Electricity Authority
Te Mana Hiko

Making hours-ahead price forecasts more accurate

Consultation paper

Submissions close: 5pm on 4 April 2017

9 February 2016

Executive summary

The Authority has been considering ways to improve the accuracy of prices in the forecast schedules available up to 36 hours in advance of real-time. This is one of two spot market refinements we are exploring.

We expect that making hours-ahead forecast prices more accurate would encourage more efficient demand-response and generation scheduling.

We also expect that it would benefit those parties looking to employ new technology and business models. Some of these developments allow electricity consumers to reduce their costs and increase their revenues by shifting their electricity use (eg, charging a battery) or by reducing demand or increasing their generation (eg, discharging a battery) during high price periods. Both consumers and generators can improve their decision making if they can rely on forecast prices produced hours in advance.

Improving the reliability of forecast prices available hours in advance would promote all three limbs of the Authority's statutory objective.[1] It would promote efficient short-term (that is, operational) decisions about demand-side participation and generation dispatch. Longer term, it would improve decisions about generation investment and retirement, as well as promoting retail innovation and confidence in the wholesale market.

Differences in the inputs used to produce forecast and real-time prices[2] (eg, mass-market demand or 'conforming load', and wind generation) are the main reason for errors[3] in short-term price forecasts. Forecasts can never be 100% accurate, but there is evidence the existing arrangements can be improved.

We have considered two broad approaches to improving the accuracy of forecast prices:

1. Continue with the administrative approach – continue to rely largely on administrative arrangements but improve the inputs used to generate forecast prices, focussing initially on the conforming load forecasts.
2. Adopt a more market-based approach – move closer to arrangements that would have wholesale market purchasers and sellers internalise the costs of inaccurate information.[4] Parties uncertain about their generation or demand choices would face the costs of any late changes, encouraging them to make trade-offs between bearing this cost or improving the accuracy of their forecast inputs.

The Authority has identified and assessed four specific options for improving spot price forecasts. The first two seek to improve pricing inputs while retaining a reliance on an administrative approach. The second two options would use a market-based approach (an

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1 The Authority's statutory objective is to promote competition in, reliability by, and efficient operation of the electricity industry for the long-term benefit of consumers.

2 The Authority is currently investigating introducing a dispatch-based real-time price to replace the existing ex-post thirty minute price. This paper uses "real-time prices" when discussing possible outcomes to mean the prices the market would settle at.

3 This paper uses the term 'error' in a technical sense, to refer to differences (from any source) between forecast and actual values. The use of this term should not be interpreted as making any judgement on the performance of parties that contribute to forecasts.

4 In some cases, the causer of the deviation (generation or demand) from the quantity forecast may not be the party that participates in the wholesale market. For example, wholesale purchasers' demand quantities can be affected by the actions of retail consumers and other parties who have rights to exercise control over that demand.

hours-ahead market) requiring wholesale market generators and purchasers to provide their own forecasts and internalise the costs of inaccurate pricing inputs.

The four options are:

Option A: improve inputs into price forecasts under existing incentive arrangements (administrative/beneficiaries pay arrangements)

Option B: improve inputs into price forecasts and improve incentives (beneficiaries/exacerbators pay arrangements)

Option C: encourage a voluntary hours-ahead market (market-like arrangements)

Option D: pursue a formal hours-ahead market (market-like arrangements).

We prefer Option A as the best approach at this stage. We think it will provide worthwhile net benefits, and that it has relatively low risks. Although the other options could provide higher benefits in some scenarios, they are subject to greater levels of uncertainty and have more implementation risk.

Although we prefer Option A as the next step forward, we might choose to adopt one of the other options at a later stage, in keeping with advice we received from the Wholesale Advisory Group (WAG). We think it is important to maintain that optionality as we are mindful that technologies and business models are evolving rapidly in the electricity sector. For example, widespread uptake of electric vehicles could make price forecasts more important to enable better optimisation of battery recharging. In that case, it could become worthwhile to move to one of the other options.

At this point, the Authority is inviting submissions on whether to seek improvements to the conforming load forecast as a step toward exploring other options at a later date.

Contents

Tables

Figures

2 What you need to know to make a submission

2.1 What this paper is about

2.1.1 This paper sets out options to improve the accuracy of price information in the wholesale electricity market in the hours leading up to real time. We seek your views on our conclusions.

2.1.2 Some consumers and generators cannot react instantly to real-time prices and need to make operational decisions based on forecasts of spot prices. Improving the forecasts of real-time prices or providing firm prices ahead of real-time, or both, should increase the likelihood that parties consume or generate power when it is economical.

2.2 What you need to do

2.2.1 Please deliver your submissions by **5pm** on **4 April 2017**.

2.2.2 Send your submission (using Microsoft Word in the format shown in Appendix A) by email to submissions@ea.govt.nz with “Consultation Paper— Making hours-ahead price forecasts more accurate” in the subject line.

2.2.3 If you cannot email your submission, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

Postal address

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Physical address

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

2.3 What we will do

2.3.1 We will acknowledge receipt of all submissions. If you do not receive acknowledgement of your submission within two business days, please contact the Submissions Administrator by sending an email to submissions@ea.govt.nz or phoning 04 460 8860.

2.3.2 We will publish all submissions. If you do not want us to publish part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part

(c) provide a version of your submission that we can publish (if we agree not to publish your full submission).

2.3.3 If you tell us you do not want us to publish part of your submission, we will talk to you before deciding whether we will publish that part.

2.3.4 However, please note that under the Official Information Act 1982, any person can request copies of submissions we receive, including any parts that we do not publish. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you did not want us to publish.

3 The Authority wants to improve the accuracy of hours-ahead price forecasts

3.1 Spot market refinements project

3.1.1 In July 2015, we announced the Authority would explore two potential refinements to the spot market:[5]

(a) settling on prices based on system conditions in real time

(b) adding or facilitating an hours-ahead market.

3.1.2 We explained that priority would be given to real-time pricing (RTP), as some hours-ahead market options depend on decisions about RTP. In April 2016, we published a paper setting out four possible RTP options. After considering feedback on the paper, we selected a preferred option which we are now developing in more detail (including proposed amendments to the Electricity Industry Participation Code 2010 (Code)) for consultation in first half of 2017.[6]

3.1.3 This paper focuses on the second of the possible spot market refinements – which was to add, or facilitate, an hours-ahead market. This market would allow parties to make decisions about consumption or generation based on firm prices determined ahead of real time. An hours-ahead market could benefit parties who need more than a few minutes to alter their consumption or generation decisions and who therefore cannot readily react to real-time prices. It would also support the use of more sophisticated algorithms for those with limited flexibility around generation and demand (eg, charging and discharging batteries).

3.1.4 Although this paper examines an hours-ahead market, it also looks at the broader issue of how to improve the accuracy of price information for people in the hours leading up to real time. Hence, this paper considers options to improve the accuracy of hours-ahead price forecasts, some of which would involve developing an hours-ahead market.

3.2 Accuracy of forecast information is important

3.2.1 We have received feedback from parties that suggests the Authority should seek to improve the accuracy of forecast information in the spot market. For example:

1. Flick Electric stated that "the EA should strive to find a market mechanism that locks in prices prior to commencement of each trading period [...] providing spot price certainty just ahead of real time is a significant enabler for smart grid technologies."[7]

2. Meridian considered that "improving the current approach to short-term demand forecasting could bring significant benefits at relatively low cost". [8]

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5 See www.ea.govt.nz/dmsdocument/19860.

6 For more information, see www.ea.govt.nz/dmsdocument/20599.

7 Flick Electric submission on Electricity Authority paper on 'Options to improve retail competition - Findings of the spot market review'. See https://www.ea.govt.nz/dmsdocument/19359. Note that Flick Electric supported the introduction of real-time pricing as the priority, with the potential benefits of an ahead market to be considered later.

8 This view (and those in subsequent bullet points) was expressed in a submission on the recent consultation regarding real-time pricing options. See www.ea.govt.nz/development/work-programme/pricing-cost-

3. Mighty River Power (now called Mercury) stated that there is “value in improving the demand forecasts applied to the calculation of the various SPD forward pricing schedules”. It also referred to the importance of improving wind generation forecasts.
4. Contact stated that “an increase in the accuracy of demand forecasting would provide more actionable prices”.
5. NZX stated that “improvements in demand forecasting would improve the alignment between forecast and final prices and reduce short-term spot price uncertainty.”

3.2.2 Market performance inquiries undertaken by the Authority have also considered forecasting issues (both demand and generation). For instance, the inquiry into winter grid emergencies in 2014 highlighted the importance of accurate forecast prices in encouraging greater participation.[9]

3.2.3 In September 2016, the Authority released a post-implementation review of the Demand Side Bidding and Forecasting (DSBF) initiative.[10] DSBF sought to improve the reliability of price forecasts by allowing demand-side parties to signal how their demand could change at different prices and incorporating these bids into price forecasts.

3.2.4 In overall terms, the DSBF review found that forecasts using price-responsive bids performed better than those without this information. However, the review also found evidence to suggest that, even after including price-responsive bids, price forecasts are biased and/or inefficient. This suggests that there is scope to further improve the quality of price forecasts.

3.2.5 More generally, the Authority recognises that forecast information is important to people because:

1. Some consumers have potential to alter their electricity use depending on wholesale prices, but need some lead time to optimise their scheduling decisions. For example, consumers with electric vehicles (EVs) could make better decisions about when to charge their batteries if price forecasts are more reliable. In principle, EVs could even be a potential power source at times, by injecting into the network during periods of extremely tight supply.
2. Some generators have significant start-up times and costs and need to decide whether to make their plant available hours before real time. Often, once started, the units must run for a minimum number of hours. These parties also rely on forecast price information to make their scheduling decisions.

3.2.6 In both cases, the scheduling decisions of these parties increases in importance when they are large enough to affect spot prices.

3.3 Illustrative examples where better forecast prices would be useful

3.3.1 Parties face uncertainty in many variables that affect their wholesale market positions, such as overall demand, the grid configuration and wind generation levels. However, for

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allocation/exploring-refinements-to-the-spot-market/consultations?c%5B15922%5D%5B4%5D%5Bstart%5D=10.

9 See www.ea.govt.nz/dmsdocument/19274.

10 See www.ea.govt.nz/dmsdocument/21265.

decision-making purposes, the accuracy of price signals is the most important issue as errors can cause regrets that have significant financial consequences.

3.3.2 Having access to accurate price forecasts would help people use the flexibility in their timing of demand or generation to achieve the best financial outcome. To facilitate this, it would be beneficial to address the underlying factors causing price forecast errors, recognising some are more important than others.[11]

3.3.3 Examples of these effects are illustrated in the boxes below.

Scheduling manufacturing processes – an industrial consumer

A large factory can temporarily cut its power use, provided it gets at least two hours' notice for an orderly shutdown. While shutdowns cause a business cost, when electricity spot prices are high enough for long enough it is still financially beneficial for the factory to cut its output, temporarily.

