Impacts of wind forecasting accuracy on the wholesale electricity market and broader electricity system

3 March 2023

RELEASE NOTICE

Ernst & Young was engaged on the instructions of the Electricity Authority ("Client") to deliver a report describing the impacts of wind forecasting accuracy on the wholesale electricity market and broader electricity system to inform the writing of an issues and options paper supporting a potential change of the Electricity Code in 2023, in accordance with the engagement letter dated 26 October 2022.

The results of Ernst & Young's work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated 3 March 2023 ("Report"). The Report should be read in its entirety including the transmittal letter, this notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

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Our work commenced on 26 October 2022 and was completed on 3 March 2023. Therefore, our Report does not take account of events or circumstances arising after 3 March 2023 and we have no responsibility to update the Report for such events or circumstances as no further work has been undertaken after that date.

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Building a better working world

3 March 2023
Imogen Turner
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1 Willis Street
Wellington 6011
New Zealand

Report on Impacts of wind forecasting accuracy on the wholesale electricity market and broader electricity system

Dear Imogen

In accordance with our Engagement Agreement dated 26 October 2022 ("Agreement"), Ernst & Young ("we" or "EY") has been engaged by the Electricity Authority ("you", "the Authority" or the "Client") to provide a report on the Impacts of wind forecasting accuracy on the wholesale electricity market and broader electricity system (the "Services").

The enclosed report (the "Report") sets out the outcomes of our work. You should read the Report in its entirety. A reference to the report includes any part of the Report.

Purpose of our Report and restrictions on its use

Please refer to a copy of the Agreement for the restrictions relating to the use of our Report. We understand that the deliverable by EY will be used for the purpose of supporting the Authority to inform an issues and options paper supporting a potential Electricity Code change in 2023. (the "Purpose").

This Report was prepared on the specific instructions of the Authority solely for the Purpose and should not be used or relied upon for any other purpose.

This Report and its contents may not be quoted, referred to or shown to any other parties except as provided in the Agreement. We accept no responsibility or liability to any person other than to the Authority or to such party to whom we have agreed in writing to accept a duty of care in respect of this Report, and accordingly if such other persons choose to rely upon any of the contents of this Report they do so at their own risk.

Nature and scope of our work

The scope of our work, including the basis and limitations, are detailed in our Agreement and in this Report.

Our work commenced on 26 October 2022 and was completed on 3 March 2023. Therefore, our Report does not take account of events or circumstances arising after 3 March 2023 and we have no responsibility to update the Report for such events or circumstances.

In preparing this Report we have considered and relied upon information from a range of sources believed to be reliable and accurate. We have not been informed that any information supplied to us, or obtained from public sources, was false or that any material information has been withheld from us. Neither EY nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided to EY.

We do not imply and it should not be construed that we have verified any of the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose.

The work performed as part of our scope considers information provided to us and a number of combinations of input assumptions relating to future conditions, which may not necessarily represent actual or most likely future conditions. Additionally, modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved, if any.

We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Our conclusions are based, in part, on the assumptions stated and on information provided by the Authority and other information sources used during the course of the engagement. The modelled outcomes are contingent on the collection of assumptions as agreed with the Authority and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither EY nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided by the Authority or other information sources used.

This letter should be read in conjunction with our Report, which is attached.

Thank you for the opportunity to work on this project for you. Should you wish to discuss any aspect of this Report, please do not hesitate to contact Chris Money on +64 4 817 0546.

Yours sincerely

Chris Money
Partner

Executive summary

The Electricity Authority (the Authority) has been investigating the impact of inaccurate wind forecasting on the wholesale electricity market in New Zealand and released an informational paper on wind forecasting accuracy in November 2022. That paper was issued alongside reviews done by the Authority, Transpower and MBIE that recommended improvements to wind forecasting as a measure to minimise future disruption to the system following the events of August 9 2022.

In this report we build on previous analysis undertaken by the Authority to investigate the impacts of inaccurate wind forecasting through quantitative analysis of market pricing in periods of inaccurate forecast and qualitative analysis of potential subsequent impacts that are not directly accounted for in market pricing. Our key finding is that inaccurate forecasting does have measurable impacts on market pricing and that the costs may be imposed on other market participants due to inaccurate forecasts by wind generators.

As New Zealand transitions to rely more heavily on intermittent renewable sources such as wind and solar, accuracy in forecasting becomes more important and consequent costs of inaccuracy are likely to grow. The analysis included in this report will support the Authority in developing policy around wind and solar forecasting arrangements and will provide guidance for stakeholders as we transition towards a future of greater reliance on variable renewable generation sources.

To provide a framework for qualitative analysis, the following scenarios have been analysed:

1. A base case of near perfect wind forecasting accuracy
2. An overestimation of a material amount of wind generation 12 hours ahead of the trading period
3. An underestimation of a material amount of wind generation 12 hours ahead of the trading period.

A 12-hour period was selected because the system occasionally relies on slow start thermal generation units as energy sources, which require 6-12 hours to start up if they are required in a situation of tight supply.

While near perfect forecasting accuracy is highly unlikely to occur, this has been selected as a base to capture the full cost that is borne with inaccurate forecasting while also demonstrating that eliminating the cost entirely is unlikely. Moreover, choosing a base case with a degree of inaccuracy would be an arbitrary decision that could date the work quickly as different forecasting methods can yield different levels of accuracy and models' accuracy can improve over time.

Our analysis has detailed the consequences of both under forecasting and over forecasting. We have undertaken statistical analysis of historical pricing and wind forecasts using market data sets held by the Authority to establish the quantitative results below. This is alongside a discussion of other impacts (such as plant start-up and future trading strategy impacts) to qualitatively capture impacts that are indirectly captured by market pricing or are external to the electricity market.

Previous analysis by the Authority has been focused on historical wind forecasting data as it has a prominent presence in the market. However, as solar penetration grows in the electricity generation mix, similar principals could be applied to solar electricity generation. This comes as grid connected solar becomes more apparent and connected to the electricity market in New Zealand.

We have evaluated that an underestimation of future wind generation may impose costs on both generators and price sensitive users.

For example, if wind is underestimated, 12 hours before the trading period, generators may make the decision to start-up slow start generation (e.g., thermal generation), to ensure supply meets demand. These generation sources are typically dispatched at higher prices due to higher running costs. However, if the supply deficit does not eventuate and higher spot prices do not eventuate, prices in the period may not be sufficient to cover the marginal cost of generation. Generators then either dispatch at prices that do not recover their costs or forgo the costs of start-up.

The losses in the trading period can flow through into trading strategies in future trading periods or lock in preferences for potentially less efficient fast start generation. Additionally, an elevation in price signals to price sensitive users may result in plans to reduce their demand to avoid paying higher prices. As the higher prices do not eventuate, these users incur an opportunity cost of foregone productivity.

Our quantitative analysis has established that under forecasting of wind is estimated to have an average impact on spot prices of -$6.9/MWh – this is estimated to have a market impact of $94 million annually.

Importantly, these costs are not borne by wind generators, but are instead borne by thermal generators. While this may look like a benefit to consumers, this conclusion is limited to the price period in question. Lower spot prices are beneficial to consumers in that trading period, but the reduced revenue during the period in question could impact consumers in the long term as generators seek to recover their costs in future trading periods.

Alternatively, if there is an overestimation of wind generation, there are potentially material costs for consumers.

For example, when wind is overestimated, 12 hours prior to the trading period, the generation schedules will show higher levels of generation than what is eventually offered. Spot prices are likely to be lower due to the lower cost of wind generation. This disincentivises start-up of thermal generation in a timely manner and could lead to security of supply issues – generation owners may need to run plant inefficiently at higher cost and the System Operator may need to call on measures such as scarcity pricing to manage the situation. This can lead to elevated prices for consumers.

On the demand side, price-sensitive users may see the low-price forecast 12 hours ahead and plan to increase in their energy usage while prices are low. However, the low prices do not eventuate, and users face higher than anticipated prices if they cannot react to price signals in time.

Our quantitative analysis has established that over forecasting of wind is estimated to have an average impact on spot prices of $3.8/MWh – this is estimated to have an impact of $107 million annually.

Again, this price is not borne by wind generators and results in a disbenefit to consumers as expensive back up generation (such as hydro and fast start thermal units) may be required to make up the under supply of wind generation.

A summary of our analysis is given in Table 1. It is important to note that the cost impacts presented in this report may have contributing factors other than wind forecasting accuracy. Other market events can occur that would result in a positive or negative impact on electricity spot prices (e.g., unplanned generation or network outages, changes to demand forecasts and/or generation offers). It is possible that these events occur at the same time as inaccurate wind forecasts and contribute to price impacts. The impact of other events has not been controlled for.

Table 1: Analysis outcomes showing he estimated cost of inaccurate wind forecasting for both an underestimation and overestimation of wind both per megawatt hour and annual impact based on a 42 TWh market.

<table>
<tr><th colspan="2">Error ranges (MW)</th><th rowspan="2">Price delta ($/MWh)</th><th rowspan="2">Percentage of trading periods</th><th rowspan="2">Annual cost[1] (million $)</th><th rowspan="2">Under forecasting/over forecasting impact</th></tr>
<tr><th>Lower bound</th><th>Upper bound</th></tr>
<tr><td>-</td><td>-200</td><td>-$6.59</td><td>0.20%</td><td>-$0.54</td><td rowspan="5">Under forecasting (32.5% of trading periods):

Price impact: -$6.90 /MWh

Annual cost: -$94 million</td></tr>
<tr><td>-200</td><td>-150</td><td>-$10.42</td><td>0.79%</td><td>-$3.47</td></tr>
<tr><td>-150</td><td>-100</td><td>-$12.13</td><td>2.41%</td><td>-$12.27</td></tr>
<tr><td>-100</td><td>-50</td><td>-$13.53</td><td>8.14%</td><td>-$46.24</td></tr>
<tr><td>-50</td><td>0</td><td>-$3.60</td><td>20.97%</td><td>-$31.69</td></tr>
<tr><td>0</td><td>50</td><td>$6.15</td><td>33.76%</td><td>$87.28</td><td rowspan="5">Over forecasting (67.5% of trading periods):

Price impact: $3.77 /MWh

Annual cost: $107 million</td></tr>
<tr><td>50</td><td>100</td><td>$0.80</td><td>22.58%</td><td>$7.55</td></tr>
<tr><td>100</td><td>150</td><td>$1.72</td><td>8.12%</td><td>$5.87</td></tr>
<tr><td>150</td><td>200</td><td>$5.97</td><td>2.24%</td><td>$5.62</td></tr>
<tr><td>200</td><td>-</td><td>$1.99</td><td>0.79%</td><td>$0.66</td></tr>
</table>

As noted above, there are cost impacts to the electricity market of inaccurate wind forecasting and while wind generators may be impacted, other market participants may also bear the costs of inaccurate forecasting. Furthermore, that inaccurate forecasts can be a contributor to security of supply events.

It is likely that as accuracy improves, these costs could be avoided. However, it is outside the scope of this report to determine the cost of, and limitations of, improving forecasting accuracy which would allow a full cost-benefit analysis to be undertaken. We also note that we have not costed qualitative impacts (such as impacts on future trading strategies) and that the quantitative analysis here may be a lower bound of actual system costs.

The analysis and findings included in this report needs to be considered in the context of New Zealand's future zero emissions electricity market where a greater proportion of generation is expected to be from intermittent sources including wind and solar[2]. Moreover, peak demand is likely to grow without generation capacity growing at the same or similar pace, resulting in an increase in the frequency of tight supply scenarios. This would lead to additional use of reserves, scarcity pricing and potential load shedding which will impact the system in varying ways, as we have detailed in this report. From a demand-side perspective it is expected that demand-side response will increase and therefore the need to have accurate signals will be increasingly important to avoid productivity impacts and mitigate security of supply events.

The shift to a zero-emissions electricity system and decarbonisation of New Zealand's energy systems is therefore likely to increase the importance of accurate forecasts.

[1] This column has been calculated by $(PriceDelta) \times (FractionOfTime) \times (AnnualDemand)$ and assumes an annual demand of 42TWh.
[2] New Zealand's electricity future: generation and future prices, Electricity Authority. Whakamana i Te Mauri Hiko, Transpower.

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1. Context of this report

Inaccurate wind generation forecasting and its contribution to inefficiencies in the wholesale electricity market has recently come to the forefront of industry discussion[3]. This discussion has been spurred in part by the 9 August 2021 event[4], where inaccurate wind forecasting led to a drop in generation in the market and was one of the contributing factors to the loss of power to several thousand customers.

The purpose of this report is to understand the potential array of impacts that could arise from inaccurate wind forecasting on the wholesale electricity market and wider electricity system. This work is intended to support the issues and options paper being developed by the Authority. The hypothesis is that intermittent generation is currently not accurately forecast which is imposing additional costs on market participants due to:

- The System Operator calls on too much generation which increases the cost of generation as thermal plants are called on unnecessarily
- The System Operator calls on too little generation which leads to increased risk of power outages and/or load shed
- The uncertainty/unreliability of forecasts may be causing the System Operator to add in a safety margin to its requests for generation or impact other bid/offer behaviours.

