Level Playing Field measures

Electricity Authority Options Paper

NZIER report to MEUG

7 May 2025

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Key points

Proposal for non-discrimination in hedging offers

The Electricity Authority (EA) in its Level Playing Field measures[1] (LPFm) options paper proposes mandatory non-discrimination obligations on gentailers to ensure that independent retailers and independent generators can access the hedge contracts that they need to compete with the four vertically integrated gentailers that control New Zealand's flexible generation base.[2] The EA states that hedge contracts '*are critical to enabling competition, which will get more power into the system … and put downward pressure on electricity prices*'.

Problem definition does not quantify scope or price effects of 'non-discrimination'

The EA wants gentailers to establish '*an economically meaningful portfolio of internal transfer prices (ITPs) for hedges.'*[3] which would allow gentailers to demonstrate to the EA that they have complied with the non-discrimination obligations. It will also provide the EA with better data for compliance and monitoring. The EA focuses on super-peak, baseload and peak hedge contracts *'for simplicity'* [4] but acknowledges there is a wide range of potential bespoke OTC hedges. The LPFm paper does not provide any estimate of either the amount of generation capacity or the wholesale price of the 'dispatchable' capacity that non- discrimination provisions would cover.

According to the latest (2022) information published by the EA, most gentailers do not currently base their internal transfer price on a forward-looking set of hedge contracts but on a variety of moving averages of futures prices with other adjustment factors. The ITPs for gentailers are estimated to be around \$130 to \$145 per MWh[5] (for the year ended 30 June 2024) compared with a wholesale spot price for the year ended 30 June 2024 of about \$186 per MWh and for the ten months to 30 April 2025 is estimated at \$215 per MWh.

The EA ITP disclosures covered gentailer supply of about 15,000 GWh; however gentailers reported sales volume to customers on fixed price variable volume (FPVV) contracts which would need to be covered via hedges is substantially higher at 21,870 GWh for 2023 and 22,410 GWh for 2024.This is about half the generation output, with the rest of the output sold through other contracts and the spot market. Essentially, there is no way of telling from the LPFm options how gentailer ITP levels would shift following the LPFm non-discrimination requirements or how the LPFm would affect the volume and type of hedging available in the 'half' of the market not supplied by FPVV contracts.

1 Electricity Authority (2025), 'Level Playing Field measures, Options paper - Energy Competition Task Force initiatives: Level playing field measures and Prepare for virtual disaggregation of the flexible generation base, 27 February 2025'

2 This paragraph is paraphrased and quoted from the first two paragraphs of the Executive Summary see LPFm page 2.

3 ' LPFm, Executive Summary, page 6

4 LPFm, Executive Summary, page 54, paragraph 6.6, footnote 54.

5 This estimate is based on comparison of ITP published by Genesis and Meridian in their annual accounts with the EA disclosure of gentailer ITP for 2023.

The LPFm options need to provide more clarity on:

- Whether the scope of the non-discrimination obligations is limited to mass market FPVV or extends to hedging arrangements for the remaining generation.
- What hedging instruments would need to be used for generation covered by non-discrimination provisions to give the EA confidence that it could detect non-compliance with non-discrimination provisions.

Overall, the LPFm is a qualitative description of an approach to improving independent retailer access to hedge contracts for a scarce and dwindling supply of flexible generation in the face of a projected increase in the demand for this type of capacity.

More wind and solar will exacerbate the shortage of 'dispatchable' firming capacity

The LPFm report[6] also notes the ongoing gap between the forward curve derived from ASX hedge process and the cost of new (wind and solar) generation build and reports two potential explanations. Neither of the explanations:

- Are related directly to the LPFm problem definition of access to hedging.
- Consider how the gap between the cost of new wind and solar generation and electricity futures prices may change in the future.

We suggest that in the absence of a material increase in dispatchable firming capacity, the gap will continue to widen because of the volatility in wind and solar generation compared to load. This volatility creates a demand for dispatchable capacity. Our analysis is based on wind output. Grid scale solar generation is developing rapidly in New Zealand.

On the cost side, most of the proposed generation seems to be solar and the cost of this technology is forecast to fall. Wind farm costs have increased sharply over the past three years, but the cost of wind farm technology is also forecast to resume a downward trend

We have compared the difference between wind farm output every half hour for each of the quarters over the calendar 2024[7] with total load (scaled so that it equals total wind output over the quarter). Based on this analysis we estimate that the wind farm capacity of approximately of about 1,200 MW available in the September quarter of 2024 which generated about 1,000 GWh over that period required dispatchable demand with a capacity of almost 600 MW and output of about 280 GWh to meet the load scaled to the wind farm output over the same period. This level of capacity is material compared to the dispatchable capacity in the system.

Increased non-dispatchable generation will not drive prices down

The system load and wind generation data used in this analysis indicates the difference between the average quarterly spot wholesale price for load and wind generation varied between $19 per MWh when spot prices are low to $87 per MWh when spot prices are high over 2024– see Table 10 and Table 11.

6 LPFm paragraph 3.41 and 3.42.

7 This quarter is given as an example. The body of the report includes analysis for each of the quarters in the calendar year 2024.

The impact of increased renewable generation capacity on average wholesale prices Is the combined effect of two opposing forces:

- Increased availability of low-cost generation over all trading periods due to the lower levelized cost of electricity and it being offered at low prices to ensure it is dispatched when available.
- Increased requirement for dispatchable generation capacity to cover mismatches between wind generation and demand.

This question cannot be settled by qualitative argument but requires modelling of how wind and solar output shortfalls can be met. However, in the near future, the following factors add an upward bias to the cost of dispatchable generation:

- Natural gas prices are rising, and supply is less reliable.
- The closest alternative fuel to coal - torrefied wood pellets is expected to cost at best about the same as coal plus carbon cost.

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1 Scope

1.1 Overview of the Level Playing Field measure options

The Electricity Authority (EA) in its Level Playing Field measures[8] (LPFm) options paper proposes to impose mandatory non-discrimination obligations on gentailers to ensure that independent retailers and independent generators can access the hedge contracts that they need to compete with the four vertically integrated gentailers that control New Zealand's flexible generation base.[9] The EA states that hedge contracts '*are critical to enabling competition, which will get more power into the system … and put downward pressure on electricity prices*'.

The LPFm paper is almost entirely qualitative with no quantification of either the difference between gentailer transfer pricing and the futures pricing available to retailers currently, the expected change in the investment in new generation as a result of the equal access to hedges or the potential impact on wholesale electricity prices. The main source of quantitative analysis quoted in the LPFm is the EA issues paper on risk management options for electricity retailers[10] (Issues Paper Nov 2024). However, the LPFm does not extend the modelling in the Nov 2024 Issues Paper to quantify either the current situation or the impact of the proposed changes.

Overall, the LPFm is a qualitative description of an approach to improving independent retailer access to hedge contracts for a scarce and dwindling supply of flexible generation in the face of a projected increase in the demand for this type of capacity.

1.2 Focus areas

This report focuses on the following components of the LPFm options:

- Problem definition with respect to quantifying the risk allocation methods currently used by gentailers and comparing these to the price and volume gaps that the LPFm options seem to be attempting to address.
- Assessment of the current and projected demand for firming capacity (over the next 5 years) based on comparing the forecast for flexible generation capacity and output with the forecast increased requirement based on the investment pipeline for wind and solar and the mismatch between the timing profile of system demand and wind and solar output.
- Assessment of the likelihood that current market settings will encourage any material investment in flexible firming generation and whether the proposed more uniform access would make a material difference to the business case for that type of investment or investment in wind and solar.

[8] Electricity Authority (2025), 'Level Playing Field measures, Options paper - Energy Competition Task Force initiatives: Level playing field measures and Prepare for virtual disaggregation of the flexible generation base, 27 February 2025'

[9] This paragraph is paraphrased and quoted from the first two paragraphs of the Executive Summary see LPFm page 2.