The factory owner would like to use this demand response capacity to save money. However, she has found spot price forecasts to be inaccurate predictors of real-time prices when the system is tight. She finds that reducing demand based on forecast prices often yields far less reward than expected. Situations also occur where real-time prices are very high but forecast prices before real-time were moderate. Owing to the risk of these outcomes, she decides not to make use of the factory's demand response capacity.[12]

Shorter-term impact: the factory is unable to correctly anticipate high spot prices so it opts for a fixed price which results in the factory consuming power when it would otherwise be more efficient for it to shut down.

Longer-term impact: not using the factory's demand response capacity means that peak demand is higher than otherwise, which results in greater investment in (higher cost) generation.

Generation scheduling – hydro generator

A hydro generator has stored water in an upstream reservoir that it can release to increase generation at its stations for each morning and evening demand peak. Once water reaches a station, storage capacity is limited, so water needs to be used within a few hours or it will be spilled without generating electricity. The generator can maximise the energy conversion efficiency of its stations if it generates when it can take advantage of high prices and minimise the quantity of water spilled.

The generator wants to optimise the release of water and short-term running patterns to maximise overall revenue, taking account of energy conversion and environmental (river flow) requirements. Expected prices over the next few hours are a key input into its optimisation decisions.

Under existing arrangements, the generator faces uncertainty over prices even a few hours ahead (in part because of inherent uncertainties). If forecast prices were more

11 As discussed in section 4.2.

12 Alternatively, she could only react at a much higher price threshold, foregoing opportunities to save costs at times.

accurate, it would be able to take greater advantage of whatever flexibility it has in the timing of its generation.

Shorter-term impact: electricity costs are higher because water is sometimes spilled unnecessarily, and/or thermal fuel is sometimes burnt when hydro generation would be more efficient. Futures contracts and retail prices are also higher as a result.

Longer-term impact: investment in some types of plant may be affected.

Innovation – smart charging/recharging

Technology change is making it easier for residential and small commercial consumers to alter their electricity use in response to spot prices. Smart control devices can schedule the timing of electricity use, such as recharging of electric vehicles, heating of water cylinders, and discharge/recharge of home batteries.

However, these decisions could produce higher benefits if the control logic could access both real-time and forecast prices, if they are sufficiently accurate.

For instance, setting up simple logic for an electric car battery to recharge whenever the real-time price is below a price threshold does not guarantee the car battery will recharge long enough to be fully charged by morning. To ensure it does, the requirement to have the battery fully charged by the morning can override the price threshold. This logic does not require any consideration of forecast prices.

However, if forecast prices are available and sufficiently accurate, it would make financial sense to adjust the logic to recharge the battery during the cheapest four hours while it is in the garage overnight (while ensuring a fully charged battery by morning). This same logic might be adapted for similar activities such as heating hot water cylinders and charging and discharging storage batteries.

Consequently, the accuracy of forecast prices influences the benefit that smart control devices can capture – improving their accuracy allows better optimisation and financial benefits, which will in turn encourage a greater uptake of smart technology.

Shorter-term impact: the reward from better optimising charging and discharging routines is lower. If use of this device increases, it will have greater influence over spot prices, with the effect of reducing the accuracy of the conforming load forecast.

Longer-term impact: sources of innovation are hindered as efficient demand response by residential and smaller commercial consumers is limited to energy sources and uses that do not need a lead time and can be interrupted and started at any time. This results in higher overall demand at times of system peak, and higher investment in more costly generation capacity.

Generation scheduling – large thermal generator

A large thermal station requires six hours to warm up and must run for a minimum of six hours once it has started. Because of its size, the decision about whether to run can have a significant effect on spot prices.

The generator has found price forecasts to be an unreliable predictor of real-time prices. It therefore applies a ‘risk premium’ to price forecasts. This makes the generator less willing to turn the plant on or off, as both actions incur future start-up costs that it might not recover.

Shorter-term impact: generation operating costs are higher than is necessary (wasted fuel burn or unnecessary running of higher cost plant at times).

Longer-term impact: may lead to sub-optimal investment and/or retirement decisions.

3.4 Measuring the accuracy of price signals

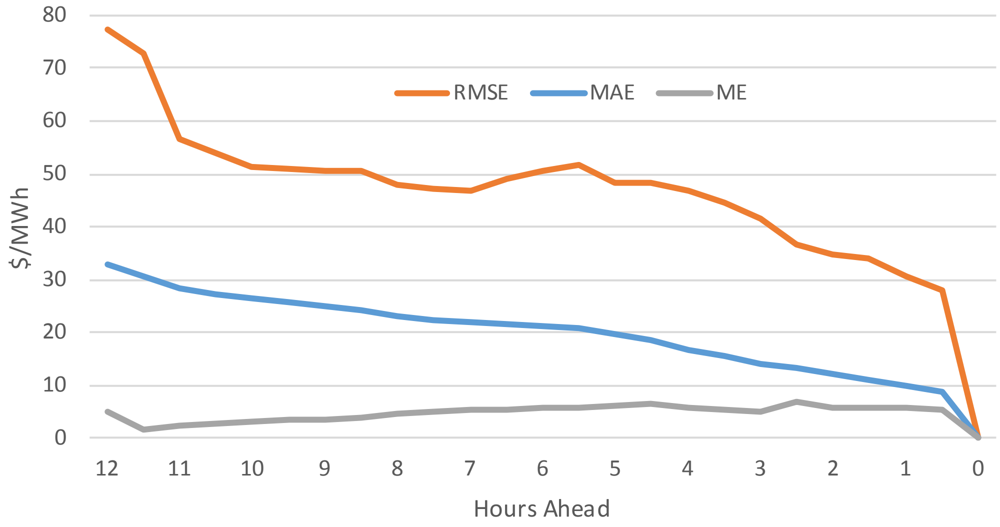
3.4.1 The accuracy of forecast prices can be measured in several ways. One measure is the mean absolute error (MAE) between forecast and final prices across all trading periods.[13] This provides an indication of the typical level of forecast error. However, bigger errors are arguably more important than smaller ones, because they are more likely to alter behaviour and cause efficiency losses. A measure that puts greater weight on large errors is the root mean square of errors (RMSE). Also of interest is the mean error (ME), which is simply the mean difference between the forecast and final prices, preserving positive and negative differences. This measure shows any bias present in the forecasts. An unbiased forecast would have a ME of 0, while a positive ME indicates final prices higher than forecast prices and vice versa.

3.4.2 Figure 1 shows these measures based on Otahuhu price data for the period from January 2013 to July 2015 inclusive. Both forecast and actual price data have been capped at $2,000/MWh, to remove the effect of 'very extreme' prices.[14] It is noticeable that all measures of error generally reduce as real-time approaches. However, they also show significant uncertainty in forecast prices in the hours ahead of time. For example, 12 hours ahead of time, the MAE was over $30/MWh, which is relatively high given that average final prices were around $75/MWh over the period. There is also a bias in forecasts, with final prices averaging about $6/MWh higher than forecast prices at 6 hours ahead of time. This difference is roughly consistent month to month, although it can range from slightly negative to greater than $10/MWh.

[13] "Final" prices were used for the analysis, because they are a better indicator of real-time prices used for settlement.

[14] Final and forecast prices have been capped at $2,000/MWh. This is a design choice. Extreme forecast prices are not considered to be reliable because they are not subject to the same post event checks as final prices. There is arguably little difference in system conditions in extreme and 'very extreme' final prices, but they have a large impact on error metrics.

Figure 1: Uncertainty in forecast prices (Jan 2013 – July 2015)



3.5 The potential benefits from more accurate price signals

3.5.1 The Authority expects more accurate price signals to provide various benefits, including:

1. Generation (productive) efficiency – generators that have significant start-up costs and/or lead-times should make better commitment decisions, leading to lower fuel, operating and maintenance costs.
2. Improved voluntary demand response – consumers could benefit from more reliable notice to reduce their use during high price periods, and/or re-schedule their demand into lower price periods. It should also enable consumers to more easily participate as dispatchable demand. This requires consumers to respond within the half-hour to dispatch instructions, which precludes some demand from participating. With more reliable forecast information (multiple hours), a greater proportion of demand may be able to participate.
3. Reliability – improved forecasts would increase the likelihood of having levels of generation offered that are efficient (eg, sufficient to meet demand plus a margin to cover contingent events).
4. Competition and innovation benefits – improved forecasts would improve competition at certain times, especially by enabling improved participation from demand response providers. This should place downward pressure on electricity prices.

3.6 Improving price signals fits with the Authority's statutory objective and priorities

3.6.1 Improving the accuracy of hours-ahead price forecasts would promote all three limbs of the Authority's statutory objective:[15]

15 The Authority's statutory objective is to promote competition in, reliability by, and efficient operation of the electricity industry for the long-term benefit of consumers.

1. Competition would be enhanced via increased scope for consumers to manage their demand in response to prices.
2. Reliability would be enhanced by reducing the need for peaking generation or involuntary load curtailment, when a more efficient alternative is available. More accurate price forecasts would promote more efficient short-term (ie, operational) decisions, such as ensuring that lowest-cost resources are employed.
3. Efficiency would be promoted if price forecasts were more accurate. Inaccurate price forecasts artificially increase the value of generation and demand response able to immediately respond to price signals and discounts the value of generation and demand response that needs some notice to respond. More accurate price forecasts would increase the pool of parties that can respond. This would ensure the lowest-cost resources are employed in both the short term (ie, decisions in real time) and in the long term (ie, investment decision making).

3.6.2 Improving the accuracy of price signals also fits with the strategic focus set out in our work programme.[16] In particular, it will contribute to improved consumer choice and competition, and encourage the efficient uptake of evolving technologies and business models.

16 See https://www.ea.govt.nz/dmsdocument/20821 for full information on the Authority's strategies and work programmes.

4 Why forecast prices are inaccurate

4.1 Changes in input quantities and prices are the main cause of price forecast errors

4.1.1 The same market software calculates both forecast and final prices.[17] Differences between them arise because of differences in inputs, which include demand bids, generation offers and grid configuration. For example, forecast prices are based on the projected levels of demand and wind generation at the time each forecast is compiled, whereas final prices are based on their actual levels.

4.2 Contribution to forecast errors varies by input

4.2.1 To improve the reliability of forecast signals, it is important to understand which inputs are the main cause of errors. The Authority analysed four inputs:[18]

1. load forecasts at conforming GXPs (ie, consumer demand except the largest industrial consumers. Demand is net of any unoffered generation behind the GXP)
2. load bids at non-conforming GXPs (ie, demand from large industrial consumers)
3. intermittent generation forecasts/offers (ie, wind generation)
4. scheduled generation offers (excluding intermittent generation).