Furthermore, as New Zealand's electricity system undergoes significant change to enable decarbonisation, any shortfalls or inefficiencies arising from inaccurate wind generation forecasts should be appropriately addressed. Currently, wind farms generate between 5-10 percent of New Zealand's electricity and make up around 10 percent of New Zealand's total installed generation capacity. As New Zealand transitions to a low carbon energy system, the proportion of intermittent generation (both wind and solar) is expected to grow materially and make up a larger proportion of the generation fleet. Consequently, any impacts experienced today from inaccurate wind forecasting may become more pronounced during the transition.

This report complements other work being completed across the industry. For example, MDAG[5] in its options paper recommended that short-term forecasts of wind, solar and demand must be improved to provide better information for decision makers leading into real-time. This is because given the increase in intermittent wind generation expected in coming years, this problem could potentially grow over time.

1.1 The Authority has already established that wind forecasting inaccuracy exists

In November 2022, the Authority released an information paper on the accuracy of wind and load forecasts.[6] This paper was also developed to support the issues and options paper that will be published by the Authority later in 2023. The purpose of the initial information paper was to better understand the accuracy of wind generation forecasts leading up to real-time. The review studied wind generation data over the 12-month period from April 2021 to March 2022.

The Authority's November 2022 information paper provided key conclusions that have direct relevance to this report. It concluded that wind forecast accuracy does not materially improve until the last 3.5 hours leading up to the wind generation window. After this point, accuracy steadily improves. This appears to correspond to the time when generators begin submitting resource

[3] Unreliable wind generation forecasts risk system – EA, Energy News
[4] Investigation into electricity supply interruptions of 9 August 2021, Ministry of Business, Innovation & Employment
[5] Price discovery in a renewables-based electricity system: Options paper 2022, Market Development Advisory Group.
[6] Accuracy of Wind and Load Forecasts: Information paper 2022, Electricity Authority.

persistence forecasts.[7] Additionally, the previous paper outlined that while the 90 percent confidence interval narrows to around +/-50 MW by the start of the trading period, outliers still extend to around +/-200 MW.

Finally, it was concluded that until the last 3.5 hours prior to generation there is a slight positive bias - i.e., forecasts tend to exceed actual wind generation on average. This bias will tend to exacerbate security issues (such as occurred on 9 August 2021), as often the wind forecast will be too high. The bias disappears once persistence forecasts are issued.

[7] Generators are not required to begin submitting resource persistence forecasts until the last two hours, but analysis implies that persistence forecasts many be submitted about four hours before real-time. The persistence model is the simplest form of forecast. It assumes the wind speed at time "$t + \Delta t$" is equal to the wind speed at time "t".

2. Scope of analysis

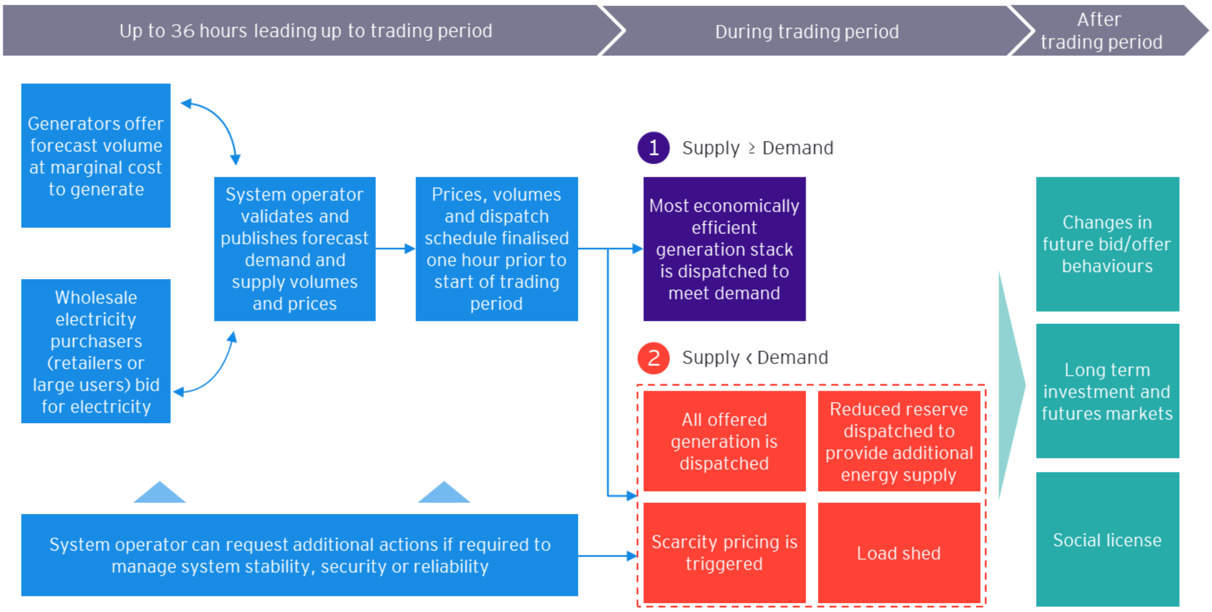
This report explores the current and potential future impacts of inaccurate wind forecasting on the electricity market and system. We have broken down our analysis by timeframe, wind forecast scenario, event type, impact, and stakeholder. In this section we briefly outline each dimension considered.

The analysis presented in this report is largely qualitative in nature. Further analysis outside the scope of this report is required to quantify each of these impacts. We have, however, provided analysis on historical price data to develop an estimate of how wind generation forecasting inaccuracy can impact the wholesale electricity price.

It is important to note that in this report we focus on wind generation forecasting based on current and historical electricity market settings. While similar discussions are also relevant for the forecasting of solar generation, it has been excluded for now due to its current low penetration in the system[8]. We have also completed this assessment on the basis that it is mostly generators that participate in the spot market at present, with very little demand side participation. We have included some considerations later in the report on how expected changes in the system, such as increased demand response, could influence the impacts discussed in this report.

An overview of the scope of our analysis is shown in Figure 1.

Figure 1: Scope of analysis



We have considered our assessment across three **timeframes** - representing the different phases of market operation/decision making - as follows:

- 36 hours leading up to trading period – with a particular focus on the impact of wind forecasting 12 hours ahead of the trading period
- During the trading period
- After the trading period.

[8] In 2021, solar units contributed less than one per cent of New Zealand's total electricity generation. Energy in New Zealand, MBIE.

2.1 Impacts and events considered

The table below provides a high-level description of the **impacts** considered in the study. This set of likely impacts is based on our analysis and was tested with the Authority. More detail on these impacts is provided in Section 2.

Table 2: Description of impacts considered in the study

Impacts	Description of Impact
Generator trading behaviours	Impact of each generator's trading strategy, particularly generators whose plants require additional start-up time and costs.
Load user trading behaviours	Impact of each load user or retailer's trading strategy, particularly large industrials who buy their electricity from the spot market and are more likely to be price responsive.
System Operator behaviours	Impact on the System Operator's strategy and tactics to maintain security of supply, reliability, and stability.
Dispatched generation and emissions	Impact on the dispatched generation stack compared to the most economically efficient stack for a given trading period. Any unnecessary deployment of fossil fuels will increase fuels costs and some plant costs while impacting electricity system emissions and associated carbon costs. These costs are generally built into the generation offer prices.
Market spot price	The generation mix dispatched in any given trading period, in conjunction with fuel costs, plant costs and the supply-demand dynamic in that specific period will impact the wholesale electricity spot price. We do not unpack all underlying drivers of electricity price in detail in this report due to complexity. We have, however, analysed correlations in high wind forecast inaccuracy and price.
Reduced reserves	Reserves are generation redundancy that ensure security when something trips off the system. Generators can supply either energy to the market or reserves with their generation capacity. Reserves are set based on the largest event that could affect a given island. There are costs associated with using reserves, as using these will increase prices.
Scarcity pricing	Scarcity pricing refers to arrangements to modify prices in the wholesale electricity market when the System Operator reduces demand through administrative action. Scarcity pricing provides a $10,000/MWh price floor to the spot market to give investors in last-resort generation plant confidence in revenue recovery.
Load shed	When there is insufficient supply to meet demand in any given period, the System Operator may ask connected parties to shed some load to ensure supply can meet demand, which incurs an economic cost. The cost of load shed is commonly referred to as the 'value of lost load (VoLL)' and is different to the cost of electricity. Instead, it reflects consumers' willingness to pay to avoid a power outage. The 2018 System Operator report identified the VoLL in NZ as $17,000-$40,000 per MWh.
Futures market and investment/ risk behaviours	Market price levels, stability, confidence and trajectory are all underlying investment drivers for new generation and electrification investments. Futures products are one avenue for purchasers and generators to mitigate risk in their portfolio. The prices that future products are set at are often a good reflection of the current market dynamics.
Social license	Social license refers to the acceptance by stakeholders, such as the public, to operate. Without social license to operate, the industry can incur delays and costs such as higher compliance costs which could impede the transition to net zero or industry build out. Social license can be heavily impacted by significant disruptions, such as power outages, or a significant increase in prices to end consumers.

When unpacking these impacts further, it was evident that our analysis needed to consider different **events.** The first event is a trading period where there is sufficient supply to meet demand, and the second is a trading period where there is tight or insufficient supply to meet demand, leading to a potential security of supply issue (see Table 3). These events link back to the Authority's statutory objectives, as shown below.

Table 3: Description of events considered in the study

	Event type	Description	EA Statutory objectives
1	**Sufficient supply** Higher frequency, lower impact event	When an economically inefficient generation stack is deployed and/or system costs are higher than necessary	► Efficiency ► Competition
2	**Tight or insufficient supply** Lower frequency, higher impact event	When supply is insufficient to meet demand and security of supply is compromised (e.g., 9 August 2021)	► Efficiency ► Reliability

2.2 Wind forecasting accuracy scenarios

In this analysis, we have considered three wind generation forecasting scenarios to understand the difference in impacts between under and over forecasting. These are described in more detail below.

2.2.1 Base case: near perfect wind forecasting accuracy

As the base case, we have used a scenario where wind forecasting accuracy 12 hours ahead of a trading period is relatively accurate. This base case will help us to understand how material under/overestimating of wind generation can vary the impacts felt by the electricity market.

In addition, having a base case is important for helping to isolate the impacts of wind forecasting accuracy. The base case helps to avoid over or understating the effects wind forecasting inaccuracy has on undesired impacts on the electricity system. For example, many of the impacts described could still happen due to other system factors, and consequently, the base case will aid us in unpacking the contribution that wind forecasting accuracy plays on our electricity system.

2.2.2 Overestimating a material amount of wind generation 12 hours ahead of the trading period

The first alternative scenario considers the consequences of when a material amount (e.g., ~100MW, equivalent to a single Stratford thermal generation unit) of wind generation capacity is offered in the market 12 hours ahead of a given trading period, that does not materialise and is not able to be dispatched in the trading period.

We have chosen 12 hours ahead as the timeframe for our study because some cold start fossil fuel plants require 6-12 hours to warm up. Therefore, some fossil fuel plants will rely on the forecast offer schedule published 12 hours ahead of the trading period to decide whether the plant is required to start up.

It is important to note that though we are only looking at wind forecasts 12 hours ahead, when we examine the timeframe leading up to the trading period (Section 3.1), we go as far as 36 hours ahead. This is because as noted in section 13.6 of the Electricity Industry Participation Code (the Code), the System Operator must receive offers at least 71 trading periods prior to the trading period in which the offer relates to.

The Authority's previous paper found that until the last 3.5 hours, wind forecasts tend to be higher than the actual wind generation. This scenario is therefore more likely than the following "underestimating" scenario.

2.2.3 Underestimating a material amount of wind generation 12 hours ahead of the trading period

The second alternative scenario considers the consequences of when a material amount of wind generation capacity is not offered in the market 12 hours ahead of generation but ends up being dispatched in the trading period, because of more accurate forecasting closer to the trading period.

2.3 Stakeholders considered

In this report we have considered the influence and impacts of several different stakeholders, including generators of different assets, demand users and the System Operator and Authority. As shown in Table 4, each have different drivers and relevant importance at difference stages of this analysis.

Note that the generators in the table below have been classified by the type of generation asset they own. Therefore, the classifications of the different generator groups are not mutually exclusive and there will be some generation companies that sit across multiple generator stakeholder groups. For example, Genesis Energy owns wind, hydro and fossil fuel plants, and Meridian owns wind and hydro assets.

Table 4: Description of stakeholder groups considered in study

Stakeholder group	Description of stakeholder	Key drivers
Generators with inaccurate wind forecasting	▶ Refers to generators who own wind generation assets and inaccurately forecast the wind generation that they can supply for a given trading period. ▶ We assume that generators offer at prices equal to or greater than their marginal cost of production ▶ Some of the generation is expected to be sold on the wholesale electricity market, while other generation might be sold through futures products ▶ Generators may also supply their generation through offtake agreements, such as a power purchase agreement or other futures products. ▶ Generators who have wind within a portfolio of other generation assets may be incentivized to increase the accuracy of their wind generation offers ahead of time to co-ordinate offers across their fleet. The Authority's recent paper[9] showed that generators with a fleet of assets tended to improve their accuracy around 3.5 hours ahead of real time, compared to 2 hours for the only independent wind generator.	▶ Cost recovery ▶ Profit
Generators with fast start fossil fuel peakers	▶ Generators who own fast start fossil fuel peakers (e.g., Contact Energy's Whirinaki plant) ▶ Makes up ~900 MW or just under half of New Zealand's thermal generation capacity	▶ Cost recovery ▶ Profit

[9] Accuracy of Wind and Load Forecasts: Information paper 2022, Electricity Authority.

