Appendix 4

HVDC charge analysis to support Transmission Pricing Review

Prepared by Electricity Commission

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Contents

1. Introduction

1.1.1 This appendix has been prepared as a contribution to Stage 2 of the Commission's Transmission Pricing Review (**the review**).

2. Potential inefficiencies created by the HVDC charge

2.1.1 A generation expansion model (GEM) experiment was carried out to estimate the inefficiency created by the HVDC charge, in terms of discouraging South Island generation in favour of potentially less economic North Island generation.

2.1.2 Two GEM runs were carried out:

(a) Base case – identical to the draft 2010 Statement of Opportunities (**SOO**); and

(b) No DC charge – as per the Base Case, but with the HVDC charge removed.

2.1.3 The two runs were then compared, in terms of post-tax 2010 net present value (**NPV**) of generation and shortage costs (8% discount rate). The results are shown below, for the five SOO scenarios (Table 1).

Table 1: Inefficiency stemming from the HVDC charge

		MDS 1	**MDS 2**	**MDS 3**	**MDS 4**	**MDS 5**	**Average**
NPV of generation and shortage costs ($M)	Base case	21,779	21,198	17,273	18,466	16,689	19,081
	No DC charge	21,772	21,186	17,254	18,461	16,653	19,065
	Difference	7	11	19	6	36	16

Excludes transmission costs (c.f. Appendix 3 which includes both generation and transmission costs).

2.1.4 This indicates an expected cost of $16M NPV stemming from discouraging South Island generation. This cost stems from deferring South Island hydro and wind generation in favour of North Island thermal, geothermal, and wind. In some cases this is appropriate, but in other cases it causes an increase in net system cost (i.e. where the South Island generation option is more economic than the North Island alternative).

2.1.5 The result should be considered with some caution, because the estimated magnitude of the inefficiency is in the order of GEM's margin of error (due to convergence issues, etc). In other words, it appears that the inefficiency is small, but the precise magnitude is hard to estimate.

2.1.6 On the other hand, it should be noted that the 2010 draft SOO assumptions place a high value on North Island capacity. The scenarios include relatively little South Island generation in early years (except where it is forced in). This means the experiment may tend to underestimate the inefficiency of deferring South Island generation options.

2.1.7 Members of the Transmission Pricing Technical Group (**TPTG**) noted that the capital costs were similar for all of the new geothermal plant and much of the new wind. The members were interested to know if a greater variation in these costs would alter the central conclusion. An experiment was undertaken whereby the capital costs for wind and geothermal were randomly selected from a range of +/-15% of previously specified costs. The result was a reduction in expected cost from $16M NPV to $8M NPV (Table 2).

Table 2: Inefficiency stemming from the HVDC charge – sensitivity with more geothermal/wind cost variation

		MDS 1	MDS 2	MDS 3	MDS 4	MDS 5	Average
NPV of generation and shortage costs ($M)	Base case	21,749	21,302	17,226	18,462	16,638	19,075
	No DC charge	21,743	21,300	17,222	18,444	16,626	19,067
	Difference	6	1	4	18	12	8

Excludes transmission costs (c.f. Appendix 3 which includes both generation and transmission costs).

3. The historical value of additional South Island peaking capacity

3.1.1 This exploratory analysis seeks to investigate the value that a hypothetical South Island generator could have gained from offering peaking hydro capacity into the market during 2007-09.

3.1.2 The experiment used the Commission's Vectorised Scheduling Pricing and Dispatch (**V_SPD**) model. The model was run over a 40-month period from the beginning of 2007 until mid-2010. Actual generation offers were used, except that an additional 120 MW of hydro generation was offered (nominally at Manapouri). Several offer strategies for the 120 MW of peaking capacity were tested (all very simple and none relying on hindsight):

(a) a fixed offer of $350/MWh at all times;

(b) an offer of $350/MWh during the 2008 dry year, falling to $120/MWh at other times; and

(c) as (b) above, or the price of the highest tranche of the actual Manapouri offer in each trading period, whichever was higher.

3.1.3 The figures of $350/MWh and $120/MWh in strategies (a) and (b) were pre-selected to roughly maximise revenue.

3.1.4 Under strategies (a) and (b), the model indicated that the 120 MW of hydro peaking capacity would have earned substantial revenue – more than enough to offset the reduction in revenue from the remainder of the Manapouri generating capacity. Offering the 120 MW of hydro peaking capacity would have led to a net increase of $20M in station revenue over the 40-month period (mainly collected during 2008).

3.1.5 This revenue increase would have been substantially more than the increase in transmission charges incurred by any generator that increased their peaking capacity by 120 MW.

3.1.6 Under strategy (c), there was no net increase in Manapouri revenue.

3.1.7 Portfolio effects have not been considered – in other words, it is not clear whether each of the three strategies would have yielded a net benefit for a hedged generator-retailer with other South Island generating capacity.

3.1.8 The conclusion is that a South Island generator could have derived benefit by offering their full capacity during 2007-09, rather than withholding some capacity to manage transmission charges. However, this would have depended on the remainder of their generation and retail portfolios, and might not have been predictable in advance.

4. Potential inefficiencies created by the HAMI pricing structure

4.1.1 This analysis seeks to assess the inefficiency created by the HAMI allocation of the HVDC charge, in terms of discouraging South Island peaking capacity.

