Memo

To	Ralph Matthes
CC	
From	Mike Hensen
Date	14 June 2017
Subject	Advice on Transpower Capex Input Methodology

Introduction

The Commerce Commission has asked for submissions on the "Transpower capex input methodology (IM)" review on five suggested focus areas including:

- Focus area 1: given the changing energy landscape, are there adjustments that could be made to the capex IM to ensure the 'right' transmission investments are being made including non-transmission solutions?
- Focus area 3: once expenditure has been approved does the capex IM appropriately deal with changing circumstances?
- Focus area 4: are the incentive mechanisms in the capex IM effective?

This note briefly discusses the increased uncertainty in the outlook for demand for transmission capacity and suggests that this uncertainty needs to be explicitly considered under Focus areas 1, 3 and 4. As the outlook for peak demand transitions from 'continuous growth' to flatter demand with more volatile peaks the question for regulation of grid investment needs to shift from 'is expansion in capacity occurring at the right speed?' toward 'what are consumer preferences for managing the grid reliability impacts for a small number of peaks and how can Transpower be encouraged to make decisions that reflect those preferences?'.

Different outlooks

Transpower is considering two quite different peak demand scenarios:

- A 'continuing growth' with 'expected' and 'prudent' peak demand forecasts that imply a need for a gradual increase in grid capacity
- *Transmission Tomorrow* which includes potential flattening of peak demands after 2025 and considers the possibility that distributed storage could become a substitute for grid reliability from 2040.

The question of how the IMs affect Transpower's capacity to combine these two scenarios into a consistent guide to its investment decisions is directly relevant to Focus areas 1 and 3.

The current incentive structure encourages Transpower to maintain transmission reliability by reinforcing the grid and does not provide an equally strong encouragement to Transpower to consider either the mismatch between the potential duration of the peak demand and the life of the reinforcing asset or to identify and use short-term alternatives. This may lead to over-investment in grid capacity over regulatory control period three (RCP3), given the outlook for short term volatility in peak demand followed by a period of no or slow growth. This issue along with the potential for change in the way grid reliability risk at the margin is managed by Transpower on behalf of stakeholders is directly relevant to Focus area 4

Demand forecasts

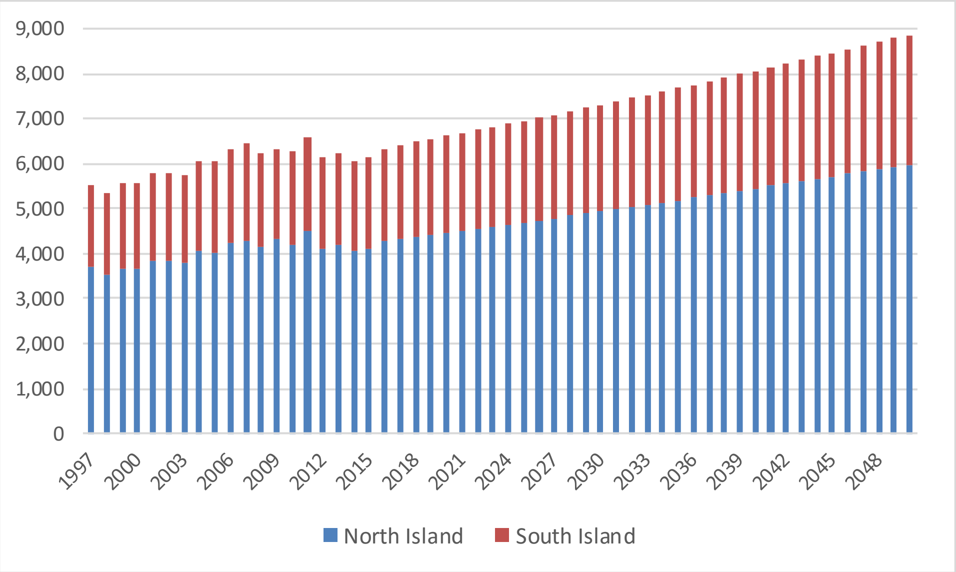
Our starting point for the analysis of peak demand is the 'Transpower Peak Demand Forecasts',[1] which are summarised in Figure 1. The chart shows the 'maximum' (of winter, shoulder and summer) peak demand over the period 1997 to 2015 and 'expected' forecast peak demand over the period 2016 to 2050. Transpower has also published a 'prudent' forecast[2] of peak demand which has a faster annual growth rate over the period 2016 to 2022 and then has the same annual growth rate over the remainder of the forecast period 2023 to 2050.