Stakeholder group	Description of stakeholder	Key drivers
	▶ Can respond quickly to changes in demand ▶ Primarily used to help meet supply needs during peak demand periods such as mornings and evenings, but may be used over longer periods of time during periods when renewable generation levels are insufficient ▶ These generators tend to have higher operating costs than wind generators due to a combination of fuel price, carbon price and plant start-up costs.	
Generators with slow start fossil fuel plants	▶ Generators who own slow start fossil fuel plants (e.g., Huntly coal units 1, 2 and 4). ▶ Makes up ~1,100 MW or just over half of New Zealand's thermal generation capacity ▶ If not already running, requires 6-12 hours of lead time to start - sometimes longer if the plant hasn't been started in a long time. [10] ▶ Primarily used to help meet supply needs over a longer period (e.g., baseload to meet high energy demand rather than peak demand) when renewable generation levels are insufficient ▶ Tend to have higher operating costs than wind generators due to fuel price, carbon price and plant start-up costs.	▶ Cost recovery ▶ Profit
Other generators	▶ Generators who own other generation types that are not covered in the above groups. This includes hydro, solar and geothermal generators ▶ We assume that generators offer at prices equal to or greater than their marginal cost of production.	▶ Cost recovery ▶ Profit
System Operator	▶ An independent Transpower function contracted to the Electricity Authority to run the wholesale electricity market and operate the power system ▶ Ensures reliability, stability, and security of the power system ▶ Note that additional costs to the System Operator such as investing in new tools and processes to manage wind forecasting accuracy (e.g., ancillary services) are not in the scope of this report.	▶ Meet obligations set out in Part 7 and 8 of the Code and Policy Statement
Regulator – Electricity Authority	▶ Independent Crown entity responsible for the efficient operation of and regulating the New Zealand electricity market ▶ Sets and enforces rules in the Electricity Industry Participation Code 2010 (the Code).	▶ Enabling statutory objectives as set in the Electricity Industry Act 2010: Competition, Reliability, Efficiency
Demand users who are	▶ Currently tend to be larger industrial loads that can flex their demand in response to spot prices	▶ Lowest cost between supply

[10] Accuracy of Wind and Load Forecasts: Information paper 2022, Electricity Authority.

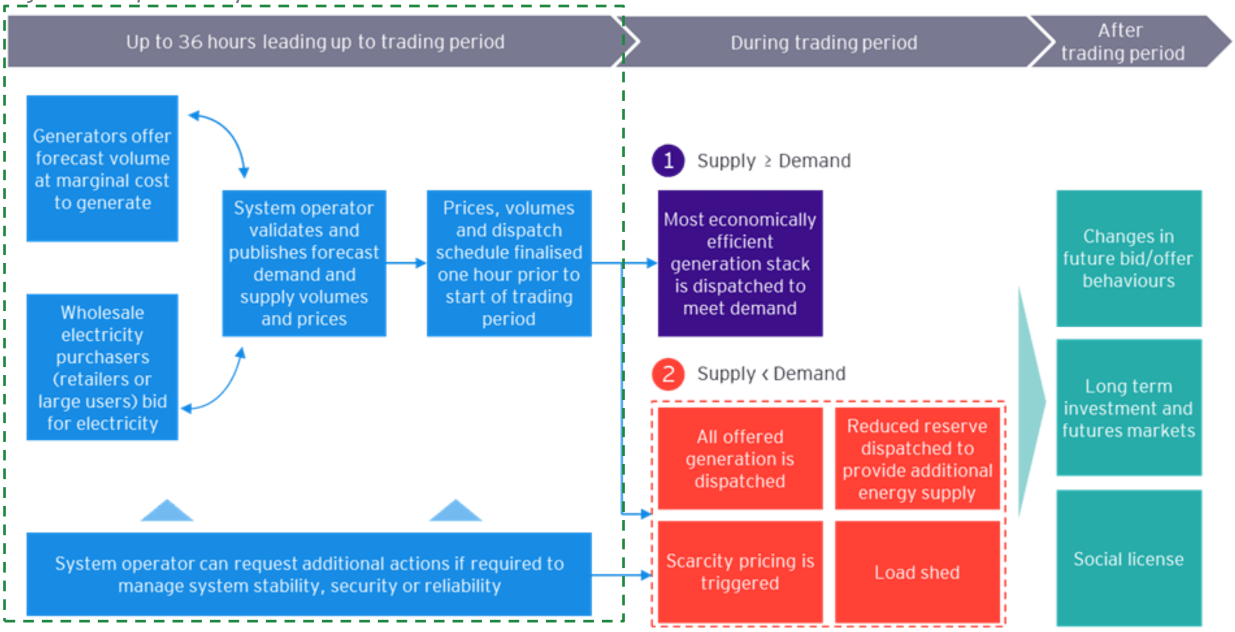
Stakeholder group	Description of stakeholder	Key drivers
sensitive to price	► Vary in their ability to respond to price signals in a timely manner ► Group expected to grow and expand into smaller commercial and/or residential demand users as demand flexibility services become better enabled in the market.	and curtailed demand ► Reliable supply
Demand users who are insensitive to price	► Currently tend to be end consumers that have limited ability or appetite to flex their demand in response to spot prices ► Residential and commercial users with contracts tend to be sheltered from spot market volatility through contracts with their suppliers. Therefore, they tend to only experience price increases during periods of sustained high prices, or if the retailer has secured supply at a higher price as a risk management tool.	► Low-cost electricity ► Reliable supply

3. Effects of inaccurate wind forecasting

In this section we explore the various impacts and the typical behaviours of stakeholders within each timeframe of our study. This is followed by a comparison of the base case, alternative scenario one (over forecast) and alternative two (under forecast).

3.1 36 hours leading up to the trading period

Figure 2: Scope of analysis



As seen in Figure 2, in the 36 hours leading up to each trading period, generators place and update offers on the wholesale electricity market and the reserve market to supply a certain amount of generation for that period.

The System Operator is responsible for validating the bids and offers for energy and reserves, publishing the schedules via the Wholesale Information Trading System (WITS). Long schedules (36 to 4 hours ahead) are updated every two hours and short schedules (4 hours ahead) are updated every trading period. Grid connected generators can update offers up until the final hour before the trading period, except for certain circumstances (e.g., safety or unexpected outages).[11]

Generators tend to offer at a price that enables them to at least recoup the costs of generating in that period (i.e., prices will be equal to or above the short-run marginal cost). For this reason, offer prices tend to be higher for fossil fuel plants as they must cover fuel and carbon costs. Generation plants with start-up costs will also offer a price that recoups this additional cost.

Intermittent generators such as wind generators can submit up to five price tranches like most other types of generators but must include an extra parameter called 'forecast of generation potential' (FOGP). The FOGP is a forecast of the total windfarm output (i.e., summed over all tranches). We note that prior to a Code change in 2019 there was no FOGP. Instead, windfarms adjusted their offers in line with the forecast output. This is a forecast of the electricity they will generate during each trading period and effectively caps their offers at this level.

Under the current Code provisions, intermittent generators must submit a revised FOGP at least once per half-hour during the last two hours before the start of the trading period. Clause 13.18A

[11] The Code, Electricity Authority.

of the Code requires intermittent generators to submit offers using persistence forecasting[12] within the two hours ahead of a trading period. As identified in the Authority's previous paper, some generators choose to switch to persistence forecasting prior to the two-hour mark.

Operators of controllable generation, such as dammed hydroelectricity, geothermal or fossil fuel plants, will offer what they know with reasonable certainty their plant can produce. These generators are required, under clauses 13.18(1) and 13.18(1A) to revise their offer before the end of the trading period if their offer exceeds by more than 5MW the total MW that they except to be able to generate for the trading period.

Some plants, particularly those that rely on heat output (such as Huntly Units 1, 2 and 4), require a 'warmup' period of 6-12 hours prior to being able to supply electricity to the market. For these plants, generators will look at offer schedules in the 6-12 hours leading up to the trading period to assess whether they would likely be dispatched at a reasonable price if they started their plant. If not, then they may choose not to put an offer in the market and refrain from starting their plant. For this reason, we have chosen to focus on wind generation forecasts the 12 hours leading up to a trading period.

These 'slow-start' plants tend to have high fuel costs with material start-up costs, and therefore can only be dispatched at a higher price. Currently these plants are all using fossil fuels, so the dispatch prices for these plants are expected to increase with rising carbon costs.

Leading up to a trading period, the System Operator is also responsible for ensuring the amount of offered generation can meet the forecast level of demand. If the System Operator foresees a situation where there might be a shortfall in supply, or configurations where system stability or security might be compromised, it will send a series of industry notifications asking market participants to adjust their offers (e.g., offer more generation) to manage the situation. For example, the System Operator issues Customer Advice Notices (CANs) when it calculates there is less than 200 MW of residual generation for an upcoming trading period. Residual generation is the remaining available capacity that could be dispatched if required but are not currently scheduled for dispatch.

An important note to consider is that many major energy users, such as large industrial loads, tend to contract their electricity ahead of time and do not always purchase electricity directly from the wholesale spot market[13]. Residential and commercial users tend to be sheltered by volatile spot market prices by their retailer. However, because spot prices are a leading indicator of contract prices, volatility in the spot market can lead to higher contract prices in the future for these users.

Table 5 below provides an overview of the impacts of different wind forecasting accuracy scenarios on behaviours in the period leading up to the trading period. It is important to note that the impacts described are considered only in relation to the accuracy of wind forecasting. Other events could occur in the hours preceding a trading period that would influence the efficiency of that trading period's dispatched generation and price (e.g., unplanned generation or network outages, changes to demand forecasts and/or generation offers).

[12] Persistence forecasts assume that the conditions at the time of the forecast will not change. For example, if two hours ahead of a trading period, wind generated is 10MW, then the persistence forecast for the trading period is also 10MW. [12] The Code, Electricity Authority.

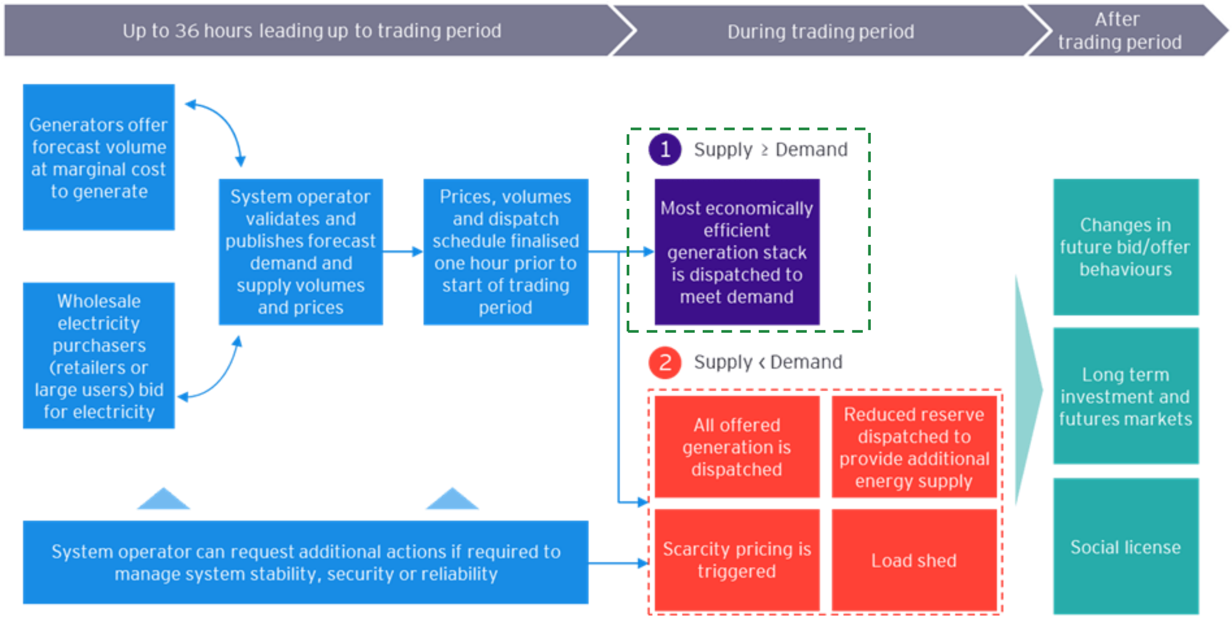
[13] Managing electricity spot price risk guide, Electricity Authority.

