Wholesale market arrangements for battery energy storage systems

Issues and options paper

11 November 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on options to improve wholesale market operations for utility scale battery energy storage systems (BESSs).[1] More fit for purpose market arrangements could better support an efficient market and a stable and resilient power system and promote more secure and affordable electricity supply for consumers.

BESSs do not generate electricity, but they can move generation in time by charging at one time and discharging later. We expect BESSs to play an important role in our power system to balance the increase of variable renewable generation, such as solar and wind farms. BESSs can charge when the wind is blowing and the sun is shining and release this energy back into the system when electricity supply is more constrained. Given the physical storage limits of current BESS technology, we expect them to be relevant primarily to intra-day ‘firming’ of intermittent generation.

BESSs are a new type of system asset with unique characteristics. With two utility scale BESSs currently connected to the power system and many more planned, it’s important we act now to ensure the market arrangements are fit for purpose. Our proposals are more in the nature of pro-competitive updates to existing arrangements than fundamental reforms, but we nevertheless expect these changes to help support efficient investment and operation of BESSs as the market develops.

We are consulting on options to address the following issues where current market arrangements do not appropriately account for the characteristics of BESSs

Issue 1: The rules for following dispatch instructions do not recognise that BESSs are highly controllable assets. Addressing this would enable the System Operator to dispatch BESS in a manner that better supports a stable and resilient power system.

Issue 2: The rules for BESS submitting bids and offers, and the System Operator’s tools for sending dispatch instructions, do not recognise BESS as single entities that can both generate and consume. Addressing this would:

- incentivise efficient investment in BESSs by reducing barriers to enter the market
- ensure secure dispatch to support a resilient system
- help support a stable and resilient power system by enabling greater future participation by BESSs in ancillary services.

Issue 3: The System Operator’s security assessment tools and the rules for BESSs finalising their bids and offers do not recognise that the optimal operation of BESSs is unpredictable as it depends on limited storage and expectations of future prices. Addressing this would help ensure BESSs can operate efficiently without compromising the System Operator’s ability to maintain a stable and resilient power system.

[1] Utility scale BESSs are large scale installations that connect directly to high-voltage networks. This excludes, for example, smaller BESSs connected to households or small businesses which are typically used for backup power or to store roof-top solar generation for self-consumption.

Issue 4: The wholesale market financial compensation rules do not recognise that BESS are highly controllable assets. Addressing this would help to promote competition between technologies by ensuring BESS are compensated in similar ways to other generators.

Addressing these issues would help to ensure a secure supply of electricity to consumers at affordable rates

BESSs can provide ‘energy arbitrage’:

- buying electricity when prices are low (at times of low demand or high output from wind and solar farms) and
- selling it when prices are high (at times of high demand or low output from solar and wind farms).

Energy arbitrage can benefit consumers by reducing average wholesale prices. Consumers who purchase from the wholesale market, such as large industrial businesses, would benefit directly. Smaller consumers, such as households and small-medium sized businesses, would benefit indirectly through cost savings passed on from their retailers.

BESSs can provide many other benefits to the power system and market, including providing ancillary services to support power system stability and resilience. We can help realise these benefits by minimising inefficient barriers to investment in BESS.

Addressing the issues in this paper aims to support:

- affordable electricity for consumers by helping to enable efficient arbitrage opportunities
- a secure supply of electricity to consumers by promoting a stable and resilient power system
- efficient investment in BESS and increased competition between different generation types for the long-term benefit of consumers.

Next steps
The Authority will consider all submissions to this consultation before making a decision on next steps. We will consult on any proposed Electricity Industry Participation Code 2010 amendments in the first half of 2026.

We would expect any changes to market systems to be in place by the end of 2027.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this paper is to consult with interested parties on issues and solution options relating to market arrangements for utility-scale battery energy storage systems (BESSs).

1.2. The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on our understanding of the unique characteristics of BESS, how they benefit consumers, and how we expect BESS to operate in the future. This feedback will inform a future Electricity Industry Participation Code 2010 (Code) amendment proposal related to the wholesale market arrangements for BESS.

1.3. We are consulting on four broad issues and a range of solution options:

(a) **Dispatch requirements for BESSs when charging** - BESSs are not currently required to follow dispatch instructions when charging. We suggest that BESSs should be required to follow dispatch instructions when charging.

(b) **Bid and offer forms for BESSs** - BESSs currently trade their charging and discharging components separately. We are suggesting BESSs trade their charging and discharging components using a single offer form and are dispatched as a single entity.

(c) **Gate closure arrangements for BESSs** - The rules for finalising trades and the tools for assessing system security do not account for the unique circumstances of BESS. We are suggesting BESSs be allowed to trade their full capability at gate closure. We are also suggesting introducing new market system constraints to ensure dispatched quantities remain feasible if a BESS's capability changes after gate closure.

(d) **Constrained off payments for BESSs** - BESSs receive 'constrained off' compensation when charging. We are considering whether to remove constrained off compensation to BESSs when charging.

How to provide feedback

1.4. We prefer to receive submissions in electronic format (Microsoft Word) using the template in Appendix F. Submissions in electronic form should be emailed to OperationsConsult@ea.govt.nz with 'Issues and options paper – BESS market arrangements' in the subject line.

1.5. If you cannot send your submission electronically, please contact the Authority OperationsConsult@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.6. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

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

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

1.7. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.8. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

1.9. In addition, please note that the Authority may share submissions or other information, including parts of submissions not published, with another public service agency, statutory entity, the gas industry body or an overseas regulator in accordance with section s47A of the Electricity Industry Act 2010. The Authority would only do so if the submissions or other information could assist that organisation in the performance of its functions, and if it is satisfied that are appropriate protections in place for maintaining the confidentiality of anything provided (including information that is personal within the meaning of the Privacy Act 2020).

When to make a submission

1.10. Please deliver your submission by 5pm on Tuesday 23 December 2025

1.11. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority at OperationsConsult@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Context for this work

BESSs are a new and growing technology on the New Zealand power system

2.1. The Authority is investigating wholesale market arrangements for BESSs because they:

(a) are a new technology and we expect their uptake in New Zealand to continue to increase

(b) have unique characteristics and current market arrangements may not be the most suitable

(c) are able to provide significant benefits to consumers.

Box 1: Understanding BESS technology

BESSs charge their batteries by consuming electricity from the power system. The electricity is converted into chemical energy for storage. This enables BESSs to generate electricity by discharging back into the power system at a later time.

There are two parameters that describe the capability of a BESS:

- **energy capacity** (MWh): how much total electricity it can store and deliver over time
- **power capacity** (MW): the maximum amount of power it can deliver or absorb at any point in time.

For example, a 100MW/200MWh BESS has a power capacity of 100MW. This means that it can:

- charge from empty (0MWh) to full (200MWh) by consuming electricity at its power capacity for two hours.
- discharge from full (200MWh) to empty (0MWh) by generating electricity at its power capacity for two hours.

The **state of charge** is the amount of energy left in the battery, compared to its full capacity. This tells us how much power the battery can still provide before it needs to charge again, and how much more it can charge before it is full.

2.2. There are two BESSs currently operating in the New Zealand wholesale market:

(a) WEL Networks’ 35MW/35MWh BESS near Huntly power station. This was commissioned in 2023 and is New Zealand’s first utility scale battery.

(b) Meridian’s 100MW/200MWh BESS at Ruakākā, Northland. This completed commissioning earlier this year.

2.3. The cost of BESSs has fallen substantially over the past several years and we are likely to see a rapid increase of BESSs connected to New Zealand's power system in the coming years.[2]

2.4. Transpower, in its role of grid owner, is observing an increase in connection enquiries for utility-scale BESSs. Its generation and battery connection queue (as of August 2025) shows that at least 300MW of new BESSs could be connected to the grid by the end of 2026:

(a) Harmony Energy: 100MW BESS at Waihou

(b) Contact Energy: 100MW BESS at Glenbrook[3]

(c) Genesis Energy: 100MW BESS at Huntly.

2.5. Transpower's connection queue also shows over 350MW of BESSs in the Waikato and Taranaki at the early stages of design.

2.6. According to the Authority's investment pipeline, more than 15% of new generation capacity being investigated in New Zealand is from BESSs. This is around 7GW.[4]

2.7. This significant investment in BESSs is encouraging, as it can provide additional supply-side flexibility and grid-stabilisation services to support variable and intermittent generation sources. Over 80% of new generation is expected to be from wind and solar energy.

We are reviewing the market arrangements for BESSs to increase benefits to consumers

2.8. BESSs are able to participate in the wholesale electricity market as purchasers when charging and as generators when discharging.

2.9. BESSs are also able to provide ancillary services, such as instantaneous reserves and frequency keeping, to support power system security.[5] BESSs can provide instantaneous reserve in the form of both interruptible load and generation reserve. Appendix A provides more information on the electricity and ancillary service markets.

2.10. While BESSs can currently participate in the electricity and ancillary service markets, regulatory change is needed to maximise BESSs' capability to support the power system and provide benefits to consumers. This work aims to reduce operational barriers for investment in BESSs by improving wholesale market arrangements for BESSs and enabling greater participation for BESSs in ancillary service markets.

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2 MDAG. Price discovery in a renewables-based electricity system – Final recommendations paper.