Peak demand has fluctuated over the period 1997 t0 2015 but there seems to have been two distinct phases over this period:

- Rising national peak demand over the period 1997 to 2007 with a compound annual growth rate of about 1.7 percent with a maximum of 6.4 GW in 2007
- Fluctuating national peak demand over the period 2008 to 2015 with:
  - a maximum of 6.6 GW in 2011 (2.6 percent above the 2007 level)
  - a minimum of 6.1 GW in 2014 (5.5 percent below the 2007 level).

Figure 1 Transpower's peak demand forecast

North Island, South Island and national peaks measured in MW



Source: NZIER

National peak demand was 6.1 GW in 2015. Transpower's peak demand forecasts ('expected' and 'prudent') both have an initial step-up in 2016, a period of 'above average' growth until 2020 ('expected') and 2022 ('prudent') before growing at 1 percent per year.

Transpower's 'expected' peak demand forecast is 6.3 GW in 2016, 6.6 GW by 2020 (an increase of 5 percent on 2016) after which peak demand increases by about 1 percent per year reaching 7.0 GW in 2025 and 7.3 GW in 2030.

1 'ELECTRICITY PEAK DEMAND FORECASTS, OVERVIEW OF OUR PEAK DEMAND FORECAST METHODLOGY', Transpower New Zealand Limited, September 2016, Appendix E, pages 31-32, available at https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower%20National-Regional%20Peak%20Demand%20Forecasts%20Jul-2016%20Information%20Document_0.pdf

2 ELECTRICITY PEAK DEMAND FORECASTS, OVERVIEW OF OUR PEAK DEMAND FORECAST METHODLOGY', Transpower New Zealand Limited, September 2016, Appendix F, page 33

Transpower's 'prudent' peak demand forecast is 6.6 GW in 2016, 7.1 GW by 2020 (an increase of 7 percent on 2016) after which peak demand increases by about 1 percent per year reaching 7.0 GW in 2025 and 7.3 GW in 2030. Also, the prudent forecast includes growth in the North Island and South Island peaks that is faster than the national growth in peak demand over the period 2018 to 2022.

The forecast step-up in peak demand in 2016 and the rate of above average growth over 2017 to 2020 ('expected') or 2022 ('prudent') are key drivers of the additional investment required in grid capacity over RCP3. If the core proposition that demand for grid capacity will continue to grow steadily until 2050 is accepted, then the investment driven by 2016 to 2022 forecast is unlikely to be permanently underused. However, the *Transmission Tomorrow* scenario suggests it is more likely that some of the investment based on the 2016 to 2022 surge could remain underused for a substantial part of its life.

Leaving aside the debate about forecast accuracy, until a set of grid capacity and reliability metrics along with more granular measures of the value of grid reliability to consumers are developed and published it is difficult to form an independent view on the reliability benefits delivered by a grid investment.

Short term volatility

The potential decommissioning of generation capacity in the upper North Island[3] and the potential change in peak demand management, following the currently proposed changes to the transmission pricing methodology, are both potential sources of short term volatility in peak demand that could materially affect Transpower's capacity to meet grid reliability targets over RCP3.

Transpower estimated the potential effect of change in demand response if the regional coincident peak demand (RCPD) based allocation of interconnection charges in its submission on the transmission pricing methodology.[4] The estimate was described in two stages:

- Scientia (for Transpower) estimated the effect of the RCPD signal on gross demand by distributors and direct connects during a trading period at 18:00 on 23 June 2015 as 625 MW of demand response by distributors and 190 MW of demand response by direct connect industrials
- Transpower[5] assessed system capacity to meet 2016 winter peak demand with reduced demand response due to the absence of *"RCPD based transmission prices"* as:
  - area north of Huntly; increase in demand of up to 100 MW *'possibly necessitating … administrative rather than price based demand management*
  - upper South Island: '*there would seem to be little incentive for Upper South Island distributors to utilise DR … which would necessitate … administrative, rather than price based, demand management'*
  - lower South Island: '*there would seem to be little incentive for Upper South Island distributors to utilise DR … if any demand increase arising from the absence of DR could not be met by local wholesale market generation it would necessitate the need for administrative demand management'.*

3 Transpower is assessing options to maintain voltage support in the upper North Island if generation capacity is decommissioned. We have not commented further on the peak demand impacts of this issue.

