Appendix 3

Analysis of the potential benefits of locational signalling for economic transmission investment

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Contents

1. Introduction and purpose

1.1 Introduction

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

1.2 Purpose

1.2.1 The purpose of this appendix is to describe the analysis the Commission has undertaken to assess whether there are potential benefits to be gained by developing further locational price signals for generators in relation to economic investments in transmission. The modelling did not consider the benefits of enhanced locational signalling on where large load would choose to locate.

1.2.2 This appendix describes:

- a background to the analysis;
- the approach used;
- results;
- analysis exploring the sensitivity of the results; and
- analysis on the impact of transmission charge allocation to the generation merit order.

2. Background

2.1.1 There exists a substantial literature describing how to calculate optimal locational prices for electricity and New Zealand is one of a few jurisdictions to adopt the optimal system of nodal spot prices. However, while it is widely accepted that nodal spot prices are a necessary part of the package of design features that ensure efficient short term dispatch, it is unclear whether nodal prices alone are sufficient to ensure appropriate long term price signals are generated. In other words, nodal prices may be incomplete. This then gives rise to the following question: is the transmission pricing regime able to augment the system of nodal spot prices such that a more efficient (least cost) pattern of investment in generation, transmission and load responsive demand can be attained?

2.1.2 Under current arrangements, investment in generation and load responsive demand facilities is left to the market whereas transmission investment is centrally planned and subject to approval by a regulatory body.

2.1.3 For planning and regulatory purposes, transmission investment is categorised as either being reliability investment or economic investment. Reliability investment is primarily to support reliable supply to load whereas economic investment is typically to reduce constraints in the transmission system with the objective of reducing generation costs and nodal prices.

3. Analysis approach

3.1.1 The Commission has used the generation expansion model (**GEM**) to derive an estimate of the national benefit, measured as a reduction in system costs, which could be obtained from an enhanced locational price signal for generators.

3.1.2 To simplify the analysis the Commission has focussed on modelling the trade-off between remote generation requiring transmission investment and generation located close to load requiring no or more limited transmission investment. Transmission investment in this context is concerned with realising the economic benefit of reduced generation costs and is accordingly categorised as economic investment.

3.1.3 The Commission has relied on the GEM model to support its thinking during the stage 2 analysis. As with any model, the model described below does not model actual outcomes but it provides a strong indication of expected outcomes. The limitations and assumptions of the model are briefly described in section 3 of this appendix[1].

[1] Further information on the model can be found at http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html and questions regarding the model can be emailed to gem@electricitycommission.govt.nz

3.2 A brief description of GEM

3.2.1 GEM is a capacity expansion model used for long term analyses of the New Zealand electricity sector. It is usually formulated and solved as a mixed integer programming problem, a type of optimisation model. The model yields a solution which minimises total system costs while satisfying a range of technical, economic and policy constraints.

3.2.2 The costs that GEM keeps track of and minimises over the entire modelled time horizon (31 years for the present analysis) include capital expenditure for new and refurbished generation plant and transmission upgrades, fixed and variable operating costs, certain classes of reserves, HVDC charges, and unserved energy.

3.2.3 GEM is supplied with over 300 potential new plants utilising various technologies and fuels, each with a fixed capacity, and specific to a particular location. Given forecasts of peak and energy demand, fuel costs, carbon costs, historical hydrological sequences, a discount rate, capital costs and other input parameters, GEM seeks to satisfy the forecast peak and energy demand by building the least cost mix of plant. In a competitive market this should also lead to least cost energy prices. A key output of the model is the resulting build schedule, i.e. a schedule of new generation plant by year and location.

3.2.4 Different regional and therefore initial network configurations, all of which are electrical aggregations of the existing grid, can be supplied to GEM. When operated in such a multi-regional mode, GEM is able to co-optimise generation and transmission expansion. This means that the decision about what plant to build where can be simultaneously considered along with the decision to commission grid upgrades. Total system cost minimisation remains the objective of the model.