3 Contact Energy has lodged a consent application that would take its total consented capacity up to 500MW at this site (from the 200MW currently consented). (Contact extends partnership with NZ Steel).

4 We do not expect all projects in the pipeline to be built. A BESS, like any other generation plant, is a significant investment for developers, and the complexities of these projects means they can take a long time to plan.

5 The ability for BESS to provide frequency keeping is currently limited, as discussed in section 4

2.11. Compensating BESSs for providing multiple services would also create additional revenue streams for BESSs and strengthen financial incentives to invest in them.

2.12. As inverter-based generation such as solar and wind generation connecting to the power system increases, BESS can play an increasingly important role to support to power system security in the coming decades. Our Future Security and Resilience (FSR) work programme[6] is focused on ensuring the electricity system remains secure and resilient and will consider the role of BESS in our future power system.

The scope of this work is limited to the immediate issues for utility scale BESS

2.13. The scope of this consultation is limited to the issues related to the wholesale market trading arrangements for utility scale BESSs. This means large BESSs that connect directly to the transmission grid or distribution networks and offer into the market.

2.14. At this time, we are only considering solution options that address:

(a) the immediate need to develop appropriate arrangements for BESSs that will be operating in the power system over the next few years.

(b) the specific issues identified (rather than broader issues).

2.15. This paper does not consider issues and options relating to hybrid arrangements – where variable renewable generation like wind or solar farms are co-located with BESSs. The Authority intends to investigate issues and options relating to hybrid arrangements in 2026.

2.16. Nor does this paper consider issues and options relating to the possible implementation of five-minute settlement. Changes to settlement intervals are not limited to BESS and would impact on all participants. Five-minute settlement would be a material change to the market and take some time to implement. The Authority considers further analysis of this issue would be required before any changes to settlement intervals could be proposed.

This work is part of our wider workplan addressing BESS

2.17. We have already implemented regulatory change and published clarifications to enable BESS to:

(a) offer energy into the wholesale electricity market by clarifying that when discharging, the Authority's view is that BESS meets the definition of generating unit in the Code (in 2018)

(b) offer interruptible load into the instantaneous reserve market by clarifying the Authority's view that BESS meets the definition of interruptible load while charging (in 2018)

(c) offer generation reserves while charging or discharging, by amending the Code and System Operator software (in 2022)

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6 Future security and resilience | Our projects | Electricity Authority

(d) operate with higher functionality and be more efficiently integrated by amending the transmission pricing methodology (coming into effect in 2026)

(e) better support the management and reliability of the power system by amending the Code to clarify that, for the purposes of Part 8 of the Code, BESS is to be treated as a generator (regardless of whether it is charging or discharging)[7].

2.18. In June 2025 we consulted on a draft regulatory roadmap for battery energy storage systems, which set out the Authority's BESS-related work over the next two years. It also discusses some BESS-related initiatives being led by others within the industry.

2.19. We received feedback on our draft roadmap from 22 stakeholders. Submitters were very supportive of the BESS roadmap and glad to see the Authority taking this step. However, several submitters were also keen to see the pace increase and match the rate of changes in the industry.

2.20. We are releasing a final version of the BESS roadmap alongside this paper.

2.21. Part of the work we are consulting on in this paper is referred to as *BESS-related wholesale electricity enhancement work* in the roadmap. We have considered submissions to the draft roadmap to inform our thinking in this paper.

2.22. This paper has also been informed by advice provided by the System Operator. This advice can be found in Appendix E.

7 The amendment also reduces transaction costs associated with larger ESSs putting in place equivalence arrangements or seeking exemptions from their obligation to provide automatic under-frequency load shedding systems.

3. Understanding the characteristics, benefits and future operation of BESSs

Arrangements for BESSs need to account for their unique characteristics

3.1. Appropriate market arrangements will allow BESSs to operate efficiently and support a stable and resilient power system, helping ensure a continuous supply of electricity to consumers at affordable rates. However, the need for efficient BESS operation needs to be balanced with other needs such as system security.

3.2. BESSs are unique in that:

(a) they both consume and generate electricity

(b) they have short-term storage and their consumption and generation are inter-dependent

(c) their optimal operation depends on expectations of prices in the near future

(d) they are highly flexible.

BESSs can both consume and generate electricity

3.3. BESSs consume for the purpose of generating later. Other purchasers in the wholesale market typically consume for purposes outside the electricity market eg, to manufacture goods or to supply electricity to households. Some arrangements designed for purchasers may therefore not be appropriate for BESSs. Instead, it may be appropriate for BESSs, when purchasing electricity, to have some similar arrangements to generators.

3.4. BESSs can transition seamlessly from consuming to generating and vice versa. It therefore may be appropriate that BESSs are treated as single entities rather than as separate purchasers and generators.

3.5. This characteristic is relevant to all four issues identified in this paper.

BESSs have short-term storage

3.6. A BESS's ability to generate depends on how much it consumes in prior periods, as this determines its available stored energy. Similarly, a BESS's ability to consume depends on its generation in prior periods, as this determines how much more it can charge before reaching its storage capacity.

3.7. BESSs can store electricity for a much shorter time than other technologies. Existing BESSs, as well as the BESSs expected to enter the market over the next few years, take 1-2 hours to charge from empty to full or to discharge from full to empty at their maximum charge/discharge rate. Most large hydro and some large thermal generators can also store fuel (eg, water in hydro storage lakes, coal stockpiles). However, this storage can take weeks to months to draw down.

3.8. This characteristic means it can be difficult to forecast the optimal operation of BESSs because any deviations from expected output will have material flow-on effects for future periods in the near term.

3.9. This means that the existing arrangements for updating BESS's bids and offers and the System Operator's tools for assessing upcoming risks to the power system may not be the most appropriate. This is relevant to issue 3 of this paper.

BESSs' optimal operation depends on expectations of prices in the near future

3.10. BESSs' willingness to pay to charge depends on the price they expect to pay to charge compared to their expectations of prices when they discharge.

3.11. On the other hand, the price BESSs are willing to accept to discharge depends on their opportunity cost of discharging. This will depend on the prices they could make if they discharged in future periods instead. It would also depend on whether, if they discharged in the given period, they would be able to take advantage of a new opportunity to charge and discharge again.

3.12. New potential profit opportunities occur each time prices decrease and then increase again. This will generally occur at least twice a day as prices rise in the morning peak, decrease through the middle of the day, and rise again for the evening peak. Prices may also decrease then increase at other times, for instance due to changes in weather conditions affecting intermittent generation output.

3.13. This means expectation of future prices within the next day or less will affect the optimal use of a BESS. The expected optimal use will change as expectations change throughout the day.

3.14. Accordingly, the existing arrangements for updating BESSs' bids and offers and the System Operator's tools for assessing upcoming risks to the power system may not be the most appropriate. This is relevant to issue 3 of this paper.

BESSs are highly flexible

3.15. BESSs are more capable than other generators and loads in meeting many power system needs. BESSs' control systems can be configured to respond in many ways to the needs of the power system. A BESS can respond by varying its power or voltage levels in a controlled fashion and at a speed appropriate to the need..

3.16. This is not relevant to current market arrangements but is relevant to the benefits BESSs may bring in the future by providing new or expanded ancillary services and network support.

BESSs should be subject to arrangements that reflect their unique characteristics

3.17. The Authority considers BESSs should be treated uniquely in some circumstances where their characteristics are different to those of other participants. In other circumstances, it may be appropriate to treat them similarly to other generators and/or purchasers.

3.18. We consider it is important to define BESSs in the Code in a manner that enables us to create simple and clear arrangements that are appropriate to each circumstance.

3.19. This will be important for both market and non-market arrangements, now and into the future.

3.20. While energy storage system (ESS) is defined in the Code, there is no definition for battery energy storage system. Because BESSs may have different characteristics to other ESSs, it may be appropriate that BESSs have their own definition in the Code.

Questions:

Q1. Do you agree we have sufficiently identified the unique characteristics of BESSs to assist in developing appropriate arrangements?

Q2. Do you have any views on how BESSs should be defined in the Code?

BESSs can help ensure consumers have an affordable and reliable supply of electricity

3.21. BESS can help deliver an affordable and reliable supply of electricity to consumers by:

(a) reducing wholesale prices through energy arbitrage

(b) supporting a stable and resilient power system by providing ancillary services

(c) helping ensure sufficient capacity in times of tight supply by balancing intermittent generation

(d) reducing dry year risk by enabling the overbuild of intermittent generation

(e) providing network alternatives and reducing location-specific high prices by building in the locations where BESS support, eg, additional supply or voltage support, is needed most

(f) reducing financial risk for generators and purchasers, with flow-on effects on prices for consumers.

3.22. The options in this paper directly relate to the benefit of reducing wholesale purchase costs through energy arbitrage. The options also indirectly promote all other types of benefits listed above by helping to promote efficient investment in BESSs. We describe these other benefits in Appendix B.

BESSs can reduce wholesale prices through energy arbitrage

3.23. Energy arbitrage is the practice of buying electricity when prices are lower, typically during off-peak hours, and selling it when prices are higher, usually during peak demand periods.