4 SUBMISSION TRANSPOWER: TRANSMISSION PRICING METHODOLOGY, 2ND ISSUES AND PROPOSALSISSUES AND PROPOSALSISSUES AND PROPOSALS PAPER, 26 JULY 2016, APPENDIX G (AND G1): IMPLICATIONS OF REMOVING RCPD SIGNAL, pages 4-43.

5 The letters in italics in this bullet point and the following three sub-bullet points are quoted from 'SUBMISSION TRANSPOWER' …., Appendix G, page 41-42.

Scientia's estimate of the demand response attributable to RCPD by distributors (625 MW) and industrial direct connects (190 MW) is about 10 percent of the current national peak or at least 5 years of projected growth in peak demand.

The potential for changes in transmission pricing methodology to affect the need for grid capacity is mentioned in *Transmission Tomorrow* but does not appear to be explicitly modelled in the 'expected' and 'prudent' peak demand forecasts.

The above comments are based on Transpower's assessment of the potential impact of the RCPD based transmission pricing. Other stakeholders argue that differences in nodal prices will still encourage demand response after RCPD based charging is removed. The draft TPM guidelines also give Transpower the opportunity to 'make the case' for a long run marginal cost component of transmission pricing which would provide an additional incentive (alongside differences in nodal prices) for demand response. The point of the comment in this section is only to describe an apparent difference in assumptions being used in short-term forecasts of peak demand.

Transmission Tomorrow

Transpower's *Transmission Tomorrow* identifies 'three sequential' states for the electricity sector which appear to have the following peak demands:

- Evolving generation – present time to about 2020 – a period of flat demand and change in the mix of generation with demand around 37 TWh and 6 GW. A key challenge for Transpower during this period is managing sudden mismatches between capacity and demand caused by either closure of thermal generation or reduced demand from major industrials.
- Changing load state – starting around 2020 to 2025 and lasting until about 2040 – mainstream adoption of emerging technology (solar photo voltaic panels, electric vehicles and network batteries) with two demand of scenarios 37-40 TWh and 6-8 GW or 37-47 TWh and 6-9 GW. A key challenge for Transpower during this period is managing temporary increase in demand for grid capacity while preparing for reduced demand for grid in the next state extensive storage
- Extensive storage – 2040 onwards – distributed storage 'behind the grid' can substitute for the reliability of the grid with demand scenarios of 37-47 TWh and 6-9 GW.

Comparison of the 'prudent' forecast referred to in the earlier section 'Demand forecasts' with *Transmission Tomorrow's* 'states' is impeded by the different levels of granularity for the two scenarios but at a high level suggests:

- A level of demand for the 'prudent' forecast (around 7 GW) measurably above the level of demand for 'evolving generation' (around 6 GW) implying a difference in the requirement for investment to increase grid capacity over RCP3
- Potentially, a lower capacity requirement over the forecast period under *Transmission Tomorrow* than under the 'prudent' forecast as *Transmission Tomorrow* forecasts capacity as a range and part of this range is below the prudent forecast.

Demand response programmes

Transpower has successfully trialled demand response programmes and has established a five-year programme to target regions where demand is likely to be constrained in the future. Current participants in the programme include supermarkets, agribusiness (including irrigated and dairy farms), hospitals and universities and are generally on annual contracts. Transpower does not appear to have published data on the location and amount of demand response it has achieved under the demand response to date or quantitative objectives for the five-year programme.

As an example, to illustrate the types of characteristics that a retail demand response programme might need to defer the need for peak investment on a network, we have analysed the top 100 coincident peaks in each of the four Transpower 'zones' of the grid for the year ended 31 March 2017 using grid export by GXP data from the Electricity Authority's market information website and summarised the information in six charts (see Figures 2 to 7).