3.2.5 GEM is a deterministic model. This means that future levels of demand for energy, hydro inflows, gas prices and availability, capital costs, CO_2 prices, and many other input parameters are assumed to be known with certainty. Clearly they are not. The generally preferred way to deal with such uncertainty in a model such as GEM is to formulate a "stochastic programming" version of the model and draw samples of the uncertain parameters from a distribution. However, doing this results in a significantly greater computational burden when solving the model.

3.2.6 An alternative approach, and the approach adopted by the Commission, is to undertake systematic sensitivity analysis to explore the robustness of the final results to the level of uncertain parameters. Some of the sensitivity analysis carried out is reported in section 5 of this appendix

3.3 Experimental design

3.3.1 Unless specifically noted otherwise, the analytical results presented in this paper are the result of a two-stage process.

3.3.2 In the first stage, GEM was configured to yield a solution representing a regime where interconnection charges (including DC assets) were subject to postage stamp pricing, i.e. locational price signals played no role in the choice of generation location and the consequent investment in grid upgrades or their timing. That is, the least cost generation options were built regardless of the interconnection costs necessitated by those private generation investment decisions (note that connection costs are modelled in GEM as being a component of the capital expenditure associated with generation investment).

3.3.3 In the second stage, GEM was configured to allow locational price signals to influence generation location decisions and, therefore, grid upgrade decisions. This second stage is intended to simulate the outcome of having a pricing regime that results in co-optimised transmission and generation investment.

3.3.4 The difference in the total system costs between the two stages was taken to be the estimate of the benefit of allowing generation developers to respond to locational price signals.

3.3.5 More specifically, the two stage modelling process was as follows:

- Stage 1 required the model to first be solved as a 2-region network – the North and South Islands. This means that within each region/island the AC transmission network is not modeled, i.e. generation and load are aggregated to a single node. However, the HVDC link, the only transmission activity in the 2-region case, was upgraded as per the recently approved HVDC grid upgrade. The variable operating costs of each plant (existing and new) are subject to regional location factors so as to mimic the impact of the cost of losses on the AC grid (which is not modeled). To complete the stage 1 part of the analysis the model was run a second time. This time the model used an 18-region network configuration but with the generation build schedule from the previous 2-region solution imposed on the model. GEM now has to make decisions about AC transmission expansion. The model is provided with a sequence of upgrades to the transmission links connecting each of the 18 regions; there are 54 potential, sequenced transmission upgrades across the interregional links, each with a specific cost, capacity and loss characteristic. To reiterate, the build schedule from the initial 2-region solution was imposed on this 18-region

GEM run so all that the model needed to determine was the dispatch pattern and the transmission upgrades needed by the predetermined generation investment. The end result is a model solution in which generation investment decisions did not take into account the costs of transmission investment. But note that such transmission investment, while it may have reliability benefits, was undertaken in GEM strictly on economic grounds. In other words, the transmission investment enabled lower system wide generation costs to be attained.

- The second stage of the analysis involved solving the 18-region configuration of the model yet again. This time, generation and transmission investment were co-optimised. In other words, generation investors faced the locational price signals that arise due to the additional capital costs of transmission investment and the transmission losses on the AC grid and across the HVDC link. To be clear, the generation build schedule that was produced by this stage 2 GEM run is different from that obtained from stage 1. The transmission expansion is different too.

3.3.6 As noted above, the approved HVDC investment is programmed to occur in all model runs associated with this analysis. In the 18-region runs of the model, and in both stages of the analysis, the approved North Island Grid Upgrade (**NIGU**) and the North Auckland and Northland (**NAaN**) investments are also programmed to take place (the NIGU and NAaN investments are meaningless in the context of a 2-region model). Taken together, these projects represent three large, committed, upcoming enhancements to the grid.

3.3.7 The nodal location factors used in the 2-region solution from stage 1 were suppressed (set equal to one) in both 18-region model runs because AC transmission losses across the interregional transmission links are explicitly modelled.