3.24. By charging when prices are low and selling when prices are high, BESSs will, on average, reduce purchase costs for other wholesale purchasers (see box 2 below). Reducing wholesale prices will directly benefit consumers who purchase from the wholesale market. Consumers who buy electricity from a retailer will also benefit as retailers will be able to on-sell their electricity at lower rates.

Box 2: How BESSs can reduce wholesale purchase costs

The figures below illustrate a typical offer stack which orders offers from lowest price to highest price. The spot price is set where the demand for electricity intersects with the stack.

When BESSs charge, spot prices either stay the same or increase. When BESSs discharge, spot prices either stay the same or decrease (Figure 1). Because of the shape of the offer stack, the average increase in prices when BESSs charge will be smaller than the average decrease in prices when they discharge (Figure 2). This will contribute to wholesale purchasers paying less on average for each unit of energy consumed.

The other factor contributing to reduced wholesale purchase costs is the level of demand when BESSs are charging compared to when they are discharging. BESSs will tend to charge at times of low demand because prices are on average lower at these times (Figure 1). Similarly, BESSs will tend to discharge when demand is high, because prices tend to be higher at these times (Figure 2). Therefore, even if the magnitude of price increases when they charge was the same as the magnitude of price decreases when they discharge, BESSs arbitrage would still lead to reduced costs for wholesale purchasers.

The shaded squares in the diagrams below represent wholesale purchase costs.

Figure 1: Example of cost reduction due to BESS offers

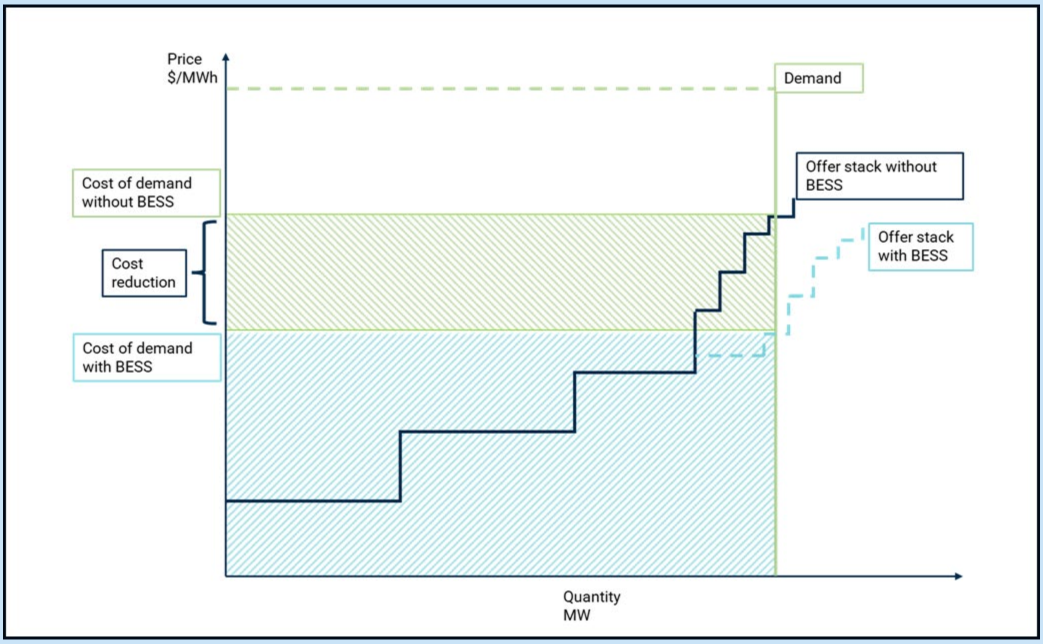
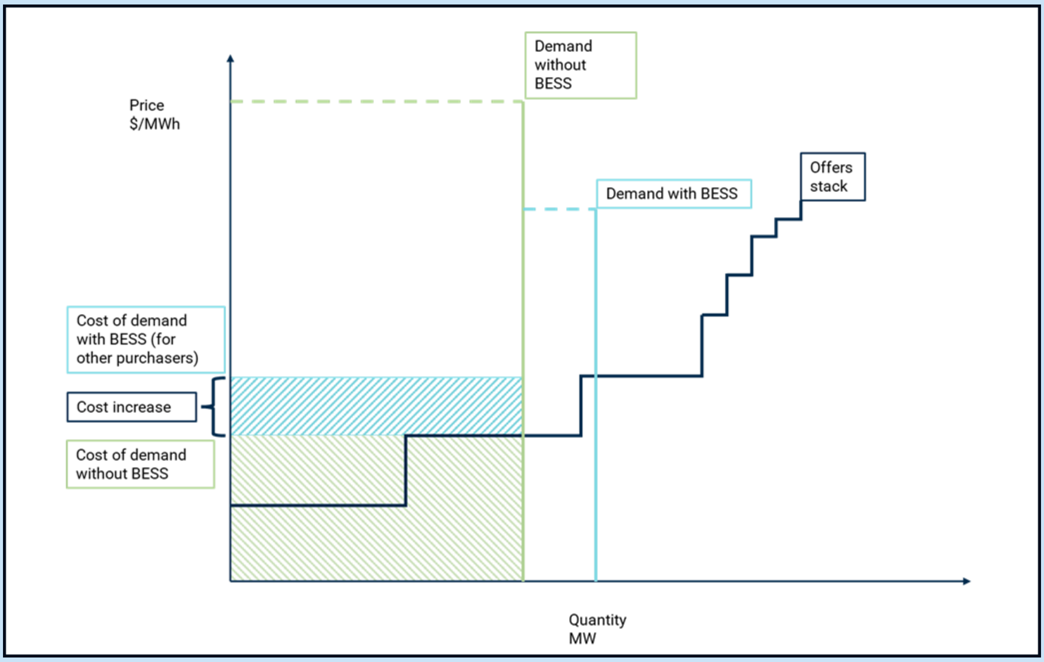


Figure 3: Example of cost increase due to BESS bids



Question:

Q3. Do you agree that BESS can deliver the benefits described? Are there any other benefits that will assist us in assessing the size of benefits of different arrangements?

How we expect BESSs to operate in the power system

3.25. Examining how BESSs' operation may evolve over time helps us to understand the potential size of the benefits from our options.

BESSs are currently seeking revenue through energy arbitrage and instantaneous reserves

3.26. The two existing BESSs on the system are currently participating in both the wholesale market and the instantaneous reserve market. Neither are participating in frequency keeping services.

3.27. The analysis below focuses on WEL network's BESS as Meridian's BESS has not yet been operating long enough to extract meaningful insights.

3.28. WEL network's BESS is operating in the energy market by buying electricity when prices are low and selling when prices are high. Our data shows that, from 1 April to 10 October 2025, the battery discharged into the grid 24% of the time and charged 31% of the time. During that period, the average charging price was $142/MWh and the average discharge price was $211/MWh.

3.29. WEL network's BESS is also operating in the instantaneous reserves market. From 1 April to 10 October 2025, it offered at least 1MW each of fast and sustained instantaneous reserves 98% of the time.

BESSs may continue to seek arbitrage opportunities

3.30. We expect BESSs' future energy arbitrage opportunities will be based on a mix of

(a) **predictable opportunities** that allow for bidding and offering based on relatively predictable trends such as:

(i) charging during demand troughs when prices are low

(ii) discharging during peaks when prices are high

(b) **unpredictable opportunities** that may lead to bidding and offering in a manner where spare battery capacity is retained so that unexpected opportunities can be realised, such as:

(i) charging when prices are low due to high intermittent generation output, and

(ii) discharging when prices are high due to low intermittent generation output or following a sudden unexpected loss of generation.

3.31. The way BESSs operate also depends on their warranty conditions, operating costs and operating efficiency. Warranty conditions will depend on the manufacturer and any bespoke terms agreed with the buyer. Operating costs and efficiency may also vary across manufacturers. We are therefore unable to predict what restrictions may apply across future BESSs.

3.32. However, we understand that BESSs are likely to be restricted to one to two full cycles per day. This means their total energy charged and discharged in a day will be limited to one to two times their storage capacity.

3.33. Therefore, there will be a limit to the number of energy arbitrage opportunities for a BESS. Most of the time, BESSs may be better suited to providing ancillary services that require less draw from their batteries.

BESSs may focus on instantaneous reserve in the short term and other ancillary services in the long term

3.34. In the short term, we expect predictable opportunities for arbitrage will play an important role in BESSs' trading strategies. However, we expect this to decrease over time. This is because, as the power system becomes more variable, it will become less predictable. Also, as more BESSs enter the market and engage in arbitrage, the opportunities will diminish. This is because BESSs will reduce prices at peaks and increase them at troughs.

3.35. In the short term, we expect BESSs will continue to operate with a focus on providing instantaneous reserve. BESSs are ideally suited to providing reserve because it rarely draws on their batteries.[8] However, as more BESSs enter the

8 BESS is only expected to respond following an event such as the sudden loss of a large generating unit.

market over time, we foresee these opportunities reducing. This is because the amount of instantaneous reserve BESSs could supply would soon exceed the typical demand for reserve.[9]

3.36. In the future we predict BESSs will want to take advantage of other ancillary services. In the short term, we expect BESSs may want to provide frequency keeping services, if current software restrictions are removed.[10] The Authority is currently investigating improvements to frequency keeping services to extend BESSs' participation.