Transpower divides the grid into fourteen grid zones which are combined into two zones[6] for each of the North Island and the South Island as follows:

- Zone 1 – grid zones 1 and 2 covering the North Island area north of Huntly
- Zone 2 – grid zones 3 to 8 covering the rest of the North Island (NI)
- Zone 3 – grid zones 9 to 11 covering the South Island area north of the Waitaki Valley
- Zone 4 – grid zones 12 to 14 covering the rest of the South Island (SI).

How sharp are peaks – how much demand needs to be 'shifted'?

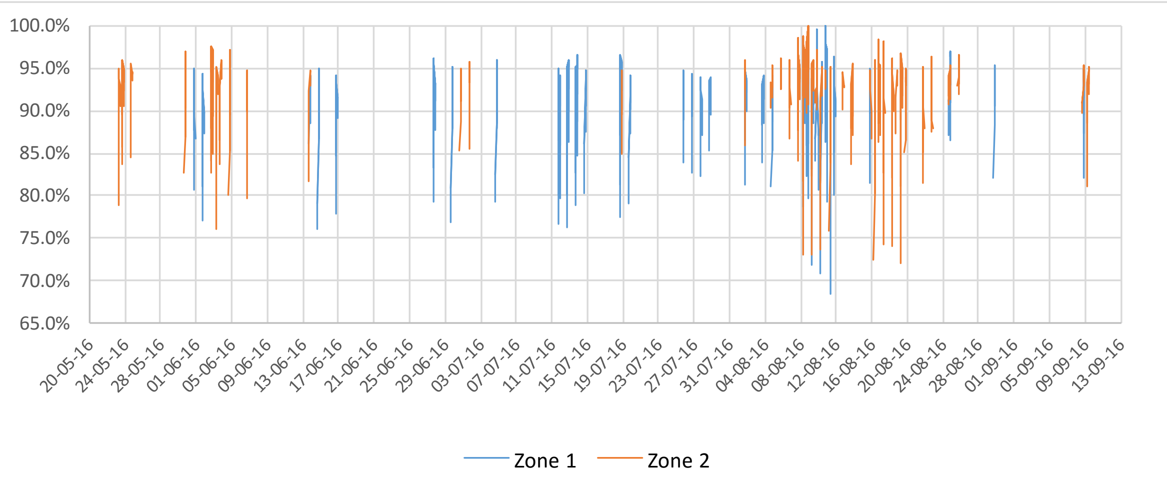
Figures 2, 3 and 4 show the top 100 peak coincident peak demands and the coincident GXP demand for the three trading periods before and after the each of the 100 peaks all expressed as a percentage of the single highest peak as follows:

- Figure 2 Zone 1 and Zone 2 – a comparison of North Island peaks
- Figure 3 Zone 3 and Zone 4 – a comparison of South Island peaks
- Figure 4 NI, SI and New Zealand – a comparison of national peaks.

The purpose of this analysis is to illustrate how quickly demand falls on either side of the peak trading period and the number of trading periods where demand is above a given percentage of the maximum peak (a temporary proxy for network capacity).

Figure 2 Zone 1 and Zone 2 peak demand timing and resolution

Demand three trading periods before and after top 100 peaks as percentage of maximum demand over the year

