Cost Effectiveness Analysis

Background

After the QEM (Quantitative Evaluation Methodology, used in the CFT evaluation of tenders) results for the Tier 1 analysis were presented to and accepted by the PMO (with the Independent Reviewer present), the blinding provisions were removed and the full results including the Tier 2 analysis were presented to the PMO. The winning portfolio (i.e. lowest NPV cost portfolio) in Tier 1 showed a significant saving relative to the next lowest Tier 1 portfolio (about $45 million NPV). The Tier 1 winning portfolio also showed a significant saving relative to the VIGP benchmark ($55 to $115 million NPV, depending on assumptions made about GHG liability for the benchmark). The results were then presented to the CFT Steering Committee. The CFT Steering Committee accepted the results, and requested an analysis assessing the overall cost-effectiveness of three possible CFT outcomes, which were: (1) award one EPA for one 252 MW project as per the Tier 1 result; (2) exercise the privative clause and award two EPAs for two projects totalling 122 MW (one possible Tier 2 result), and (3) exercise the privative clause and cancel the entire CFT (the "No Award" scenario).

The latest BC Hydro load forecast shows that VI has a capacity requirement of 261 MW in Fiscal 07/08. The need increases on average about 30 MW per year between Fiscal 07/08 and Fiscal 13/14. The capacity purchased in the CFT, under either the Tier 1 or Tier 2 outcomes, is not sufficient to meet the load requirement in Fiscal 07/08, and the gap increases further if the 230 kV AC cable experiences delays.

Approach

Depending on which CFT outcome is being considered, the amount, type (i.e. cost) and timing of resources BC Hydro would need to acquire to meet the system and VI needs would be different. Therefore, the general approach is to examine the net present value (NPV) of each CFT outcome, incorporating the different amounts, types and timing of subsequent resource additions into the analysis. The best outcome is the one that results in the lowest NPV cost to BC Hydro and its ratepayers, on a risk-adjusted basis.

In order to fairly compare the three CFT outcomes, it is necessary to "equalize" both the energy and the capacity being added to the system under each of the three CFT outcomes.

With respect to the energy requirements, the system is starting to become energy critical in 2010. Thus, the analysis "equalizes" the energy being added to the system by 2010. The total volume of new energy supply being added to the system under each of the three CFT outcomes was based on the Tier 1 plant energy contribution, and this translated to approximately 1800 GWh per year as determined by the dispatch model used in the QEM of the CFT. In the Tier 2 case, the volume of expected energy for the two projects as determined by the dispatch model was estimated to be about 600 GWh per year (the vast majority coming from the base loaded biomass project, with very little coming from the gas-fired peaking plant). Therefore, in the Tier 2 case the energy shortfall of 1200 GWh per year was backfilled starting in 2010. Under the "No Award" case, the energy shortfall of 1800 GWh per year was backfilled starting in 2010.

In both the Tier 2 and “No Award” scenarios, the energy backfill was assumed to come from new mainland generation (e.g. new IPPs in response to future calls), at two price scenarios: 100% and 90% of the unit price of the Tier 1 project on VI but without the associated firm gas tolls in both cases. Avoided transmission losses for energy generation on VI versus generation in the Interior was also accounted for, based on a 4.8% energy losses differential between these two locations. Avoided energy losses, as well as the energy volume differences between the three CFT outcomes prior to 2010, were valued using the same Energy Information Administration (EIA) gas and corresponding electricity market price forecast that was used in the QEM model.

With respect to the VI capacity requirements, depending on the CFT outcome being considered and the assumed in-service date of the 230 kV AC cable, any unmet capacity requirement in VI is filled first with load curtailment based on the Demand Management proposal submitted by Norske Canada and then, if necessary, with TM2500 temporary generators. Capacity from the Demand Management proposal is used ahead of temporary generators because of its lower cost and because of the higher permitting risks associated with temporary generators. Demand Management from Norske Canada offers capacity of up to 140 MW, with minimum commitment of 30 MW, scaleable in 10 MW increments. Temporary generators used in the analysis are GE distillate-fired mobile generators, each rated at 23 MW. Both Demand Management and temporary generators are assumed to operate at 240 hours a year to meet the load requirement (eg. to cover one 2-week cold temperature event coincident with a major single contingency event on the BC Hydro system).

Neither Tier 1 nor Tier 2 resulted in any deferral of the 230 kV AC cable. However, both were credited with deferral of the next 230 kV AC cable: from 2020 to 2026 in the case of Tier 1, and from 2020 to 2023 in the case of Tier 2.