3.37. As the power system evolves, there may be a need for more ancillary services to ensure the power system remains stable and resilient to shocks. BESSs may be suited to provide some of these services given their high level of flexibility. The Authority and System Operator are investigating the future needs for maintaining a stable and resilient power system as part of our FSR work programme.

BESSs are likely to focus on financial risk and network support opportunities in the long term

3.38. BESSs can help reduce financial risks for participants as described in Appendix B. We believe this incentive for BESSs is likely to increase in the future as there will be greater need to balance intermittent generation and manage the price volatility it causes.

3.39. There may also be greater opportunities for BESSs to provide contracted services to transmission and distribution network providers. These services would provide alternatives to network assets such as new lines or devices to support grid stability.

Questions:

Q4. Do you agree with our description of how BESSs are likely to operate and how this will change over time? If not, why?

Q5. Do you have any other insights about potential BESS operation that will help with assessing the benefits of our options?

[9] The demand for instantaneous reserves only exceeded 435MW 1% of the time over the year ending 30 October 2025, and we are expecting over 435MW of BESS capacity on the system over the next few years.

[10] As described in section 5.

4. Issue 1: Dispatch requirements for BESS when charging

The existing arrangements

Large generators are required to offer and respond to dispatch instructions so consumers' electricity needs can be met at lowest cost

4.1. BESSs have the same offer and dispatch obligations as generators when they are discharging.

4.2. If generators want to sell electricity, they need to be able to meet the requirements of the market and power system. In particular, large generators need to:

(a) submit offers so the lowest cost generators can be dispatched and spot prices formed

(b) respond to dispatch instructions to help maintain the balance of supply and demand as consumers' electricity needs change across time.

4.3. The requirements for offering, and therefore for following dispatch instructions, are:

(a) generators connected to the transmission grid with capacity greater than 10MW must submit offers[11]

(b) if required by the System Operator,[12] generators with capacity greater than 10MW indirectly connected to the grid (e.g. through a distribution network), or with capacity 10MW or less but connected to the grid, must either:

(i) submit offers or

(ii) provide information regarding their intended output in some other form agreed with the System Operator.

Purchasers are not required to submit dispatchable bids because it may be impossible or impractical to follow dispatch instructions

4.4. When charging, BESSs have the same bid obligations as purchasers.

4.5. Purchasers do not have the same spot market participation requirements as generators. This is because they may be unable to comply with dispatch instructions due to the variable nature of their consumption or the inability to control it. For example, a retailer purchasing from the wholesale market has little control over the consumption of its residential customers, and this consumption will vary across a trading period.

4.6. Only 'dispatchable bids' are used in forming prices and determining dispatch instructions.

4.7. The requirements for submitting dispatchable bids, and therefore for following dispatch instructions, are:

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[11] Clauses 13.6(1) and 13.25(1) of the Code

[12] Clauses 8.25(5) and 13.25(2) of the Code

(a) only dispatchable load purchasers can submit dispatchable bids[13]

(b) dispatchable load purchasers can decide whether to submit dispatch bids or non-dispatch bids at any given time[14]

(c) purchasers are not required to participate as dispatchable load purchasers

(d) the System Operator cannot require distribution-connected purchasers to participate in the market

(e) to be able to operate as a dispatchable load purchaser, a purchaser must apply to the System Operator for approval.[15] This is so the System Operator can be confident that the purchaser will follow dispatch instructions. The System Operator relies on participants following dispatch instructions to maintain a stable and resilient power system.

Issues with existing arrangements

BESSs are not required to be dispatchable while charging despite being able to follow dispatch instructions

4.8. BESSs are able to follow dispatch instructions when charging and discharging because they have full control over their operation. When they act as purchasers, they are doing so to be able to generate at a later time. It is therefore appropriate that BESSs, when charging and discharging, have the same requirements that generators have for participating in the market.

Requiring BESSs to apply separately to become dispatchable purchasers creates unnecessary costs

4.9. The System Operator will know that a BESS can follow dispatch instructions if it has already approved them to operate as a generator as part of the commissioning process. It is therefore unnecessary to require a BESS operator to make a separate application to operate as a dispatchable load purchaser. This adds unnecessary costs to both the BESS owner and the System Operator.

BESSs not being dispatchable while charging could threaten the disruption of consumers' electricity supply

4.10. If BESSs are not dispatchable when charging, they could decide to charge based on predictions of, or reactions to, dispatch prices. This could lead to unexpected changes in the supply-demand balance. Given the scale of BESSs expected to enter the market, these changes could significantly compromise the System Operator's ability to maintain a stable power system.

4.11. In addition, if the System Operator cannot rely on BESSs' bids, because they are not dispatchable, its ability to forecast the state of the power system may be

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[13] Clause 13.3A of the Code

[14] Subclause 13.7(2) of the Code

[15] Clause 13.3A of the Code

compromised. This could reduce its ability to assess potential system risks and prepare mitigating measures.

4.12. Finally, BESSs not being dispatchable while charging may prevent them from providing ancillary services. This is because the System Operator can give itself more certainty that BESSs will provide ancillary services by dispatching the resources. Ancillary services are provided for the purpose of maintaining a stable and resilient power system, so it is important the service can be provided when called upon by the System Operator.

4.13. These issues could increase the risk of an unforeseen capacity shortfall, potentially requiring the disconnection of some consumers' electricity supply.

BESSs not being dispatchable while charging may lead to less affordable electricity for consumers

4.14. The market system selects the least cost combination of offers and dispatchable bids for dispatch. If BESSs are not dispatchable, this could lead to inefficient operation for them and other participants. Because spot prices are based on dispatch prices, this would cause inefficient price signals.

4.15. Inefficient price signals could lead to inefficient investment decisions in new generation and load plant. This is because inefficient price signals may not accurately signal the value of electricity at different times of the day and different locations across the grid.

Solution option

4.16. The Authority considers there is likely only one option that will adequately address this problem.

The Authority considers that BESSs should have the same participation requirements as generators when charging

4.17. The Authority considers that BESSs, when charging, should be required to submit dispatchable bids and respond to dispatch instructions. In summary:

(a) BESSs would have the requirements appropriate for an entity participating in the market for the purposes of selling energy, and aligned with their ability to follow dispatch

(b) It would remove unnecessary costs to:

(i) BESS owners for applying to become dispatchable purchasers; and

(ii) the System Operator for assessing the applications.

(c) The System Operator would be better able to maintain a stable and resilient power system, minimising the risk of disruptions to consumers' electricity supply

(d) The market could more efficiently select resources to balance supply and demand and set more efficient price signals. This would help ensure affordable electricity for consumers.

4.18. This is consistent with the Authority's previous decision to recognise large BESSs as generating stations, whether generating or consuming, for the purposes of Part 8 of the Code.[16] This Code amendment came into effect on 1 May this year.[17]

Questions:

Q6. Do you agree with the way we have framed the issues?

Q7. Do you agree with the Authority's preferred option? If not, what are alternative options that would better address the issues? Are there any particular risks with our preferred option that you would like to identify?

[16] In particular, this applies to asset owner performance obligations and technical requirements

[17] Clause 8.1B of the Code

5. Issue 2: Bid and offer forms for BESS

The existing arrangements

The market system treats a BESS's charging and discharging components as separate entities

5.1. When discharging, a BESS must submit generator offers.[18] The same BESS may also offer generation reserves.[19]

5.2. If the energy and reserve offers are submitted at the same market node (a unique identifier), the market system can recognise that they are from the same entity. As a result, the market system will ensure that the total cleared energy and generation reserve does not exceed the unit's total generation capacity.[20]

5.3. Similarly, when charging, a BESS may submit dispatchable bids.[21] The same BESS may also offer interruptible load.[22]

5.4. If a dispatchable bid and interruptible load offer are submitted at the same market node, the market system can recognise that they are from the same entity. This enables the market system to ensure the amount of interruptible load cleared is no more than the total load cleared, as only dispatched load can be interrupted.

5.5. A BESS will receive separate dispatch instructions for generation, load, interruptible load, and generation reserve.

BESS can currently participate in multiple frequency keeping as a generator

5.6. The System Operator procures the frequency keeping ancillary service to maintain a stable system frequency.

5.7. The System Operator typically procures this service as multiple frequency keeping (MFK). This means more than one frequency keeping provider can be selected to maintain system frequency in each island at the same time.[23]

5.8. The System Operator sends frequency regulating instructions to each selected frequency keeper specifying an upward or downward MW variation from their dispatch set point.

5.9. Generators can participate under the current MFK software, but purchasers cannot. Therefore, BESSs are currently restricted in their ability to participate in MFK.

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18 Schedule 13.1, Form 1.

19 Schedule 13.1, Form 5.

20 The market system does this by applying a constraint.

21 Schedule 13.1, Form 4.

22 Schedule 13.1, Form 6.

23 The System Operator will dispatch a single frequency keeper in each island on rare occasions such as when the MFK system is unavailable.

Issues with existing arrangements

Requiring separate trades creates unnecessary costs

5.10. The current requirements can create unnecessary set-up and operating costs for BESS owners. This is due to the need to submit separate load bids, generation offers, interruptible load offers, and generation reserve offers, and to respond to separate dispatch instructions for each. This arrangement does not recognise the nature of a BESS as a single entity that can transition seamlessly from charging to discharging or vice versa.