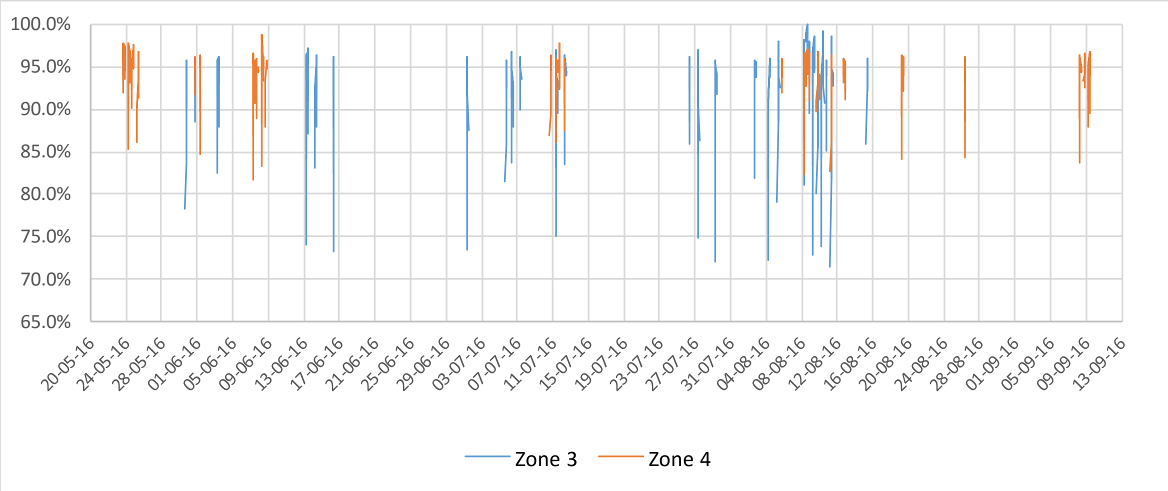


Source: NZIER

6 The boundaries for the four zones seem to be similar to the four regions used for the calculation of the RCPD currently used to allocate inter connection charges.

Figure 3 Zone 3 and Zone 4 peak demand timing and resolution

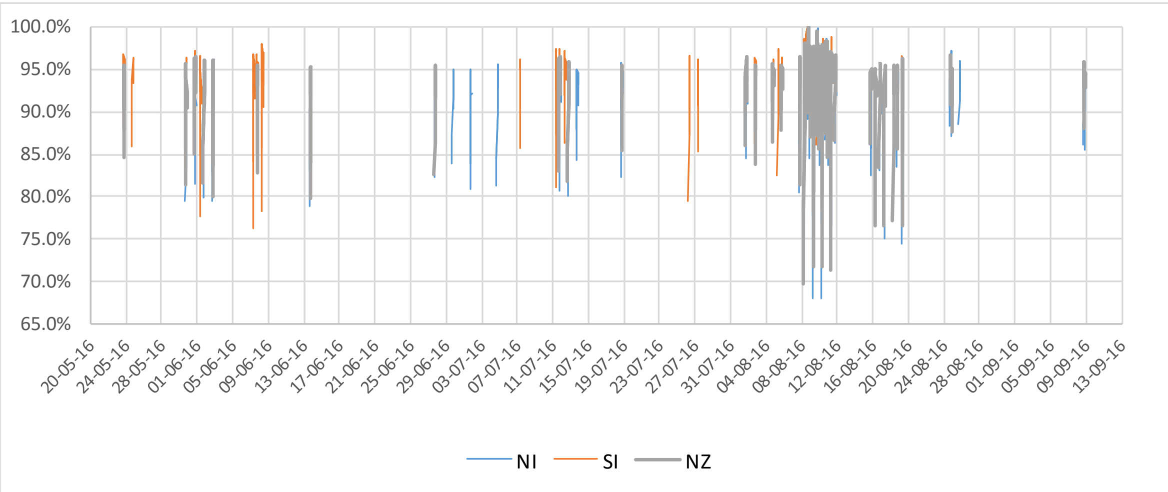
Demand three trading periods before and after top 100 peaks as percentage of maximum demand over the year



Source: NZIER

Figure 4 NI, SI and NZ peak demand timing and resolution

Demand three trading periods before and after top 100 peaks as percentage of maximum demand over the year



Source: NZIER

The duration and resolution of peaks varies markedly between zones. Table 1 shows the number peaks where demand one hour before and after the peak is less than a given proportion of the maximum demand peak demand for the year.