Table 5: Overview of wind forecasting accuracy impacts leading up to trading period

Scenario	Impacts of wind forecasting accuracy
Base case	Under a base case where wind forecasting is near perfect, it is expected that the amount of wind forecast ahead of a trading period is close to the amount of wind dispatched in the trading period. Accurate information around wind forecasting 12 hours ahead of the trading period allows slow start thermal generators to start their plants, if required. As higher cost thermal generation is only called on when required, the market price should represent the optimal use of available generation.
Under forecast of wind	If wind is materially under forecast in the 12 hours ahead of the trading period, then generation forecasts will show lower levels of available generation ahead of time than what is generated in the trading period. This underestimated generation could signal to the market that more generation is required to meet demand. Where demand is sufficiently high, this may mean that higher cost generation, such as thermal generation, is seen to be required to ensure supply meets demand. For this reason, slow start thermals may be turned on, if not already, with the expectation that they can be dispatched at a level that will enable them to recoup their costs. As a result, forecast spot prices may increase. These elevated forecast prices could also incentivise higher-cost generation with minimum running constraints to choose to continue generating in the expectation of higher spot prices that do not eventuate. This could incur a cost to the generator if it is not dispatched. An elevation in forecast prices could also lead to price-responsive demand users reducing their demand to avoid paying higher prices. If prices do not increase as expected, then the demand user pays the opportunity cost of foregone productivity.
Over forecast of wind	If wind is materially overestimated in the 12 hours of the trading period, then generation schedules will show higher levels of generation than what is offered in the trading period. This higher volume of renewable electricity offered could then decrease forecast spot prices. These depressed forecast prices could incentivise higher-cost generation to either stop generating if already running or choose not to start their plant ahead of the trading period. In the 2-3 hours leading up to the trading period, when wind forecasting becomes more accurate, the generation schedule shows a decline in the level of wind generation available. As a result, other renewable generation may be offered if required to replace the decrease in wind generation, or fast start peakers may be brought online at an additional cost to the system. Security of supply challenges may arise if there is insufficient generation available to fill the gap. Additionally, these prices could lead to price-responsive demand users to increase their demand to take advantage of lower electricity prices. If they are not able to decrease their output when more accurate schedules are published in the 2-3 hours leading up to a trading period, then they may have to pay a higher energy cost that could have been avoided.

3.2 During the trading period, when supply ≥ demand

Figure 3: Scope of analysis



As highlighted in Figure 3, this section discusses the impacts for wind forecast accuracy during the trading period when supply can meet demand.

During each trading period, the System Operator instructs generation dispatch based on the least cost configuration of the generation stack. All offers that are selected from the stack then get paid the same amount as the highest offer selected on a nodal basis. This is called the spot price for the trading period. Note that this is a highly simplistic explanation of the market. The market operates under the Electricity Industry Participation Code (the Code).[14]

Due to their low marginal cost, wind and solar generation are expected to be dispatched when offered, if required to meet demand. The remainder of the generation stack is expected to include renewable generation when offered due to the low costs of other renewable electricity sources, such as hydroelectricity.

However, when required, thermal generation is likely to be dispatched to meet the remaining supply needs. As discussed earlier, thermal generation tends to have higher short run marginal costs due to their higher fuel, carbon, and start-up costs. These costs are paid for by the generators as part of their operating costs and are priced into their generation price offer. When dispatched, these thermal sources tend to set the spot price. Therefore, prices tend to be lower during periods of high renewable generation, and higher during periods when fossil fuels need to be dispatched.

When wholesale prices are elevated because of external factors, such as when lake levels are lower than expected, the spot price can be sensitive to small changes in demand or supply capability. Under these conditions, the forecast and output of intermittent generation can have larger impacts on the wholesale spot price.

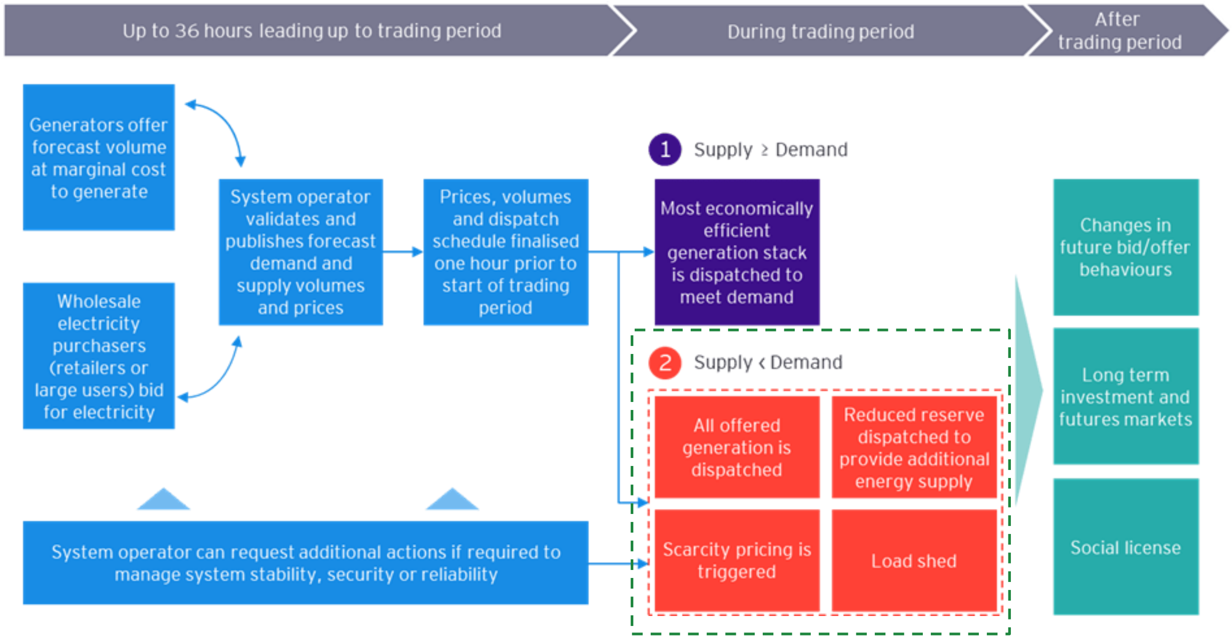
Until recently, final prices were typically only published two days after the trading period. In November 2022, Real-Time Pricing (RTP) was introduced, which enables final pricing to be published immediately. We discuss the effect this may have, in respect to the impacts of wind forecasting, in Section 3.5.

[14] The Code, Electricity Authority.

The impacts of under and over forecasting wind when supply is sufficient to meet demand are consistent with those described later in Table 7 (Section 3.6) where we quantify the impact of forecast inaccuracy.

3.3 During the trading period, when supply < demand

Figure 4: Scope of analysis



As highlighted in Figure 4, in very tight periods where demand is higher than normal, issues may arise when slow start thermals are required to start up to meet supply needs. If there is an overestimation of wind generation, the generators do not perceive a signal to start their plant ahead of the trading period. This is only in the case where the plants are not already running in preceding trading periods.

It is important to note here that inaccurate wind forecast is not the only driver of tight supply situations. Other drivers include:

- Very high/peak demand
- Unexpected outages on network or generation plant
- Low hydro storage
- Low residual generation available

There are a series of actions that the System Operator can trigger to manage such an event and avoid loss of supply. These have costs associated with them and are detailed later in this section.

The table below (Table 6) provides an overview of the impacts of different wind forecasting accuracy scenarios on behaviours during the trading period when supply is tight or insufficient.

Table 6: Overview of wind forecasting accuracy impacts during the trading period

Scenario	Impacts of wind forecasting accuracy
Base case	Under a base case where wind forecasting is near perfect, it is expected that the amount of wind forecast ahead of a trading period is equal to the amount of wind dispatched in the respective trading period. Tight supply events may still occur even when wind forecasting is very accurate due to other factors and the System Operator will require actions from various players to rebalance the system.
Under forecast of wind	Under forecast of wind generation is unlikely to increase the likelihood of a tight supply event because there will be more wind generated in a trading period than expected.
Over forecast of wind	Over forecast of wind generation is likely to increase the likelihood of a tight supply event because there will be less wind generated in a trading period than expected. Provided the rest of the electricity market cannot adequately compensate for the decreased wind generation, the System Operator may be required to reduce reserves, activate scarcity pricing and/or instruct load shed. All of these incur system costs.

3.3.1 Reduced reserves

Instantaneous reserves are a security product that ensures that electricity demand can continue to be met in the event of unplanned generation or transmission interruptions. Reserves are spare generation capacity in addition to forecast demand and is a redundancy mechanism that ensures security when another source of supply or network outage trips off the system. Reserves are set based on the largest event that could affect a given island.

Generators can supply either energy or reserves with their generation capacity. Energy and reserves are co-optimised, allowing generators to offer capacity on both markets.

During a trading period, if the energy market has insufficient supply, then the System Operator will instruct the dispatch of the reserve generator. Most of the time, the cost of providing spare capacity as reserve is low. However, there are several circumstances where dispatching reserve generation can increase the electricity spot price. For example:[15]

- Additional costs can be incurred to a generator if they must run their plant inefficiently to provide reserves. As a result, the generator may offer their reserve at a higher price to recover costs.
- Costs can also increase if generators are required to forego higher energy prices to provide reserve. This results in the reserve price increasing to cover the opportunity cost.
- Some units can only provide reserves if they are also generating for the energy market. This means that occasionally, higher-cost generation will be brought online so that it can provide reserve as well.

[15] Keeping the lights on with reserves, Electricity Authority.

3.3.2 Load shed

When there is insufficient supply to meet demand in any given period, the System Operator may ask connected parties to shed some load to ensure supply can meet demand.

The System Operator only manages demand as a last resort to prevent cascade grid failure, which would result in widespread power outages for a longer period of time than that if demand was proactively managed. In most situations, working with lines companies to switch off hot water cylinders (with minimal impact on consumers) is sufficient.

There are, however, circumstances where load in addition to hot water control must be shed to avoid cascade grid failure. The System Operator may also as a last resort use Automated Under Frequency Load Shedding (AUFLS), which are a set of relays in New Zealand which automatically trip blocks of load, following a severe under-frequency event, to restore the system frequency. [16]

Any power outages are referred to as 'lost load' and come at a cost to New Zealand. The Value of Lost Load (VoLL) is an economic measure of the benefit lost from the amount of energy foregone. It represents the loss that is incurred by customers in case of electricity service interruption. In other words, it is the consumers' willingness to pay to avoid a power outage.

The 2018 System Operator report[17] identified the VoLL in NZ as $17,000-$40,000 per MWh with a central figure of $25,000 per MWh. This is significantly higher than the cost of electricity to the consumer because it represents a significant disruption to 'business as usual'.

3.3.3 Scarcity pricing

Scarcity pricing refers to arrangements to modify prices in the wholesale electricity market when the System Operator is implementing load shedding. Forced power outages can put downwards pressure on the spot price which undermines the incentive for generators to keep generating and for users to reduce their demand. Scarcity pricing is an important tool for incentivizing generators to invest in last-resort generation.

In simplified terms, scarcity pricing provides a $10,000/MWh price floor to the spot market to give investors in last-resort generation plant confidence in revenue recovery. It also provides a $20,000/MWh price cap to provide assurance to wholesale purchasers that spot prices in emergency load shedding will not settle well above the level expected in a workably competitive market.[18]

Given the very high price cap and floor, if scarcity pricing is triggered partly due to inaccurate wind generation forecasts, then this would increase the electricity spot price unnecessarily.

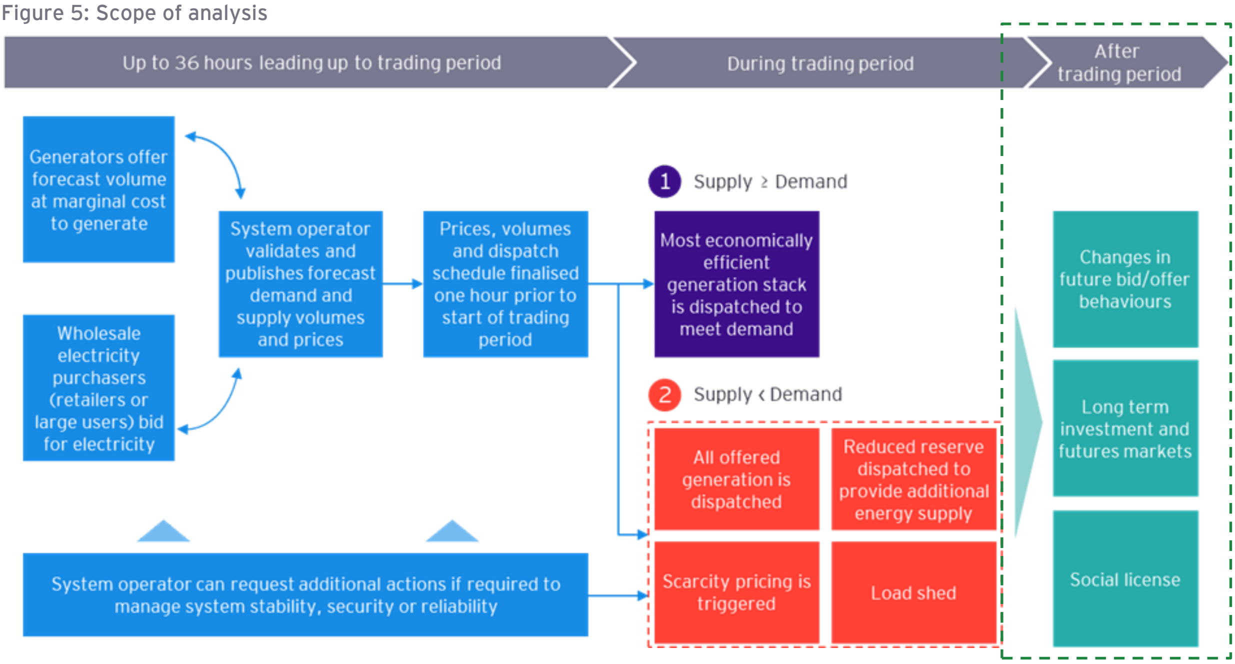
3.4 After the trading period

The impact that inaccurate wind forecasting has on dispatched generation and the wholesale electricity price may potentially flow on to behaviours beyond the trading period itself. In this section, we discuss the potential impacts that inaccurate wind forecasting could have on trading behaviours, the futures market, plant investment and social license.