Physically impossible dispatches threaten system security and efficient operation

5.11. Current arrangements can also lead to physically impossible dispatch outcomes. This is because the charging and discharging components of BESS are not recognised as the same entity in the market system.

5.12. A BESS may be dispatched to consume and generate at the same time, which is physically impossible. They may also be dispatched to provide interruptible load in this situation, which would also be physically impossible if generating.

5.13. This could create confusion for system coordinators and BESS owners, making it more difficult for the System Operator to manage the power system, and potentially lead to insufficient instantaneous reserve being armed. As a result, the system may be less resilient to events like the sudden loss of a large generator, increasing the risk of disruptions to consumers' electricity supply.

Separate bids and offers limit future involvement in MFK

5.14. BESSs are physically able to provide frequency keeping services while charging and discharging, and while transitioning from either state to the other.

5.15. The System Operator needs to ensure a MFK provider has enough room to regulate its output in both the upward and downward direction to meet its cleared band given its set point for energy dispatch.

5.16. Figure 3 illustrates the available capacity a BESS can use for frequency keeping under the current arrangements compared to possible options of:

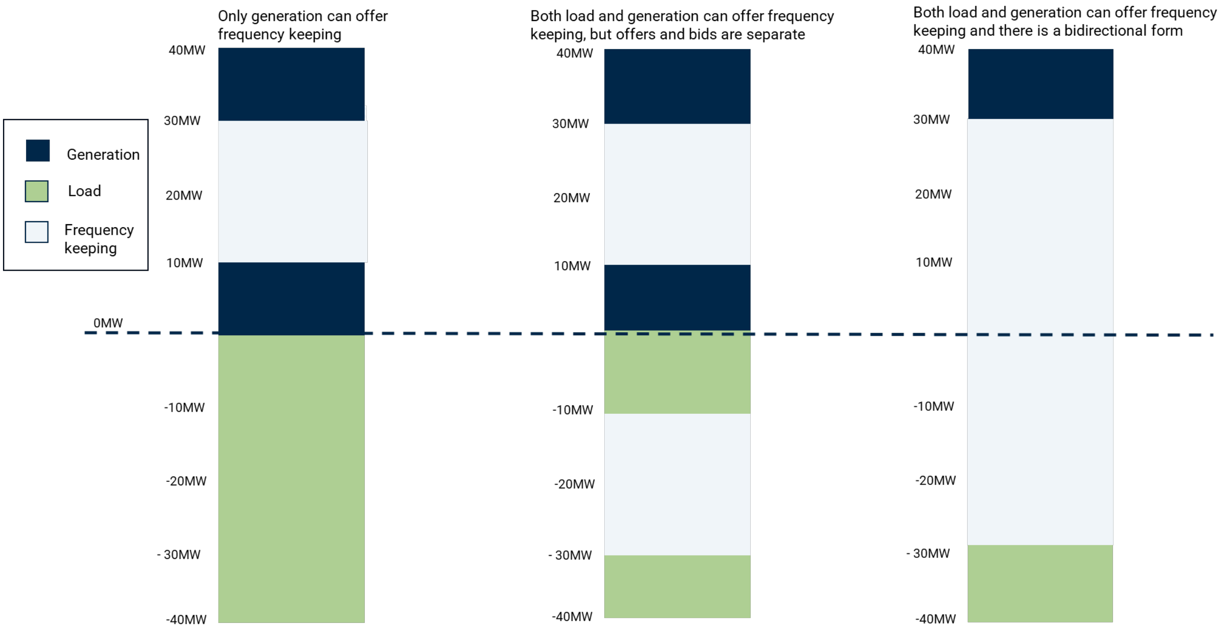
(a) participating in MFK as a separate generator and purchaser

(b) participating in MFK as a single entity.

5.17. As shown, if a BESS is recognised as a single entity, they would have greater capacity to provide frequency keeping when idle or at low levels of operation.

5.18. We anticipate BESS operators will be most inclined to provide MFK when idle or operating at low output. This is because we believe BESSs will likely charge or discharge at high output only when the value of doing so is reasonably high. Providing frequency keeping in these situations may restrict their ability to realise that value.

Figure 4: Available frequency keeping capacity BESS under different scenarios



Solution Options

5.19. To address the issues identified, the Authority's preferred option is to implement:

(a) a single bi-directional offer form to allow BESS to bid and offer as a single entity, and

(b) a single offer form for reserves that includes both generation reserve and interruptible load.

5.20. We also considered the option of linking nodes to address the issue of physically impossible dispatches. We have not considered any other options to address the other two issues.

The System Operator identified two options to address the issue of physically impossible dispatch solutions

5.21. We asked the System Operator to investigate options to resolve the issue of physically impossible dispatch solutions.[24]

5.22. The System Operator identified two options:

(a) **bi-directional offers** - this would allow generation to be offered as a positive quantity and load to be offered as a negative quantity on the same offer form

(b) **linking nodes** – this would allow the market system to recognise when bids and offers are from the same BESS.

5.23. For the bi-directional offer solution, the System Operator also confirmed that the market system could be updated to:

[24] The System Operator's advice is detailed further in section 5 of its report (see Appendix E)

(a) accept single offers for reserve that include both the interruptible load and generation reserve components, and

(b) create new constraints between the separate energy and reserve offers to ensure for BESS:

   (i) instantaneous reserve is not dispatched to more than what is achievable when charging

   (ii) total generation and reserve dispatched is no more than what is achievable when discharging.

A bi-directional offer form and single reserve offer form would reduce unnecessary costs and enable full participation by BESS in MFK in the future

5.24. A bi-directional offer form and single reserve offer form would also address the other two issues identified.

(a) It would reduce unnecessary costs associated with separate trades and dispatch for charging and discharging, and for providing interruptible load and generation reserve.

(b) It would help enable BESS to offer its full capacity into the MFK market, regardless of whether they are dispatched to charge, discharge, or neither. However, this would require enhancements to the existing MFK software. We are currently working with the System Operator to investigate these and other improvements to the MFK arrangements as part of a separate workstream.

5.25. By contrast, the linking nodes option would only resolve the issue of physically impossible dispatches.

The System Operator advised that a bi-directional offer form may limit BESSs' participation in MFK under the current arrangements but the Authority considers this is unlikely to be an issue

5.26. We also asked the System Operator to consider how these options would affect BESSs' ability to participate in MFK with the existing software.

5.27. The System Operator advised that implementing a bi-directional offer solution may require enhancements to the current MFK selection tool to retain BESSs' existing participation abilities, ie, to participate as generation when dispatched for energy to a level above their cleared band.

5.28. The Authority considers this is unlikely to cause any issues for BESSs. We note that BESSs do not currently participate in MFK. We believe BESSs do not participate in MFK under the current arrangements given the limitations outlined in paragraphs 5.14 to 5.18. The Authority seeks input from stakeholders on this point.

5.29. If stakeholders are of the opinion that BESSs are willing to provide MFK under the current arrangements,[25] the Authority could consider:

[25] Ie, before any potential enhancements to MFK

(a) further investigations to determine whether simple software changes could be made to the current MFK toolset to retain existing participation capabilities, if and when bi-directional offers are implemented; or

(b) delaying implementation of the bi-directional form until after any decision about whether the full MFK enhancements should be made.

The Authority prefers the option of a bi-directional offer form for energy and a single offer form for reserves

5.30. The Authority's opinion, supported by the System Operator's report, is that bi-directional offers along with single reserve offers are preferable to the linking nodes option as it would address all three issues. In summary, it would:

(a) prevent physically impossible dispatches, reducing the risk of disruption to consumers' electricity supply

(b) remove unnecessary costs for submitting separate offers and responding to separate dispatch instructions

(c) enable BESSs' full charge and discharge capacity to be used in MFK, following any necessary enhancements to the MFK tool.

5.31. We consider that our preferred solution would help promote competition, leading to more affordable electricity for consumers in the long run.

The Authority considers the benefits of this solution are likely to exceed the costs

5.32. The System Operator has provided a rough order of magnitude cost estimate of $1.3m to implement bi-directional offer forms and single forms for reserve offers.[26]

5.33. There would also be some costs to update the wholesale information and trading system (WITS) tools as well as Clearing Manager tools to handle bi-directional offers. We consider these costs are likely to be relatively low.

5.34. Overall, the Authority considers it likely the value of the benefits listed above will far exceed these costs.

Questions:

Q8. Do you agree with how we have framed the issues?

Q9. Do you agree with our preferred option? If not, what other options would better address the issues identified?

Q10. Do you think further restrictions to BESS participation in MFK under the current arrangements would have any effect on their participation?

[26] See section A.1.3 of the System Operator's report at Appendix E. In particular, the System Operator estimates a total cost of $1.9m if this solution was implemented at the same time as our preferred option for Issue 3 (gate closure arrangements), approximately $0.5m less than if implemented separately.