4.1.2 The HAMI allocation discourages South Island generators from:

(a) adding additional peaking generation capacity (e.g. choosing low capacity factor designs when constructing new hydro plant);

(b) maintaining existing peaking generation capacity (e.g. keeping all units in service, if some are used rarely);

(c) upgrading existing peaking generation capacity (e.g. taking options during plant refurbishment that add additional MW output); and

(d) pursuing resource consents that allow increased peak output.

4.1.3 South Island generators have indicated that roughly 200 MW of incremental South Island peaking capacity is not economic due to the HAMI allocation, but would be economic if it did not face a peak-based transmission charge.

4.1.4 If the exact amount of potential capacity and the cost of accessing it were known, then it would be possible to accurately estimate the inefficiency arising from the HAMI allocation. In fact costs have not been provided to the Commission. However, it is possible to infer the costs and put bounds on the inefficiency through a simple calculation.

4.1.5 Suppose there is 200 MW of South Island incremental peaking capacity, and that:

(a) without a peak-based transmission charge, this capacity would be economic and would all be built in 2014;

(b) with the current HAMI allocation, this capacity is uneconomic and will never be built – instead 200 MW of thermal peaking capacity would be built in the North Island in 2014; and

(c) the incremental peaking capacity would come with little or no increase in total energy output.

4.1.6 Suppose further that half this capacity belongs to Meridian, and the remaining half to Contact and Trustpower. (These figures are somewhat different to the actual numbers provided by generators – which were provided under commercial confidence and cannot be reproduced here.) Assume that Meridian will face a marginal cost of additional capacity of $10/kW after 2012, and Contact and Trustpower $30/kW.

4.1.7 Building 200 MW of liquid-fuelled OCGTs and running them very occasionally to meet peak demand would cost approximately $30M p.a. (capex, operation and maintenance and minimal fuel). Then, from assumption (b) above, the annualised cost of the incremental hydro must be less than $30M per annum. – otherwise it would not be economic even without the HAMI allocation.

4.1.8 However, from assumption (a) above, the annualised cost of the incremental hydro must be at least $26M ($30 M - 100 MW * $10/kW - 100 MW * $30/kW) – otherwise it would be economic even with the HAMI allocation.

4.1.9 Therefore, the national net benefit of building the hydro must be somewhere in the range of $0 - $4M per annum from 2014 onwards. The resulting post-tax NPV would be in the range of $0-25M over 2014-2040 (8% discount rate).

4.1.10 In the absence of substantive information from generators on the cost of their incremental hydro options, we cannot be more exact.

4.1.11 GEM analysis was also carried out to test these figures. The GEM modelling indicates that South Island hydro cannot, in fact, replace North Island peaking thermal generation one-for-one. If South Island incremental capacity was installed, it would run rarely, and North Island peaking generation would still be needed. This would imply that the inefficiency was close to zero. However, GEM possibly understates the value of South Island peaking capacity due to its high level representation of transmission and security.

5. Potential inefficiencies of per-MWh charging

5.1.1 One option considered is to allocate HVDC costs to South Island generators, proportional to total generation in MWh. This section seeks to determine the extent of the inefficiency of a per-MWh allocation, in terms of operation of existing generation.

5.1.2 NERA has suggested that per-MWh charging is inefficient because it results in a non-least-cost dispatch.[1] This may be true, and a per-MWh transmission pricing is likely to cause significant inefficiency in a thermal-dominated system, but in the hydro-dominated South Island the inefficiency of this effect may be much less.

5.1.3 A hydro generator receives a given quantity of water each year, which converts to (more or less) a given quantity of energy. If they face a per-MWh transmission charge, the only way for them to reduce that charge is to spill more and generate less. Spilling more water is not usually an economic option, given that the price of energy is normally many times higher than the per-MWh transmission charge. Thus, the transmission charge has little effect on behaviour. (Compare this with a thermal generator, who will likely decide to use less fuel and generate less in an attempt to reduce transmission charges.)

5.1.4 The overall effect is expected to be that hydro generators are slightly less averse to spill and run lakes closer to the full level; energy shortage is slightly less common; and thermal fuel consumption is slightly higher.

5.1.5 An experiment has been carried out, using the Stochastic Dual Dynamic Programming (SDDP) model, to determine the level of inefficiency of a per-MWh allocation of HVDC costs to South Island generators. The baseline assumptions of the experiment are loosely based on the ‘Sustainable Path’ scenario of the 2008 SOO. Two runs were carried out:

(a) a base case with no HVDC charging; and

[1] *New Zealand Transmission Pricing Project*, NERA, (p91)

(b) an alternative case with a charge of $7.50/MWh on all South Island generation (sufficient to recover approximately $130M p.a.) In practice this charge would vary from year to year, in inverse proportion to total South Island generation, but this was not considered in the experiment.

5.1.6 For each of the two runs, the SDDP model:

(a) calculated optimal water values; and

(b) simulated outcomes over a five-year period (plus one additional year to avoid end-of-period-effects).

5.1.7 The difference between the two runs, in terms of overall system costs, was slight – on the order of $1M NPV over the five-year period.

5.1.8 The conclusion is that per-MWh charging would not produce significant inefficiencies, in terms of operation of existing South Island hydro generation.

5.1.9 It should be noted, however, that if new baseload or mid-order thermal generation was constructed in the South Island, a per-MWh charge could lead to inefficient dispatch. (Peaking thermal generation would not be significantly affected by the per-MWh charge, since the charge would be very small relative to the peaker's SRMC.)