4.2.2 To assess the impact of conforming load errors on forecast prices, we first ran a version of the market software (vSPD) with inputs for final prices (including actual demand at conforming GXPs) and then ran it again with the conforming load forecast from the Price Responsive Schedule[19] (PRS) 3½ hours ahead. Any differences between the two runs were due solely to the different conforming load forecast. The Authority performed this process for every trading period during four separate months: June 2015, September 2015, March 2016, and April 2016. Other inputs were treated similarly.

4.2.3 Figure 2 shows the resulting price variances for each trading period in September 2015. The error values vary each trading period and are normally close to zero. However, occasionally they can be much larger, ranging from about 100 $/MWh to about 300 $/MWh.

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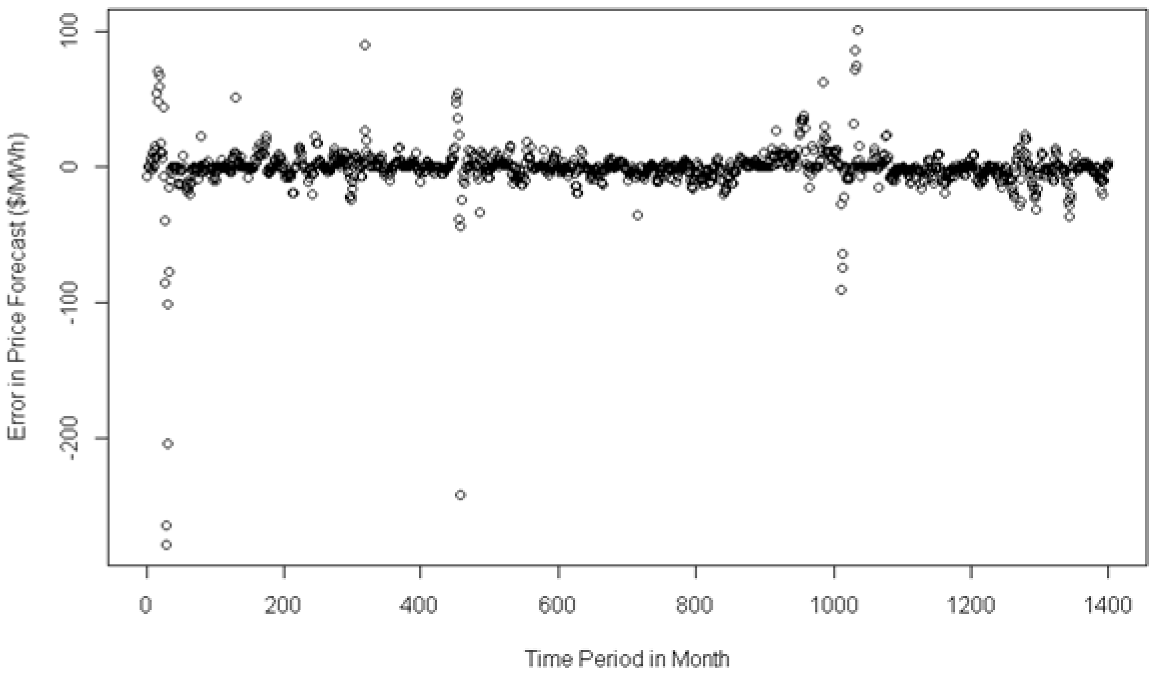
17 The software is used for scheduling, pricing and dispatch, and is often referred to as 'SPD'.

18 The analysis excludes some other factors that affect prices, such as changes in grid availability between forecast and real-time, and the effect of ramp rates. All such effects combined amount to about 10% of total price differences. This is non-negligible, but is smaller than each of the inputs considered.

19 A price responsive schedule issued within 3 ½ hours of real-time is referred to as a PRS Short. A schedule issued more than 3 ½ hours ahead of real-time is referred to as a PRS Long. The term PRS is used to refer to both types.

Figure 2: PRSS conforming load price error for September 2015



4.2.4 To enable comparisons in error contribution across different inputs, the Authority calculated two different measures of the errors:

- Mean Absolute Error (MAE)[20] – this provides the 'typical' error in any trading period.
- Root Mean Squared Error (RMSE)[21] – this applies more weight to the largest errors meaning that a small number of large errors can result in a high RMSE.

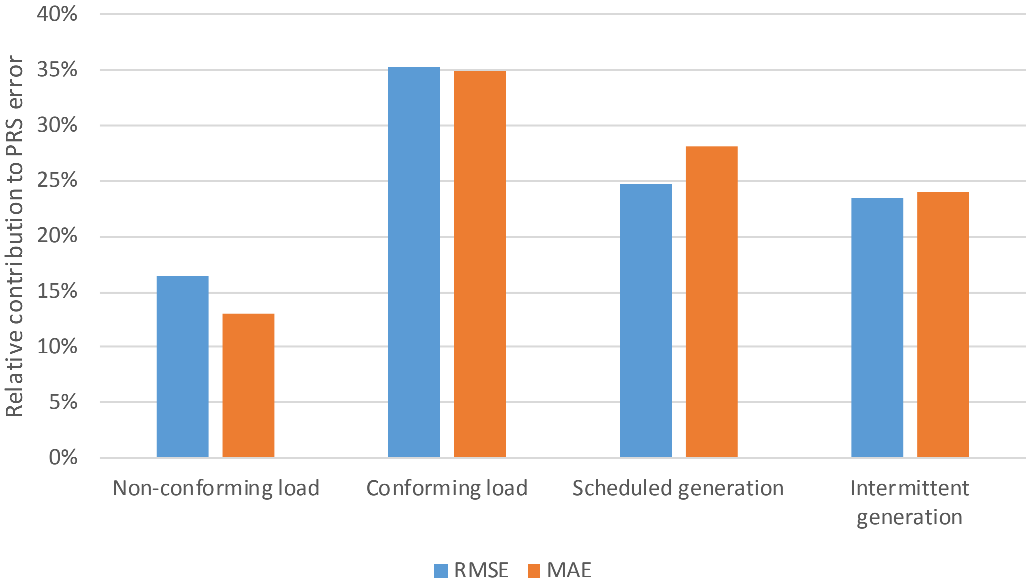
4.2.5 Figure 3 shows the relative contribution of each forecast input to the overall price error (expressed as final price minus forecast price).[22] It shows that all four inputs contribute to the overall error.

20 The mean of all the price errors (expressed as positive values to avoid unders and overs cancelling out).

21 The square root of: the sum of the squares of the errors divided by the number of observations.

22 The size of each input error is shown relative to sizes of the other input errors. They are presented so that the total of the errors adds to 100%.

Figure 3: Contribution to forecast price error 3 ½ hours before real-time



4.2.6 We repeated the exercise for other months to increase our confidence in the results (June 2015, March 2016, April 2016). Conforming load is the largest error source, accounting for ~35%, which is slightly more than twice that of non-conforming loads' 13-16%. Scheduled and intermittent generation contribute a similar amount each of about 24-28%. The MAE measure is more stable across different months, because large errors influence it less than the RMSE.

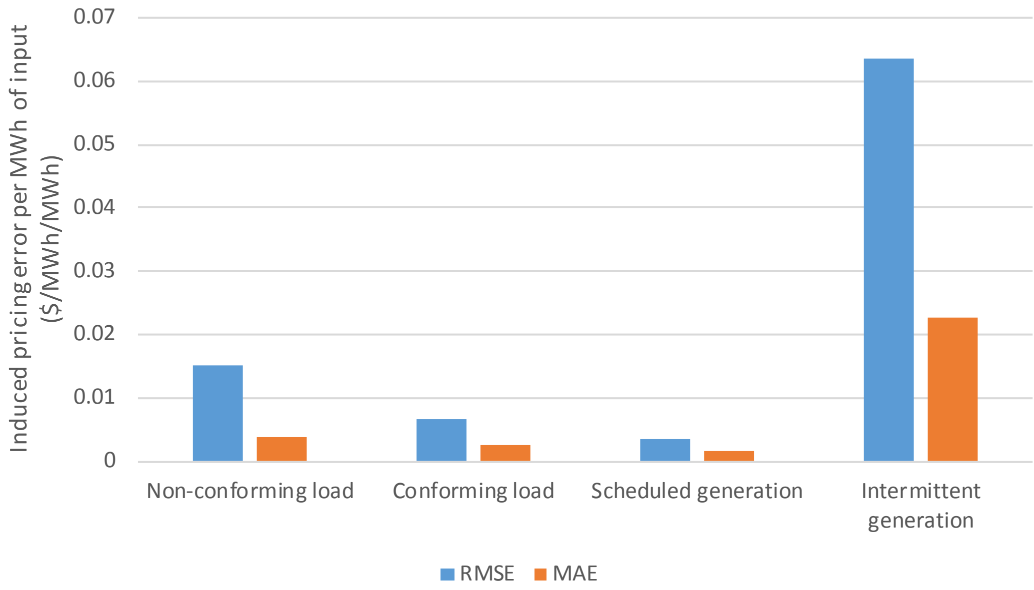
4.2.7 Figure 3 shows the relative contribution of each input to the total error in price forecasts, and ignores the fact that the inputs vary in their absolute size. There is more scheduled generation than intermittent generation, and more conforming load than non-conforming. Figure 4 shows the "MWh adjusted" error. The y axis is the uncertainty in the forecast price caused by a MWh of each input.[23] Intermittent generation is clearly the highest contributor on this measure, because although it contributes a similar amount to forecast price uncertainty overall, there is less intermittent generation than other inputs (when measured in MWh).

4.2.8 Ultimately the size of the impact on the system is what "matters" – the relative size of the contributor in MW does not change how they affect the accuracy of forecast prices. However, the large differences in "MWh adjusted error" (as defined in paragraph 4.2.7 above) suggest that increasing intermittent generation would increase the error in price forecasts more than increasing any of the other inputs.[24]

[23] For example, 0.04 means that for each MWh of wind generation output in the period, there was an error contribution of $0.02/MWh.

[24] Assuming the forecasts provided for new generation are no better than the average shown in Figure 4.