6. Issue 3: Gate closure arrangements for BESS

6.1. In this section:

(a) references to ‘purchasers’ and ‘bids’ relate specifically to dispatchable bids;

(b) we use the term ‘generators’ to mean non-intermittent generators, unless the distinction is required for clarity; and

(c) the discussion is for general information only. It is necessarily high-level and generic to facilitate feedback and engagement on the topic of gate closure.[27]

The existing arrangements

Gate closure enables a stable and resilient power system and prevents gaming

6.2. Wholesale market participants must finalise bids, offers, and reserve offers[28] by ‘gate closure’. Gate closure, while different for different participants, is typically one hour prior to the start of the trading period for which the trade applies.

6.3. The primary purpose of gate closure is to enable the System Operator to assess power system risks and prepare mitigations ahead of dispatch. The gate closure period enables this by providing the System Operator with some certainty of the future state of the power system. This includes the quantities of different types of generation and loads across different locations.[29]

6.4. Trade quantities can be revised under special circumstances.[30]

6.5. Trade prices cannot be revised after gate closure under any circumstances. This removes the opportunity for participants to set prices after gate closure.

Gate closure rules differ for different types of participants

Non-intermittent generators can revise their offer quantities

6.6. Non-intermittent generators can revise their offer quantities after gate closure when their expected capability changes. We expect this to happen only in rare circumstances, because they can generally estimate their expected capability with high confidence by gate closure. The intent of this rule is to ensure the System Operator has the most accurate information available when dispatching the system.[31]

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[27] This discussion is not a substitute for, nor does it form part of, the Code. It does not address other obligations participants may have under other parts of the Code not discussed in this section. It does not place any obligation on the Authority to follow any interpretation contained in this paper when carrying out any of its functions under the Electricity Industry Act 2010 or the Code.

[28] We will refer to these collectively as ‘trades’.

[29] Section 3.1 of the System Operator’s report in Appendix E provides more information on the System Operator’s security checking process.

[30] Clauses 13.17 – 13.19C.

[31] Clause 13.18.

Intermittent generators have greater flexibility

6.7. In contrast to most generators, intermittent generators (wind and solar generators) are able to offer their full capacity along with a forecast of generation potential that caps their output based on expected capability.[32] They are then required to update their expected capability after gate closure when this expectation changes.[33] This is because their generation capability can be difficult to predict due to changing expectations of weather conditions.

Embedded generators have shorter gate closure

6.8. Embedded generators are generators that connect to distribution networks rather than the transmission grid. They have a gate closure of 30 minutes.[34] It may be appropriate that they have shorter gate closure than grid connected generators because they:

(a) may have less predictable generation (eg, hydro generators that rely on the run of the river because they do not have storage lakes)

(b) are typically small and will not have significant market power to set prices.

Purchasers have limited ability to update trades after gate closure compared to generators

6.9. Purchasers submitting dispatchable bids have greater limits compared to generators when updating their trade quantities after gate closure. They are not allowed to update their quantities after gate closure except in rare circumstances or if their expected consumption changes beyond a threshold.[35]

6.10. The Authority believes it may not be appropriate for dispatchable purchasers to have greater restrictions on updating trade quantities than generators. This is however beyond the scope of this paper and will be considered as part of our future work when investigating future arrangements for dispatchable demand.

Issues with existing arrangements

6.11. Gate closure arrangements for BESSs vary depending on whether the BESS is charging or discharging and whether the BESS is embedded or grid-connected.

6.12. The arrangements also do not consider the unique characteristics of BESSs or balance the need for flexible trading with system security requirements and the need to limit gaming opportunities.

32 Clause 13.9B of the Code.

33 Under Clause 13.18A(1) of the Code, intermittent generators must submit a revised offer following each new generation forecast provided by an approved provider.

34 See ‘gate closure period definition’ in Part 1 of the Code – preliminary provisions (Clause 1.1).

35 Compare Clauses 13.19A, 13.19B of the Code for dispatchable purchasers, with Clauses 13.17 to 13.19AA for non-intermittent generators.

Shorter gate closure for embedded BESSs creates inefficient investment incentives

6.13. We consider that the shorter gate closure period for embedded generation would be inappropriate for BESSs. This is because embedded BESSs would have greater opportunities to take advantage of new information about expected prices than grid-connected BESSs.

6.14. This advantage could incentivise more BESS owners to connect to a distribution network instead of the grid. This could be inefficient if this connection were more expensive from a system perspective. For example, additional energy would be lost as heat on distribution lines when transporting electricity from a BESS's location to where it is needed. This would lead to less affordable electricity to consumers to the extent additional costs are passed through.

Different gate closure rules for BESSs when charging and discharging is inefficient

6.1. Currently, BESSs have different gate closure arrangements depending on whether they are in charging or discharging mode. However, the optimal arrangements for BESSs depend on their unique characteristics. As these characteristics are similar when charging and discharging, the optimal rules will be the same for both modes.

6.2. It is also potentially confusing to have different rules for each mode. This can create additional costs compared to the same rules applying to both modes. These costs could lead to less affordable electricity for consumers by either reducing efficient investment in BESSs or passing the additional costs on to consumers.

Gate closure rules do not account for BESSs' unique characteristics and can lead to conservative trading or frequent offer revisions

6.3. The existing gate closure arrangements do not take into account a BESS's short term storage capacity. A BESS's ability to discharge depends on how much it has stored in prior periods (and vice versa for charging). Therefore, a BESS's potential capability can change significantly after gate closure.

6.4. This can lead to conservative bidding or frequent offer revisions after gate closure to ensure the BESS can meet its dispatch instructions.

6.5. Conservative bidding means a BESS bidding less than its full capability. This could occur because of their limited ability, under the Code, to update bids after gate closure. See Box 3 below for a detailed explanation.

6.6. In contrast, BESSs do not face the same issues when discharging, as they may be able to update offers after gate closure when their expected capability changes. However, this could lead to BESSs often needing to revise their offers after gate closure and could make it more difficult for the System Operator to assess system risks and prepare mitigations.

6.7. Due to their short storage capacity, a deviation from expected dispatch after gate closure would frequently impact BESSs' expected capability in the next one or two trading periods.

6.8. This contrasts with the intent of the Code for generators, where the need to reoffer after gate closure is expected to be infrequent.

6.9. It appears that both BESSs currently operating in the wholesale market are trading conservatively. This includes conservative offering for at least one of them, possibly to align with the operator’s understanding of the Code’s intent.

6.10. In this context, trading conservatively could either mean being conservative with trade prices, or conservative with trade quantities. In either case, conservative trading may limit BESSs’ efficient use for energy arbitrage, limiting affordability benefits to consumers.

Box 3: what it means to be conservative

Being conservative in quantities:

Conservative in quantities means, when finalising trades at gate closure, restricting quantities to what can be achieved given the worst-case state of charge outcomes after gate closure. This means limiting:

(a) bid quantities based on the assumption that their bids in the preceding hour are fully dispatched

(b) offer quantities based on the assumption that their offers in the preceding hour are fully dispatched.

For example, a BESS has been operating during a period where they are not expecting it will be profitable to charge or discharge. However, they also want to have bids and offers in place in case an opportunity arises. This means they have priced their offers above, and their bids below, the expected dispatch prices.

For simplicity, we assume the BESS has a MW capacity equal to its MWh capacity, with its batteries are 50% full at gate closure when setting its trades.

We can foresee at least two different trading behaviours:

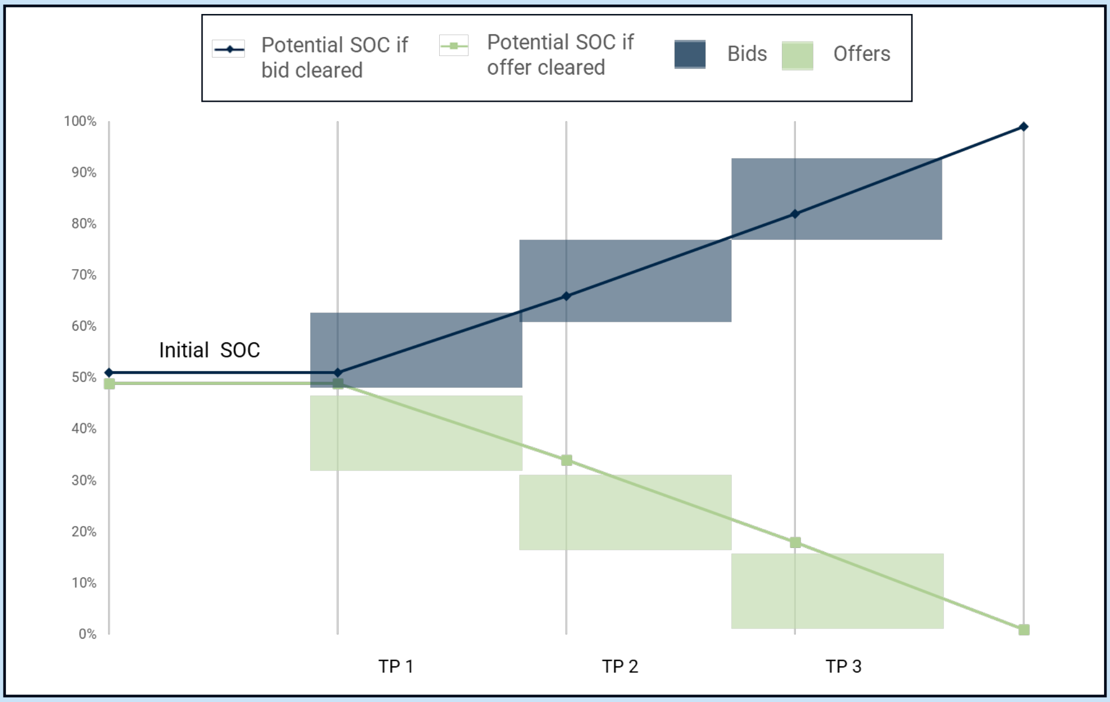
(a) If it is acting conservatively, it needs to restrict its quantities to spread its trades across more periods (Figure 4). In this case, the BESS’s trades depend on worst case state of charge outcomes.

