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Mr Len Gould
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Dear Len

Upper North Island Reactive Support Investigation Project

Thankyou for the opportunity to provide feedback on Transpower's consultation document, and for the technical meeting on 30 June. This letter summarises the points we raised at the technical meeting, and responds to the specific questions asked in the consultation document.

Q1. Are there any other issues or considerations that Transpower should incorporate into the Upper North Island Reactive Support Investigation Project?

Some consideration needs to be explicitly given to the impact of increasing levels of static and dynamic reactive support on network harmonic performance – in particular, will there be unforeseen resonance effects? Vector has observed a trend of steadily increasing background harmonic levels in its distribution network as a result of the connection of more and more non-linear loads, and is concerned that it can no longer be simply assumed that there will be no harmonic-related problems arising from ever-increasing levels of reactive support on the grid.

Q2. Do respondents consider that the demand assumptions are appropriate for this project?

Vector has several concerns about the demand assumptions made. In no particular order, these are:

- The demand forecasts have been taken from the 2008 APR – has there been any cross-checking with relevant lines company forecasts to see how well they are aligned?
- The "extreme summer" forecast has been derived from the winter forecast data using 2005 historical data – how typical was the 2005 summer? Has the same calculation been run for other years to see whether there are significant differences? Summer 2007/08 was abnormally warm and dry – how do the data for this summer compare with the 2005 reference case?
- The "extreme summer" forecast is based on a noon to 2 pm period from mid-January to mid-March – our experience is that in that part of the year, the daily peak demand often occurs in mid to late afternoon, rather than around mid-day.
- The "extreme summer" demand forecast assumes that the ratio of summer/winter peak does not change over time, and that the power factor for corresponding periods remains constant from year to year – we would observe that both of these assumptions are likely to be incorrect. Observed summer power factor has tended to drift down slowly over time, and the summer peak in parts of our network is growing faster than the winter peak.

- Table 4.1 shows diversity factors – those for the CBD appear strange, particularly those for LST_PEN and PEN_QUAY (very low). Note that the CBD load is summer peaking, so I would expect CBD diversity factors >100% if they are based on the winter demand. Also the 2005 data reflect the configuration of the Vector subtransmission network at the time (ie the lower CBD fed from Penrose, and the upper CBD from Roskill). The whole CBD load is now permanently fed from Penrose.
- Recent BRANZ research forecasts a rapid growth in the uptake of domestic air-conditioning units (heat pumps) in Auckland. This is expected to add around 300 - 400 MW to the forecast summer peak demand in the short to medium term, over and above normal load growth, while making a minimal difference to the winter peak demand. There will also be an associated decline in power factor – this does not appear to have been included in the “extreme summer” demand forecast.

Q3. Do respondents consider that the motor load forecast approach is appropriate for this project?

The approach seems to be reasonable in principle. The key assumption that the proportions of the various types of motor load will remain constant over time seems questionable, particularly given the forecast increase in domestic air-conditioning load. Robust sensitivity analysis may be necessary to address this issue.

The modelling assumption that each GXP equivalent distribution transformer has an impedance of 8% needs to be examined carefully, given that many of the smaller motors will be connected at 400 V, and therefore see MV and LV network impedance as well as the zone substation and distribution transformer impedances.

Q4. Do respondents consider that the generation assumptions are appropriate for this project?

Given that units 1-4 at Huntly, and Otahuhu B, are likely to be retired within the analysis period, the assumption is made that they will be replaced with equivalent capacity at the same site. We are unable to comment on the validity of this assumption, but it is perhaps not material unless the replacement generation is located significantly further north.

Q5. Do respondents agree with Transpower’s approach for developing long list options?

In principle the approach seems reasonable.

Q6. Are there any other qualifying alternatives/components which should be considered in the exercise of compiling development plans as options?

The following options should be included on the long list, so they can be evaluated and either ruled out or added to the short list:

- Automatic undervoltage load shedding
- Synchronous condensers
- Superconducting Magnetic Energy Storage devices

It is possible that Vector may be interested in providing voltage support as a transmission alternative, but no detailed work has been done on this.

Q7. Do respondents consider that a Base Case identified using this approach would be appropriate for this investigation project?

In principle the proposed approach seems reasonable. Presumably the alternative of a development plan based on N-G-1 would be tested by the GIT, as it may in fact be more economic when the value of expected unserved energy is taken into account (as was the case for NIGU).