Figure 4: Pricing error scaled by size of input

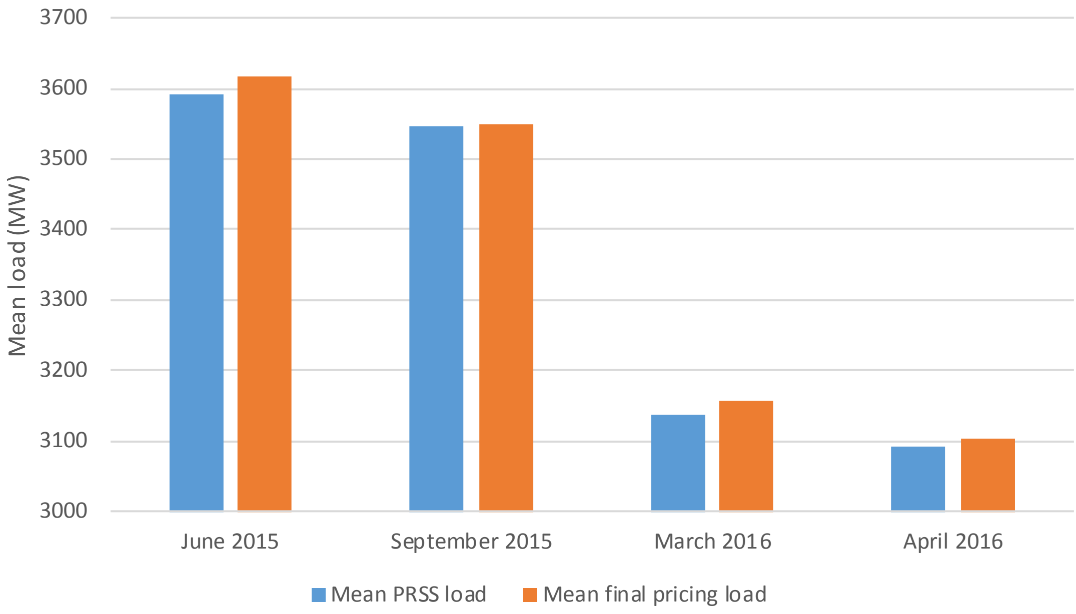


4.2.9 As shown in Figure 3, no single input accounts for most of the forecast errors (measured by MAE or RMSE). Furthermore, the overall error reflects the combined impact of the different contributors. Statistical theory tells us that improving the accuracy of one category's inputs will produce a less than proportional improvement in the overall error. For example, a 50% reduction in conforming load error is expected to reduce the overall error by approximately 19%.[25] Conversely, improving the accuracy of all contributors to the error will yield a proportional improvement in forecast accuracy. For example, if all individual contributors were improved by 19%, that would also improve the overall error by 19%.

4.2.10 One notable source of error in the conforming load forecast is a persistent bias. The mean error in Figure 1 above, shows that final prices are usually higher than forecast prices (as evidenced by MAE being positive). Similarly, Figure 5 shows that conforming load in the final pricing schedule is usually higher than in PRS (averaging 16MW higher for the four months analysed). All other things being equal, higher demand will lead to a higher price, so it is likely that these effects are related.

25 Statistical theory indicates the overall error will be equal to the square root of the sum of the squares of individual errors, provided the individual sources are independent of each other. Statistical tests of the data suggest that the sources of error are largely independent of one another in this case.

Figure 5: Difference between PRSS and Final Pricing mean load



5 Improving the reliability of forecast information

5.1 What better arrangements would achieve

5.1.1 Better information leading into real time would yield benefits as discussed in section 3.5. However, improving the quality of the inputs into the forecasting process will incur a resource cost. For example, intermittent generators may need to apply greater effort to meteorological forecasts to improve the predictions about the level of wind generation. Similarly, more forecasting effort would be needed to reduce the differences between predicted and actual demand at non-conforming GXPs, which would likely incur a greater cost.

5.1.2 From an economic perspective, the issue can be viewed as optimising the effort that parties should apply to forecasting accurately– recognising that applying additional effort has both benefits and costs.

5.2 Optimising resources applied to establishing quantities and prices in forecast schedules

5.2.1 The Authority has previously described its preferred decision-making and economic (DME) framework in relation to electricity transmission charges.[26] It sets out a hierarchy of preferred arrangements directed at maximising economic efficiency, and ensuring the optimum level of resource is applied.

5.2.2 The principles in that framework, applied here, provide the following hierarchy (in descending order of preference):

1. Market-based or market-like arrangements – each participant decides the effort they put into providing accurate forecast information, while directly facing the benefits and costs associated with their choice. A market-based approach tends to be more efficient than other approaches because parties, in a workably competitive market, can seek to achieve efficiency gains whenever and wherever possible. The main reasons a market-based option may not be the most efficient are because there is little competition or because the option may impose transaction costs greater than the efficiency gains.
2. Incentivise exacerbators - exacerbators are parties whose action or inaction leads to a cost from forecast errors, and who would change their behaviour if faced with the social cost of their action or inaction.
3. Recover costs from beneficiaries – a beneficiary is a party for whom the private benefits of an action exceed its share of the costs, and who would therefore be willing to pay a portion of the cost if that were the only means of acquiring the benefit.
4. Alternative administrative options – where it is impractical to adopt 1, 2 or 3, it may be necessary to socialise some costs of forecasting effort and forecasting errors.

5.2.3 Table 1 shows how this hierarchy might be applied in the current context.

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26 See https://www.ea.govt.nz/dmsdocument/12978. The same approach has been used by the Authority for consideration of other issues, such as extended reserves.

Table 1: Possible application of DME framework to preparation of inputs into forecast schedules

Hierarchy options	Characteristics the Authority expects to apply:
Market-based incentives	Parties would determine how much individual effort to apply to forecasting and would forego benefits and/or face costs caused by their errors (eg, generators would pay real-time prices for generation required if they are short of quantity scheduled and consumers and retailers would pay real-time prices for extra consumption if demand is higher than quantity scheduled). Parties would determine whether and how to engage specific providers of retail load forecasts, wind generation output, etc, if it were economic to do so (ie, cost of extra forecasting effort does not exceed reduction in the cost of the forecasting errors).
Incentivise exacerbators	A minimum level of forecasting effort would be administratively determined – eg, by use of a defined methodology or minimum standards for forecast inputs. Parties whose actions or inactions lead to large forecast errors would face financial incentives to improve their performance – eg, parties whose forecast quantities are less predictable would contribute more to forecasting costs than those that were more predictable.
Recover costs from beneficiaries	A minimum level of forecasting effort would be administratively determined (as above). All scheduling parties would contribute to forecasting costs roughly according to the benefit they receive.
Alternative administrative options	A minimum level of forecasting effort would be administratively determined (as above). Service provider costs would be recovered in a generalised manner, rather than specifically targeting exacerbators or beneficiaries.

5.2.4 The next section assesses the extent to which current arrangements align with this preferred hierarchy.

5.3 Review of current arrangements reveals weak incentives

5.3.1 Table 2 shows the major inputs into the price forecast process. It also shows the parties whose actions or inactions directly affect the quality of each input. These parties are referred to as exacerbators because their actions (or inactions) influence the level of forecast errors, which can cause costs to arise. The table does not show beneficiaries for each input into price forecasts, because these are the same in all cases – being all parties with a capability to alter their demand or generation levels.

5.3.2 The table also shows the parties currently responsible for supplying input data under the Code, and the nature and quality of incentives on them.

Table 2: Current arrangements - sources of inputs into price forecasts

Input to forecast prices	Relevant participant and any underlying exacerbators[27]	Current provider of forecast input data	Incentives on provider	Comment
Conforming load	Retailers as purchasers but influenced by: - Retail consumers - Distribution lines companies - Distributed generators[28] - Load aggregators	System operator (with ability to seek information from some types of participants)	General obligation to act as reasonable and prudent operator. No specific incentives	System operator not directly incentivised to optimise forecasting resource Exacerbators not exposed to cost of errors
Non-conforming load	Relevant consumers as purchasers	Relevant consumers	Administrative via compliance regime for bids	Administrative incentives may be too strong or too weak
Dispatchable demand (DD)	DD providers as purchasers	DD providers	Administrative via compliance regime for bids	Administrative incentives may be too strong or too weak
Intermittent generators (IG)	IG as generators	IG (subject to methodology rules in Code)	Administrative via compliance regime for offers	Administrative incentives may be too strong or too weak. Methodology currently specified by the Authority or system operator may be limiting improvements

27 Parties shown as potential exacerbators are those whose decisions can affect the size of the error in the forecast input. For example, wind generators may adopt robust or poor methods for forecasting their output.

28 Distributed generators with capacity above 30 MW are required to submit offers. For distributed generators of less than 30 MW, the system operator may require offers pursuant to clause 8.25 of the Code.

Input to forecast prices	Relevant participant and any underlying exacerbators[27]	Current provider of forecast input data	Incentives on provider	Comment
Scheduled generation	Scheduled generators	Scheduled generators	Administrative via compliance regime for offers	Administrative incentives may be too strong or too weak
Grid configuration	Grid owner	Grid owner	Administrative via compliance regime	Administrative incentives may be too strong or too weak

5.4 Key issues with current arrangements

5.4.1 Key observations from Table 2 are:

1. The current arrangements do not encourage wholesale market participants to apply the optimal level of effort to the scheduling process because there is no information on the costs associated with changing their bids/offers between forecast schedules and real-time. If parties faced the costs associated with such deviations, then they could decide whether it is cheaper to bear these costs or to apply more forecasting effort.
2. Similarly, parties responsible for forecasting inputs have limited incentives to optimise forecasting effort. For example, the system operator is responsible under the Code for forecasting non-dispatch-capable load at conforming GXPs,[29] and must act as a reasonable and prudent operator.[30] However, the system operator is not exposed to the cost of any forecasting errors. Nor is it responsible for improving the forecast if the benefit exceeds the cost.
3. There are several parties who take actions that affect demand at GXPs (ie, cutting demand) but who are not required to provide input information. Distribution network companies, demand aggregators, distributed generators[31] and other parties can all affect conforming load, but none of them are required to provide information about their intentions to the system operator. Several distribution network companies have ripple control rights over large blocks of hot water load that total about 700 MW.

5.4.2 There is a general reliance on administrative mechanisms in the Code that require parties to supply their information in the forecast schedules. While these mechanisms are relatively simple and have low transaction costs, there is less assurance that forecasting effort is optimal. Moreover, while the existing administrative approach might reduce forecasting effort and cost, the Authority has little information with which to make

29 Under clause 13.7A of the Code.

30 Under clause 7.1A of the Code.

31 More specifically, distributed generators with capacity below 30 MW do not submit offers, unless specifically required by the system operator under clause 8.25 of the Code.

efficient decisions about how much effort to apply to improve inputs into price forecasting.

5.4.3 A mix of centralised (eg, the system operator forecasts conforming load) and decentralised processes (eg, scheduled generators forecast their output for different price levels) are used at present. This makes sense because there can be benefits to forecasting on a centralised basis where errors from individual demand sources are relatively small and often offset each other (such as for residential demand).