Table 1 Peak demand shape indicator

Number of 'top 100' peaks where demand is less than a threshold expressed as a percentage of the maximum peak for the trading period one hour before and one hour after the peak

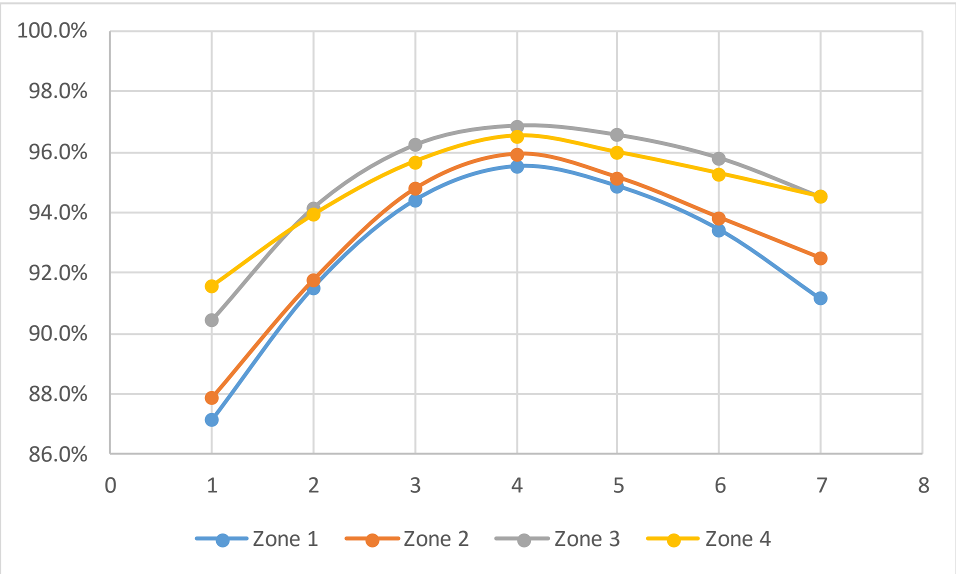
Area	Threshold level		
	94 percent	95 percent	96 percent
Zone 1	28	52	71
Zone 2	30	58	70
NI	**18**	**41**	**67**
Zone 3	1	7	27
Zone 4	1	15	45
SI	**0**	**5**	**16**
NZ	**13**	**29**	**47**

Source: NZIER

Figures 5 and 6 show the (simple) average shape of peak demand in each of the four zones and for NI, SI and NZ. Demand for each trading period is expressed as a percentage of the maximum peak demand for the zone. Each number on the horizontal axis is one trading period.

Figure 5 Average shape of demand peak for Zones 1 to 4

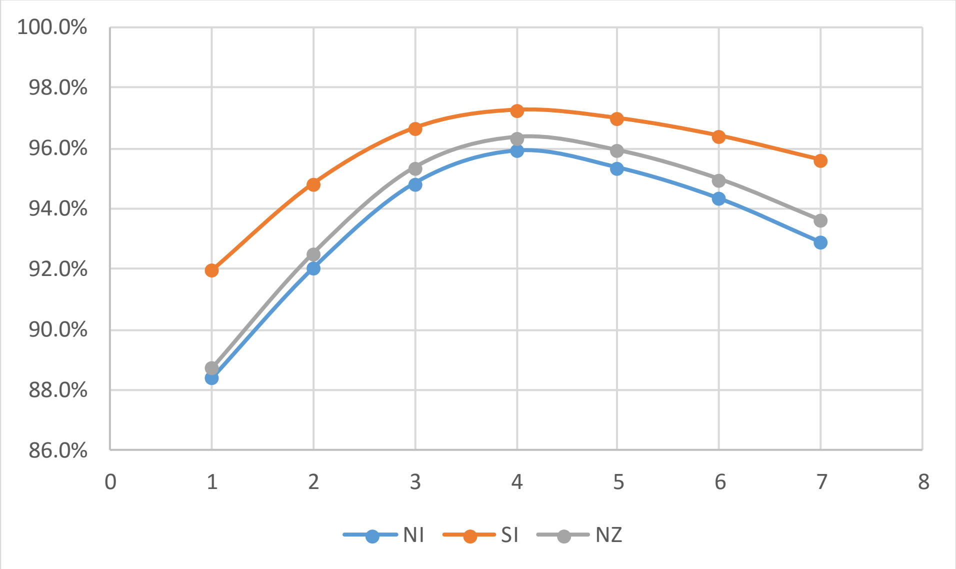
Average demand three trading periods before and after the average of the top 100 peaks



Source: NZIER

Figure 6 Average shape of demand peak for NI, SI and NZ

Average demand three trading periods before and after the average of the top 100 peaks



Source: NZIER

The key observations from these charts are that on average:

- NI peaks are lower and have a steeper profile than SI peaks implying more time to mobilise demand response and shorter required duration for demand response in the NI than in the SI
- once demand response has been used to flatten a peak 'recharge' cannot begin until several hours after the peak.