It is important to note that while we expect that inaccurate wind forecasting might have an influence on these more medium to long term market impacts, there are other factors that will also influence these impacts. At this point, there is insufficient analysis readily available to assess the extent to which wind forecasting inaccuracy influences the impacts discussed below.

[16] Automated Under Frequency Load Shedding (AUFLS) Project, Transpower.
[17] Value of Lost Load Study, Transpower.
[18] Scarcity Pricing Overview, Electricity Authority.

Figure 5: Scope of analysis



3.4.1 Changes in future bid/offer behaviours

It is currently understood in the market that wind generation forecasts more than four hours ahead of a trading period have a reasonable likelihood of being inaccurate.[19] This creates uncertainty in forecast schedules that may influence how generators, large purchasers and the System Operator behave in how they bid, offer, or instruct in the market.

For example, due to the schedule uncertainty, some generators may choose not to offer generation into the spot market unless they are confident that they will be dispatched. If, under more certain circumstances, more generation would have been dispatched if offered, then this could result in an inefficient market outcome. Furthermore, if a provider withholds its offer and is unable to offer closer to the trading period when schedules are more certain, this could result in an event where the system is short on capacity.

Similarly, electricity purchasers may not have confidence in the available generation or prices in the schedules leading up to the trading period. To limit their exposure, price-sensitive purchasers who have the ability to change their demand might not bid for as much electricity as what would be more efficient. Purchasers for non-price sensitive loads are unlikely to change their bid behaviour and will accept the expected cost associated with inaccurate wind generation forecasts.

The System Operator may also behave in response to the uncertainty created by sustained inaccurate wind forecasts. For example, it may require higher levels of residual generation in a trading period or invest more in its own wind forecasting tools to decrease the risk that a significant proportion of wind generation drop off does not create critical issues for the electricity system.

3.4.2 Futures market and new generation investment

Market prices levels, stability, confidence, and trajectory are all underlying investment drivers for new generation and electrification investments. For New Zealand to meet its decarbonisation targets, high levels of electrification and investment in new generation are required. In turn, the right market signals that encourage investment are also required. Futures products are one avenue for purchasers and generators to mitigate risk in their portfolio.

[19] Accuracy of Wind and Load Forecasts: Information paper 2022, Electricity Authority.

The forward electricity market allows electricity buyers to purchase a forward contract for supply from generators. This contract protects buyers from volatility in spot prices by fixing their electricity price for a certain period. The contract also guarantees the supplying generator a certain level of earnings.

Forward prices are an important indicator for the expectations of future electricity demand and generation costs as the prices of these contracts are agreed by both the buyer and the sellers. Generally, forwards prices are low when there is the expectation that there will be an abundance of low-cost renewable generation. Conversely, forwards prices will tend be higher when there is more uncertainty about the availability of low-cost renewable generation in the future. Higher forwards prices can signal the need for new generation investment.

Wind forecasting inaccuracy can further contribute to the real-time spot price volatility already contributed by increasing intermittent renewables on the system. This volatility can put upwards pressure on forwards prices. However, wind forecasting inaccuracy is only one of many drivers of the forward prices and therefore the magnitude of its impact should not be overstated. There are several factors that contribute to the price setting of futures products. These include the projected hydro storage, seasonal climate forecasts, corporate announcements about new projects or upcoming interruptions, gas storage levels and fuel prices.

3.4.3 Social license

Social license refers to the acceptance by stakeholders, such as the public, of electricity industry operating practices and financial returns. Without social license to operate, the industry can suffer delays and incur increased costs (e.g. higher compliance costs, more industry investigations etc). These delays and costs are a drain on industry resources and shift focus from the necessary industry transformation for a net zero carbon energy system to maintaining the right to operate. Maintaining social license requires transparent, predictable behaviour by industry stakeholders. In the context of this investigation, maintaining social licence is focused on keeping prices to end consumers at a reasonable level and by avoiding significant disruptions such as power outages.

Because the impact of wind generation forecasting on price appears to be relatively small ($1-2/MWh) in the context of average spot prices, the impact of accuracy is unlikely to create material social license issues for the electricity industry. However, when wind forecasting inaccuracy contributes to a high impact event, such as widespread outages, social license for all parties involved can be negatively impacted.

3.5 Impact of changes to the future electricity system

Currently, the wholesale electricity market and wider electricity system are undergoing significant change as they transform to meet New Zealand's decarbonisation ambitions. These changes are expected to influence or be influenced by the impacts of inaccurate wind forecasts. These impacts could be substantial if our electricity system does not keep up with recommendations.[20]We discuss these potential impacts in the following sections.

3.5.1 Increasing peak demand

As our economy becomes more reliant on the electricity system, both energy and peak demand are expected to grow.

This growth has already been observed in recent years. In its Winter Review Paper[21] the System Operator noted in the past decade, the ten largest peak demands all occurred in 2021 and 2022, with six out of ten occurring in 2022. The grid emergency on 9 August 2021 saw a record high New Zealand peak demand. The paper notes that the growth in demand is partly due to the increase in working from home and EV charging.

[20] MDAG Options paper, December 2022
[21] Winter Review Paper, System Operator, Transpower

If peak demand grows faster than available supply capacity, there is also an increased risk that for any peak period, available supply capacity will not be sufficient to meet demand. This is already being observed. The System Operator noted[22] that there were no Grid Emergency Notices (GENs) issued in 2018, 2019 or 2020 relating to insufficient generation offers. However, in 2021, the System Operator issued three, and in 2022, they issued two. They also state that the increased number of low-residual Customer Advice Notices (CANs) issued in 2021 and 2022 indicate that peak demand growth may not be sufficiently balanced by existing generation availability.

The Authority have also recently released their consultation document *Driving efficient solutions to promote interests through winter 2023* on this issue.[23]

In respect of inaccurate wind forecasting, provided that all other system characteristics remain the same, increasing peak demand is likely to increase the frequency of instances where supply is tight and increasingly sensitive to the forecast accuracy of wind generation. This would result in an increase of the frequency of impacts discussed in Section 3.3. These impacts are typically only material in periods where wind has been significantly under forecast.

3.5.2 Increasing capacity of intermittent renewables

For New Zealand to transition to a low carbon energy system, significant amounts of renewable electricity generation investment is expected to be required over the next few decades. Some estimates suggest that the country's generation capacity is required to increase by at least 10GW by 2050 - a doubling of the current capacity on the system.[24] Of the new generation build required, most is expected to be wind and solar.

Increasing penetration and distribution of intermittent generation could increase the overall forecast error of the intermittent generation fleet due to there being more sources of error. However, the overall system error may not grow proportionately with the intermittent generation capacity due to the potential for errors from different plants to offset each other. How the generation is distributed geographically across the country may also impact the magnitude of total forecast error.

While increasing the renewable generation fleet capacity is desirable for the transition, increased wind and solar generation can also create challenges for maintaining system security and reliability due to their intermittent nature and inverter-based technology. This can result in increased system costs due to the System Operator investing in the right tools and processes, as well as potential opportunity costs associated with generation curtailment.

For example, Ireland, (like New Zealand) is facing an increase of intermittent renewable energy in their power system. In Ireland, there is a limit on the amount of intermittent renewable energy that can be produced, as measured by the System Non-Synchronous Penetration (SNSP) Limit.[25] The limit is placed on intermittent renewable energy to ensure that the system operates safely and to avoid an overload on the system. Previously, all generators on the system were synchronous, however, to reach decarbonisation targets, the Ireland grid will need to be operated with almost 100 percent of sources that are non-synchronous with the power system.

Since wind accuracy is sometimes unpredictable and forecasting can be inaccurate, more wind energy is dispatched and produced than the power system can take (as it exceeds the SNSP limit). Consequently, EirGrid (Ireland's system operator) must send out an order called a 'Dispatch Down', which forces a wind farm to stop their wind turbines from producing further energy, until it is safe for them to continue producing energy within the SNSP limit.[26] The wind energy lost in this process is replaced by fossil fuel plants, as they are completely synchronous with the demands of the power system. This can result in an increase in fossil fuel use and difficulty in maintaining financial

[22] Winter Review Paper, System Operator, Transpower
[23] Driving efficient solutions to promote consumer interests through winter 2023, Electricity Authority
[24] Whakamana i Te Mauri Hiko, Transpower, The future is electric, BCG
[25] System Non-Synchronous Penetration, EirGrid
[26] 'Dispatch Down' and the fight against climate change, Wind Energy Ireland

stability for the wind farms forced to dispatch down. Note that if New Zealand decided to adopt a similar mechanism, there would be differences in its application to account for the material volumes of synchronous renewable generation capacity (hydroelectricity and geothermal).

3.5.3 Decreasing capacity of thermal generation

As New Zealand transitions to a low carbon energy system, it is expected that the thermal generation fleet will eventually retire. The System Operator expects several thermal generation units to retire in the next year. It states that decarbonisation and the uneconomic cost of thermal operation is accelerating thermal generation retirement.[27]

New Zealand's thermal generation fleet currently contributes around ~2,000 MW of generation capacity, equivalent to almost a fifth of the generation fleet. Of this, approximately ~1,100 MW, or just over half of the generation capacity is from slow-start units, which typically require 6-12 hours of warm up time.

Slow-start thermal generation is expected to be phased out first due to the critical role that the fast-start thermal units play in balancing intermittent generation. Eventual phase out of slow start thermals may mean that 12 hours ahead forecasts may be less critical during periods of tight supply.

Fast-start units will also eventually be phased out if New Zealand is to meet its aspirational 100 percent renewable electricity targets. Because fast-start units can respond to changes in intermittent generation relatively quickly, while they remain in the system, inaccurate wind forecasting 12 hours ahead of time creates less of a risk that supply will not meet demand.

With the growth of intermittent generation capacity expected to ramp up significantly, the solutions required to balance the system, in addition to the fast-start thermal units, need to have sufficient capacity and ability to respond. If the low-carbon solutions required to balance the system require a lead time to start up (e.g., hours vs minutes), then wind generation forecasting accuracy may need to increase. Discussing solutions to balance the system are out of scope in this report, but we expect that system balancing solutions will be able to respond quickly given the types of technologies becoming increasingly available (e.g., demand response, grid scale batteries).

Finally, a coordinated and timely phase out of the thermal generation fleet, regardless of slow or fast start, will be required to ensure overall system stability and security of supply. Consistent under-forecasting of wind could undermine this timeliness, as under-forecasting wind generation can shorten asset lives of thermal generators. This is because thermal generators may turn on in anticipation of low wind in each trading period. If the increased wind generation displaces the thermal generation, which then are not dispatched, then this shortens the asset life of the generator. Thermal generators are likely to have finite asset lives as there is little appetite to build new thermal generation.

3.5.4 Increasing demand-side flexibility

Demand-side flexibility is the ability for consumers to increase or decrease their electricity consumption based on a set of market signals, typically the electricity price. Historically, the capacity of demand-side flexibility in New Zealand has been relatively low. The main source of demand flexibility has been ripple control, which has been in place since the 1950s and allows distribution businesses to turn off customers' hot water systems during times of tight supply. Other sources of demand-side flexibility include those that participated in Transpower's demand response trial.

[27] Winter Review Paper, System Operator, Transpower

Moving forward, demand-side flexibility capacity is expected to increase materially through:

- Several large industrial energy users have or are considering building demand flexibility into their units[28]
- Smart homes/EV charging/appliances
- Aggregators entering the market, VPPs
- Grid-scale batteries

Furthermore, several industry participants are collaborating to increase the uptake of demand flexibility in the market through the formation of FlexForum.[29] Also, in Section 9 of its options paper *Price discovery in a renewables-based electricity system*[30], MDAG put forward several options to increase demand-side flexibility.

Demand flexibility is expected to play an important role in balancing the electricity system, especially with the increasing intermittent generation capacity. When wind and/or solar generation is high, spot prices are expected to decrease, encouraging consumers to use electricity. When wind and/or solar generation is low, spot prices are expected to increase, encouraging consumers to reduce their energy use and gain the benefit of avoiding high prices.

Demand flexibility is expected to be able to respond at relatively short notice to changes in the electricity system and will therefore more likely rely on wind forecasts closer to the trading period compared to the 6-12 hours required for slow-start thermal generation units. However, it is also important to note that demand side participants, such as industrial participants, require several hours' notice to ramp down, and therefore it is necessary to bid their demand response several hours ahead of real time. If the capacity of demand-side flexibility and enabling market mechanisms are sufficiently high compared to the capacity and variability of intermittent generation moving forward, then demand-side flexibility will likely alleviate some of the negative effects of inaccurate wind forecasting – particularly when wind is over forecast. MBIE in their report *Investigation into electricity supply interruptions of 9 August 2021*[31] identified that better demand side participation on that night could have helped to avoid the power outages.