3.3.8 The current HVDC charges that are usually represented in GEM are turned off for this analysis.

3.3.9 Investment decisions in GEM are usually represented with binary (0/1) integer variables. In other words, each potential generation or transmission investment is either made (i.e. the variable equals one) in a given year or it is not (i.e. it equals zero). Throughout this analysis, all integer variables were relaxed. This means that in each modelled year, every integer variable was able to take on any value between its bounds of zero and one. A consequence of this computational convenience is that the lumpiness of generation and transmission investment is ignored. However, given the long time horizon of the analysis, this may be an acceptable abstraction because the impact of discounting means that the unrealistic deferment value that the integer relaxation implies, i.e. from assuming gradual increments rather than an earlier lumpy investment, is not likely to be significant. In any event, further analysis of this issue is to be undertaken.

3.3.10 Throughout this analysis, GEM was run from 2010 out to 2040, a modelled time horizon of 31 years. The analysis was undertaken for all five market development scenarios (**MDS**) comprising the grid planning assumptions and the results were averaged (evenly weighted) over all five scenarios.

3.3.11 The input data defining the underlying assumptions for the scenarios is the same data to be used in the draft 2010 Statement of Opportunities (**SOO**) to be published later this year. The scenarios are outlined in table 1 below. Further details about the input data and assumptions for the five scenarios can be found on the Commission's website[2].

[2] http://www.electricitycommission.govt.nz/consultation/2010-draft-soo/view

Table 1: The five Market Development Scenarios (MDS) summarised

Scenario	Carbon price ($/t$CO_2$)	Coal and lignite price ($/GJ)	Gas price ($/GJ) in 2020-2030-2040	Renewables available	Demand side
Sustainable path (mds1)	60	5.50 and 2.70	15-25-25 (LNG imports)	Extensive hydro, wind and geothermal. Biomass available	Baseline + electric vehicles + extensive demand side participation
South Island wind and hydro (mds2)	50	5.50 and 2.70	15-19-19 (LNG imports)	Extensive hydro, wind in SI and less geothermal. Biomass available	Baseline
Medium renewables (mds3)	30	5.50 and 2.70	13-13-7 (Indigenous)	Extensive wind and geothermal, and some hydro available. Biomass available	Baseline + Tiwai phased out beginning in 2025
Coal (mds4)	20	5.50 and 2.70	13-13-7 (Indigenous)	Extensive wind and geothermal, and little hydro available. Biomass available	Baseline
High gas discovery (mds5)	40	5.50 and 2.70	8-8-8 (LNG exports)	Extensive wind and geothermal, and some hydro available. Biomass available	Baseline

4. Results

4.1.1 The Commission's analysis to date suggests that there may be little benefit to locational signals for generators when considering options for transmission investment for solely economic reasons, given the current grid and generation patterns and likely generation and transmission expansion scenarios.

4.1.2 The Commission considers that these results reflect the fact that remote generation investments are likely in the short to medium term to be driven more strongly by other factors than transmission costs; factors such as fuel costs, fuel availability, and resource consents.

4.1.3 Selected results from the above described analysis are presented in table 2.

Table 2: System-wide costs with committed transmission investment, $m PV

	mds1	**mds2**	**mds3**	**mds4**	**mds5**	***average***
'Postage stamp pricing'						
Total costs	21,162	20,807	17,219	18,393	16,577	*18,832*
Generation plant capex	9,666	9,421	6,490	6,046	4,723	*7,269*
Fixed and variable O&M	10,196	10,079	9,457	11,052	10,565	*10,270*
Transmission capex	1,300	1,306	1,273	1,295	1,289	*1,293*
'Locational pricing'						
Total costs	21,154	20,795	17,214	18,365	16,561	*18,818*
Generation plant capex	9,794	9,556	6,528	6,155	4,791	*7,365*
Fixed and variable O&M	10,064	9,946	9,419	10,940	10,508	*10,175*
Transmission capex	1,296	1,293	1,267	1,269	1,262	*1,278*
Postage stamp pricing less locational pricing						
Total costs	8	12	5	28	16	***14***
Generation plant capex	-128	-135	-38	-109	-69	*-96*
Fixed and variable O&M	132	133	38	112	57	*95*
Transmission capex	4	13	6	26	27	*15*

4.1.4 The key value to focus on is the $14m in the fourth to last row of the far right column. This represents the difference in the total system-wide costs, averaged over all five scenarios, between the case where transmission services are postage stamped and the case where a locational price signal is evident.