[10] Electricity Authority (2024), 'Reviewing risk management options for electricity retailers – issues paper 7 November 2024' downloaded from https://www.ea.govt.nz/documents/5980/Reviewing_risk_management_options_for_electricity_retailers__issues_paper.pdf

'Appendix B: Modelling methodology and results' describes the quantitative analysis used in the amin Issues es Paper Nov 2024.

2 Gentailers discriminate against independent retailers

2.1 LPFm problem definition

The EA problem definition is that independent retailers cannot get access to wholesale price risk management on the same terms as the gentailers own retail divisions. The argument is that because gentailers own scarce flexible generation resources, they supply their in-house retail divisions on more favourable terms.

The problem definition implicitly assumes that the vertically integrated gentailers:

- Operate their wholesale generation and retail units as arms-length units that are free to trade with each other or with other participants in the market.
- The projected customer demand for electricity and supply of generation can be contracted in advance.

In practice, gentailers do not seem to operate in this way and actively take advantage of the additional flexibility from vertical integration to smooth the allocation of wholesale price and volume volatility to their in-house retail divisions. The approach varies across gentailers and does not seem to rely on a structured approach of using forward contracts to allocate price risk between the retail and wholesale units of gentailers. (Allocation using forward contracts would require a different volumes of contracts for different periods and a more specific range of contracts than the current baseload and peak options).

The 'demand side' exposure of the gentailers' wholesale operation of an open-ended obligation to supply its retail unit is mitigated by the gentailer ownership of the retail business and the relatively predictable nature of retail demand. This suggests the main risk for the gentailer wholesale operation in meeting its commitment to supply the in-house retailer is managing fluctuations in the wholesale prices caused by fluctuations in the availability of generation to meet a reasonably predictable demand.

2.2 Value and volume of gentailer 'retail' activity

The LPFm paper does not quantify the potential volume of retail generation or how the wholesale cost of electricity for this volume of electricity should be set relative to other price indicators such as wholesale market prices and ASX futures. ITP methodology

The EA has disclosed gentailer margins for the year ended 2022 and the transfer prices with benchmarks for the period 2018 to 2022. The main observations are:

- The transfer prices are similar across the gentailers in each year and have not altered materially over the past five years. The first observation is not surprising, as the transfer prices are calculated on the same basis. The second observation is surprising in view of the volatility of both spot wholesale prices and futures prices over the past five years.
- Four of the five gentailers base their transfer price on a simple average of ASX futures prices over the past three years with some variation in the periods chosen within the three-year period. Mercury appears to be the only gentailer to use a forward-looking average based on futures prices for the next three years. While the statement of the methodology is clear, the ITP calculation for 2021 to 2022 appears to be lower than it

should be as ASX future prices for settlement in 2022 to 2024 were much higher than the historic averages used for the calculation of ITP by other gentailers.

- Locational, shape and seasonal factors are used by four of the five gentailers but are not significant in comparison to the average of the ASX futures price. These variables account for less than 10 percent of the ITP.
- All of the gentailers describe the ITP in the same terms – as a notional accounting transfer tool to shift short-term management of price volatility to the wholesale segment and allow a long-term view of the profitability of the retail segment. Meridian's description of its ITP methodology is a good example of the descriptions used by the gentailers:

  simulates a "book build" process that is reflective of the long-term nature of the relationship between wholesale and retail segments. If independent retailers continually transacted through an equivalent book build process, we anticipate they would see a similar effective price to Meridian's ITP price. [11]

  (The use of the term 'book build' is unusual in this context. It normally refers to a process of discovering demand prices in segments and then using this process to set a price when a supply target is met.)
- **Mercury is the only one of the five gentailers to report a discretionary adjustment and at $-13 per MWh, it is the largest of any of the adjustment factors applied by the gentailers.** The discretionary adjustment changes Mercury's ITP from the highest of the gentailers to 'middle of the pack'.

As part of the ITP disclosure, the EA has published responses by each of the gentailers describing the methodology they use to calculate the ITP and their response to part 13.256(3) of the Electricity Industry Participation Code in which the EA sets out the ITP information that it requires from gentailers. These responses and examples for 2022 are summarised in Table 1 over the page. Some of the gentailers provide examples of the calculations and the data used.

[11] Meridian comment on compliance with Electricity Industry Participation Code 2010 - Part 13 in 'Meridian Energy - FY22 ITP disclosure.xlxs, Sheet 1, D6.

Table 1 Internal transfer price calculation

Process used for 2022 retail margin calculation

Component	Contact[1]	Genesis[1]	Manawa Energy[1]	Mercury[1]	Meridian Energy
Base	Otahuhu and Benmore 'Base Quarter' ASX contracts. Three years of daily trades ending three months prior to the start of the quarter The FY22 ITP is the load-weighted average of each quarter.	Otahuhu and Benmore ASX contracts. Three-year average[2] of the ASX futures prices for the relevant period (e.g. FY2022) over the 90 days preceding the date of the ITP calculation.	Average of futures prices in November for the past three years.	Average SSP (internally derived price path) prices at Otahuhu for the next three years forward start by 2 quarters, i.e. 1 January 2022 to 31 December 2024. Base price Otahuhu node (OTA2201).	An ITP for each quarter is calculated as the average of daily ASX futures prices set at Otahuhu and Benmore for that quarter over the last three years. The ITP is calculated one quarter prior to the year (i.e. FY22 ITP is calculated in Q4 FY21).
	$101.60 per MWh.	$105.32 per MWh	$95.42 per MWh	$106 per MWh	Not stated
Adjustment factors	Monthly adjustment factor to reflect difference from quarterly average: $0.69 per MWh. Day adjustment for business vs non-business days: $0.07 per MWh. Trading period factor: $3.89 per MWh.	Shape adjustment (based on several years of spot price history to convert monthly prices to typical business day and non-business day half-hourly prices): $6.41 per MWh.	Shape adjustment based on reference nodes at Huntly, Haywards and Benmore.	Mass market profile. An 8% uplift from base load equivalent price to reflect the time of use (TOU) profile of a mass market customer: $8.00 per MWh. Plus, a 5% uplift to reflect losses: $5.00 per MWh. **Management discretion: $-13.00 per MWh.**	Each quarterly price is shaped into a monthly price, using 20-year profiles of wholesale spot prices.
	Location factor: $1.30 per MWh.	Location factor: $-0.73 per MWh and Locational hedging: $0.16 per MWh.	Location factors by individual node.	Location factor: $-2.00 per MWh.	
ITP	$107.55 per MWh.	$111.16 per MWh.	$101.60 per MWh.	$104 per MWh.	$99.62 per MWh.

Notes:

1 Contact, Genesis, Manawa and Mercury all refer specifically to 'monthly ITP' prices.

2 Genesis uses a rolling three-year hedging approach so that the most recent ASX Futures forward prices will contribute only 33% to the ITP in any given year. This reflects the market practice of partially hedging future year volumes and reduces volatility between financial years.

Source: NZIER

The EA wants gentailers to establish '*an economically meaningful portfolio of internal transfer prices (ITPs) for hedges.*'[12] which would allow gentailers to show the EA that they have complied with the non-discrimination obligations and provide the EA better data for 'compliance monitoring'. The EA focuses on super-peak, baseload and peak hedge contracts *'for simplicity'* [13] but acknowledges there is a wide range of potential bespoke OTC hedges. The LPFm paper does not provide any estimate of either the amount of generation capacity or the wholesale price of the 'dispatchable' capacity that non- discrimination provisions would release into the market

A starting point for assessing the expected price effect of the non-discrimination proposal is the difference between the internal transfer prices used by gentailers and average spot wholesale prices shown in Table 2 below (or expected baseload futures prices.)