The Tier 2 and “No Award” outcomes were credited with $13 million (NPV) to reflect the expected salvage value of the VIGP assets, and the Tier 1 outcome was credited with $47 million (NPV) to reflect the $50 million purchase price for the VIGP assets.

Various scenarios were performed, based on (1) different load requirements on VI, and (2) different in-service dates for the 230 kV AC cable. In addition to the EIA electricity price forecast described earlier, a high gas price forecast scenario (without a corresponding high electricity price) was also developed and analyzed.

<u>Results</u>

The detailed results of various scenarios are summarized in Attachment A. All dollar amounts are expressed in millions of 2003 dollars. Note that the results are presented in relative terms, with the Tier 1 result as the “base”. Positive values represent higher NPV costs (i.e. less favourable), and negative values represent lower NPV costs (i.e. more favourable), than the corresponding Tier 1 outcome.

For the purposes of this analysis, the base case assumptions are considered to be: 261 MW load requirement for fiscal 07/08; EIA electricity price forecast; pricing for mainland generation same as Tier 1 price (i.e. VI 250 MW CCGT) excluding gas tolls; one year delay in the cable (i.e. 2010 in-service). Under this base case scenario, Tier 1 shows a savings of $88 million and $53 million over Tier 2 and “No Award” respectively.

In general, the NPV depends greatly on the expected in-service date of the AC cable. In all scenarios, the NPV of Tier 1 relative to Tier 2 and "No Award" improves as the AC cable in-service date is delayed. Consequently, because of its size, Tier 1 is the CFT outcome most capable of mitigating any delay in the AC cable.

If, in the base case scenario, the pricing for mainland generation is 10% lower than the Tier 1 price, the Tier 1 outcome shows a savings of $21 million over the Tier 2 outcome, and a premium of $47 million over the "No Award" case. If, in the base case scenario, the High Gas – Low Electricity forecast is substituted for the EIA electricity price forecast, the Tier 1 outcome shows a savings of $2 million over the Tier 2 outcome, and a premium of $33 million over the "No Award" case. Both of these alternate scenarios are considered stress tests of the base case scenario.

If the load requirement in Fiscal 2007/2008 is 350 MW, in general the savings of Tier 1, relative to the other two CFT outcomes, is increased. If the load requirement in Fiscal 2007/2008 is only 150 MW, in general the savings of Tier 1, relative to the other two CFT outcomes, is reduced. Based on the most recent load forecast information, this latter scenario is very unlikely.

Overall, from a purely quantitative standpoint, Tier 1 shows the lowest cost to rate payers, especially when taking the uncertainty of the cable timing into consideration. However, in addition to the quantitative results, there are a number of non-quantitative considerations worth highlighting:

- Permitting Risks: Tier 2 and especially the "No Award" scenarios rely more on the availability of temporary generators than Tier 1 (See Attachment A). Preliminary investigation on the temporary generators indicates that there may be significant permitting risks associated with such generators (i.e. operating restrictions and in-service length). Therefore, the availability of temporary generators under Tier 2 and "No Award" scenarios may be overestimated, and BC Hydro's ability to meet the VI requirement, especially if the cable is late, is left in doubt.

- Cost Certainty: Cost information relating to temporary generators and Demand Management is still at the preliminary stages whereas the costs relating to the CFT bids are firm and legally binding. This favours Tier 1 since Tier 1 as a whole has the highest degree of cost certainty among the three CFT outcomes being considered.

- Competitive Tendering: The CFT establishes a tender evaluation and selection methodology directed toward a Tier 1 outcome as the objective of the process, with the Tier 2 methodology available only as a fall-back in the case of insufficient bid capacity or a Tier 1 result which is simply not cost effective.

Conclusion

The conclusion of the cost-effectiveness analysis is that the Tier 1 result is the most cost-effective outcome for the ratepayer, on a risk-adjusted basis.