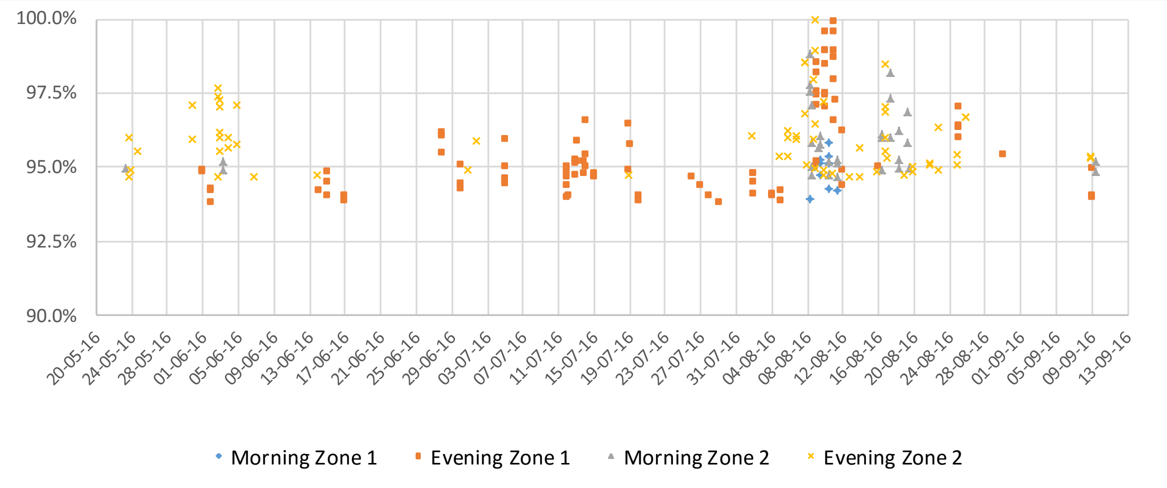
This provides an indication of the required duration of the demand response as well as the time to which consumers need to shift demand or begin recharging batteries. It also provides a starting point for estimating the size and frequency of increases in marginal demand – a key consideration in comparing the cost of 'reliability insurance' offered by grid investment to cover spikes in demand at the margin with the cost and benefit of alternative ways of managing infrequent reduction in reliability. Aside from the period 6 August to 14 August the zones generally had peaks on different days.

Who contributes to the peaks – who could 'shift' demand?

Figures 7, 8 and 9 show the timing (morning or evening) of the top 100 coincident peaks expressed as a percentage of the maximum peak demand for each zone.

Figure 7 Timing of peaks for Zones 1 and 2

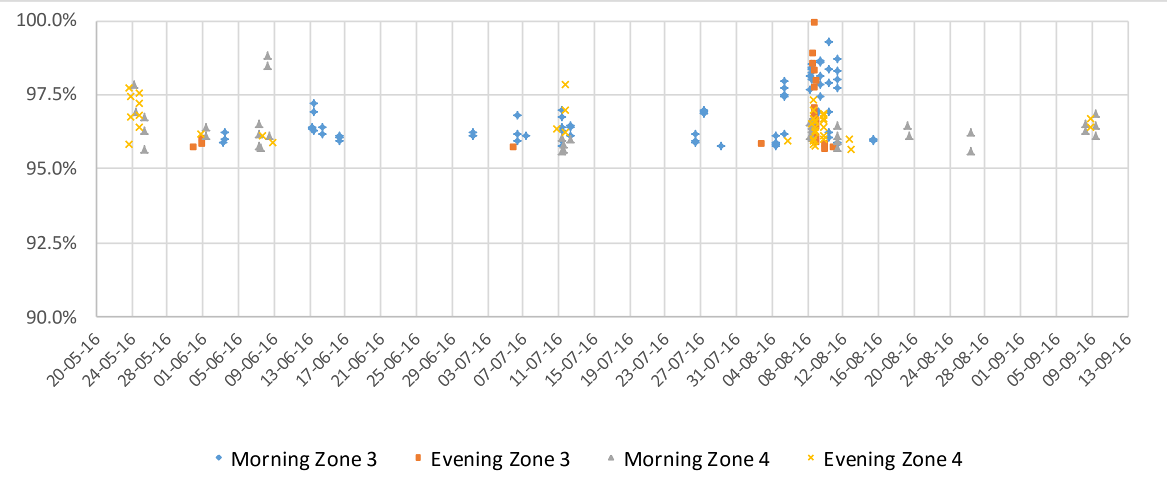
Top 100 peaks as percentage of maximum demand over the year