High penetration of demand flexibility could also improve the efficiency of the electricity system, by responding to high electricity prices that might be partly due to inaccurate wind forecasting. We discuss this dynamic further in the following section.

3.5.5 Real-time pricing

Real time pricing (RTP) is already a change that has been implemented in the electricity system from 1 November 2022. RTP allows for the spot price information in the market to be released in real time, updating immediately when the price changes. The settlement price for each trading period is then calculated as a time-weighted average and is then published at the end of a trading period.

Prior to the implementation of RTP, indicative spot prices for a trading period were provided, but not finalized until at least two days after the trading period. This meant that industry participants could only make decisions based on forecasts of final prices and estimated the financial consequences of their market actions. Indicative prices typically provided a reasonable estimate of

[28] Price discovery in a renewables-based electricity system: Options paper 2022, Market Development Advisory Group.
[29] New Zealand's FlexForum, Ara Ake.
[30] Price discovery in a renewables-based electricity system: Options paper 2022, Market Development Advisory Group.
[31] Investigation into electricity supply interruptions of 9 August 2021, Ministry of Business, Innovation and Employment.

final prices, but large variances could occur during periods of system stress, such as tight supply. This uncertainty made it harder for parties to make sound decisions being made.

Under RTP, consumers and generators will have more certain and real-time price signals that they can respond by decreasing their demand, the spot prices would go down – resulting in a lower final price for the trading period.

One of the key benefits of RTP is that it better enables the delivery of demand flexibility services, and therefore improves system flexibility, which is important for handling more variable types of supply, such as wind and solar. RTP supports aggregated flexibility to be bid and offered in the wholesale market and provide cost effective alternative to more expensive peaking generation.

Because of this, RTP may help to counter the negative effects of inaccurate wind forecasting, particularly during periods of tight supply because consumers may be incentivized to reduce their demand at short notice and receive a benefit from doing so.

3.6 Quantifying the impact of forecast inaccuracy

To better understand the quantitative impact of wind forecast accuracy on price, we analysed historical price and wind forecast inaccuracy data. Further detail on the methodology of our analysis is provided in Appendix A. Our key conclusions are summarised in Table 7, followed by our detailed assessment.

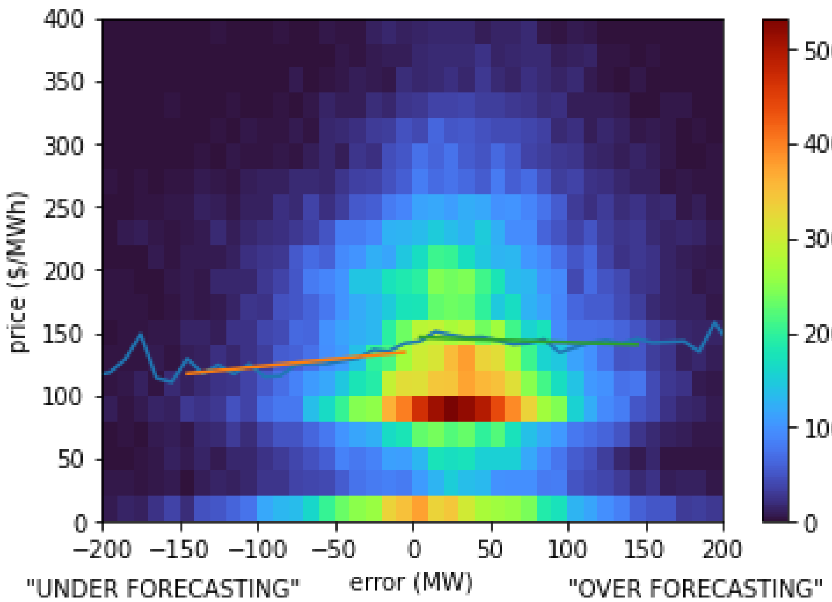
Table 7: Summary of price and market impacts of forecast inaccuracy

	Under forecasting wind generation	**Over forecasting wind generation**
Percentage of trading periods where forecasting error occurs	32.5%	67.5%
Average impact on electricity spot price	**-$6.90/MWh** ► Disbenefit to thermal generators and price sensitive users	**$3.80/MWh** ► Disbenefit to consumers
Annual cost impact due to price effects	**- $94 million**	**$107 million**
Potential impact on market efficiency	► Sub-optimal generation dispatch – slow start thermal units unnecessarily relied on	► Sub-optimal generation dispatch – fast start thermal units or scarce hydro relied on
Potential impact on market competition	► Under recovery of slow start thermal start-up costs ► Thermal operators adjust trading strategy to recover lost revenue ► Opportunity cost to low-cost generators (including inaccurate wind generation forecasters)	► Benefit to generators (including inaccurate wind generation forecasters) ► Preference for and lock in of investment in less efficient fast start thermal

	Under forecasting wind generation	Over forecasting wind generation
Potential impact on market reliability	► Higher risk perception for investment in more efficient slow start thermal	► Dry-year hydro reserves may be called on unnecessarily
Incentives to improve wind forecasting accuracy[32]	► **Medium-low:** Some incentive for wind generators to increase accuracy to reduce negative price impact and capture increased price ► Incentive is lower if decreased price still enables generator to make a reasonable profit	► **Low:** Increasing accuracy would likely decrease price and revenue

When investigating the different impacts of over and under forecasting, we found that low forecast error (i.e., more accurate wind forecasting) was generally correlated with high prices. This can be seen in Figure 6 below where the price trend lines for under and over forecasting increase as the error tends to zero. The cause of this correlation can be supported by the observation that "*it is easier to forecast no wind than it is to forecast how much wind*". An absence of wind is linked to an absence of an appropriate weather system while the strength of the wind is linked to the strength of the weather system. The latter is more difficult to forecast.

Figure 6: Relationship between wind forecast error and price in a trading period



Source: EY analysis.

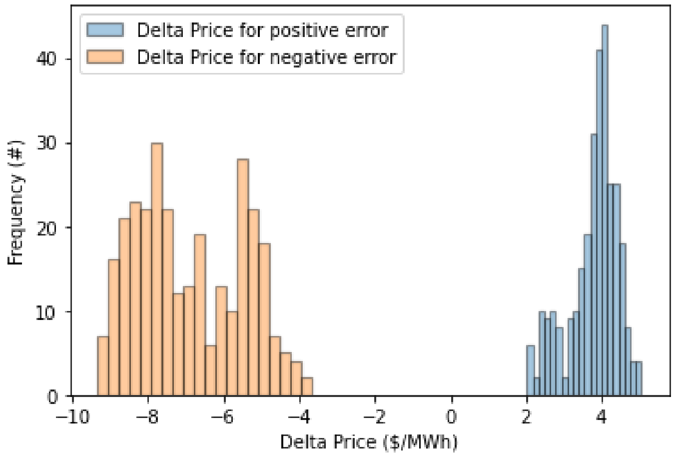
About Figure 6: The coloured bins show the density of trading periods as a function of wind forecast error (horizontal axis) and price (vertical axis). In total there are 52,608 trading periods shown here (3 years). The solid blue line shows the mean price within each error bin. Linear trend lines (least squares) on either side of zero error are also shown.

[32] Section 2.1

The high prices observed when the forecast error is small is because these trading periods coincide with periods of low wind, which is when thermal generation is more likely to operate. Due to the higher costs of thermal generation, low wind periods tend to have higher spot prices.

To confirm our findings on negative pricing delta correlation with under forecasting and positive pricing delta with over forecasting, we examined the distribution of pricing delta. Our statistical analysis makes use of a standard data pre-processing technique known as data-binning and uses price data from a single point of connection (POC). To confirm our findings are not dependent on the data pre-processing or the choice of POC for price data, we repeated the analysis for a wide range of data-binning parameters (bin sizes) and three distinct choices of POC (see Appendix A for further details). The distribution of results is shown in Figure 7. This strongly supports our statement that negative pricing delta correlates with under forecasting and positive pricing delta with over forecasting.

Figure 7: shows the range of price increase or decrease (price delta) for all different choices of bin sizes and point of connection price data.



Source: EY analysis.

We have further developed our analysis to understand the changes in price that occur with differing levels of forecast error as shown in Table 8 below. The first row demonstrates that with an error of more than -200MW than what was forecast, the price delta is -$6.59. This was found to occur 0.20 percent of the time and would result in an annual cost of -$0.54 million in a 42 TWh market. We note the following points on the distribution of price delta:

- Price delta generally increases then remains steady as negative forecast error increases. We note the low price delta at forecast error of more than -200MW and attribute this to potential sample error due to the low number of data points in this range.

- For positive forecast errors, the price delta increases for forecast error between 0 and 50 MW and then drops until forecast error is greater than 150 MW. While we have not investigated this effect fully, we think this may be attributed to low forecast error occurring at times of high pricing in the market. As we noted at times when forecast error is low, there is likely to be little wind generation and greater likelihood of higher priced thermal generation. This point could be investigated in future studies.

It is important to note that the cost impacts presented in this report may have contributing factors other than wind forecasting accuracy. Other market events can occur that would result in a positive or negative impact on electricity spot prices (e.g., unplanned generation or network outages, changes to demand forecasts and/or generation offers). It is possible that these events occur at the same time as inaccurate wind forecast and contribute to price impacts. The impact of other events has not been controlled for.

Table 8: Distribution of price delta by forecast error and associated annual cost for a 42 TWh market.

Error ranges (MW)		Price delta ($/MWh)	Percentage of trading periods	Annual cost[33] (million $)
lower bound	upper bound			
-	-200	-$6.59	0.20%	-$0.54
-200	-150	-$10.42	0.79%	-$3.47
-150	-100	-$12.13	2.41%	-$12.27
-100	-50	-$13.53	8.14%	-$46.24
-50	0	-$3.60	20.97%	-$31.69
0	50	$6.15	33.76%	$87.28
50	100	$0.80	22.58%	$7.55
100	150	$1.72	8.12%	$5.87
150	200	$5.97	2.24%	$5.62
200	-	$1.99	0.79%	$0.66

The "*Error ranges (MW)*" column in Table 8 is an example of the data-binning technique that was discussed earlier in relation to Figure 7. The bin size of 50 MW was chosen to balance the need for a sufficient sample size within each bin with the attraction of results at a higher resolution. We reviewed the sensitivity of our binned data and checked the sensitivity to the choice of bin size by repeating the analysis for specific ranges of bin sizes. We have concluded that through our sensitivity analysis, our calculated results are reasonably robust. This is detailed more in Appendix A.

Table 9 below provides an overview of the impacts of different wind forecasting accuracy scenarios on price and behaviours.

Table 9: Overview of wind generation forecasting accuracy impacts on price

Scenario	Impacts of wind forecasting accuracy
Base case	Under a base case where wind forecasting is near perfect, we can expect that the amount of wind forecast ahead of a trading period is equal to the amount of wind dispatched in the respective trading period. As wind has a low marginal cost, any offered wind is likely to be dispatched and will put a downward pressure on the price.
Under forecast of wind	Our analysis finds that under forecasting of wind correlates with an average price decrease of approximately -$6.90/MWh. The 90% confidence interval for the decrease in price is from -$8.90/MWh to -$4.70/MWh. Historically, we find the total wind forecast has been over forecast 67.5% of the time and under forecast 32.5% of the time. Based on an annual average

[33] This column has been calculated by $(PriceDelta) \times (FractionOfTime) \times (AnnualDemand)$ and assumes an annual demand of 42TWh.

<table>
<tr><th>Scenario</th><th>Impacts of wind forecasting accuracy</th></tr>
<tr><td></td><td>

electricity consumption of 42 TWh, we find that the total annual cost associated with the price decrease is -$94 million.

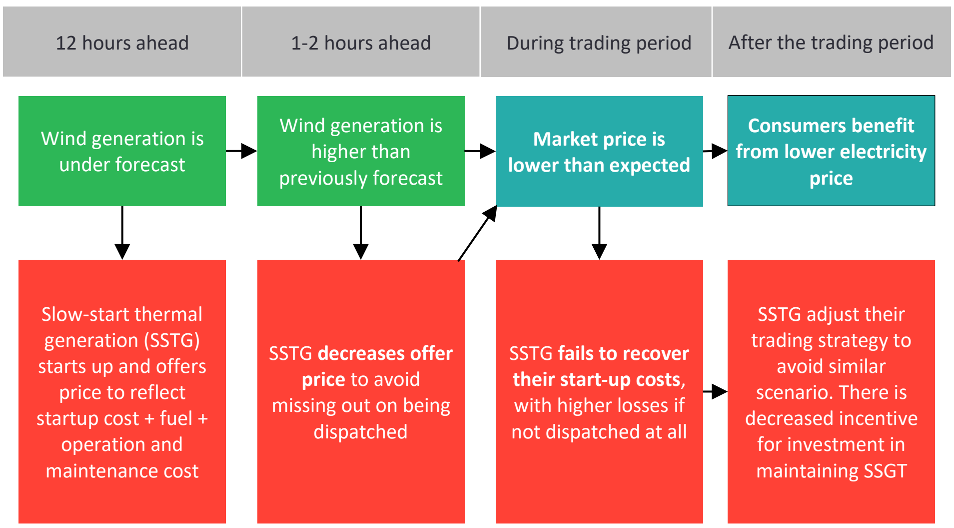
This price decrease is a weighted average across the historical levels of forecast inaccuracy (limited to times of underestimation). Note that our analysis does not consider the time of day when under forecasting occurs (e.g., during morning/evening peak periods compared to overnight). Further analysis is required to understand how this dimension impacts electricity price and the total annual cost.