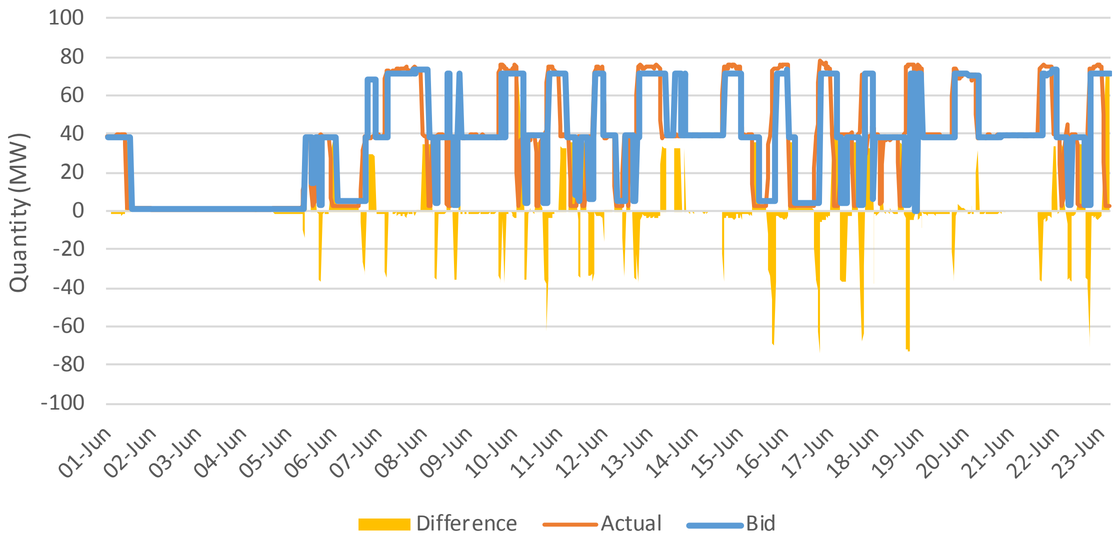
5.4.4 On the other hand, this 'top-down' centralised approach is less well-suited to forecasting demand from larger decentralised sources (bottom-up) where individual error contributions are less likely to offset each other. Determining where to use top-down versus bottom-up approaches is a key issue.

5.4.5 Under a centralised forecasting system, the Authority is responsible for making decisions about the effort required of wholesale market participants and the cost/quality of central forecasting. While the Authority's decisions are informed by its own analysis and advice from the system operator, it is nonetheless not aware of all information available to market participants.

5.4.6 To illustrate this point, the Authority has a list of outstanding issues raised by wholesale market participants and the system operator that require consideration. These include:

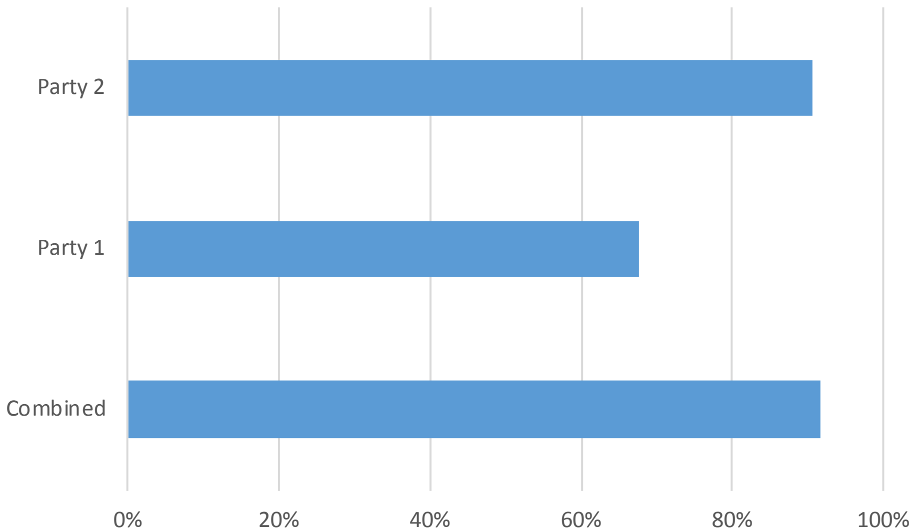
1. The forecast of conforming load exhibits a discernible systematic bias (shown in Figure 5).
2. Transpower has shown there are forecasting providers and techniques that would improve the forecast of conforming load (see paragraph 6.2.2).
3. Transpower demand response revises the load forecast (withdrawing load) just outside gate closure when it plans to test its distributed energy reserve resources rather than place difference bids to reveal its plans to the market.
4. Trustpower cannot place a price threshold for wind generation above $0.01/MWh so has removed its wind generation offer quantities on occasion when forecast prices are below a threshold.
5. There are noticeable differences in the accuracy of bids provided at non-conforming loads – it is not clear whether this reflects differing levels of effort (arguably a concern), or variation in forecasting difficulty across consumers (arguably not a concern). Figure 6 shows an industrial consumer forecasting a highly variable load. Although the consumer appears to accurately bid demand, errors in timing occasionally lead to large differences. This shows the difficulty inherent in forecasting certain types of load.

Figure 6: Bid and actual demand for an industrial consumer



6. The accuracy of forecasts also varies noticeably among wind generators and none are very accurate. For example, forecasts submitted at 2 ½ hours before real time appear to be less accurate than persistence forecasts. Figure 7 shows the relative performance of two different wind generators to a persistence forecast (100% being as good as a persistence forecast, and >100% being better).

Figure 7: Accuracy of forecast wind generation compared to persistence forecast



6 The Authority has considered four options to improve the accuracy of hours-ahead forecast prices

6.1 The four options reflect a point in the DME framework

6.1.1 Taking account of the concerns referred to above, the Authority has identified and assessed four options to improve the accuracy of spot price forecasts:

Option A: improve inputs into price forecasts under existing incentive arrangements (administrative/beneficiaries pay arrangements)

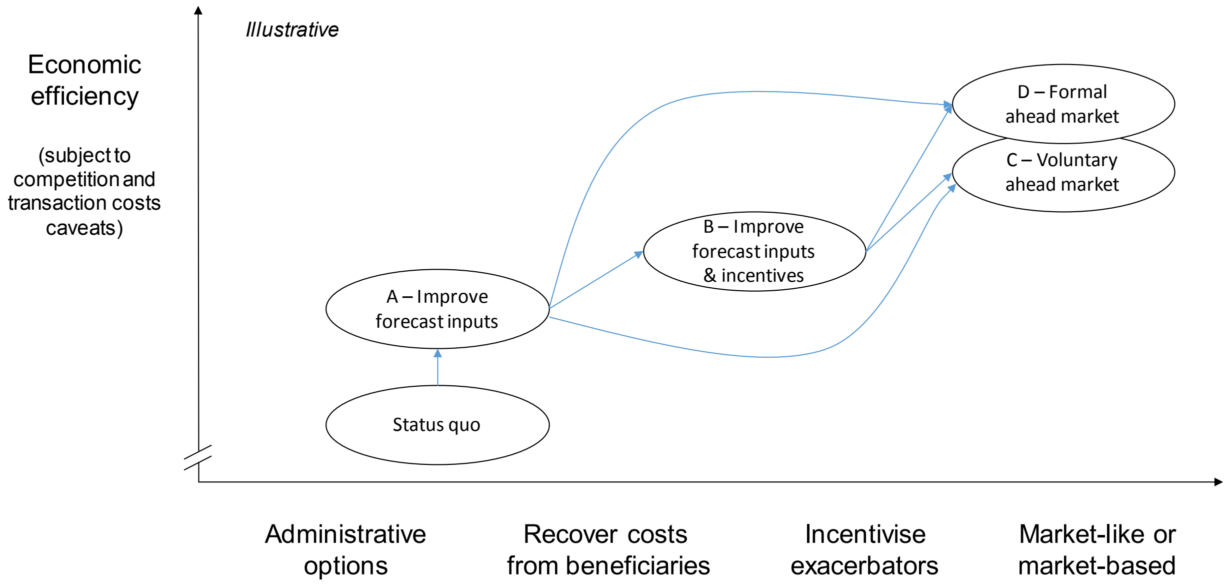
Option B: improve inputs into price forecasts and improve incentives (beneficiaries/exacerbators pay arrangements)

Option C: encourage a voluntary hours-ahead market (market-like arrangements)

Option D: pursue a formal hours-ahead market (market-like arrangements).

6.1.2 Each option reflects a point in the DME framework discussed in section 5.2. This is shown in Figure 8.

Figure 8: Options to improve hours-ahead price forecasts



6.1.3 Figure 8 shows that:

(a) Option A would focus on improving the inputs into the price forecasting process while retaining the existing accountability and incentive arrangements. This would be a relatively low risk option that would provide some benefits, but would not seek to address underlying issues. The initial focus would be on improving the conforming load forecast, because it is the largest existing source of price errors (refer Figure 3). There is also scope under this option to improve other inputs that contribute to price errors, such as intermittent generation and non-conforming load.

(b) Option B would also seek to improve inputs into the price forecasting process, but would go a step further and seek to strengthen incentive arrangements (eg, requiring forecasts to meet minimum accuracy metrics). The objective would be to give greater responsibility to the parties most closely associated with supply of inputs into the price forecasting process, such as purchasers for conforming load, while ensuring the inputs achieve minimum accuracy metrics. Again, while the initial focus would be on the conforming load forecast, consideration would be given to extending the accuracy metrics to the forecasting of intermittent generation.

(c) Options C and D would each involve developing an hours-ahead market, which could be voluntary (Option C) or mandatory (Option D). As discussed further below, an hours-ahead market could provide a means to generate more reliable price forecasts. Further, an hours-ahead market could provide a mechanism for parties to make trade-offs between bearing exposure to the real-time price uncertainty, or improving the reliability of their forecast bids/offers. This is because parties who do not provide accurate bids or offers into the ahead-market would settle their quantity deviations in the real-time market.

6.1.4 Each of the options is described further below. The system operator's report (attached as Appendix C) provides details and potential costs associated with several variations of Option D.

6.1.5 Section 7 evaluates the relative merits of the different options.

6.2 Option A – Improve inputs into price forecasts under existing incentive arrangements

6.2.1 Under this option, the focus would be on improving the inputs into the price forecasting process, while retaining the existing accountability and incentive arrangements. The initial focus would be on the conforming load forecast because it is the largest existing source of price errors (refer Figure 3).

6.2.2 An improved methodology would be adopted for the conforming load forecast. The system operator has previously trialled alternative forecasts and this suggests a large reduction in load forecast error is possible. For example, one of the trialled methodologies was significantly more accurate than the existing Transpower model in most circumstances and overall.[32] It produced national and island load forecasts with errors less than 50% of the existing model. It also produced zone and GXP load forecasts with errors from 25% to 67% of the existing model, depending on the zone or GXP respectively.

6.2.3 Improvements could be progressed by use of:

1. Proprietary methodology – a contract could be entered with a forecaster to use their proprietary methodology to generate conforming load forecasts. Several parties are active in this field internationally, and they have built up significant specialist expertise. This approach would offer a direct route for accessing this expertise and should also enable rapid improvements in load forecast accuracy. The principal drawback with this approach is that it may be less flexible in the longer run. For example, it may be more difficult or expensive to alter the methodology to reflect new developments, such as technology uptake by households.

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32 Measured as mean absolute percentage error in load. See www.teslaforecast.com/wp-content/uploads/2016/02/MTLFTrialReport-TESLA-2March2015.pdf and www.transpower.co.nz/sites/default/files/news-articles/attachments/New%20load%20forecasting%20service%20offers%20improved%20market%20information.pdf.