Table 2 Gentailer internal transfer prices

Prices in $per MWh for year ended 30 June

Gentailer	2019	2020	2021	2022	2023
Contact Energy	81.08	87.51	91.92	107.55	129.55
Genesis Energy	83.53	84.40	87.30	111.16	125.53
Manawa Energy	85.37	89.91	97.20	101.60	101.10
Mercury NZ	88.00	89.00	99.00	99.00	115.00
Meridian Energy	75.82	81.17	88.55	99.62	111.06
Wholesale spot	130.94	98.71	178.01	140.47	86.84

Source: EA ITP benchmark data

The EA did not collect ITP data for 2024, but the ITP prices are expected to have increased by about 30 percent[14] to around $130 to $140 per MWh. Information gathered by the EA gentailer ITP methodology indicates a variety of approaches to the base indicator used to set prices, the weighing of past and present values of the base indicator in setting the ITP and the consideration of other factors. The wholesale spot price for the year ended 30 June 2024 was about $186 per MWh and the ten months to 30 April 2025 is estimated at $215 per MWh.

The load covered by the ITP data for 2022 and 2023 was about 15,500 GWh and 15,100 GWh respectively[15]. However, the load reported by gentailers as being sold to customers on fixed price variable volume (FPVV) contracts which would need to be covered hedges is substantially higher at 21,870 GWh for 2023 and 22,410 GWh for 2024.

12 ' LPFm, Executive Summary, page 6

13 LPFm, Executive Summary, page 54, paragraph 6.6, footnote 54.

14 This estimate is based on the movement in internal transfer price published by Meridian and Genesis in their annual accounts. These transfer prices tend be higher than the prices reported in the ITP data and seem to cover a larger generation base.

15 The EA collected but did not report the generation by the five independent retailers included in the ITP survey.

This overview summarises the key outputs from the gentailers internal hedging of mass market customers on FPVV contracts. The LPFm options need to provide more clarity on:

- Whether the scope of the non-discrimination obligations is limited to mass market FPVV or extends to hedging arrangements for the remaining generation.
- What hedging instruments would need to be used for generation covered by non-discrimination provisions to give the EA confidence that it could detect non-compliance with non-discrimination provisions.

The comments in the LPFm report under the heading *'Tension between scarcity and competition'*[16] suggest the EA has collected some data on the operation of the OTC and hedge markets and has concluded that:

- The prices for OTC baseload and peak hedge contracts are likely to be competitive.
- Prices OTC super-peak hedges were affected by both scarcity and the exercise of market power.

2.3 EA modelling of the objectives and effects of hedging

The objectives of the ITP methodology used by gentailers in 2022, as reported by the EA are not clearly stated and there is very little visibility on how the gentailers co-ordinate the management of their wholesale asset portfolio and retail businesses.

In its November 2024 Review of risk management options papers – Appendix B,[17] the EA considered several business objectives for independent retailers and modelled the outcomes of various hedging products and strategies for independent retailers. This analysis would provide a useful framework for analysing what the gentailers current ITP delivers to their retail divisions and how hedge products could be combined to offer similar management of future spot market price risk to independent retailers.

2.4 Other aspects of the problem definition

The problem definition also discusses the scarcity of flexible generation but does not comment on the root causes of the scarcity. The problem definition mentions but does not discuss either the persistent premium of futures prices over LRMC or the mechanism through which more uniform access to futures contracts based on a scarce pool of flexible generation will encourage investment in flexible (firming) capacity.

2.5 Conclusion

The proposed EA approach assumes gentailers follow a structured approach to risk allocation between gentailer wholesale and retail divisions, but they do not seem to do this now. Therefore, the EA objective for removing discrimination by gentailers between their own and independent retailers seem to require solutions on a continuum that ranges from:

16 LPFm paragraphs 3.39 and 3.41.

17 EA 2024 '*Reviewing risk management options for electricity retailers – issues paper, 7 November 2024*' available at https://www.ea.govt.nz/projects/all/risk-management-review/consultation/risk-management-options-for-electricity-retailers/ was the overview report . EA 2024 '*Appendix B: Modelling methodology and results*' included the detailed modelling scenarios and results.

- Extension by gentailers of the current smoothed wholesale pricing to independent retailers
- Development of new arms-length hedging contracts that offer the same access to gentailer retail divisions and independent retailers.

For this approach defining and measuring the future supply of dispatchable generation including the different levels of probability that it will be available is a key issue in making non-discrimination provisions workable in advance and demonstrating they delivered non-discrimination after the event.

3 Change in demand for firming as renewables increase

3.1 Effect of renewables

Increased deployment of wind and solar generation increases the volatility in generation output of any given period and increases the demand for dispatchable generation to cover mismatches between wind and solar output and demand. This demand increases as more renewable capacity is deployed. This section describes an approach to quantifying the excess of load over wind generation over half hour periods. here is little data on grid scale solar output, so this analysis focuses on the mismatch between load and wind generation.[18]

3.1.1 Comparing wind output to demand

We analyse the mismatches by comparing the recent output profile for wind and solar by trading period to 'scaled' demand. Demand for each trading period is scaled so that quarterly demand for electricity equals the quarterly wind output. The scaled demand is subtracted from the wind output and grouped into strings of consecutive trading periods where scaled demand exceeds wind generation output – output shortfalls. We record summary characteristics of each of the strings of output shortfalls including:

- Duration: start, end and length in trading periods of each string.
- Energy: minimum and maximum shortfall during each string and the total energy shortfall over each the string (GWh).

We use two approaches to identifying which half-hour shortfalls are included in 'output shortfall strings':

- Low estimate: shortfalls are only included if the spot price for load in the trading period is above the threshold for dispatchable generation being in demand. The calculation of the threshold is described in Appendix B and the results from this calculation are included in this section of the report.
- Maximum estimate: all shortfalls are included irrespective of whether the average spot price is low which indicates that there is a surplus of dispatchable generation capacity. The results of these calculations are included in Appendix C as indication of the upper limit of the dispatchable generation challenge for the current wind portfolio.

[18] We have full output data for 2024 for one solar farm – Kohirā (24 MW) operated by Lodestone near Kaitaia which began generating in November 2023. Rangitaiki (24 MW) solar farm began generating in March 2024. Lauriston (47 MW) sola farm began generating in December 2024 and reached full output capacity in February 2025.

The ‘Low’ and ‘Maximum’ estimates both identify similar maximum peak shortfalls and maximum average levels of demand shortfall but for the ‘Low’ there are fewer strings and they require less energy overall than for the ‘Maximum’ estimate as shown in Table 3 below. (The shortfall values in Table 3 are measured in GWh per half hour. Therefore, the capacity required to cover this shortfall in MW is the value in the table multiplied by 2,000.)

In other words, the size of the dispatchable capacity required to cover wind generation shortfall are about the same for both the ‘Low’ and ‘Maximum’ estimates at nearly 600 MW for the current wind farm capacity of about 1,200 MW reached in the quarter ended September 2024. The average generation per half hour during a string is also similar at about 0.11 GWh to 0.15 GWh for the ‘Low’ estimate and 0.09 to 0.13 GWh for the ‘Maximum’ estimates. However, the dispatchable capacity is required much less often in the ‘Low’ than in the ‘Maximum’ estimate.

Table 3 Highest peak demand for 'Low' and 'Maximum' estimate

Demand scaled to quarterly wind generation for YE 31 December 2024. Results grouped in 2 GWh bands.

