Comment on Strata and Sense Modelling in their Consulting Document: Elaborating on our approach to assessing costs and benefits of the proposed TPM guidelines

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General Comments

1.1 The comments here represent my understanding of what is being proposed, which is by no means complete. The comments should be interpreted in that light.

1.2 The modelling is still a work in progress. While the general intention of the modelling is relatively clear, some of the equations don't quite reflect that intent. This note sets out the issues I have identified. This will no doubt be dealt with as the modelling progresses, but we will need to monitor it as modelling progresses to ensure that there are no mistakes.

1.3 My understanding is that three interrelated models are proposed:

(a) A energy consumption model that chooses demand for energy to maximise consumer welfare given the relative price of energy and other parameters that are fixed in the short run (ie, as per paragraph 95).

(b) An investment model that chooses demand for energy (presumably from the energy consumption model, as per paragraph 94) and investment in DER (distributed energy resources) to maximise consumer welfare, given that the grid owner seeks to socially optimise grid investment.

(c) A model that chooses investment in grid connected generation to maximise profits.

These three models are connected by electricity prices and quantities traded in the wholesale market.

1.4 The welfare function at para 57 appears to assume that all energy consumption is by final consumers (eg, households). It is not clear how the functional form chosen can be interpreted to represent consumption by businesses. This needs some rationalisation.

1.5 Relatedly, the short term price risk is borne by retailers or their counterparties rather than households and the like. I presume that paragraph 33 is intended to address this point. If so, it needs some explanation to show why this is a reasonable modelling assumption.

1.6 The document states that the modelling is to be applied regionally, but the equations largely abstracts from this. It is therefore not clear the modelling will ensure that the individual parameters will be modelled at the appropriate level. For example, the AoB charge needs to be applied to the consumers who are affected by the relevant investment; that is, applied regionally. In contrast, the RCPD charge needs to be spread across all consumers; that is, applied nationally.

1.7 The AoB charge for an investment is intended to be applied to both load and generation that benefit from it. The modelling as presented appears to model the benefit to load (at para 162) and generation (at para 200) separately, so that in effect transmission is charged for twice.

1.8 The policy intent is that customers will be able to reduce their AoB charge for a new transmission investment by, for example, investing in DG before the transmission investment is undertake, but will be unable to alter their charges after the investment is committed.

(a) For load, the discussion at paragraph 138 suggests that the latter is achieved but not the former. This may be a reasonable modelling assumption, but it does need some justification.

(b) For generation, the equation at para 199 appears to allow generation disinvestment after the date of transmission investment to reduce the generator's AoB charges for the investment. It should be possible to deal with this problem by imposing the modelling requirement that $g_{it} >= g_{it-1}$ in each region. Ie, to assume that generation, once installed is refurbished or replaced so that it does not depreciate.

Specific Comments

1.9 Para 41. It is important presentationally to note that under the proposed TPM, nodal pricing will provide the required peak price signal. This also means that the introduction of the AoB charge could lead to less investment as a result of scrutiny, and so a reduction in consumption associated with higher nodal prices. Same comment applies to para 43.

1.10 Para 134. The optimisation will need to take account somehow of the fact that DG/ DER will have a terminal value. Eg, it could define C(d) as the PV of the costs of DER over the time horizon of the simulation. The same applies to the optimisation of generation and transmission.

1.11 Para 146 to 156. I think the thinking is correct here, but there is something is not quite right in the treatment of the parameter e and the relationship between the variables. In particular:

(a) The variable e is defined in words as "excess" capacity, (T/X – 1), yet the formula defining the variable P suggests that e is T/X.

(b) In the formula in paragraph 146, e appears to correspond to the maximum T/X in the sawtooth graph of T/X. ie, T/X ϵ [1,e]. In contrast, in the description and in paragraph 154, e and e_t seem to refer to T/X; ie, e_t = T/X ϵ [0,e]. Using this definition, in the first equation in paragraph 151, it appears the last e should actually be e_t, whereas the other 3 e's should be as written.

(c) Para 152. P is a function of e (as shown in paragraph 146), so the differentiation with respect to e must include the upper limit of the sum just before the second equals sign. This may be easier to do if the sum is converted to an integral (ie, continuous time).

(d) Para 154. The reference to P in the text should presumably be a reference to P* = ln(e*)/ln(α), and "expected lifetime of the investment" should presumably be "expected time between transmission investments".

(e) Para 154. I cannot replicate the equation at paragraph 154. Intuitively, it seems to me that there should be a scale multiplier, probably X, on each term on the RHS. If this is so, I think it would be more realistic if R in paragraph 155 is also scaled with X; ie replace R in the equation with R" * X, R" constant. It may be even better to replace G(e,X) in paragraphs 147 and 148 with G"(e,X) *X, so that G"(e,X) represents the cost of capacity expansion per unit of total capacity, and therefore does not scale over time.

(f) Para 155. I think "optimal excess capacity" should be "optimal maximum excess capacity".