4.1.5 In line with expectations, the co-optimised solution (locational pricing) results in an overall lower total cost for every scenario than the postage stamp solution. In the co-optimised solution the generation plant capex is $96m more on an averaged, present value basis when generation investment is subject to locational price signals compared to the case where it is not. However, this is offset by an increase in fixed and variable operating costs ($95m) and an increase in transmission investment costs ($15m), i.e. $14m = $95m + $15m - $96m.[3] The results in the five MDS columns reveal the range around the final average column.

4.1.6 These results suggest the benefit from full locational signalling is very low. In fact, given the margin of error associated with estimating the input parameters for the modelling, it is reasonable to interpret the $14m benefit as being zero.

[3] Note that the figures in the table do not sum exactly due only to rounding.

5. Sensitivity of results

5.1.1 A number of sensitivities were undertaken to test the robustness of the results. For example, we tested to see if the three already committed and approved major transmission investment projects were suppressing locational signals by virtue of being so large and/or committed to early. Re-running the experiment presented above in Table 2 without forcing in the three large committed transmission investments saw the benefit increase from $14m to $21.5m – still a relatively small result. Similarly, testing the sensitivity of the results to the transmission investment costs resulted in the benefit from locational signalling increase to $27.3m if costs were doubled.

5.1.2 It is worth reiterating that expenditure in the early years of the modelled time horizon carries more weight than expenditure far off into the future due to the effect of discounting when converting expenditure in all years to a present value basis. Hence, the three large transmission investments forced into the GEM solution early (in 2012 and 2014) tend to dominate other investments, namely generation investments.

5.1.3 A further test was undertaken to see what difference the integer relaxation had on the results. The 18-region version of GEM with co-optimised transmission investment contains over 7,000 binary variables and takes almost a day to solve for all five MDSs. The resulting estimate of the benefit was on the order of $30m - similar to the relaxed integer case - although it is somewhat awkward to compare integer solutions because of the non-zero convergence tolerance required to solve an integer programming problem.

5.1.4 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; it did not. An experiment was undertaken whereby the capital costs for wind and geothermal were randomly selected from a range of +/- 15% of previously specified costs.

5.1.5 The previously estimated benefit of $14m increased to $16m, which can still be interpreted as zero. The composition of the changes between the locational pricing and the postage stamp pricing solutions is practically the same as before.

5.1.6 Compared with the result reported in section 4, there is no change in the amount of geothermal plant built in any of the MDSs. Minor changes in the wind plant commissioned were observed in some scenarios with MDS1 and MDS3 having the largest change. In MDS1, a little less South Island hydro was constructed and about 80MW more South Island wind was built. Conversely, MDS3 built about 120MW less North Island wind and replaced that with a little more North Island coal and biogas co-generation plant.

5.1.7 After substantial testing and sensitivity analysis (not all of which has been reported here), no feasible scenarios that the Commission tested would cause the benefit to increase above the $20m - $25m mark.

5.1.8 The available generation technologies and their costs are such that, for the short to medium term, at least, the most economic options are quite geographically specific. For example, investment in geothermal generation is, rather obviously, only able to occur in locations where the geothermal resource is located.

5.1.9 In an entirely contrived and unrealistic experiment, the Commission also tested the impact that the geographical specificity of the generation resource had on the results. If gas was available everywhere in unlimited quantities and, moreover, if it was the only generation technology available, then it is possible to observe benefits of several hundred million dollars from locational price signals. Although this is of course an unrealistic option, it does suggest that the low benefit results are not just an artefact of the model or experimental design, but rather a result of prevailing market conditions and cost bases.