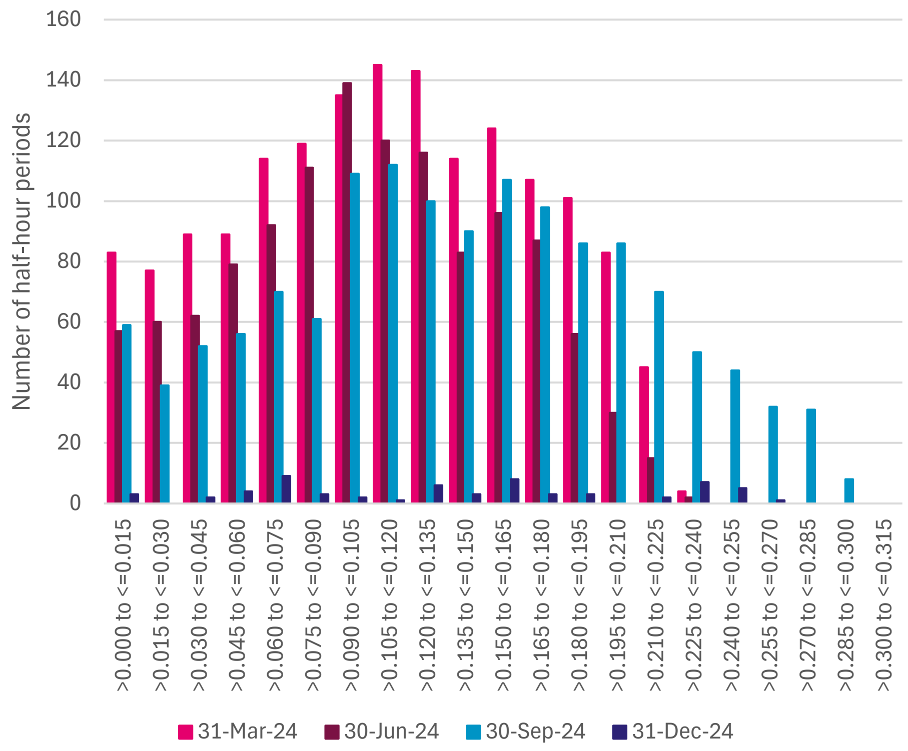
Band (GWh) for string shortfall	Low estimate: Highest shortfall (GWh per half hour)					Maximum estimate: Highest shortfall (GWh per half hour)				
	Mar 24	Jun 24	Sep 24	Dec 24	2024	Mar 24	Jun 24	Sep 24	Dec 24	2024
>0 to <=2	0.196	0.190	0.283	0.256	**0.283**	0.161	0.158	0.217	0.105	**0.217**
>2 to <=4	0.218	0.219	0.289	0.236	**0.289**	0.218	0.177	0.253	0.219	**0.253**
>4 to <=6	0.199	0.188	0.281		**0.281**	0.205	0.159	0.227	0.194	**0.227**
>6 to <=8	0.218		0.231		**0.231**	0.222	0.186	0.231	0.256	**0.256**
>8 to <=10			0.277		**0.277**	0.231	0.219	0.224	0.209	**0.231**
>10 to <=12						0.204	0.206	0.200	0.216	**0.216**
>12 to <=14			0.296		**0.296**		0.208		0.209	**0.209**
>14 to <=16	0.220				**0.220**	0.220	0.226	0.281	0.195	**0.281**
>16 to <=18			0.233		**0.233**			0.251	0.269	**0.269**
>18 to <=20										
>20 to <=22									0.253	**0.253**
>22 to <=24							0.220			**0.220**
>24 to <=26										
>26 to <=28										
>28 to <=30										
>30 to <=32										
>32 to <=34										
>34 to <=36										
>36 to <=38										
>38 to <=40						0.220		0.289		**0.289**
>40 to <=42									0.242	**0.242**
>42 to <=44										
>44 to <=46								0.296		**0.296**
>46										
Total	**0.220**	**0.219**	**0.296**	**0.256**	**0.296**	**0.231**	**0.226**	**0.296**	**0.269**	**0.296**

Source: NZIER

3.2 Wind requirement for dispatchable generation capacity

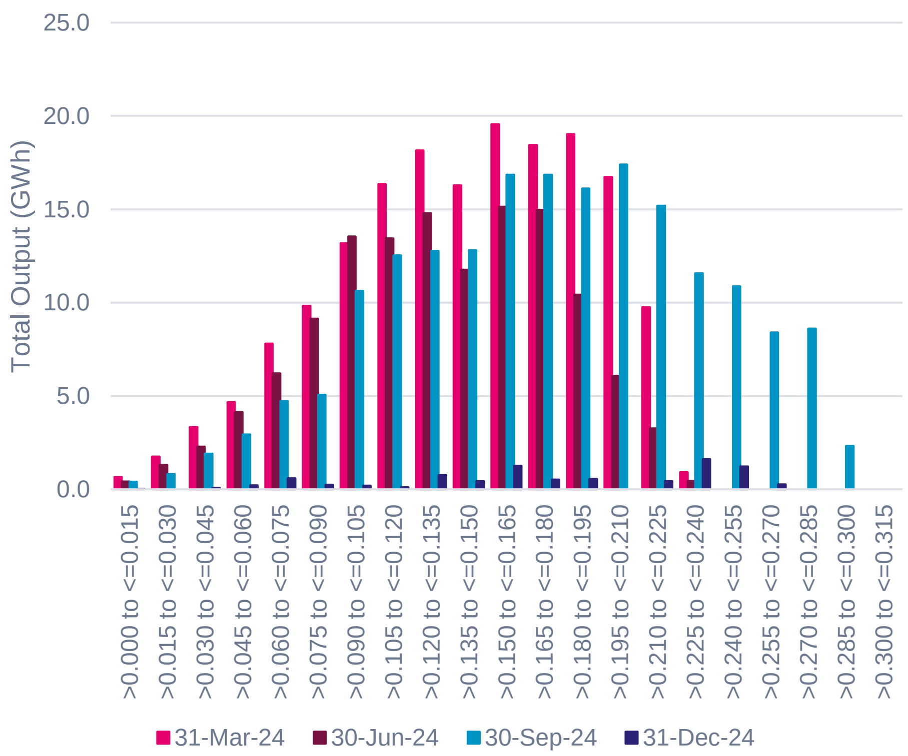
The following figures and tables illustrate the difference between the characteristics of the shortfalls for the four quarters of 2024. Figure 1 and Figure 2 below indicate the variation in the shortfall over the four quarters and the severity of the shortfall in the September quarter which had more periods with shortfall and larger shortfalls than any of the other quarters.

Figure 1 ‘Low’ number of half hours grouped by half hour output band (GWh)



Source: NZIER

Figure 2 ‘Low’ total output shortfall grouped by half hour output band (GWh)



Source: NZIER

Table 4 'Low' Number of shortfall strings and total shortfall (GWh)

Demand scaled to quarterly wind generation for YE 31 December 2024. Grouped in 2 GWh bands

Band (GWh) for string shortfall	Number of excess demand strings					Total excess demand (GWh)				
	Mar 24	Jun 24	Sep 24	Dec 24	2024	Mar 24	Jun 24	Sep 24	Dec 24	2024
>0 to <=2	65	65	58	16	**204**	18.7	25.6	23.4	6.2	**74**
>2 to <=4	8	2	7	1	**18**	23.0	5.1	20.4	2.3	**51**
>4 to <=6	2	1	2		**5**	10.6	4.4	9.4		**24**
>6 to <=8	1		2		**3**	7.3		14.3		**22**
>8 to <=10			1		**1**			8.1		**8**
>10 to <=12										
>12 to <=14			1		**1**			13.4		**13**
>14 to <=16	1				**1**	15.7				**16**
>16 to <=18			1		**1**			17.9		**18**
>18 to <=20										
Total	**77**	**68**	**72**	**17**	**234**	**75.3**	**35.2**	**106.9**	**8.5**	**225.9**

Source: NZIER

The key points from Table 4 are:

- Although the number of excess demand strings for the March, June and September quarters were similar and accounted for almost all the excess demand, the need for additional volume generation was concentrated in the September quarter.
- There are two distinct capacity replacement challenges:
  - Small output gaps that occur often (about 95 percent of the strings), require up to 4GWh of output and account for about 125 GWh of output (about 55 percent of the output gap).
  - Large output gaps that occur infrequently (about 5 percent of the strings) require 4 to 18 GWh of out and usually include the highest half hour shortfalls.