Q8. Do respondents consider this commensurate GIT approach to be reasonable for Transpower to apply when considering the UNI Reactive Support Investigation Project?

Yes, provided the test is applied to the overall (staged) development plan as a whole, and not separately to individual augmentations.

Q9. Are there other market costs or benefits which should be reflected in the analysis?

It is difficult to assess at this point whether transmission losses would be materially different for the various options – this will need to be considered at the time.

Q10. Do respondents consider that this Value of Lost Load is appropriate for valuing lost load in the Upper North Island Reactive Support Investigation Project?

We note that the EC is currently undertaking a comprehensive review of the VoLL, and the revised number(s) should be used if available in time. Failing that, as a second-best substitute, the \$20,000/MWh number in the Rules should be escalated using an appropriate index (possibly PPI). If Transpower was able to substantiate a different value by its own research, then use of that value would be appropriate.

Additional specific comments on Attachment A are as follows:

Section 3.1

- Was the ROS-HEP 110 network split open or closed?
- Were faults north of Otahuhu considered (previously there have been concerns about possible voltage collapse in Northland, cascading back to Albany/Henderson, for loss of critical cross-isthmus circuits)?

Section 3.2

- Presentation of results is too coarse to allow meaningful discussion
- “fails performance criteria” - fails how badly?
- How sensitive are the results to the assumed split between groups 1, 2 & 3?
- Is there any feel for the rough probability of the group 1 tripping percentage falling outside the band that produces acceptable performance – how big is the risk here?

Section 4.3.4

It is fairly clear that there will be no generators commissioned at Rodney within the period of the analysis shown (up to 2012), so not sure what the relevance of this section is, other than to illustrate that a significant power station north of Auckland will help considerably. It is not clear whether Figures 12 and 13 are for 1 x 240 MW CCGT at Rodney, or two.

Section 5

- The summer period (ie excluding "extreme summer") does not appear to have been studied. Are we sure that there are no voltage support issues in this period?
- Given the sensitivity of the outcomes to the various key assumptions, has enough work been done to justify significant expenditure?
- What are the "safe" ranges of "% group 1 tripping"? What is the probability of landing outside these ranges? What are the sensitivities around this?
- Does the modelling extend beyond 2012, or is the modelling work done so far simply to justify the immediate need for additional dynamic support?
- What is the long-term strategy – is it intended that there will be an integrated overall development plan that will proceed in stages as required, or will there be a series of expedient "just-in-time, just-enough, cheapest-option-for-right-now" projects?

Appendix A

Current static support (MVAR) is ~50% of winter peak demand, with a further +/- ~10% of dynamic support on top of that. It would be helpful to have some comment on where that sits in relation to the Transmission Code limits of acceptability. At what point do we expect to reach that limit if we haven't already?

Appendix D

- Did all the modelled committed projects shown as included (up to winter 2009) actually happen?
- Does the modelling extend beyond 2012 (in which case is the NAaN project included)?
- Has it been assumed that the 30 MVAR capacitor banks on interconnector tertiaryies at Otahuhu, Henderson and Albany will not be replaced?
- It has been assumed that the Otahuhu A machines will be available "across the planning horizon" (however long that is) – this would appear to be a brave assumption, given their age and condition.

Appendix F

F.1

- We don't understand the "credible event which removes a device from service without a short circuit fault" list, other than loss of HLY5. How would a transmission line be unexpectedly removed from service in the absence of a fault?

- Loss of Otahuhu B or Southdown does not appear to have been considered as a credible event – surely this would be among the most onerous tripping events?
- Has the tripping of a large capacitor bank/SVC been considered?

With regard to the breakdown of the SKM source tables provided on 03 July 2009, we are unable to comment on the split between the various load categories. We assume that this is 2005 data, in which case the following subsequent changes in our network need to be taken into account for forecasting purposes:

- ALB33/ALB110: Approx 30 MVA of winter load has been transferred from ALB110 to ALB33
- All of the Auckland CBD load is now supplied from PEN110, so the ROS110 load is now only the Kingsland bulk supply point
- Around 7 MVA of winter peak load has been transferred from PEN22 (Onehunga) to ROS22 (Hillsborough)

We also note that the recorded data for MNG110 (Pacific Steel) appear low compared to more recent data. This may be a reflection of how Pacific Steel was operating their plant in 2005.

Thank you for the opportunity to comment at this stage of the process. We look forward to working constructively with Transpower to achieve the best overall outcome for this project.

Yours sincerely



Tim Chatterton