meridian

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Electricity Demand and Generation Scenarios
Ministry of Business, Innovation & Employment
By email EDGS@mbie.govt.nz

Draft Electricity Demand and Generation Scenarios

Meridian welcomes the opportunity to comment on the MBIE's Draft Electricity Demand and Generation Scenarios (EDGS). As the recent significant transmission cost increases illustrate, it is essential that the basis for new transmission investments is sound, that efficient investments are made given possible futures, and also that the merits of those investments can be assessed adequately as uncertainty is revealed. The assumptions and outputs of the EDGS are crucial inputs to the process of assessing transmission investments. Given this, Meridian supports the open and responsive approach taken by MBIE for developing them.

Meridian's feedback to the consultation questions is appended. Some of the points covered in this submission were made in person at the workshop and have not been repeated here. Our key observations about the EDGS are:

- We agree with purpose of EDGS scenarios being to inform transmission investment. The discussion and measures of impacts should be aligned with this purpose, which they are. The EDGS commentary should be consciously differentiated from Government policy analysis and it made clear it is not intended for this purpose.
- It would be prudent for MBIE to check the validity of the core scenarios with a simulation model that captures storage dynamics. The amounts at stake are material enough to warrant this additional work. It may result in a slight change to the EDGS modelling process, though would add to the credibility and robustness of the scenarios.
- The EDGS assumes that output from existing hydro schemes remains at the status quo. This needs to be stated explicitly. Consideration should be given to a scenario which models the potential impacts on hydro generation from re-consenting and changes to water planning.
- Changes to the Transmission Pricing Methodology could change the economics of new generation options, especially in combination with an altered allocation of demand growth between the North and South islands. Lower prices for consumers would flow through to the demand forecasts. More clarity is expected over 2015, which can be fed in to an update to the EDGS, or the next version.

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If you would like to discuss this submission, please contact me.

Yours sincerely,

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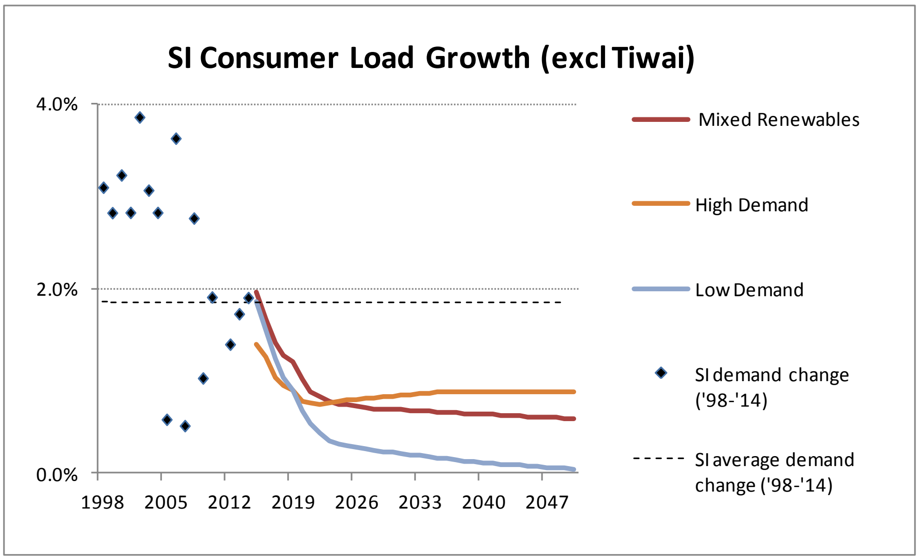
Appendix 1: Table of responses