Table 5 Total and average shortfall duration measured in half-hour periods

Demand scaled to quarterly wind generation for YE 31 December 2024. Results grouped in 2 GWh bands.

Band (GWh) for string shortfall	Total length of excess demand strings (half hour periods)					Average length of excess demand strings (half hour periods)				
	Mar 24	Jun 24	Sep 24	Dec 24	2024	Mar 24	Jun 24	Sep 24	Dec 24	2024
>0 to <=2	238	233	213	47	**731**	3.7	3.6	3.7	2.9	**3.6**
>2 to <=4	210	25	111	15	**361**	26.3	12.5	15.9	15.0	**20.1**
>4 to <=6	84	29	49		**162**	42.0	29.0	24.5		**32.4**
>6 to <=8	40		104		**144**	40.0		52.0		**48.0**
>8 to <=10			35		**35**			35.0		**35.0**
>10 to <=12										
>12 to <=14			59		**59**			59.0		**59.0**
>14 to <=16	102				**102**	102.0				**102.0**
>16 to <=18			132		**132**			132.0		**132.0**
>18 to <=20										
Total	**674**	**287**	**703**	**62**	**1,726**	**8.8**	**4.2**	**9.8**	**3.6**	**7.4**

Source: NZIER

The numbers in Table 5 are counts of half hour periods and need to be divided by two to convert them to hours. The key points from Table 5 are:

- The average length for strings with a shortfall less than or equal to 4GWh, is less than 12 hours and the total duration of all the strings in this band is about 63 percent of the total duration of all strings. This suggests short-term dispatchable capacity such as run of river hydro may have an output profile suitable for covering theses shortfalls.
- The longer duration strings which also tend to include the highest shortfalls need a specialised form of dispatchable capacity that can maintain output over periods from 16 hours to 3 days but would have been required only 12 times over 2024 and only three times to run for more than a day.

Table 6 Average energy per shortfall string and per half hour

Demand scaled to quarterly wind generation for YE 31 December 2024. Results grouped in 2 GWh bands

Band (GWh) for string shortfall	Average energy per excess demand string (GWh)					Average energy per half hour period (GWh)				
	Mar 24	Jun 24	Sep 24	Dec 24	2024	Mar 24	Jun 24	Sep 24	Dec 24	2024
>0 to <=2	0.3	0.4	0.4	0.4	**0.4**	0.1	0.1	0.1	0.1	**0.1**
>2 to <=4	2.9	2.5	2.9	2.3	**2.8**	0.1	0.2	0.2	0.2	**0.1**
>4 to <=6	5.3	4.4	4.7		**4.9**	0.1	0.2	0.2		**0.2**
>6 to <=8	7.3		7.2		**7.2**	0.2		0.1		**0.1**
>8 to <=10			8.1		**8.1**			0.2		**0.2**
>10 to <=12										
>12 to <=14			13.4		**13.4**			0.2		**0.2**
>14 to <=16	15.7				**15.7**	0.2				**0.2**
>16 to <=18			17.9		**17.9**			0.1		**0.1**
Total	**1.0**	**0.5**	**1.5**	**0.5**	**1.0**	**0.1**	**0.1**	**0.2**	**0.1**	**0.1**

Source: NZIER

The key points from Table 6 mirror the observations drawn from Table 4:

- The September quarter had a much higher average energy shortfall per string and per half hour than any of the other quarters despite having the most stringent filter of any of the four quarters.
- The average energy shortfall per half hour does not appear to be correlated with the duration of the string.

3.3 Solar requirement for dispatchable capacity

As noted at the beginning of this report the data on the output profile of grid scale solar generation is too sparse to complete the generation shortfall analysis that has been completed for wind. For this analysis we assume that the peak capacity shortfalls estimated for wind generation are a reasonable proxy for the shortfalls that could occur with solar but that the number of stings will be lower and the duration of strings. This is based on the qualitative comparison of wind and solar output over the operating hours for solar in Table 7 below.

Table 7 Comparison of solar and wind generation

Attribute	Solar	Wind	Comment
Operating hours	Daylight only.	24 hours.	Solar output shortfalls will be higher than wind shortfall for early morning and early evening periods.
Seasonality	Lowest output in winter, highest in summer	Less seasonal variation than solar	Solar shortfalls in the June and September quarters are likely to be higher than the estimate for wind generation shortfall

Source: NZIER

The absence of solar generation over-night and the adequacy of other generation to meet growth in overnight demand is a separate generation shortfall issue that is not included in our estimate of the additional dispatchable demand required as solar capacity increases.

3.4 Investment pipeline and implied requirement for additional capacity

3.4.1 Investment pipeline

For the assessment of the potential increased requirement for dispatchable capacity, we have made the following assumptions:

- New generation investment scenarios from the 'Electricity Demand and Generation Scenarios (2024)' (EDGS 2024) GEM scenario[19]
- The estimated additional peak demand for dispatchable generation is based on the wind generation shortfall for output for the September 2024 multiplied.

The scenarios indicate an increase in wind farm capacity of between 620 MW and 1,720 MW by 2030 (Table 14) and an increase grid-scale solar generation of between 250 MW and 1,005 MW over the same period (Table 15).

The EA has also published an estimate of the investment pipeline[20] that classifies investment intentions into categories such as 'Committed', 'Actively Pursued' and 'Other'. This listing of projects indicates the following investment over 2025 to 2030:

- 'Committed' investment in wind capacity of 150 MW and solar capacity of 646 MW.
- 'Actively Pursued' investment in wind capacity of 2,303 MW and solar capacity of 6,946 MW.

The EA survey of investment intentions along with a scan of the wind and solar construction underway and Fast Track Act consent applications in progress suggest the EDGS scenarios are a conservative estimate of the likely wind and solar construction by 2030.

19 MBIE 2024 'Electricity Demand and Generation Scenarios (2024) – Results, GEM build schedule' downloaded from https://www.mbie.govt.nz/assets/Data-Files/Energy/electricity-demand-generation-scenarios-2024-results.xlsx

20 See 'Wholesale category / Datasets Generation - fleet and output Generation fleet Generation investment pipeline' available at www.emi.ea.govt.nz/Wholesale/Datasets/Generation/GenerationFleet/Proposed/20240912%20Generation%20investment%20pipeline.csv

Table 8 EDGS wind generation scenarios

Annual increase in capacity (MW) for each of the five EDGS scenarios

Year	Constraint	Reference	Growth	Environmental	Innovation
2025	100.0	100.0	100.0	100.0	150.0
2026	0.0	0.0	168.5	198.1	492.1
2027	0.0	126.5	270.5	442.1	416.0
2028	46.5	195.5	213.7	362.3	292.4
2029	114.6	349.7	444.8	226.3	109.2
2030	355.4	255.1	94.1	86.8	257.5
Total	**616.4**	**1,026.8**	**1,291.7**	**1,415.6**	**1,717.2**

Source: NZIER

Table 9 EDGS solar generation scenarios

Annual increase in capacity (MW) for each of the five EDGS scenarios

Year	Constraint	Reference	Growth	Environmental	Innovation
2025	0.0	0.0	0.0	12.1	80.0
2026	150.0	150.0	230.0	217.9	150.0
2027	100.0	180.0	100.0	100.0	100.0
2028	0.0	0.0	0.0	0.0	200.0
2029	0.0	0.0	0.0	200.0	0.0
2030	0.0	0.0	100.0	145.0	475.4
Total	**250.0**	**330.0**	**430.0**	**675.0**	**1,005.4**

Source: NZIER

3.4.2 Expected increase in dispatchable capacity

The average output of grid scale solar is about half that of wind (average capacity factor of 20 percent for grid scale solar and 40 percent for wind). Accordingly, for the purpose of estimating the additional requirement for dispatchable capacity to cover new solar capacity we assume the requirement is equivalent to half of the requirement of the same amount of wind capacity.