2. Open source methodology - a revised forecasting methodology could be implemented in a way where intellectual property rights are vested with the Authority on behalf of wholesale market participants (as is the case with market systems contracts). This route may take more time to obtain the same initial level of improvement, but retains more control over the future development path to further improvements.

6.2.4 The introduction of a new conforming load forecast methodology could be progressed under the system operator contract, or by a separate service provider agreement. In either case, the Authority could monitor demand forecasting performance, and periodically assess options for further improvement.

6.2.5 Improving forecasts is likely to result in some additional cost for development work by the system operator or external provider fees, or both. Existing arrangements provide for such costs to be recovered through the electricity levy. In practice, this means that costs would be recovered from all generators and purchasers based on their share of total energy volumes.[33]

6.2.6 The system operator has advised us that it is unlikely to obtain offsetting cost savings from discontinuing the existing forecast approach. There may be some participant cost savings, if a more accurate central load forecast allows them to reduce their own forecasting efforts. At this point, we have not factored in any cost-saving from either source into our analysis.

6.2.7 Under Option A, the Authority (with advice from the system operator) would continue to arrange for the supply of some forecasting inputs (notably conforming load) on a centralised basis. In effect, this means the Authority would implicitly determine *what* standard of accuracy is required, and explicitly determine *how* it will be delivered. For other inputs, the Authority would continue to rely on administrative mechanisms to ensure their quality (such as non-conforming load).

6.3 Option B – Improve inputs into price forecasts and improve incentives

6.3.1 Option B would also seek to improve the inputs into price forecasts, but there would be more emphasis on achieving this via enhancement of participants' incentives and involvement in determining how forecasting inputs should be supplied.

6.3.2 Unlike Option A, the Authority would not set a mandatory approach for *how* forecasting inputs should be created. Instead, it would seek to specify the standards of quality that should be achieved, and participants with responsibility for supplying those inputs would decide how best to meet those standards, either by supplying them directly or arranging a third party to do so on their behalf. Participants who supply inputs below the required standard would face an incentive to improve the accuracy of their inputs.

6.3.3 The approach would be analogous in some ways to that currently applied to intermittent generators under the Code. This requires intermittent generators to use a so-called 'persistence model' for forecasts made within 2 hours of real-time. The Code allows wholesale market participants to use an alternative model, if they have prior agreement with the Authority.[34] This allows participants (with Authority approval) to adopt an alternative approach if it is lower cost and/or more accurate.

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33 Assuming that any additional cost would be treated as "market operations" expenditure and recovered under that part of the levy regulations.

34 See clause 13.17(3)(a) of the Code.

6.3.4 If this approach were applied to the conforming load forecast, the Authority would not select a methodology. Rather, the Authority (with advice from the system operator) could set minimum performance standards that suppliers of forecast inputs should meet. Alternatively, the Authority might define a default methodology to be used for certain inputs, with parties able to use a different methodology if their inputs achieved the same standard of accuracy.

6.3.5 The current approach to intermittent generation forecasting could also be refined under Option B. The Code currently sets a default methodology for forecasts within two hours of real time. There is currently no methodology requirement for forecasts before the two-hour mark. If intermittent generation becomes a more significant source of forecast price uncertainty, there may be merit in reviewing this provision in the future.

6.3.6 The overall aim of Option B would be to give greater responsibility for the supply of forecasting inputs to the parties who have the best information about each input.

6.3.7 Option B would require some issues to be defined further before it could be implemented for conforming load. One issue would be determining the participant classes accountable for forecasting conforming load. Retailers have financial responsibility as purchasers for conforming load in the wholesale market, and would be the most obvious contender to provide conforming load forecasts. Indeed, retailers are likely to already forecast this load for their own purposes in many cases.

6.3.8 However, as discussed in section 6.7, some parties other than retailers can influence conforming load, including network companies (via load control), load control aggregators etc. Provided retailers have visibility regarding the intentions of such other parties, it should be workable to place forecasting accountability on retailers. However, it is not clear that such visibility exists under current arrangements – and it would be important to ensure there are no institutional or other barriers to gaining visibility.

6.3.9 Another key issue would be the design of the incentive arrangements. This would require definition of the target level of performance for the supply of forecast inputs. Ideally this would be set by weighing the costs to improve price forecasts, versus the costs from greater forecast errors. Because the latter costs are less readily observable, a degree of judgement would need to be applied in setting quality standards.

6.3.10 In addition, some forecast load errors will give rise to greater costs than others. For example, forecast load errors by two individual retailers might offset each other, and the aggregate forecast would be accurate. It is likely that no inefficiency cost would arise in this case, even though there were some errors at the individual retailer level.

6.3.11 Conversely, a relatively modest forecast error could give rise to a large efficiency cost, if it occurred at a time of very tight supply. It would be challenging to design a set of incentives that took account of all possible situations, and some trade-off between simplicity and precision would be required (as discussed in the next sections, the two market-based options would address this issue).

6.3.12 The Authority expects Option B to have higher implementation costs than Option A because it would require more policy development and associated Code changes. It is also likely to have higher ongoing transaction costs. On the other hand, adopting a more outcome-focussed approach should enable the wholesale market participants themselves to make efficient trade-offs and provide higher benefits over time.

6.3.13 Finally, it is important to note that many of the challenges with Option B also arise with Option A, but they are less visible. For example, when the Authority determines the methodologies to be applied for conforming load and intermittent generation it is effectively determining a quality standard, which will give rise to benefits and costs that accrue to different parties.

6.4 Option C – Informal hours-ahead market

6.4.1 Options A and B seek to reduce the error in price forecasts, but parties needing to make firm decisions before real-time would not be able to lock-in those forecast prices.

6.4.2 An alternative approach that would allow such lock-in of prices would be to facilitate development of an hours-ahead market. This would be a market where buyers and sellers can enter into short-term financial contracts in (say) the 2-12 hours leading up to real time. These contracts could be similar to existing futures contracts or two-way hedge contracts, although they would have a much shorter duration and lead time than most existing contracts.[35]

6.4.3 Hours-ahead market contracts would settle against real-time prices in the same way as existing risk management contracts. Wholesale market participants would determine which nodes were used for pricing purposes, although trading would be likely to focus at some nodes for liquidity reasons. Wholesale market participants would be able to consume or generate at levels that differ from the hours-ahead contract volume, but any such differences would be settled at the real-time spot price.

6.4.4 Provided wholesale market participants' actual demand or generation reflected the quantity in their hours-ahead contracts, they would not face any exposure to differences between the forecast price (in the hours-ahead market) and real-time spot price. However, they would be exposed to any locational price risk caused by differences between the node referenced in the contract and their injection or offtake node. Purchasers would also remain exposed to any constrained-on charges.[36]

6.4.5 Hours-ahead market contracts should strengthen wholesale market participants' incentives to optimise their short-term forecasting effort and all participants would realise any benefits from accuracy improvements. For example, if forecast generation/load volume (ie, volume in an hours-ahead contract) is accurate, parties can lock-in prices in the hours-ahead market. If their actual demand or generation differs from the forecast level, they would be more exposed to real-time price risk.

6.4.6 On average, prices in the ahead-market should be an unbiased predictor of real-time prices, as traders should arbitrage away any systematic bias. However, price differences would exist for individual trading periods, and these would likely be correlated with the size of any divergence between forecast (ahead market) and actual conditions. For example, if a generating station cleared 300 MW in the hours-ahead market, but it became unavailable, real-time prices would likely be higher than the hours-ahead market price. The generator would be required to pay the real-time price less the hours-ahead price multiplied by 300 MW (the quantity cleared in the hours-ahead market).

6.4.7 This dynamic should strengthen the incentive on parties to optimise their forecasting effort, because they are penalised for inaccurate forecasts in the real-time market. The size of any penalty would be based on the difference between the hours-ahead and real-

[35] However, some existing contracts have similar lead times. Disclosures indicate that 16 contracts were entered into in June 2016 with lead times of less than a week ahead, and for durations of less than a week. The average size was approximately 20 MW, and the maximum size was 50 MW.

[36] In the same way that existing two-way contracts do not hedge purchasers against constrained on costs.

time prices, reflecting the impact on the system. For example, when a large generator is unexpectedly unavailable, if there is a need for alternative generation or demand response, the cost of that resource would manifest in real-time prices. On the other hand, if the generator unavailability coincided with an unexpected reduction in demand, there would be little effect on the system, and the generator would face a small (or possibly zero) penalty.[37]

6.4.8 The Authority expects an hours-ahead market would supplement existing risk management contracts that manage medium and longer-term price risks (such as the effect on average prices of wet or dry conditions). The volume they trade in the hours-ahead market could vary more readily to reflect short-term influences such as weather on their demand or generation output. In this respect, ahead contracts would provide an additional tool for wholesale market participants to fine-tune their net exposure to the spot market closer to real-time, when they have better information about their own volume position, but still face market price uncertainty.[38]

6.4.9 In this Option C, participation in an hours-ahead market would be voluntary. Parties that perceive a benefit would participate, and those that did not perceive a benefit would not.

6.4.10 This option envisages that the development of 'rules' for an hours-ahead market would be participant-driven, rather than being formally incorporated in the Code (unlike Option D). For example, wholesale market participants would determine the form of risk management contract, reference location for pricing, gate closure for trading etc. Nonetheless, the Authority could play an active facilitating role. This might also include amending the Code if needed to enable a voluntary hours-ahead market.

6.4.11 In principle, the process could be similar to the development of the futures contract market. Wholesale market participants sponsored and oversaw the process, but the Authority encouraged its development and publicised its expectations regarding policy objectives.

6.5 Option D – Formal hours-ahead market

6.5.1 A more formal approach would be to introduce a two-stage settlement process. The first set of binding commitments (hours-ahead market) would be formed some hours ahead of real-time based on bids and offers in the existing PRS.[39] Parties whose actual demand or generation deviated from their cleared hours-ahead market quantities would settle those differences based on prices calculated in the real-time market.

6.5.2 This option is described as a formal hours-ahead market because the rules and processes would be part of the Code. Participation would not be voluntary for wholesale market participants required to submit scheduling information under the Code. However, they would have sole discretion over their bids and offers.

6.5.3 The real-time 'spot' market would continue to operate as a gross pool, with all energy injected into the grid sold in the market. Introducing a formal hours-ahead market might be considered after dispatch-based real-time prices had been operating for a period, as it is these prices that would usefully settle differences in quantities.

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37 This is effectively an 'exacerbator-pays' example. Conversely, a party that acts to offset an unexpected change by another party would be financially rewarded.

38 As shown in Figure 1.

39 The PRS is a better predictor of final prices than the Non-Response Schedule (NRS). See http://www.ea.govt.nz/dmsdocument/21265.