Attachment A – Results Summary

261 MW Load Requirement in Fiscal 07/08

Mainland generation is the same as VI 250 MW CCGT excluding gas tolls (price forecast = EIA)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ 16	$ 54	$ -
2010 Cable In-Service	***$ 53***	***$ 88***	***$ -***
2011 Cable In-Service	$ 90	$ 106	$ -
2012 Cable In-Service	$ 137	$ 130	$ -
2013 Cable In-Service	$ 163	$ 135	$ -
2014 Cable In-Service	$ 197	$ 156	$ -

Generation cost in the mainland assumed to be 10% lower (price forecast = EIA)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ (84)	$ (13)	$ -
2010 Cable In-Service	$ (47)	$ 21	$ -
2011 Cable In-Service	$ (10)	$ 39	$ -
2012 Cable In-Service	$ 37	$ 63	$ -
2013 Cable In-Service	$ 63	$ 68	$ -
2014 Cable In-Service	$ 97	$ 89	$ -

High Gas – Low Electricity forecast (pricing for mainland generation = VI 250 MW CCGT less gas tolls)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ (70)	$ (32)	$ -
2010 Cable In-Service	$ (33)	$ 2	$ -
2011 Cable In-Service	$ 4	$ 20	$ -
2012 Cable In-Service	$ 51	$ 44	$ -
2013 Cable In-Service	$ 77	$ 49	$ -
2014 Cable In-Service	$ 111	$ 70	$ -

Required Temporary Generators (MWs)

	"No Award"	Tier 2	Tier 1
2008	138	0	0
2009	161	46	0
2010	184	69	0
2011	253	115	0
2012	276	138	23
2013	299	184	46

350 MW Load Requirement in Fiscal 07/08

Mainland generation is the same as VI 250 MW CCGT excluding gas tolls (price forecast = EIA)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ 40	$ 93	$ -
2010 Cable In-Service	$ 87	$ 116	$ -
2011 Cable In-Service	$ 115	$ 128	$ -
2012 Cable In-Service	$ 154	$ 150	$ -
2013 Cable In-Service	$ 191	$ 170	$ -
2014 Cable In-Service	$ 226	$ 188	$ -

Generation cost in the mainland assumed to be 10% lower (price forecast = EIA)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ (60)	$ 26	$ -
2010 Cable In-Service	$ (13)	$ 49	$ -
2011 Cable In-Service	$ 15	$ 61	$ -
2012 Cable In-Service	$ 54	$ 83	$ -
2013 Cable In-Service	$ 91	$ 103	$ -
2014 Cable In-Service	$ 126	$ 121	$ -

High Gas – Low Electricity forecast (pricing for mainland generation = VI 250 MW CCGT less gas tolls)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ (46)	$ 7	$ -
2010 Cable In-Service	$ 1	$ 30	$ -
2011 Cable In-Service	$ 29	$ 42	$ -
2012 Cable In-Service	$ 68	$ 64	$ -
2013 Cable In-Service	$ 105	$ 84	$ -
2014 Cable In-Service	$ 140	$ 102	$ -

Required Temporary Generators (MWs)

	"No Award"	Tier 2	Tier 1
2008	230	92	0
2009	253	115	0
2010	276	161	23
2011	322	207	69
2012	345	230	92
2013	391	276	138

150 MW Load Requirement in Fiscal 07/08

Mainland generation is the same as VI 250 MW CCGT excluding gas tolls (price forecast = EIA)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ (18)	$ 49	$ -
2010 Cable In-Service	$ 2	$ 53	$ -
2011 Cable In-Service	$ 24	$ 58	$ -
2012 Cable In-Service	$ 60	$ 66	$ -
2013 Cable In-Service	$ 91	$ 88	$ -
2014 Cable In-Service	$ 122	$ 106	$ -

Generation cost in the mainland assumed to be 10% lower (price forecast = EIA)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ (118)	$ (18)	$ -
2010 Cable In-Service	$ (98)	$ (14)	$ -
2011 Cable In-Service	$ (76)	$ (9)	$ -
2012 Cable In-Service	$ (40)	$ (1)	$ -
2013 Cable In-Service	$ (9)	$ 21	$ -
2014 Cable In-Service	$ 22	$ 39	$ -

High Gas – Low Electricity forecast (pricing for mainland generation = VI 250 MW CCGT less gas tolls)

	"No Award"	Tier 2	Tier 1
2009 Cable In-Service	$ (104)	$ (37)	$ -
2010 Cable In-Service	$ (84)	$ (33)	$ -
2011 Cable In-Service	$ (62)	$ (28)	$ -
2012 Cable In-Service	$ (26)	$ (20)	$ -
2013 Cable In-Service	$ 5	$ 2	$ -
2014 Cable In-Service	$ 36	$ 20	$ -

Required Temporary Generators (MWs)

	"No Award"	Tier 2	Tier 1
2008	23	0	0
2009	46	0	0
2010	69	0	0
2011	138	0	0
2012	161	23	0
2013	184	69	0