The estimate in Table 3 for September 2024 quarter is that 1,200 MW of wind capacity requires up to 600 MW of dispatchable capacity to cover generation shortfall. Applying this ratio to the EDGS projections for generation investment implies the following increase in the requirement for dispatchable generation by 2030:

- A minimum of 370 MW under the 'Constraint' scenario – 308 MW for wind and 63 MW for solar.
- A maximum of 1,010 MW under the 'Constraint' scenario – 859 MW for wind and 251 MW for solar.61

3.5 Conclusion

The projected increase in wind and solar generation by 2030, could require an increase in dispatchable generation of 370 MW to 1,010 MW or 61 to 168 percent of the estimated dispatchable demand required for the existing wind capacity by. Neither the EDGS nor the EA investment pipeline estimate include material amounts of new dispatchable generation.

4 How does improved access to hedging affect investment

4.1 Encouraging investment in renewable generation

The LPFm refers to the availability of standardised flexibility products[21] and PPA supporting generator entry (investment)[22] and the EA wants to be satisfied that *any restriction on offered volumes … was justified solely by scarcity, and did not represent any economic withholding by the Gentailers.'*[23]*.*

The general impression from the LPFm paper is that encouraging investment in wind and solar by independent generators will improve competition in the market. Improving the availability of long-term hedges to independent wind or solar farm investors (or their major customers) increases the certainty of wind or solar cash inflows and therefore lowers the cost of financing this type of generation.

These statements are reasonable in isolation, but they need to be viewed in the broader context of the value that the market sets for wind and solar output and the availability of the dispatchable generation needed to meet wind and solar output shortfalls.

4.2 Spot market value

The main factor that drives the spot price for wind and solar generation is the spot price for dispatchable generation (see Table 10). As the timing of wind and solar generation is dependent on the weather, it tends to earn lower spot market revenue because its output cannot be increased to higher market spot prices (see Table 11).

The quarterly average prices (see Table 10) for load over 2024 ranged from a low of $46.65 per MWh (December quarter) to a high of $325.50 per MWh (September quarter). The increase in spot price between March quarter and the June and September quarters and the collapse in spot prices in the December quarter was a clear demonstration of the sensitivity of the spot market to the scarcity and then abundance of dispatchable generation. Change in thermal fuel prices was not a major factor in these price movements as:

- The changes in thermal generation fuel costs over the first nine months were modest and output increased (see Table 12).
- Average spot prices in the December quarter were well below average thermal fuel costs even though this thermal pant was still running.

21 '*The **standardised flexibility product** is a new, standardised super-peak hedge OTC contract that was co-designed with industry and announced in December.'* See LPFm Page 7

22 LPfm page 12, paragraph2.7 (b)

23 LPFm, page 62, paragraph 6.38.

Table 10 Comparison of wind and load spot wholesale prices

Volumes and revenue are collated EA EMI Dataset reports. Average price is 'revenue'/'volume'*1,000.

Description	Unit	Mar 24	Jun 24	Sep 24	Dec 24	2024
Wind						
Generation volume	GWh	897	790	1,062	1,028	3,777
Revenue	$m	143	183	253	28	607
Average price	$/MWh	158.92	232.10	238.16	27.72	160.81
Load						
Demand volume	GWh	9,994	10,693	11,033	9,913	41,634
Revenue	$m	1,956	2,916	3,591	462	8,926
Average price	$/MWh	195.72	272.68	325.50	46.65	214.39
Load vs Wind price	$/MWh	36.81	40.58	87.34	18.93	53.58

Source: NZIER

The distribution of wind prices and outputs suggest that increased wind and can place downward pressure on half hour price when there is adequate supply, but this effect is no match for the upward pressure created by a shortage of dispatchable generation. These comments would also apply to solar generation.

Table 11 Comparison of load and wind volume distribution over price bands

Load and wind generation volume by price band as a proportion of the quarterly total load and wind generation.

Spot price band ($ per MWh)	Mar 24		Jun 24		Sep 24		Dec 24		2024	
	Load	Wind	Load	Wind	Load	Wind	Load	Wind	Load	Wind
>0 to <=25	6.9%	18.7%	1.0%	11.9%	15.2%	24.6%	53.6%	66.2%	18.7%	28.2%
>25 to <=50	1.9%	4.4%	0.3%	3.1%	2.2%	3.1%	13.9%	14.2%	4.4%	5.6%
>50 to <=75	1.7%	3.6%	0.3%	3.1%	1.9%	3.0%	11.1%	9.1%	3.6%	4.2%
>75 to <=100	3.6%	4.0%	0.5%	5.6%	2.9%	3.7%	9.3%	4.3%	4.0%	3.8%
>100 to <=125	4.7%	3.5%	0.8%	6.2%	3.5%	3.6%	5.0%	2.5%	3.5%	3.5%
>125 to <=150	6.6%	3.2%	1.4%	10.0%	1.9%	2.6%	3.3%	1.7%	3.2%	4.2%
>150 to <=175	8.0%	3.6%	2.0%	9.6%	2.6%	3.6%	2.1%	1.5%	3.6%	4.8%
>175 to <=200	12.4%	5.0%	4.2%	13.3%	2.6%	3.0%	0.9%	0.5%	5.0%	5.8%
>200 to <=225	12.8%	5.8%	7.5%	14.0%	2.7%	3.7%	0.3%	0.1%	5.8%	7.4%
>225 to <=250	14.7%	8.6%	17.0%	13.5%	2.7%	3.1%	0.0%	0.0%	8.6%	9.7%
>250 to <=275	14.4%	11.3%	27.6%	6.7%	2.7%	3.7%	0.0%	0.0%	11.3%	7.4%
>275 to <=300	6.8%	8.1%	20.3%	2.2%	4.7%	5.1%	0.0%	0.0%	8.1%	3.7%
>300 to <=325	2.6%	4.5%	8.8%	0.3%	6.0%	5.1%	0.0%	0.0%	4.5%	2.2%
>325 to <=350	0.7%	2.8%	3.7%	0.2%	6.2%	5.8%	0.0%	0.0%	2.8%	1.8%
>350 to <=375	0.3%	2.3%	1.2%	0.0%	7.4%	6.2%	0.0%	0.0%	2.3%	1.8%
>375 to <=400	0.3%	2.0%	0.6%	0.2%	6.7%	3.7%	0.0%	0.0%	2.0%	1.1%
>400 to <=425	0.6%	1.3%	0.6%	0.1%	3.9%	2.2%	0.0%	0.0%	1.3%	0.7%
>425 to <=450	0.4%	0.8%	0.2%	0.0%	2.5%	1.4%	0.0%	0.0%	0.8%	0.4%
>450 to <=475	0.2%	0.6%	0.2%	0.0%	1.8%	1.0%	0.0%	0.0%	0.6%	0.3%
>475 to <=500	0.1%	0.5%	0.2%	0.0%	1.6%	1.3%	0.0%	0.0%	0.5%	0.4%
>500	0.3%	5.4%	1.7%	0.1%	18.2%	10.3%	0.4%	0.0%	5.4%	3.1%

Source: NZIER

4.3 What does independent ownership of wind and solar achieve?

Independent ownership of wind and solar generation does not change the fundamental lack of controllability of the output and dose not materially affect the attractiveness to the owner of selling the output through long term contracts.

4.4 Conclusion

The vague suggestion in the LPFm paper that encouraging investment in wind and solar by independent generators will improve competition in the generation market and help to lower prices is unconvincing because:

- Wind and solar generators can only consistently displace more expensive forms of generation when there is sufficient dispatchable generation to cover wind and solar shortfalls.

- The market is currently short of dispatchable generation and increasing the proportion of system generation from wind and solar without increasing the supply of dispatchable generation proportionately makes the sport market more prone to price spikes.