(b) If it is acting based on expected outcomes, it does not need to restrict its quantities (Figure 5). In this case, the BESS’s trades depend on the predicted state of charge.

Figures 4 and 5 show that when trading based on expected outcomes, a BESS can submit much greater quantities compared to if they were conservative (in this example, three times as much).

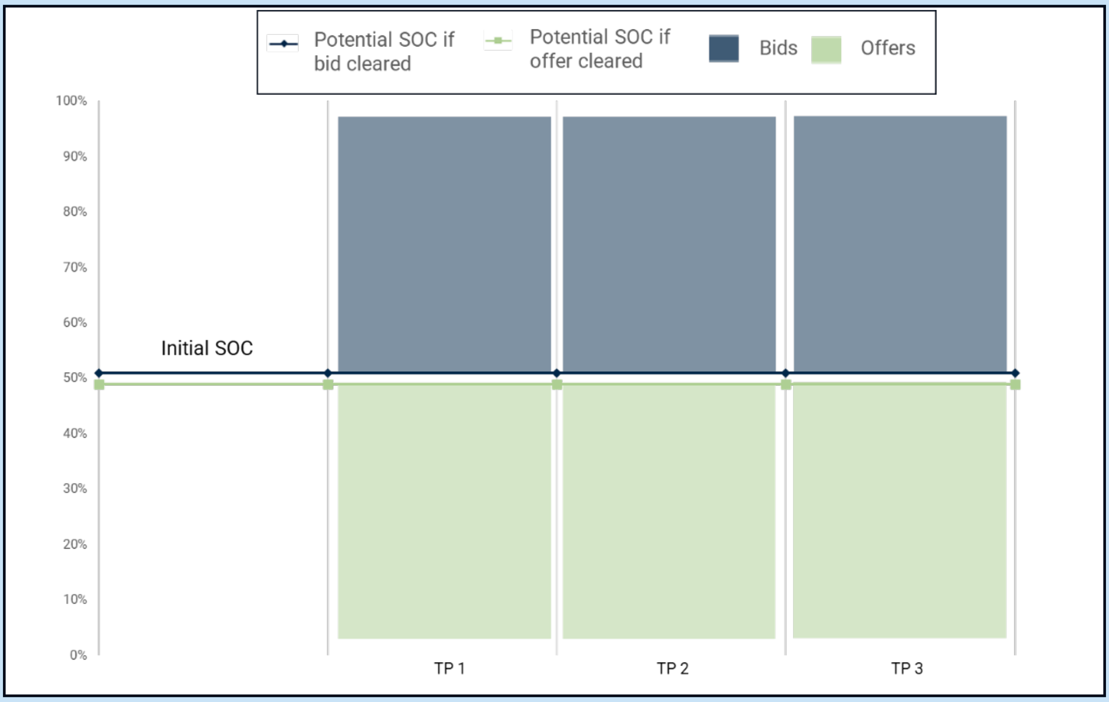
However, if trading based on expected outcomes, a BESS may need to revise trades after gate closure. In this example, if it was dispatched to charge or discharge during the hour after gate closure but before trading period 3, it would need to revise its bid or offer for trading period 3 as its capability to achieve it would have changed.

Figure 4: Example of BESS trading conservatively



Note: *SOC means state of charge and TP means trading period.*

Figure 5: Example of BESS trading based on expected outcomes



Note: *SOC means state of charge and TP means trading period.*

Being conservative in prices

Conservative in prices means bidding and offering at prices that provide high confidence the traded quantities will clear, ie, offering at close to $0 and bidding at very high prices (near scarcity). In this way, there would be little uncertainty as to their expected capability to charge or discharge during the period for which they are bidding or offering.

Not being able to submit economic prices, however, would expose the BESS to potential losses if final prices turned out differently from expected.

It would also prevent BESSs from being open to opportunities that arise from prices being different from expected. This is because they would have to predict when to charge and discharge ahead of time.

The existing arrangements for BESSs can create scheduling uncertainty

6.11. In addition to issues related to uncertainty of trades at gate closure, BESSs can create uncertainty in the forecast schedules at longer horizons, due to their short storage. BESSs need to predict their state of charge when submitting trades. This may be especially difficult at longer time horizons because it requires predicting how trades in all intervening periods will clear.

6.12. This could create uncertainty to the System Operator about how BESSs will operate, impacting its ability to plan for and manage potential system security risks. This could increase the risk of disruption to consumers' electricity supply.

6.13. It could also reduce the accuracy of price signals for the forecast schedules. This could result in other participants making inefficient decisions. In particular, some thermal generators need to operate for long periods to recover high start-up and shutdown costs. They need to decide whether to offer into the market based on the expected revenues they will make over an extended period. If prices in forecast schedules are inaccurate, these generators may not be able to make the most efficient decision. This could lead to less affordable electricity for consumers.

Preferred Solution Options

6.14. We considered a range of options to address the issues identified. Table 1 summarises the issues and our preferred solution options.

Table 1: Issues with current arrangements and solution options

Issue description	Solution option
Having different requirements for BESS (depending on the connection type or mode of operation) is inefficient	
Embedded BESS has shorter gate closure requirements	Embedded BESSs should have the same gate closure period as grid connected BESSs

Issue description	Solution option
Different gate closure rules for BESS when charging and discharging	Gate closure requirements for BESS should be the same when they are charging and discharging
Balancing the need for efficient BESS operation with security requirements and the need to limit gaming opportunities	
Existing arrangements could lead to conservative trading or frequent offer revisions Existing arrangements can create scheduling uncertainty	Full solution: • introduce state of charge constraints • allow BESSs to trade their full capability at gate closure maintain one-hour gate closure

The Authority wants to promote efficiency by removing unnecessary differences in requirements

6.15. We want to promote efficiency by ensuring all BESS connection types and operation statuses are treated equally.

The Authority considers embedded BESSs should have the same gate closure period as grid connected BESSs

6.16. The Authority considers embedded BESSs should have the same gate closure as grid connected BESSs. In our view, this would reduce incentives to connect to a distribution network when it is inefficient to do so.

6.17. We have not identified any alternative options to address this issue.

The Authority considers gate closure requirements for BESSs should be the same when charging and discharging

6.18. The Authority considers BESSs should have the same gate closure arrangements when charging and discharging. This would reduce potential confusion and ensure optimal arrangements for both states. This would help ensure the right balance between consumers' needs for affordable and reliable electricity.

6.19. We have not identified any alternative options to address this issue.

The Authority wants to appropriately balance the need for BESS flexibility with gate closure objectives

The Authority's preferred solution is to allow trading at full capacity with state of charge constraints and one-hour gate closure for BESS

6.20. We have considered a range of solutions to address the issue of balancing the System Operator's security checking needs with the efficient use of BESS, and the need to limit gaming opportunities.

6.21. Our preferred solution includes:

(a) introducing state of charge constraints for BESS

(b) allowing BESS to trade at their full capacity at gate closure

(c) maintaining a 1-hour gate closure for BESS

6.22. These arrangements would apply equally to the charging and discharging states, and to all BESSs submitting trades whether connected to the grid or distribution networks.

6.23. An alternative option would be to require BESS to trade conservatively.

6.24. We also considered the option of reduced gate closure for BESS. We have considered this alongside conservative trading, as well as alongside trading at full capacity with state of charge constraints.

6.25. Our preferred solution involves three separate but interrelated areas of market arrangements. Table 2 shows our preferred solution and the alternative options we are considering.

Table 2: Areas of change and preferred options

Area of change	Preferred options	Alternatives
Tool changes Improve the System Operator's tools to enable it to manage greater uncertainty in BESS operation	Introduce state of charge constraints	Do not introduce state of charge constraints
Trade and trade revision provisions Update the level of certainty a final trade must provide at gate closure, and permissions for revising trades after gate closure	Trading similarly to intermittent generation	Trading conservatively
Gate closure period Change the gate closure period for BESS	Keep gate closure at one hour	Reduce gate closure to 30 minutes

We considered the System Operator's recommendations and submissions on the BESS roadmap

6.26. In selecting our preferred options, we considered a range of suggestions made by the System Operator in its report, as well as by submitters on the BESS roadmap.

6.27. The System Operator advised the following options may allow for shortened gate closure in the future:[36]

(a) implementing state of charge constraints in the forecast and dispatch schedules. These would constrain cleared quantities to what is available given the expected state of stored energy

(b) introducing rules to allow the System Operator to constrain BESS to charge when anticipating capacity shortfalls

(c) enhancing sensitivity scheduling and improved situational awareness tools for system coordinators.