Source: NZIER

Figure 8 Timing of peaks for Zones 3 and 4

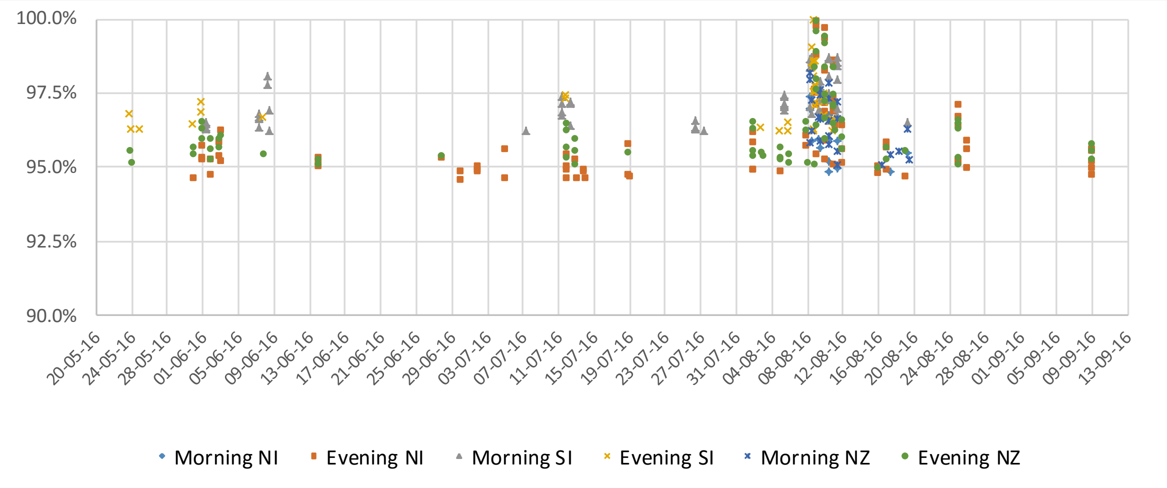
Top 100 peaks as percentage of maximum demand over the year



Source: NZIER

Figure 9 Timing of peaks for NI, SI, and NZ

Top 100 peaks as percentage of maximum demand over the year



Source: NZIER

The number of peaks in the evening (likely to be driven by residential load) and the number of peaks in the morning (likely to be driven by commercial load) vary depending on the area chosen as shown in Table 2.

Table 2 Comparison of morning and evening peaks

Number and average size of peak as a proportion of maximum peak

Area	Morning		Evening	
	Number	Average share of top peak	Number	Average share of top peak
Zone 1	9	94.9%	91	95.6%
Zone 2	32	95.9%	68	96.0%
NI	**15**	**96.0%**	**85**	**95.9%**
Zone 3	78	96.9%	22	96.9%
Zone 4	60	96.6%	40	96.5%
SI	**63**	**97.3%**	**37**	**97.3%**
NZ	**24**	**96.5%**	**76**	**96.3%**

Source: NZIER

Some key points from the table are:

- the average severity of morning and evening peaks is about the same
- almost all (90 percent) of zone 1 peaks occur in the evening and the timing and intensity of Zone 1 (NI north of Huntly) drives the timing of peaks for both the NI and NZ 'zones'

- most SI peaks occur in the morning with the dominance of morning peaks strongest in Zone 3 (SI north of the Waitaki Valley).