Appendix A Gentailer ITP updates

A.1 Coverage

Genesis and Meridian publish ITP in their annual reports. These ITP differ from the ITP published by the EA but follow a similar trend. Contact and Mercury do not publish ITP data.

A.2 Meridian ITP

A.2.1 2024

Electricity sold to residential, business and industrial customers on fixed price variable volume contracts is purchased from the Wholesale segment at an average annual fixed (transfer) price of $133 per megawatt hour (MWh) (2023:$104 per MWh). The transfer price is set in a similar manner to transactions with third parties.

- *Electricity sold to business and industrial customers on spot (variable price) agreements is purchased from the Wholesale segment at prevailing wholesale spot market prices.*
- *Agency margin from spot sales is included within "Contracted sales, net of distribution costs".*[24]

A.2.2 2023

Electricity sold to residential, business and industrial customers on fixed-price variable volume contracts is purchased from the Wholesale segment at an average annual fixed (transfer) price of $104 per megawatt hour (MWh) (2022: $93 per MWh). The transfer price is set in a similar manner to transactions with third parties.

Electricity sold to business and industrial customers on spot (variable price) agreements is purchased from the Wholesale segment at prevailing wholesale spot market prices.[25]

A.3 Genesis

A.3.1 2024

The electricity transfer price per MWh charged between Wholesale and Retail was $146.26 (2023: $124.73).[26]

24 MERIDIAN INTEGRATED REPORT 2024 **MENU 128, FINANCIAL PERFORMANCE NOTES TO THE FINANCIALS — FOR THE YEAR ENDED 30 JUNE 2024 MERIDIAN**

25 MERIDIAN INTEGRATED REPORT 2023 page 203, A : Financial performance

26 GENESIS INTEGRATED REPORT 2024, page 80, **A. Financial performance**

A.3.2 2023

Sales between segments is based on transfer prices developed in the context of long-term contracts. The electricity transfer price per MWh charged between Wholesale and Retail was $124.73 (2022: $106.56).[27]

Appendix B Filter for 'Low' wind farm shortfall estimate

B.1 Measuring the wind farm shortfall

Wind farm output is not dispatchable (the amount available for dispatch cannot be set in advance). The gap between load and wind for each half hour trading period is a measure of the dispatchable generation required to meet the shortfall between demand and wind generation. This a maximum measure of the required capacity.

To estimate a measure of the requirement for dispatchable generation when there is high demand for this capacity, we have calculated the wind generation shortfalls for the subset of trading periods where the spot price is a above an indicator of high demand for dispatchable generation. For this analysis we have defined this indicator as:

- When coal generation is at or above 100 GWh in a quarter, the maximum of the quarterly average spot price and quarterly average cost of coal or gas for thermal generation (including the cost of emissions) as reported by Genesis Energy.
- When coal generation is below 100 GWh in a quarter, the maximum of quarterly average spot price and quarterly average cost of gas for thermal generation (including the cost of emissions) as reported by Genesis Energy.

The values for this filter for each quarter are shown in Table 12 below. The analysis in the body of the report is based on the 'Low' wind shortfall calculated using the filters.

Table 12 Price filter for calculation of wind shortfall calculation

Genesis quarterly average thermal fuel cost and quarterly average wholesale spot prices

Quarter ended	Gas		Coal		Spot	Filter	
	$/MWh	GWh	$/MWh	GWh	$/MWh	$/MWh	Source
31-Mar-24	117.50	491.7	161.50	194.3	195.72	195.72	Spot
30-Jun-24	118.91	522.4	141.88	735.6	272.68	272.68	Spot
30-Sep-24	154.23	586.7	156.92	694.3	325.50	325.50	Spot
31-Dec-24	169.65	275.9	236.54	10.1	46.64	169.65	Gas

Source: NZIER

Wind output is reasonably stable on average and the fluctuations between trading periods tend to be modest. This means that wind generation falls below average it can take some time to return to average levels.

[27] GENESIS INTEGRATED REPORT 2023, page 75

Appendix C Maximum estimate of wind farm shortfall

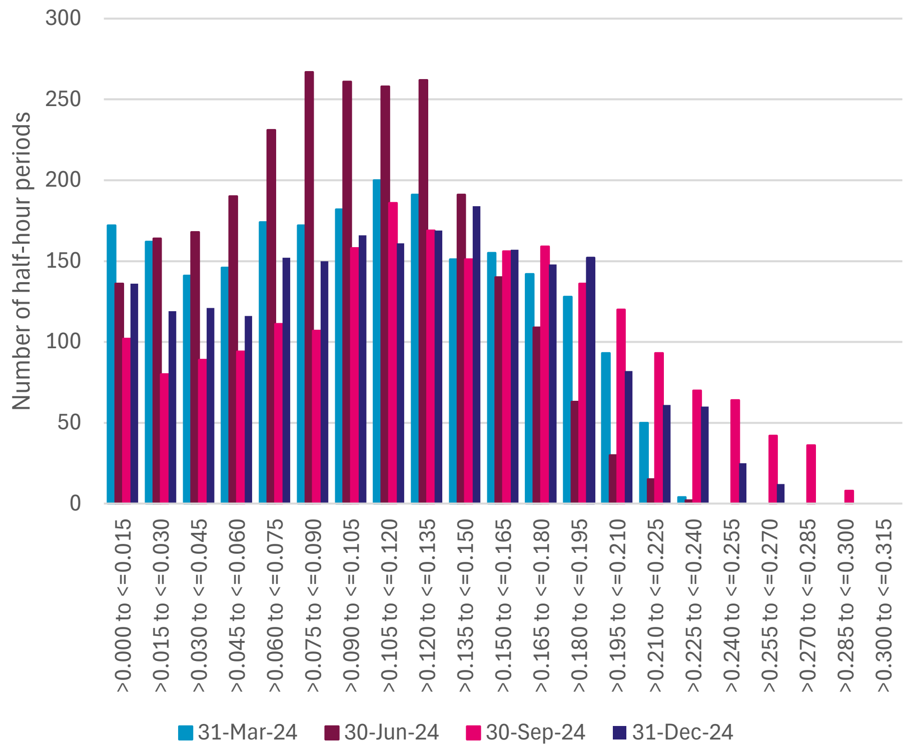
C.1 Rationale

The level of dispatchable generation is declining relative to load – both because load is increasing and the hydro capacity is effectively fixed while thermal capacity is declining due to fuel supply uncertainty as well as aging plant. As this happens the simple comparison of wind output and demand becomes a more credible estimate of the pressure on the system for dispatchable generation created by increased reliance on wind capacity. The following figures and tables use the same method as section 3.2 but includes all periods where scaled load exceeds wind generation.

