRP[3]
$646	7/25/2008	GE LMS100 100MW	Industrial Info Resources[4]
$881	6/24/2008	GE LMS100 100MW	Industrial Info Resources[5]
$584	8/1/2007	GE 7EA 85MW	NEPPA E-Newsletter[6]
$819	3/10/2008	240MW	Industrial Info Resources[7]

Table 4.8 **– Sources for combustion turbine capital costs. Converted to $CAD using conversion of $1 USD = $1.0342 CAD.**

These CTs are larger than the proposed 24MW duct firing resource, but the costs per kW from these sources indicates to us that stand-alone peaking capacity is economically viable, and likely preferable to the duct firing in that it would avoid the heat rate penalty that duct firing imposes on TUC6, while also providing flexibility in terms of size, timing of construction, and operation. Additionally, a dual-fuel CT would have the flexibility of being able to run oil or natural gas.

5. Conclusion

Based on the revised filing from NSPI, converting Tufts Cove units 4 and 5 into a combined cycle plant is again well justified based on the gains in fuel efficiency. The Company's case for the duct firing portion of the project is unconvincing. After taking the cost allocations, heat rate penalty, and risks and benefits into account, we recommend that the duct firing portion of the proposed project not be approved.

[2] Electric Power Daily, "US May Face 'Significantly Higher' Power Prices for Years," quoting the FERC staff report that specified CT cost range of $500-$1000 per kW, June 20, 2008. No particular unit type specified.

[3] New Mexico Public Regulation Commission Integrated Resource Plan, filed June 10, 2008. No particular unit type specified

[4] Industrial Info Resources (Sugar Land, TX), "Topaz Power Completes $125 Million Expansion Project at Laredo Power Station." Article quotes $125 million cost for 2 100MW GE combustion turbines for $625 per kW.

[5] Industrial Info Resources (Sugar Land, TX), "Basin Electric Completes Construction of $81 million Expansion Project at Groton Peaking Station" Article quotes $81 million cost for 1 95MW GE Energy LMS100 unit.

[6] NEPPA e-Newsletter, "New England systems invest in new generation." Article quotes $47-$49 million for 85MW GE 7EA unit. http://www.naylornetwork.com/ppa-nwl/printFriendly.asp?projID=626.

[7] Industrial Info Resources (Sugar Land, TX), "Power Generators Plan Big Expansion in Florida as Part of $35 Billion Industrial Project Push." Article quotes $190 million cost for 240MW peaking unit.