(g) Para 156.

(i) The variable u is defined as the inverse of T/X, yet the sum limits in para 156 seem to assume the opposite. I think the u_t is actually much the same as e_t as defined in subparagraph (b) above.

(ii) I cannot replicate the formula in this paragraph either

(h) Paras 160 to 165. While I have no problem with the intuition behind these paragraphs, it is not clear to me what they add to the previous analysis. You have already determined the timing of the first investment increment, (P(bar) in para 154) and subsequent investment increments (which are P* apart), and the size of the increment, $e^*.X_t - 1$. They do introduce the scalar ψ, but that could equally be introduced into the equation at paragraph 151.

1.12 Para 168. The benefit calculation will be the same as the social benefit calculation, but only where the net benefits are positive; ie, disbenefits are not taken into account. This means that the denominator would not be total social benefit, but the sum of positive net private benefits. The same applies for generation at paragraph 203.

1.13 Para 173 to 175. The incentive to misrepresent benefits would still exist under the AoB charge, since if I can convince Transpower that my benefits are lower than they actually are, my share of the AoB charge is reduced. However, there is also a countervailing effect, since I actually want an efficient investment to go ahead. In any case, the effect is likely to be smaller than under the RCPD charge, since then the marginal charge for an investment that benefits me is near zero. Related to this and the point in paragraph 1.6 above, the RCPD term in the first equation in paragraph 175 would be near enough zero on the assumption that the benefits of the investment would be regional and the RCPD charge would be spread across all consumers; ie, in the status quo equation, term in the inner curved brackets should simply be b_c.

1.14 Para 194.

(a) As specified, the equation appears to assume that all generation is run continuously in high and low price periods. I would have expected to see the terms like x_i rather than g_i in the price terms and in C(g), subject to the constraint that $x_i < g_i$. Alternatively, there may be a modelling assumption about the expected average load factor for each type of generation.

(b) It is not clear to me what the profit function $\pi(g_i)$ contains that is not already in the rest of the equation. If it is required, it should appear as $\pi'(g_i)$ in the equation at paragraph 199.

Minor comments/ typos

1.15 Para 40. Related to para 40(c), prices for transmission that are based on energy use, thus artificially discouraging use when the grid is not congested.

1.16 Para 43, figure 5.

(a) Under the stated assumptions, D' would move to where the vertical C line intersects with the horizontal DG LRMC line.

(b) The line "wholesale price plus AoB charge" probably should read "wholesale price plus variabilised AoB charge", since the AoB charge is a fixed annual charge.

(c) It is not clear why the line "wholesale price plus AoB charge" is so different from the line "grid investment efficient trigger price". In other words, efficient investment is triggered when the nodal price saving per annum is equal to the annual holding cost of the transmission investment

1.17 Para 52(c). Also, changes in technology.

1.18 Para 57, equation. Presumable LHS should be Max U_j, and the maximisation is with respect to demand for energy use of various types, holding other things constant (apart from wholesale prices).

1.19 Para 70. One of the two βs should have subscript nj.

1.20 Para 87. It's not clear to me why you make the assumption in para (e), given that the interconnection charge must collect Transpower's recoverable revenue.

1.21 Para 88. I am not clear about the reason for this assumption, or why the equivalence in brackets holds.

1.22 Para 124. The equation in this paragraph appears to assume that DER is operated as base load if it is built, which implies that its SRMC is less than prices in the generation abundant situation.

1.23 Para 130. The δ is presumably the one year discount factor, not discount rate.

1.24 Para 131. Presumably the equation should contain the term A_0 rather than A_t

1.25 Para 134 and para 143. I think the two *d* terms in the equation should be deleted, as the differential of d is 1.

1.26 Para 135. C'(d) is presumably the cost of investing in DER and the PV cost of operating DER (although it might be better to incorporate the latter separately).

1.27 Para 136. The RHS of the equation needs a term for the AoB charge for historic investment. This would of course be eliminated in the differentiation to calculate the maximisation.

1.28 Para 138. The equations here are replicated (and more accurately) at para 168 and 169.

1.29 Para 140. The h in the equation is not defined until para 178.

1.30 Para 149 equation and para151, 2nd equation. I think these may be missing terms θ and (1-.θ). Also, the X variable presumably should be X_0.

1.31 Para 150. "over the life of the investment" should presumably be "until it is optimal to increase transmission capacity again", or something similar

1.32 Para 151. I believe that you will want to minimise social cost per year. If that is so, the second term on the RHS should be divided by P.

1.33 Para 167. It would seem better to place this before para 146.

1.34 Para 196. "local" should presumably be "low".

1.35 Para 199. Para 206, footnote 23. The effect stated is of course much larger under the RCPD charge.

1.36 Para 201 and 202. It seems to me that the E[K] term in the equation should not be subscripted by i, since the DC charge is spread across all South Island generation according to its means injection. Also, K is South Island total system generation.