Q#	Question	Meridian response
1	Do you agree with this description of the purpose of the EDGS, including the material in the appendix?	The description and purpose are aligned with the Commerce Commission requirements. The scenarios are essentially guidelines to test the potential value of actual transmission projects at the time the investment is being considered. We suggest MBIE make it explicit that the EDGS is not intended for policy analysis. Any policy or aspirational analyses are best addressed separately, even though a similar modelling methodology could be used.
2	In the absence of regional and prudent peak demand projections being a part of the EDGS, the Ministry would like to ask for your feedback on the best way to independently verify regional and prudent peak demand projections.	There is no "best" way to verify the projections. MBIE need to take ownership of peak (prudent peak & regional peak) demand forecasts if EDGS are to be used for transmission expansion planning and/or transmission investment justification. Transmission expansion is all about peak transfers – in and out of regions. This does not mean MBIE need to carry out the forecasts, but they do need to drive and own the inputs and outcomes. Regarding possible options (which are not mutually exclusive): - An informal discussion between industry experts could be a worthwhile approach to answering this question. Having this discussion in advance of using the forecasts is advisable. - Transpower could demonstrate consistency at the time they are used and allow industry to critique it. Regardless of the approach, distributor forecasts needs to be considered. Reference to history and some sense of validation of any proposed approach (for both growth & prudent peak) in terms of a "hindcast" would be a good starting point. For example, MBIE have the SI demand growing (0.5% pa) at 1/3 of the rate of the NI (1.5% pa) – which is not supported by history.
3	Do you agree that the key uncertainties identified in this section, and the proposed eight equally weighted scenarios, sufficiently represent overall uncertainty for the purpose of the EDGS?	The scenarios are dictated by the purpose of the EDGS and a reasonable summary of future rational possibilities. With that in mind, we have the following suggestions: **Hydro output**. We note that the hydro output is presumed to remain at status quo levels in the future, with some increased hydro coming in to the supply mix as well. We consider this assumption should be stated explicitly for existing hydro. Consideration of an additional scenario is warranted to represent the risks of reductions in hydro output from a combination of adverse outcomes affecting hydro output, including hydro re-consenting and changes in water planning/policy. **Transmission Pricing Methodology**. As the consultation paper notes, the transmission pricing methodology (TPM) influences decisions about the location of future load and generation including as a result of the HVDC charge increasing the cost of South Island generation relative to North Island generation (see [73] and [203]-[204]). It is likely that the TPM will be revised over the next few years as a result of the Electricity Authority's current review and that these changes will impact on the EDGS. One option would be to introduce scenarios into the EDGS that allow for a revised TPM (for example, by subsuming the current HVDC charge within general interconnection charges). However, there is probably insufficient certainty about the form of changes to do so at this stage. Accordingly, Meridian suggests that MBIE should expressly note that any changes to the TPM may impact on the EDGS and that the EDGS would have to be revised when the nature of any such changes becomes clear.

Demand allocation to North/South Islands. The allocation of forecast national demand to the North and South islands will have a strong influence on the level and location of transmission builds, as well as new generation. This North/South assumption was a material assumption in the decision around the timing of building the HVDC link – MBIE's base case demand allocation between the islands should be considered carefully and verified against existing/recent levels, as noted in Q2. For example, the chart below shows historic SI demand growth and assumed compound growth rates for three EDGS. This suggests that SI demand growth may be significantly different to that assumed by MBIE. This could have a material impact on generation and transmission requirements within the South Island, and throughout the country. This could be addressed by either revising the assumptions, or expressly modelling this uncertainty.



Low demand. Near-term forecasts could reflect recent trends then revert to modelled demand projections. The same principle should apply if the growth is high or low.

Tiwai demand. From a pure modelling perspective, we suggest removal of the 400MW Tiwai demand scenario because it is a midpoint between 2 extremes and would be captured by Transpower as variation to an EDGS (as it was in September 2013 when Transpower considered the upgrade to local transmission[1]). Removing this 400MW option as a scenario would not diminish the effectiveness of the scenarios.

[1] See https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/LSI%20Renewables%20CUWLP%20Review%20Consultation%20Document_Final.pdf

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<tr><td>4</td><td>Do you have any specific feedback on the proposed EDGS capital cost assumptions which are sourced primarily from the PB generation data update 2011?</td><td>MBIE’s approach of splitting out the capital costs by different currencies, and modelling transmission connection costs, is robust.

Transmission Pricing Methodology (TPM): The current TPM distorts the incentives for new generation located between the North and South Islands, with South Island plant incurring an additional transmission cost from their share of the HVDC link (around $150m per annum). As noted by MBIE, the TPM is being reviewed and if changed, will likely impact on the relative economics of new generation, and therefore impact <u>all</u> EDGS scenarios. We also note that due to this distortion, Meridian has looked at embedding new South Island generation in the local network so that it does not incur HVDC charges.

Thermal retirements. Thermal retirement dates are assumptions rather than modelled outcomes. It is not clear why these have not been treated on an economic basis, or as a scenario. Instead, deterministic assumptions have been made. For example, it may be cheaper for thermal to stay in the market and defer new investment. Running the scenario outcomes through a reservoir simulation model and checking for revenue adequacy would test the assumptions/outcomes.

Meridian projects. We note the following changes to EDGS assumptions relating to Meridian projects:
Maungaharuru: 96MW / 320GWh.
Hurunui: Fully consented. 71 MW / 220 GWh.
Central Wind 380GWh.
Titiokura 45MW / 150GWh.
MBIE should update any other assumptions in its modelling to be consistent with these revised figures. Meridian has different views to MBIE about the LRMC of its projects.</td></tr>
<tr><td>5</td><td>Is the variation in key assumptions consistent with the scenario design and future uncertainty?</td><td>Seems reasonable. Meridian has different views on many of the inputs for its projects, which mean our view on the economics will differ from MBIE.</td></tr>
<tr><td>6</td><td>Given the current flat demand environment, should we put more weighting on low demand growth scenarios?</td><td>No.