This price decrease could be caused by (as shown below in Figure 8).

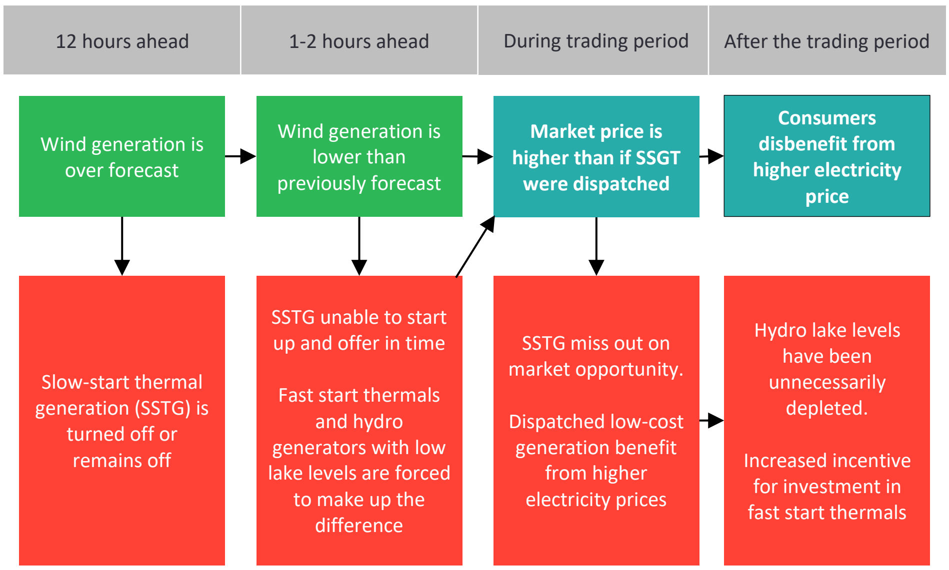
- Slow-start thermal generators being turned on with the expectation that they would be dispatched but are not dispatched. Because the unit does not generate, it would not put upwards pressure on the spot price. While consumers pay less for their electricity, the generator bears the sunk start-up costs.
- Slow-start thermal generators being turned on with the expectation that they would be dispatched but are dispatched or not fully dispatched. The generator may offer its generation (usually their minimum output and/or their contracted load) at a lower price to ensure that their load is dispatched and to gain some revenue. Generators tend to accept that they will not fully recover the costs of starting the plant. While consumers pay less for their electricity, the generator bears the cost of unrecovered revenue.

While a decrease in spot price is desirable for consumers, this may lead to increases in prices in future periods as generators seek to make good on unrecovered cost. Moreover, these costs are born by the thermal generators and not the wind generators giving inaccurate forecasts. In effect the cost of inaccuracy is being socialised.

Figure 8 under forecasting wind generation can lead to price decreases



</td></tr>
<tr><td>Over forecast of wind</td><td>Our analysis finds that over forecasting wind correlates with an average price increase of approximately $3.80/MWh. The 90% confidence interval for this price increase is from $2.50/MWh to $4.60/MWh. This price increase is likely</td></tr>
</table>

Scenario	Impacts of wind forecasting accuracy
	due to the dispatch of fast-start, higher cost generation to compensate for the loss of scheduled wind generation. Historically, we find the total wind forecast has been over forecast 67.5% of the time and under forecast 32.5% of the time. Based on an annual average electricity consumption of 42 TWh, we find that the total annual cost associated with the price increase is $107 million. This price increase is a weighted average across the historical levels of forecast inaccuracy (limited to times of overestimation). Note that our analysis does not consider the time of day when over forecasting occurs (e.g., during morning/evening peak periods compared to overnight). Further analysis is required to understand how this dimension impacts electricity price and the total annual cost. The price increase implies that the dispatched generation stack in this scenario is sub-optimal and does not support the Authority's statutory objective to promote efficiency and competition. If wind had been correctly forecast 12 hours ahead, then more economically efficient generation could have been dispatched prior to resorting to higher cost fast-start units (as shown in Figure 9). Again, the cost of the inaccuracy is not borne by the wind generators but socialised with consumers. In some cases, the wind generators may even receive a benefit from increased prices and therefore may not have sufficient incentive to increase the accuracy of their forecasts. Figure 9 wind generation can lead to price increases 

4. Summary of findings

In this study we set out to unpack the potential market impacts that inaccurate wind forecasting has on the electricity market. It has already been well established that wind forecast inaccuracy occurs consistently in the market and creates the potential for inefficiencies in the market operation. We also saw in the events that occurred on 9 August 2021 that inaccurate wind forecasting can contribute to security of supply events, as identified by MBIE in their report *Investigation into electricity supply interruptions of 9 August 2021*[34].

We focused our analysis on the impact of forecasts 12 hours ahead of a trading period due to our system's reliance on slow start thermal generation units - especially during periods of tight supply.

Our high-level analysis suggests that inaccurate wind forecasting can lead to impacts that work against the Authority's objectives to promote efficiency and competition in the market:

- **Underestimate forecasting of wind leads to average price decreases of approximately -$6.90/MWh, equivalent to -$94 million over a year.** While decreased electricity prices benefit the consumer, the decrease in pricing likely incurs costs to generators who start up their plants (particularly slow-start thermal units) with the expectation that they will be dispatched at a level that enables them to fully recoup their costs. They will either forgo the cost of plant start-up or not recover the full cost of generation. This could cause generators to factor this recovery into increased prices in future price periods. This dynamic does not promote market efficiency or competition, especially because the generators that bear this additional cost have little or no influence on the wind forecasting accuracy.

- **Overestimate forecasting of wind leads to average price increases of approximately $3.80/MWh, equivalent to $107 million over a year**. This price increase is likely due to the dispatch of fast-start, higher cost generation to compensate for the loss of scheduled wind generation. The price increase implies that the dispatched generation stack in this scenario is sub-optimal and does not promote market efficiency and competition. If wind had been correctly forecast 12 hours ahead then a more economically efficient generation unit could have been dispatched prior to resorting to fast-start units. Again, the cost of this inaccuracy is not borne by the wind generators.

Our high-level analysis also supports the argument that inaccurate wind forecasting can be a contributing factor to low frequency, high impact security of supply events that work against the Authority's objectives to promote reliability and efficiency.

It is expected that if the accuracy of wind forecasting increases, some of these costs may be avoided. In the unlikely situation where all wind forecasting becomes perfect, all these costs could be avoided. It is outside the scope of this report to assess the cost of, and limitations on improving wind forecasting accuracy.

As discussed in this report, there are several impacts that are directly and indirectly influenced by inaccurate wind forecasts. These impacts have associated costs that contribute to inefficiencies in the price discovery process, an upwards pressure on the wholesale electricity cost and/or additional costs borne to industry participants that are external to the electricity price. Further analysis is required to understand the extent to which each of these other impacts influence electricity price and which of these impacts have the greatest influence.

The benefit of improving wind generation forecasting accuracy should also be considered within the context of the transition to a zero-emission electricity system and other market changes. The system may become more sensitive to the accuracy of wind forecasts 12 hours ahead in some

[34] Investigation into electricity supply interruptions of 9 August 2021, Ministry of Business, Innovation and Employment

areas. For example, peak demand is expected to continue to grow and if generation capacity does not grow at a similar pace, then increasing peak demand is likely to increase the frequency of instances where supply is tight and more sensitive to the forecast accuracy of wind generation. This could result in more use of reserves for energy, load shed and scarcity pricing, all of which put upwards pressure on the electricity price.

In other areas, however, the impact of 12 hour ahead wind forecasts may become less material. For example, real-time pricing and the expected increase in demand-side participation is likely to increase the flexibility of the electricity system. this increases the ability for the electricity system to efficiently respond to fluctuations in intermittent generation at short notice and reduces the impact of inaccurate forecasts.

How each of these external changes are phased with any improvements to wind generation forecasting accuracy should be considered in more detail when developing any case for requiring improvements in wind forecast accuracy.

Appendix A Methodology for determining relationship between wind forecast accuracy and price

This appendix outlines the methodology and findings of the quantitative analysis of historical price and wind forecasting inaccuracy.

Summary

At the highest level, our analysis finds that:

- Over forecasting wind correlates with a weighted average price increase of approximately **$3.80/MWh**. The 90% confidence interval is from $2.50/MWh to $4.60/MWh.

- Under forecasting wind correlates with a weighted average price decrease of approximately **-$6.90/MWh**. The 90% confidence interval is from -$8.90/MWh to -$4.70/MWh.

The weighted averages in both cases are for periods of over forecasting and under forecasting respectively. Historically, we find the total wind forecast has been over forecast 67.5% of the time and under forecast 32.5% of the time.

To gain a deeper understanding of the relationship between price changes and forecast error, we have broken this down into a more granular level of detail in the table below:

Table 10: Detailed relationship between price changes and forecast error

Error ranges (MW)		Price delta ($/MWh)	Percentage of trading periods	Annual cost[35] (million $)
Lower bound	Upper bound			
-	-200	-$6.59	0.20%	-$0.54
-200	-150	-$10.42	0.79%	-$3.47
-150	-100	-$12.13	2.41%	-$12.27
-100	-50	-$13.53	8.14%	-$46.24
-50	0	-$3.60	20.97%	-$31.69
0	50	$6.15	33.76%	$87.28
50	100	$0.80	22.58%	$7.55
100	150	$1.72	8.12%	$5.87
150	200	$5.97	2.24%	$5.62
200	-	$1.99	0.79%	$0.66

[35] This column has been calculated by $(PriceDelta) \times (FractionOfTime) \times (AnnualDemand)$ and assumes an annual demand of 42TWh.

Input data

The input data for this analysis was drawn from a range of electricity market data sets held by the Electricity Authority. The structure and a sample of the data is shown in Table 11 below.

Trading date and period

Our analysis spans all trading periods between 1/11/2019 and 31/10/2022 (inclusive). A code change in 2019 allowed wind generators to make non-zero offers to the market. Therefore data prior to 1/11/2019 requires separate analysis. Data prior to 1/11/2019 was therefore excluded from our analysis.

We used the trading date and period, along with a flag for daylight savings, to establish a trading date/time in Coordinated Universal Time (UTC).

Actual total wind generation

The actual generation of wind farms was defined using reconciled wind data provided to us by the Electricity Authority. The data provided covered 1/1/2014 to 31/10/2022 (inclusive). For the reason discussed above, we have only used data between 1/11/2019 and 31/10/2022 (inclusive).

We draw attention to the treatment of Mahinerangi wind farm which is a 36MW wind farm – 4.5% of total installed wind capacity of around 800MW. Unfortunately, both Mahinerangi wind farm and Waipori hydro are embedded behind HWB0331. The reconciled wind data did not distinguish between generation from these two stations. Hence, we excluded Mahinerangi wind farm from our analysis.

Forecast wind generation

The forecast generation of wind farms was defined using offer data from the Electricity Authority's website[36]. We used offer data between 1/11/2019 and 31/10/2022 (inclusive). We used the variables *UTCSubmissionTime* and *UTCSubmissionDate* to identify the lead-time between when the offer was submitted and the time of the applicable trading period. Our analysis focused on the 12-hour lead-time forecast.

Forecast error

Forecast error was defined as

$$Forecast\ error = Forecast\ generation - Actual\ generation$$

Under this definition positive forecast error corresponds to "*over forecasting*" and negative error corresponds to "*under forecasting*". The forecast error varies with lead-time. To verify our analysis, we reproduced the forecast error plots in appendix A of the Electricity Authority's report[37]. This confirmed our analysis was consistent with that of the Electricity Authority.

Market prices

Price data was taken from the Electricity Authority's website. We used final pricing data at the OTA2201, HAY2201, and WKM2201 nodes in this analysis. Note that only the interim final pricing data is available for August 9th, 2021.

[36] Electricity Authority - EMI (market statistics and tools) (ea.govt.nz)
[37] Accuracy of Wind and Load Forecasts, April 2021 – March 2022, Information paper, 17 October 2022.

Table 11 Input data structure and sample data

52,608 data points in total

Trading Date	Trading Period	Trading DateTime_UTC12	Forecast MW	Generation MW	Error MW	Prices OTA2201	Prices HAY2201	Prices WKM2201
1/11/2019	1	31/10/2019 23:00	346.273	281.098	65.175	102.02	95.47	97.2
1/11/2019	2	31/10/2019 23:30	360.306	300.036	60.27	81.98	74.01	75.13
1/11/2019	3	1/11/2019 0:00	264.757	314.758	-50.001	102.2	94.61	93.91
1/11/2019	4	1/11/2019 0:30	261.096	309.426	-48.33	75.82	70.6	69.72
1/11/2019	5	1/11/2019 1:00	325.27	315.652	9.618	76.11	70.6	70.09
...								
31/10/2022	48	31/10/2022 22:30	177.92	90.904	87.016	38.79	38.89	36.62

Note: Column headings refer to the variables in relevant datasets and are defined as follows:

- forecastMW = forecast wind generation
- generationMW = actual total wind generation
- errorMW = forecast error
- priceOTA2201 = final market price at OTA2201
- priceHAY2201 = final market price at HAY2201
- priceWKM2201 = final market price at WKM2201

Source: Electricity Authority - EMI (market statistics and tools) (ea.govt.nz).