6.5.4 Decisions would be required on several issues including how far in advance of real-time an hours-ahead market would clear. Increasing the number of hours ahead the market settles would make it easier for some parties to respond to wholesale prices while increasing uncertainty for other parties. There would be a trade-off between these considerations.

6.5.5 To determine the commitments formed in the hours-ahead market, it would be necessary to apportion demand where GXPs have multiple purchasers (ie, retailers). Purchasers could directly provide this information (via 'bottom-up' load bids at conforming GXPs). Alternatively, for purchasers that did not wish to provide their own bids, a default bid could be calculated from an apportionment of the conforming load forecast. This should create an incentive for purchasers that can do better than the central forecast (in either accuracy or cost of provision) to self-forecast, which should improve overall outcomes.

6.5.6 As discussed in section 6.7, the conforming load attributed to retailers as purchasers can be influenced by a range of parties, only some of which have contractual relationships. It would be important to consider whether any changes to existing arrangements are warranted to provide purchasers with more 'visibility' over these other influences.[40]

6.5.7 As with Option C, a formal hours-ahead market would not supplant the need for longer-term electricity price risk management contracts. Parties would need to decide which price (spot or ahead) is the most suitable reference for those longer-term contracts (usually the ahead price is chosen).

6.5.8 The system operator's TASC report (attached as Appendix C) explains in more detail how Option D would operate. The report also considers an alternative sub-variant referred to as an "Hours-Ahead Unit Commitment". In this sub-variant, generators would submit 'complex' offers that more precisely specify their generation capability,[41] rather than 'simple' price-quantity offers for different generation output levels. The market scheduling system would use the complex offer information to identify the least-cost generation mix, and determine commitment and operating schedules.

6.5.9 The Authority does not favour this sub-variant because it would require substantive changes to existing dispatch tools, and offer little marginal benefit to a simpler hours-ahead market. The availability of a firm hours-ahead price with Option D provides many of the benefits provided by an "Hours-Ahead Unit Commitment" market. Therefore, it is unlikely to produce a positive marginal cost-benefit analysis. In any case, implementing Option D would not preclude developing the alternative variant in the future.

Q1. Are there any major options you think we missed? If so, please describe them.

6.6 Quick wins

6.6.1 In addition to choosing one of the options above, it might be possible to make some quick improvements to the quality of forecast price information provided to people.

6.6.2 These include:

1. Correcting the apparent systematic average bias present in the conforming load forecast

[40] There are some practical issues that would need to be considered, such as how to treat sunk costs of centralised forecasting processes (e.g. software development), if parties opt out once those costs are incurred.

[41] Complex offers are offers that include start costs, minimum loads, minimum run times and other parameters.

2. Making other low-cost incremental improvements to the conforming load forecast.

3. Examining the reasons for apparent relative differences in forecasting performance among intermittent generators, and among non-conforming load sources.

6.6.3 The Wholesale Advisory Group proposed some other 'quick win' initiatives in its report to the Authority on spot market improvements.[42] Several of these have since been completed or are in progress – such as the removal of the HVDC dead band constraint in settlement pricing, and shortening gate closure. A full list of the initiatives proposed by the Wholesale Advisory Group (only some of which were quick wins) and their status is set out in Appendix E.

Q2. Are there any quick wins you think we missed? If so, please describe them.

6.7 Issues common to all options

6.7.1 For non-conforming load, scheduled generation and intermittent generation, it is relatively easy to identify a wholesale market participant with a direct 'line of sight' to the underlying physical source of uncertainty (ie, a generator or load source).

6.7.2 This is not the case for conforming load. Retailers are financially liable for the electricity used by conforming load. However, the accuracy of the conforming load forecast is subject to influence from several potential exacerbators, including:

1. the actions of consumers the load forecast does not account for (eg, consumers responding to spot prices)

2. the level of output from unoffered embedded generation (which reduces observed GXP demand). Where such generation directly affects retailers' purchase obligations, it appears reasonable to expect retailers to account for it in their load forecasts. However, some embedded generation may not be financially associated with any retailer, but will still affect conforming load at a GXP. It is not clear how much generation is in this category, but it could be well over 100 MW in total.

3. load control activity by electricity distribution businesses for network management purposes. In total, the Authority estimates networks have about 700 MW of ripple control capacity under their management

4. load control activity by aggregators for energy trading purposes (such as offering interruptible load)

5. demand response managed by Transpower as part of its grid alternatives programme.

6.7.3 Some of these influencers can have a material effect on load and on the accuracy of the conforming load forecast.

6.7.4 Another important factor is the adoption of new technology and business models. For example, energy 'banks' are emerging in some jurisdictions. These parties can control the timing of household battery charging/discharging cycles and 'trade' this storage capacity on behalf of households. Ultimately, such business models could have a

42 See https://www.ea.govt.nz/dmsdocument/17108.

material effect on conforming demand, if energy banks control a significant amount of storage capacity.

6.7.5 The issues described above are relevant to all four options. For Options A and B, it may be important to ensure the party or parties charged with preparing forecasts can gather the required information. The Code already provides for obtaining information about embedded generation in some circumstances, but it may be desirable to broaden this scope.[43]

6.7.6 For Options C and D, retailers would be the parties most likely to participate in an hours-ahead market for conforming load, because they are typically financially responsible as wholesale purchasers of the electricity used by such load. However, it is not clear whether the current arrangements allow for efficient contracts to emerge between retailers, consumers, and other parties regarding load management rights. For example, one major network company has indicated that it is difficult to offer new load management practices where multiple retailers operate on its network and have differing commercial drivers.

6.7.7 Irrespective of which of Options A to D is preferred, it is likely to become increasingly important to ensure that conforming load forecasts reflect the full range of influences on this demand source – especially as uptake of new technology and business models will make this category of demand more dynamic over time. This is an area the Authority is looking at more closely in the Mass Participation project.

Q3. Are there any other issues that are common to all options that should be examined? If so, please describe them.

[43] See clauses 8.25(5) and 8.25(6) of the Code.

7 Qualitative benefits and costs of each option

7.1 Option A – Improve inputs into price forecasts under existing incentive arrangements

7.1.1 This option would be more straightforward to implement than the other options. While it would not require any Code amendments, it may involve some changes to the existing market tools. It would consider all inputs into the price forecasting process, with the initial focus on improving the conforming load forecasts as the largest current source of price errors.

7.1.2 Given the scope to improve the conforming load forecast, this option should provide benefits from a relatively early date. The key challenge would be selection of a forecast provider, or methodology. As set out in paragraph 6.2.7, the Authority would effectively determine both the quality standard for this input, and how it is to be met. This would require some care to ensure that the selected methodology can be refined over time as necessary.

7.1.3 While Option A would improve the error in forecast inputs, it would not address any of the broader incentive issues discussed in section 5.4.

Q4. Are there any qualitative benefits and costs for Option A we missed? If so, please describe them.

7.2 Option B – Improve inputs into price forecasts and improve incentives

7.2.1 This is also focussed on improving the inputs into price forecasts, but decision-making would be more driven by the relevant wholesale market participants, subject to meeting minimum performance standards. Again, the initial focus would be on improving the conforming load forecast.

7.2.2 Establishing the framework for the conforming load forecast would require an amendment to the Code. The Authority would need to determine a minimum quality standard for conforming load forecast inputs, the incentives to discourage poor performance, and classes of participant responsible for forecasting conforming load. These steps are expected to take some time. Considering these factors, Option B is expected to take somewhat longer to improve the conforming load forecast and hence price forecasts.

7.2.3 On the other hand, Option B would assist in improving participants' incentives and allow greater flexibility and innovation in how inputs into price forecasts are generated and supplied.

7.2.4 In this respect, Option B is expected to be intermediate between Option A and Option D. If very simple arrangements are implemented, it would provide similar benefits to Option A. This could be the case if relevant participants are simply required to adopt a particular methodology when supplying forecasting inputs, and face compliance based penalties. At the other end of the spectrum, if participants have more flexibility but face more granular incentives to maintain quality (such as 'paying for' price differences caused by poor inputs), it would be more like Option D.

Q5. Are there any qualitative benefits and costs for Option B we missed? If so, please describe them.

7.3 Option C – Voluntary hours-ahead market

7.3.1 Options A and B should reduce the error in key inputs to forecasts, and therefore make forecasts more accurate. However, parties wanting to make firm decisions before real-time would find it hard/costly to lock-in those forecast prices with bilateral arrangements.

7.3.2 This would change if there were an hours-ahead market. In this case, parties wishing to lock-in the forecast price would do so by trading in the hours-ahead market. Wholesale market participants would also have better incentives to optimise their level of forecasting effort, because differences between cleared quantities in the ahead market and actual quantities would be settled at the real-time price.

7.3.3 Option C would also have the advantage of providing flexibility to evolve over time in response to need, because market arrangements would be determined by the parties using the market.

7.3.4 The main disadvantage with Option C is that it appears unlikely to develop voluntarily without encouragement, given that it has not developed to date. There was an indication that some wholesale market participants were considering a voluntary hours-ahead market-type mechanism in 2014-15, but those discussions appear to have been shelved.

7.3.5 It is possible that the lack of interest in a voluntary hours-ahead market simply reflects a genuine absence of net benefits. In that case, the 'right' answer would be not to do anything further. Alternatively, the lack of spontaneous development may be due to a 'chicken and egg' issue, where the absence of sufficient market scale holds back participant interest, and vice versa.

7.3.6 The situation may be similar to the ASX hedge market, where there is now widespread participation but this only developed after tighter market-making services were encouraged by the Authority. If so, the Authority could facilitate arrangements that lower the participation costs and/or increase the incentives to participate.

Q6. Are there any qualitative benefits and costs for Option C we missed? If so, please describe them.

7.4 Option D – Formal hours-ahead market

7.4.1 A formal hours-ahead market would provide incentives for exacerbators to improve their forecast inputs,[44] where it is efficient to do so. They would be expected to optimise the trade-off between improving forecast inputs versus accepting greater price exposure in the real-time spot market.

7.4.2 Parties with price-responsive demand or generation would be incentivised to signal their genuine preferences in ahead bids and offers, since this information would be used to generate binding commitments at firm prices. For these reasons, Option D would provide incentives to address all major sources of price error that affect the forecast relevant to

[44] As discussed in section 6.7, the potential exacerbators for conforming load forecast errors covers several different parties.

the commitment period in the ahead market (such as 8 hours ahead of real time). Forecast reliability for other time periods would also be likely to improve, given that similar resources and techniques would be applied to generate those forecasts.

7.4.3 A formal hours-ahead market is expected to involve more change and cost than the other options. There would be some establishment costs for the system operator, market service providers and wholesale market participants, and some ongoing costs for operation.

Q7. Are there any qualitative benefits and costs for Option D we missed? If so, please describe them.