Given MBIE is confident with both its demand forecasting approach and the third party forecast of the inputs, then it has no reason to deviate based on recent drivers. If MBIE is seeking a low demand alternative scenario, then it could assume recent GFC-type conditions repeat themselves, or start forecasts using suppressed demand trends in the near-term then transition to a forecast long term average.

The scenario weights can be adjusted for any capex scenario used in an investment test and can be consulted on (see para 234 in the consultation paper). A protracted debate about scenario weightings at this point in time is not required.</td></tr>
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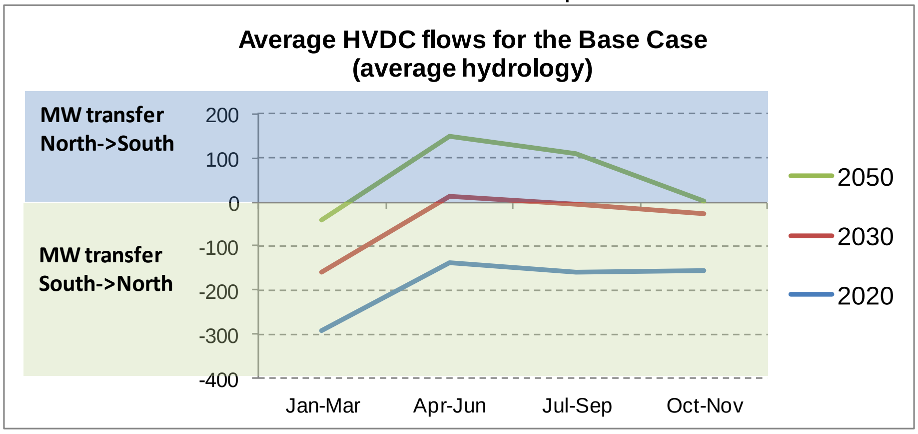
7	Does the high uptake of electric vehicles (and Solar PV) that are used in our Global Low Carbon Emissions scenario adequately reflect future uncertainty?	Given the purpose of the EDGS, these are reasonable at this stage, and definitely worth reconsidering at the next EDGS. Careful analysis of who pays/benefits should be undertaken for extreme scenarios. For example, affordability should be considered for a high uptake of solar.
8	Should we put more weighting on the low gas availability option given the current level of oil prices?	No. See question 6. It is far too soon to speculate on oil price impacts on NZ gas reserves and on new discoveries. We have at least 10 years of gas reserves available to the market in NZ. This is plenty of time for oil prices to recover to levels suggested by the IEA and to encourage further oil-led exploration that may lead to additional indigenous gas discoveries. Few commentators suggest low-price oil will be a long-term feature of the international market.
9	Does the range of retirement for the Huntly units across the scenarios adequately reflect the associated uncertainty?	No. See earlier comments about retirement dates being assumed inputs rather than modelled outcomes. There is potential value in Huntly and the stockpile, and therefore the scenarios are missing a “Huntly stays” option (albeit at a small size). Without Huntly, the NZ system needs to solve the thermal storage problem or build more baseload generation than would otherwise be the case, and probably build additional GT units running on gas (or diesel).

10	Are there any comments on the build schedules or other key results published in this document and the accompanying excel files?	**TPM**. As noted earlier, changes to the TPM will have an impact on the economics of any new renewable plant over the coming decades. **Measuring impact**. Important to discuss estimates of system cost in any modelling e.g., NPV of capital and operating costs by technology. **Model calibration**. There is value in simulating core scenarios with a reservoir optimisation model to ensure key out outputs (e.g., lost load, meeting peak demand, wholesale prices, spill, revenue adequacy, location factors) are feasible and sensible. As a simple example, we understand that location factors are assumed to be constant the GEM simulations. This is a material driver of relative economics of new builds. A key driver of those is the supply balance between the North and South Islands as this drives the wholesale price differences and is likely a factor in new builds being dominated by North Island projects. Following the workshop, MBIE published HVDC flow information[2] and the chart below depicts the change in average HVDC flows for the base case across calendar quarters.  This illustrates that over a relatively short time (in terms of generation and transmission planning), average HVDC flows are expected to transition to neutral for a large part of the year (2030) then *southwards*, which has flow on effects for modelled location factors, expected prices, new generation builds, and ultimately transmission requirements. MBIE needs to account for this in their modelling. **GEM modelling**. We suggest that the GEM inputs are provided along with a description of the approach used by MBIE. **Project names**. Meridian suggest that any projects built post-2030 are named generically and not mapped to particular companies. This is because there is no guarantee that existing consent holders will still hold those consents in 15+ years. **South Island builds**. A number of factors are distorting the number of South Island builds: the Transmission Pricing Methodology, static location factors, and the assumed North/South demand balance.

[2] http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/electricity-demand-and-generation-scenarios/pdf-and-document-library/hvdc-flows.xlsx