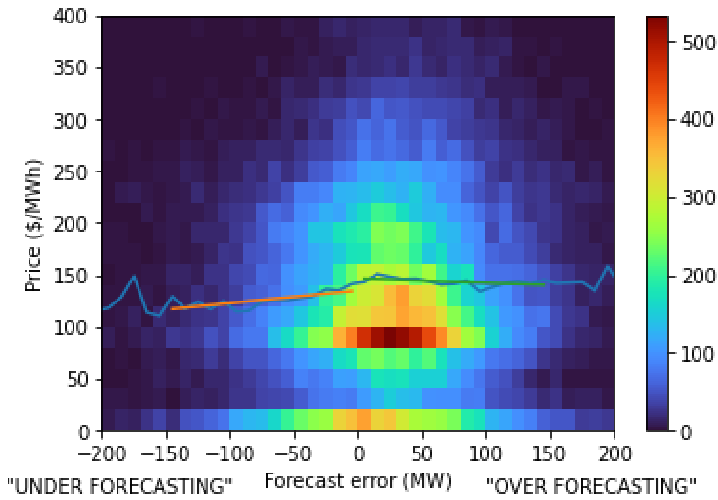
Calculating the impact on price of forecast error

Correlations between market prices and forecast error

We began by considering whether a direct correlation between market price and forecast error can be seen. We binned trading periods in 2 dimensions according to forecast error and price. Interestingly, we found that low forecast error (i.e., more accurate wind forecasting) was generally correlated with high prices.

This result can be seen in Figure 8 below where the price trend lines for under and over forecasting increase as the error tends to zero. The cause of this correlation can be supported by the observation that *"it is easier to forecast no wind than it is to forecast how much wind"*. An absence of wind is linked to an absence of an appropriate weather system while the strength of the wind is linked to the strength of the weather system. The latter is more difficult to forecast.

Figure 8: Relationship between wind forecast error and price in a trading period



Source: EY analysis.

About Figure 9: The coloured bins show the density of trading periods as a function of wind forecast error (horizontal axis) and price (vertical axis). In total there are 52608 (3 years' worth of) trading periods shown here. The solid line shows the mean price within each error bin. We also plotted linear trend lines (least squares) on either side of zero error.

The high prices observed when the forecast error is small is because these trading periods coincide with periods of low wind, which is when thermal generation is more likely to operate. Due to the higher costs of thermal generation, low wind periods tend to have higher spot prices.

Correlations between market prices, forecast error and total wind generation

To control for total wind generation on the system, we binned[38] the trading periods in 3 dimensions according to forecast error, total wind generation and price. This provides us with a distribution function for the distribution of trading periods according to forecast error, price, and total wind generation. This function is denoted as follows:

[38] A sensitivity analysis that investigated the materiality of the choice of bin size was also performed.

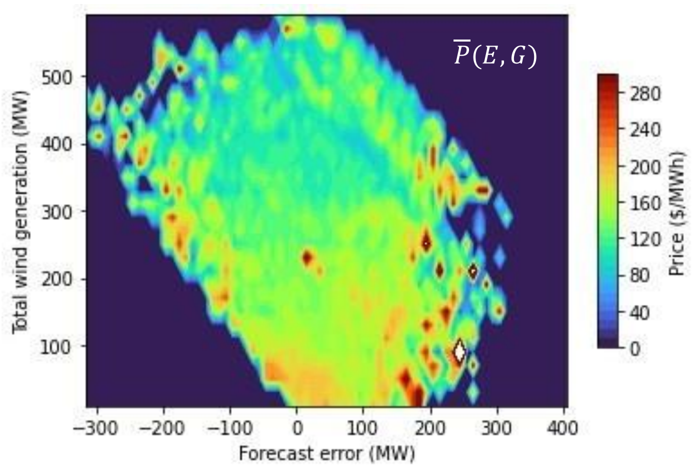
Equation	Explanation
$f_{3D}(E,P,G) = \textit{distribution of trading periods as a function of}$: $E = \textit{forecast error}$, $P = \textit{price}$, $G = \textit{actual total wind generation}$	The quantity f_{3D} is a distribution function (or probability density function).
	The function is created from the input data set described in Table 11.
	The function tells us how many rows in our dataset lie within the bin (or bucket) $[E, E + \Delta E]$, $[P, P + \Delta P]$, $[G + \Delta G]$.
	The function cannot be negative.

We began by finding the average price for a given forecast error and actual total wind generation. This was calculated using the equation below:

Equation	Explanation
$\overline{P}(E,G) = \frac{\int_0^\infty dP\, P\, f_{3D}(E,P,G)}{\int_0^\infty dP\, f_{3D}(E,P,G)}$	This is a standard formula for the mean value of a distribution.
	The integrals could equally be expressed as a sum.

We show the average price, $\overline{P}(E,G)$ in Figure 9. We note that certain combinations of forecast error and total wind generation are not possible. For example, it is not possible to under-forecast when the total actual wind generation is zero. Similarly it is not possible to over-forecast when the total actual wind generation is maximum. Obviously we did not observe any trading periods within these excluded regions. Any region where no trading periods were found are displayed as zero price priods in In Figure 9.

Figure 9: The average market price, $\overline{P}(E,G)$, as a function of forecast error and actual total wind generation.



Source: EY analysis.

We then used the 2-dimensional distribution function to average along the forecast error and total wind generation. This distribution function was calculated using the equation below:

Equation	Explanation
$\boldsymbol{f_{2D}(E,G) = \int_0^{\infty} dP\, f_{3D}(E,P,G)}$ $= \boldsymbol{distribution\ of\ trading\ periods\ as\ a\ function\ of}$: $\boldsymbol{E = forecast\ error}$ $\boldsymbol{G = actual\ total\ wind\ generation}$	By summing (integrating) over the price dimension, we reduce the 3-dimensional distribution function to a 2-dimensional one.
	An equivalent way to arrive at this 2-dimensional distribution function would be to bin data directly from Table 11.

To establish the impact on price we needed to compare with an *ideal scenario*, i.e., one where forecast error is zero (or close to zero). We therefore define the following ideal distribution:

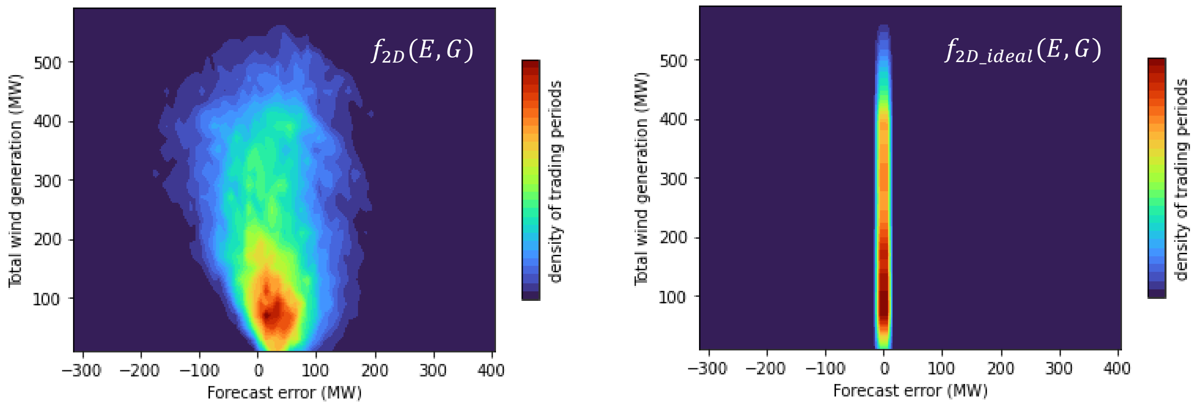
Equation	Explanation
$\boldsymbol{f_{2D\_ideal}(E,G) = \delta(E) \int_0^{\infty} dP \int_{-\infty}^{\infty} dE'\, f_{3D}(E',P,G)}$	By summing (integrating) over both the price and forecast error dimensions, we reduce the 3-dimensional distribution to a 1-dimensional one.
	This 1-dimensional distribution function is the distribution of actual total wind generation.
	An equivalent way to arrive at this 1-dimensional distribution function would be to bin data directly from Table 11
	We then multiply this by the $\delta(E)$ which is the *"ideal"* distribution of error wherein the forecast error is always zero.

In the formula for f_{2D_ideal}, the symbol $\delta(E)$ is the Dirac-delta, or unit impulse, function. This gives the distribution function zero width along the forecast error dimension – i.e., the forecast error vanishes. The distribution functions f_{2D} and f_{2D_ideal} are shown graphically in Figure 10.

It is important to note that the distribution functions f_{2D} and f_{2D_ideal} are normalized to the same value:

Equation	Explanation
$$\int_0^\infty dG \int_0^\infty dE\ f_{2D}(E,G) = \int_0^\infty dG \int_0^\infty dE\ f_{2D\_ideal}(E,G)$$	This formula simply tells us that the normalization of f_{2D} and f_{2D_ideal} is the same.
	This can be derived from the definitions of f_{2D} and f_{2D_ideal}

Figure 10: Both charts show the density of trading periods as a function of forecast error and total wind generation. On the left is the actual density from historical data, $f_{2D}(E,G)$. On the right is the ideal distribution in a situation where no forecast error occurs, $f_{2D\_ideal}(E,G)$.



Source: EY analysis.

The change in price due to forecast error was then calculated for each range of forecast error as follows

Equation	Explanation
$$\Delta\overline{P}_{Range} = \frac{\int_0^\infty dG \int_{Range} dE\ \left[f_{2D}(E,G) - f_{2D\_ideal}(E,G)\right]\ \overline{P}(E,G)}{\int_0^\infty dG\ \int_0^\infty dE\ f_{2D}(E,G)}$$	This equation defines the *"change in price"* (ΔP) for a forecast error that lies within a given forecast error range (*Range*).
	In this report we have set *Range*, to reflect the different intervals of interest: ▪ $E > 0$ (over forecasting) ▪ $E < 0$ (under forecasting) ▪ $0 < E < 50$ ▪ $50 < E < 100$ ▪ … etc.
	The ΔP is the difference in price between trading periods that have forecast error lying within *Range* and trading periods that have zero (or close to zero) error.
	Crucially, the difference only involves trading periods with the same (or similar) amounts of actual total wind generation. This means the direct correlation between price and forecast error has been accounted for.

The price deltas that are discussed in the main body of the report are calculated using this equation.

Sensitivity

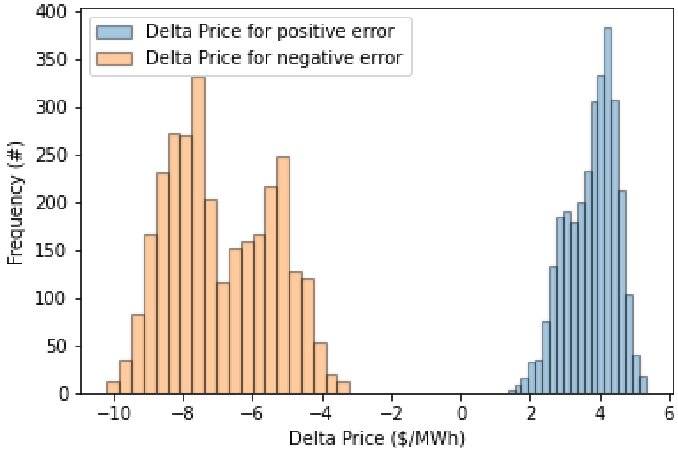
We performed a sensitivity analysis to assess the robustness of our conclusion. We repeated the calculation of $\Delta\overline{P}_{Range}$ using 3,000 distinct choices of bin size and price data.

In our analysis we binned the data according to forecast error, total wind generation, and price. We have checked the sensitivity to the choice of bin size by repeating the analysis for the following range of bin sizes

- 10 values of forecast error bin width, equally spaced between 20MW and 100MW
- 10 values of total wind generation bin width, equally spaced between 20MW and 100MW
- 10 values of total wind generation bin width, equally spaced between \$20/MWh and \$200/MWh

Calculation of $\Delta\overline{\overline{P}}_{E>0}$ and $\Delta\overline{\overline{P}}_{E<0}$ was performed for every combination of price data and bin volume. The distribution of results is illustrated in **Error! Reference source not found.**.

Figure 11 shows the range of $\Delta\overline{\overline{P}}_{E>0}$ and $\Delta\overline{\overline{P}}_{E<0}$for all different choices of bin sizes and point of connection price data.



Source: EY analysis.

Our sensitivity analysis reveals that our conclusions are robust with respect to choices around discrete data binning and price data. For bins volumes differing by a factor of 250 and three choices of POC price data, our conclusion remains reasonably tightly bound (variance is less than a factor of 2). In addition to the mean-value of this analysis, we report the 90% confidence intervals to provide perspective on this sensitivity.

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