7.5 Qualitative assessment summary for the four options

7.5.1 Table 3 summarises the qualitative assessment of the four options.

Table 3: Summary of qualitative assessment of options

	Option A	**Option B**	**Option C**	**Option D**
Size of potential benefit (qualitative assessment)	Worthwhile benefit expected from improving inputs – especially conforming load forecast	Likely to exceed benefit of Option A – but less than Options C or D	Greater than A and B	Largest potential benefit
Cost (qualitative assessment)	Lowest	Between Options A and D – depending on design details	Intermediate	Highest
Timing	Swiftest to implement	Intermediate	Unclear (may not occur voluntarily)	Longest lead time and implementation period
Degree of implementation risk	Little change required to existing arrangements	Between Options A and D – depending on design details – unclear whether approach has been used to improve price forecasts in other jurisdictions	Modest – if implementation were to occur	Significant changes to existing arrangements – but ahead-markets are a well-tested mechanism in other jurisdictions

7.5.2 Option C (voluntary hours-ahead market) appears unlikely to develop voluntarily based on experience to date in New Zealand. Nor is the Authority aware of any voluntary hours-ahead markets in other jurisdictions. For this reason, Option C has not been evaluated on a quantitative basis.

7.5.3 Among the remaining alternatives, Option B is somewhat intermediate between Option A and Option D in terms of benefits. If it was implemented with a very simple incentive structure (such as a requirement to use a particular methodology with compliance-based-penalties), the benefits over Option A are likely to be quite modest.

7.5.4 Conversely, if the cost of forecasting errors was reflected through to exacerbators via a sophisticated incentive structure linked to real-time prices, then it would be more like Option D in terms of benefits. The costs associated with Option B are also likely to vary depending on the degree of sophistication in the incentive structures.

7.5.5 In light of these factors, Options A and D have been subjected to a more detailed quantitative assessment. Option B has not been assessed in quantitative terms because it is a variant of Option A or D in some respects. Further comments on Option B are made in section 8.2.

Q8. Do you disagree with the options chosen for quantitative assessment? If so, please describe the reasons why.

8 Quantitative assessment of benefits and costs for options A and D

8.1.1 The quantitative assessment of options A and D adopts the following approach:

1. The analysis is undertaken from an economy-wide perspective based on the expected incremental benefits and costs.
2. Effects are assessed over a 15-year period, starting from when the option is implemented.
3. Values are estimated in 2016 dollars using a 6% real discount rate. Sensitivity cases with discount rates of 4% and 8% are also considered.
4. The counterfactual assumes that existing arrangements remain in place, except that we assume real-time pricing and the ‘quick wins’ set out in section 6.6 are implemented. Of the quick wins, the most relevant is the removal of systematic average bias present in the conforming load forecast.

8.1.2 Options A and D promote all three limbs of the Authority’s statutory objective,[45] providing four sources of benefit:

1. more efficient scheduling and dispatch of generation
2. more efficient demand response
3. more retail market competition and innovation
4. more efficient investment and plant retiring decisions.

8.1.3 The analysis considers the effect on costs for the system operator, the clearing manager and for wholesale market participants.

8.1.4 More detail on the analysis is set out in Appendix B including the key assumptions. Table 4 summarises the results of the analysis.

Table 4: Summary of estimated benefits and costs ($M present value)[46]

Summary $M PV	Option A			Option D		
	Lower	Base	Upper	Lower	Base	Upper
Gross benefits	$ 20	$ 32	$ 44	$ 37	$ 63	$ 95
Costs	$ 16	$ 12	$ 9	$ 40	$ 25	$ 16
Net benefits	$ 5	$ 20	$ 35	$ (3)	$ 38	$ 79

8.1.5 Options A and D both generate net benefits under the base case assumptions, with Option D having higher net benefits than Option A. However, under the lower-case assumptions, Option D has a negative net benefit while Option A has a material positive net benefit.

8.1.6 Both options generate net benefits under the upper-case assumptions, with Option D having a greater net benefit than Option A.

45 The Electricity Authority’s objective is to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers.

46 Note in the lower sensitivity cases, low benefits are combined with high costs, and vice versa.

8.1.7 The Authority considers that Option A is the preferred option based on current information because:

1. Option A is lower risk - it has positive net benefits in all sensitivity cases, while Option D has net costs in the lower case.
2. Advancing Option A would not preclude Option D (nor indeed other options) at a later date if they are judged to be worthwhile – in fact some elements of Option A would provide a useful foundation element for other options.
3. More information is likely to be available on the incremental benefits and costs of an hours-ahead market once real-time pricing improvements have been implemented.
4. Option D is more complex than Option A and its benefits are more uncertain as they depend on greater participation in the wholesale market. This is reflected in the sensitivities for Option D, which shows net costs (rather than net benefits) in the lower case.
5. Preferring Option A is consistent with the tie-breaker provisions in the Authority's Code Amendment Principles because: [47]
   (i) Option A is more consistent with Principle 4 – Preference for Small-Scale 'Trial and Error' options.
   (ii) While Option D is more consistent with Principle 6 – Preference for Market Solutions. However, Option A does not rule out later adoption of a market solution (Option D) if that was judged to be desirable.[48]
   (iii) Option A is more consistent with Principle 8 – Preference for Non-Prescriptive Options – given that Option D would require prescription around a number of key issues, such as the ahead period for formation of binding financial commitments.

Q9. Do you agree with the cost benefit assessment? If not, why not?

8.2 Possible transition paths and triggers

8.2.1 The Authority prefers Option A. The CBA for this option is positive in all sensitivities, and it has relatively low implementation costs. It also provides a useful foundation for transition to other options in future if that becomes desirable, as shown in Figure 9.

8.2.2 Some of the reasons that accurate forecast pricing may become more important in the future (and hence Options B, C or D may become more attractive) are:

(a) **Increased uptake of batteries, and other similar technology.** Owners of batteries can shift energy consumption and production across time. This is most efficient if the owner can maximise a battery's ability to discharge stored energy in

47 Tie-breaker 1 applies when quantitative cost-benefit analysis demonstrates a positive net benefit relative to the counterfactual, but is inconclusive about which is the best option. See http://www.ea.govt.nz/dmsdocument/14242.

48 The same comments apply to subsequent adoption of Option C – if there was a spontaneous move to develop an hours-ahead market.

trading periods when prices are highest and charge it when prices are lowest. Clearly, the accuracy of price forecasts will be a key influence in maximising this ability. The efficient use of storage devices becomes increasingly important as the use of batteries increases.

(b) **Increased quantity of load that responds to pricing signals.** Changes to transmission pricing and distributed generation pricing principles could make it more likely that demand and distributed generation will respond to *price signals*, rather than to *demand signals*. This is a positive result for the system but it increases the importance of forecast spot prices.

(c) **Rising proportion of uncontrollable or must-run generation.** Changes in the supply-side's ability to respond to changes in demand may be reducing over time. If such a trend is real and it continues, it is likely to result in more volatile spot prices. This, in turn, makes accurate forecasting more important because "getting it wrong" will result in larger price differences between forecast and final prices. Similarly, it will be important to ensure that flexible resources are appropriately rewarded for the services that they provide to balance inflexible or intermittent supply sources.

(d) **Increased proportion of price-responsive demand.** A rising level of participation by price-responsive load would make forecasting more important for two reasons. Price-responsive load will be likely to desire more accurate forecasts to inform its decisions. In addition, load forecasts that do not take account of price-responsiveness will become less reliable. Options B, C or D would all improve the reliability of the load forecast to different extents.

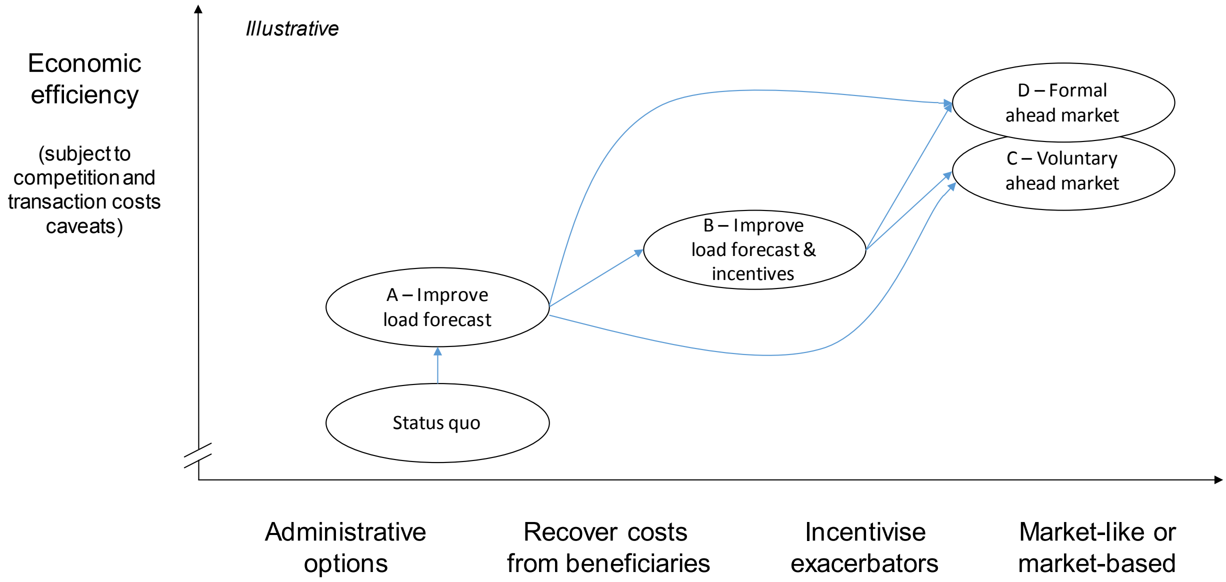
(e) **Development of market for risk management contracts.** The market for risk management contracts is continuing to evolve and develop over time. Although it currently appears unlikely, it is possible that Option C may develop voluntarily in the future – particularly as the influences listed in (a) to (d) increasingly affect the sector.

8.2.3 These factors suggest that Option A is a good first step at this stage, and that maintaining the optionality to consider further improvements to forecast prices will be important for the future.

Q10. Do you agree that Option A is preferred at this point? If not, why not?

Q11. If Option A is implemented, are there any factors that should be taken into account to maintain the potential to move on to Options B, C or D at a later point?

Figure 9: Possible transition path options to improve hours-ahead price forecasts



Glossary of abbreviations and terms

Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
Final price	Price paid or received for spot market transactions
GXP	Grid exit point
MAE	Mean absolute error
ME	Mean error
NRS	Non-responsive schedule
PRS	Price-responsive schedule
PRSS	Price-responsive schedule short (a PRS issued within 3½ hours of real-time)
RMSE	Root mean square of errors
Real-time price	Price available to parties in real-time (may differ from final price)
RTD	Real-time dispatch
RTP	Real-time pricing
TASC	Technical Advisory Services Contract
WAG	Wholesale Advisory Group