This change does not materially alter the required dispatchable generation capacity (highest) output shortfalls (see Table 3) but it does substantially increase the volume or electricity that this dispatchable generation capacity needs to produce. In particular the:

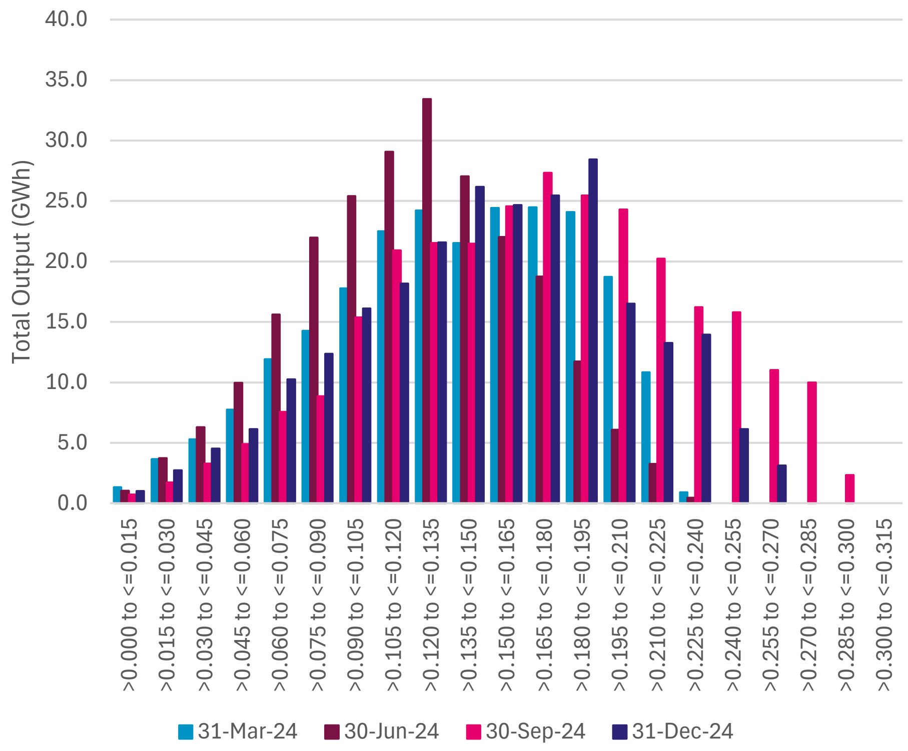
- Number of strings of wind output shortfall is increased by about 20% but the volume of electricity required is increased about four times (Table 13 compared to Table 4).
- The duration of the strings is about four times longer (Table 14 compared to Table 5).

Figure 3 Maximum number of half hours grouped by half hour output band (GWh)



Source: NZIER

Figure 4 Maximum total output shortfall grouped by half hour output band (GWh)



Source: NZIER

Table 13 Maximum: number of shortfall strings and total shortfall (GWh)

Demand scaled to quarterly wind generation for YE 31 December 2024. Grouped in 2 GWh bands

Band (GWh) for string shortfall	Number of excess demand strings					Total excess demand (GWh)				
	Mar 24	Jun 24	Sep 24	Dec 24	Total	Mar 24	Jun 24	Sep 24	Dec 24	Total
>0 to <=2	48	43	51	49	**191**	17.2	24.3	12.7	6.9	**61.2**
>2 to <=4	9	8	3	6	**26**	26.3	22.9	8.6	18.1	**75.9**
>4 to <=6	5	2	5	3	**15**	24.5	9.6	25.6	16.8	**76.5**
>6 to <=8	8	3	2	3	**16**	56.8	20.9	14.9	21.6	**114.1**
>8 to <=10	3	2	4	3	**12**	27.3	17.0	38.5	27.3	**110.0**
>10 to <=12	1	3	1	2	**7**	11.3	33.0	10.5	22.1	**76.9**
>12 to <=14		2		2	**4**		25.7		26.2	**51.9**
>14 to <=16	2	4	1	1	**8**	30.3	59.2	15.6	14.6	**119.7**
>16 to <=18			2	2	**4**			35.4	34.6	**69.9**
>18 to <=20										
>20 to <=22				1	**1**				20.6	**20.6**
>22 to <=24		1			**1**		23.3			**23.3**
>24 to <=26										
>26 to <=28										
>28 to <=30										
>30 to <=32										
>32 to <=34										
>34 to <=36										
>36 to <=38										
>38 to <=40	1		2		**3**	39.9		76.6		**116.5**
>40 to <=42				1	**1**				41.8	**41.8**
>42 to <=44										
>44 to <=46			1		**1**			45.4		**45.4**
>46										
Total	**77**	**68**	**72**	**73**	**290**	**233.7**	**235.9**	**283.6**	**250.6**	**1,003.8**

Source: NZIER

Table 14 ‘Maximum’ shortfall duration measured in half-hour periods

Demand scaled to quarterly wind generation for YE 31 December 2024. Results grouped in 2 GWh bands.

Band (GWh) for string shortfall	Total length of excess demand strings (half hour periods)					Average length of excess demand strings (half hour periods)				
	Mar 24	Jun 24	Sep 24	Dec 24	2024	Mar 24	Jun 24	Sep 24	Dec 24	2024
>0 to <=2	388	470	273	228	**1,359**	8.1	10.9	5.4	4.7	**7.1**
>2 to <=4	285	247	88	210	**830**	31.7	30.9	29.3	35.0	**31.9**
>4 to <=6	222	101	206	155	**684**	44.4	50.5	41.2	51.7	**45.6**
>6 to <=8	552	231	118	192	**1,093**	69.0	77.0	59.0	64.0	**68.3**
>8 to <=10	237	171	306	204	**918**	79.0	85.5	76.5	68.0	**76.5**
>10 to <=12	89	301	85	200	**675**	89.0	100.3	85.0	100.0	**96.4**
>12 to <=14		261		219	**480**		130.5		109.5	**120.0**
>14 to <=16	201	529	84	128	**942**	100.5	132.3	84.0	128.0	**117.8**
>16 to <=18			259	238	**497**			129.5	119.0	**124.3**
>18 to <=20										
>20 to <=22				160	**160**				160.0	**160.0**
>22 to <=24		176			**176**		176.0			**176.0**
>24 to <=26										
>26 to <=28										
>28 to <=30										
>30 to <=32										
>32 to <=34										
>34 to <=36										
>36 to <=38										
>38 to <=40	289		475		**764**	289.0		237.5		**254.7**
>40 to <=42				237	**237**				237.0	**237.0**
>42 to <=44										
>44 to <=46			237		**237**			237.0		**237.0**
>46										
Total	**2,263**	**2,487**	**2,131**	**2,171**	**9,052**	**29.4**	**36.6**	**29.6**	**29.7**	**31.2**

Source: NZIER

Table 15 ‘Maximum’ average energy per shortfall string and per half hour

Demand scaled to quarterly wind generation for YE 31 December 2024. Results grouped in 2 GWh bands

Band (GWh) for string shortfall	Average energy per excess demand string (GWh)					Average energy per half hour period (GWh)				
	Mar 24	Jun 24	Sep 24	Dec 24	2024	Mar 24	Jun 24	Sep 24	Dec 24	2024
>0 to <=2	0.4	0.6	0.2	0.1	**0.3**	0.0	0.1	0.0	0.0	**0.0**
>2 to <=4	2.9	2.9	2.9	3.0	**2.9**	0.1	0.1	0.1	0.1	**0.1**
>4 to <=6	4.9	4.8	5.1	5.6	**5.1**	0.1	0.1	0.1	0.1	**0.1**
>6 to <=8	7.1	7.0	7.4	7.2	**7.1**	0.1	0.1	0.1	0.1	**0.1**
>8 to <=10	9.1	8.5	9.6	9.1	**9.2**	0.1	0.1	0.1	0.1	**0.1**
>10 to <=12	11.3	11.0	10.5	11.1	**11.0**	0.1	0.1	0.1	0.1	**0.1**
>12 to <=14		12.8		13.1	**13.0**		0.1		0.1	**0.1**
>14 to <=16	15.1	14.8	15.6	14.6	**15.0**	0.2	0.1	0.2	0.1	**0.1**
>16 to <=18			17.7	17.3	**17.5**			0.1	0.1	**0.1**
>18 to <=20										
>20 to <=22				20.6	**20.6**				0.1	**0.1**
>22 to <=24		23.3			**23.3**		0.1			**0.1**
>24 to <=26										
>26 to <=28										
>28 to <=30										
>30 to <=32										
>32 to <=34										
>34 to <=36										
>36 to <=38										
>38 to <=40	39.9		38.3		**38.8**	0.1		0.2		**0.2**
>40 to <=42				41.8	**41.8**				0.2	**0.2**
>42 to <=44										
>44 to <=46			45.4		**45.4**			0.2		**0.2**
>46										
Total	**3.0**	**3.5**	**3.9**	**3.4**	**3.5**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**

Source: NZIER