6.28. In its submission on the BESS roadmap, NewPower suggested the Authority consider:

(a) shortening gate closure windows

(b) allowing limited intra-period adjustments

(c) clarifying rules for revising trades after gate closure based on changes in state of charge

6.29. Meridian Energy suggested the Authority should consider regulatory changes to allow BESSs to block dispatch within gate closure to firm co-located intermittent generation.

We shortlisted options that deliver benefits early

6.30. At this stage, we are not considering:

(a) **enhancing sensitivity scheduling and improved situational awareness tools for system coordinators**. The Authority is aware that the System Operator already plans to implement enhancements in this area in 2027.[37]

(b) **allowing the System Operator to constrain BESSs to charge when anticipating capacity shortfalls.** This is already permitted under the current rules. We expect the System Operator to lead the development of this policy and engagement with participants.

(c) **limiting intra-period adjustments or introducing any rules-based permissions for revising trades after gate closure.** We believe any rules allowing trade revisions after gate closure should remain limited to rare circumstances. Frequent revisions would disrupt system coordination and complicate compliance monitoring.

(d) **introducing any rules specific to hybrid arrangements.** These changes are part of a broader problem of how to treat hybrid systems in the power system. We will be reviewing rules for hybrid arrangements next year.

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[36] Section 4 of the System Operator’s report (Appendix E) provides more details on these options and the System Operator’s assessment.

[37] This is contingent on the outcome of its investigations

State of charge constraints can reduce schedule uncertainty and enable trading at full capacity

State of charge constraints limit quantities based on the state of stored energy in the battery

6.31. The Authority proposes that software enhancements be made to apply state of charge constraints to the System Operator's scheduling and dispatch model.

6.32. A state of charge constraint would ensure schedule and dispatch quantities for each BESS are feasible given the amount of energy stored in the battery and its storage limits. There would be state of charge maximum and minimum constraints.

(a) A state of charge ***maximum*** constraint would limit the MWh cleared to *charge* to be no more than the difference between the starting state of charge and the *maximum* state of charge.

(b) A state of charge ***minimum*** constraint would limit the MWh cleared to *discharge* plus the MWh cleared to *provide sustained instantaneous reserve* (as generation reserve) to be no more than the difference between the starting state of charge and the *minimum* state of charge.

6.33. These constraints would limit:

(a) charge and discharge such that they were achievable for the full trading period in a forecast schedule, and 5 minutes in a dispatch schedule[38]

(b) sustained instantaneous reserve so that it is achievable for 15 minutes if required at the end of the trading period in a forecast schedule or the end of 5 minutes in a dispatch schedule.[39]

6.34. BESSs would be required to provide real time telemetry of their state of charge and to submit state of charge maximums and minimums as part of their offers. We consider it appropriate to include state of charge maximums and minimums as part of offers rather than static values because it provides greater ability for BESS to reflect changing capabilities and warranty requirements.

6.35. For dispatch, the starting state of charge would be based on a real time telemetered value supplied to the System Operator by BESSs. For forecast schedules, the starting state of charge for the first period would be based on the real time telemetered value. The starting state of charge for subsequent periods would be calculated in the market system based on the previous period's starting state of charge adjusted for cleared charge or discharge quantities.

6.36. We note that the System Operator is already proposing to require BESSs to provide real time telemetry for state of charge information.[40]

[38] Forecast schedules solve for half hour trading periods in the future whereas dispatch schedules solve for 5-minute periods.

[39] This is based on advice from the System Operator that BESS needs to ensure any SIR response required can be maintained for 15 minutes.

[40] See chapter 8 of the System Operator's Connected Asset Testing and Information Standard consultation.

Benefits

State of charge constraints would help the System Operator manage the power system and enable flexible trading

6.37. State of charge constraints would provide greater certainty to the System Operator of how BESSs will operate, enhancing its ability to plan for and manage potential system security risks.

6.38. State of charge constraints would also enhance the feedback provided to traders through the forward schedules, as to whether their bids and offers are likely to clear as expected. This would enable BESS traders to update their trades regularly, providing more accurate price signals.

6.39. By providing the System Operator with greater certainty of BESSs' outcomes, we consider state of charge constraints would enable more flexible offer rules.

Costs

State of charge constraints come with implementation costs and time

6.40. The System Operator has provided a rough order of magnitude cost estimate of approximately $1.1m to implement state of charge constraints.[41] The System Operator estimated that state of charge constraints would take approximately 17 months to implement following a decision by the Authority to make these changes.

6.41. We consider the costs to BESSs for the increased offer requirements would be low.

6.42. We consider the costs for the WITS manager would also be low, especially if we decided to implement bi-directional offer forms[42] at the same time.

State of charge constraints could cause inaccuracies in forecast schedules at longer time horizons

6.43. State of charge constraints may reduce the accuracy of forward schedules for some periods at longer forecast horizons. This is because the longer the forecast horizon, the more likely the scheduled state of charge will differ from the BESS owner's actual intentions. This is because there would be more opportunities for cleared amounts to differ from expectations in the intervening periods.

6.44. For example, state of charge constraints may result in the schedule forecasting insufficient stored energy to discharge in the following evening's peak, even if the BESS would definitely want to discharge at that time.

6.45. However, this misalignment between scheduled outcomes and the intention of the BESS owner would signal to the traders to update their offer. Additionally, if this

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[41] See section A.1.3 of the System Operator's report at Appendix E. In particular, the System Operator estimates a total cost of $1.9m if this solution was implemented at the same time as our preferred option for Issue 1 (bid and offer forms), approximately $0.5m less than if implemented separately.

[42] Preferred solution for issue 2.

became a major concern, the System Operator would have flexibility to apply state of charge constraints on a shorter time horizon.

The Authority considers the benefits of state of charge constraints likely outweigh the costs

6.46. It is important that the System Operator has the tools it needs to manage the power system, to minimise the risk of disruptions to consumers' electricity supply. State of charge constraints would also enable greater flexibility in offers, which help ensure more affordable electricity for consumers.

6.47. As state of charge constraints would take some time to implement, we are also considering whether an interim solution may be justified (as described in paragraphs 7.83. – 7.85).

Allowing BESSs to trade their full capacity can lead to more affordable electricity to consumers

6.48. The Authority's view is that trading at full capacity alongside state of charge constraints provides an appropriate balance between the needs for system security and maximising the use of BESSs. In particular, we consider it would provide a better balance than conservative trading without state of charge constraints.

The Authority considers BESS should be able to trade at full capacity with state of charge constraints

6.49. State of charge constraints would allow BESSs to bid and offer their maximum charge and discharge rates regardless of whether they would be able to achieve them based on state of charge. This is because the state of charge constraints would ensure outcomes are constrained to what is expected to be achievable.

6.50. Under this proposal, however, BESSs would still be able to trade at quantities below their full capacity. This would help ensure they still have sufficient control to operate within ranges that limit damage and degradation of their batteries and satisfy any warranty conditions.[43]

6.51. However, we consider that BESSs should not be allowed to revise their trade prices following gate closure. This aligns with the current rules for all dispatchable participants with the intention being to limit the potential for unduly influencing prices.

6.52. Finally, we suggest BESSs would only be allowed to change their bid and offer quantities after gate closure in rare circumstances eg, reasons relating to bona fide physical reasons and grid emergencies.[44] We suggest bona fide physical reasons could include potential breaches of warranty conditions due to reasonably unforeseeable circumstances.

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[43] Some warranty conditions will relate to MW output rather than MWh, so state of charge constraints would not be sufficient to comply with them.

[44] These are the same reasons currently permitted when submitting dispatchable bids or offers.

Trading at full capacity with state of charge constraints would be similar to intermittent generation offer rules

6.53. These arrangements would be similar to the arrangements for intermittent generation. While intermittent generators have to update their forecast of generation potential as their expected capability changes, state of charge constraints would perform the same function for BESS.

6.54. BESS and intermittent generation are similar in that it can be difficult to predict their expected capability:

(a) For BESS, it is because of their short storage and the inter-dependency of their consumptions and generation.

(b) For intermittent generation, it is because of weather conditions. For this reason, intermittent generation is required to update its capability after gate closure[45] to ensure its efficient output levels are not constrained.

6.55. However, BESS is different from intermittent generation in that its optimal trade prices depend on expectations of future prices. This means the later BESS is able to update its trade prices, the more economically efficient its operation. However, late updates to trade prices would create risks to other aspects of market operation.

Benefits

State of charge constraints enable trading at full capacity without compromising the System Operator's system assessment process

6.56. State of charge constraints ensure the forecast schedules account for the capability of BESS. This means BESSs could trade their full capacity without compromising the accuracy of the schedule outputs. This would help ensure the System Operator's system assessment is accurate and reliable.

Trading their full capacity protects BESS owners from financial losses and provides greater arbitrage opportunities

6.57. Trading their full capacity would mean BESSs would not need to restrict quantities or prices when finalising their trades at gate closure.

6.58. This means they could protect against making losses while being open to unexpected profit opportunities.

Disadvantages

Conservative trading would make it easier for the System Operator to maintain system security

6.59. Conservative trading would make it easier for the System Operator to assess system security risks and prepare mitigations.

[45] By changing their forecast of generation potential (FOGP)

(a) If a BESS is conservative with prices, the System Operator will have a high level of certainty as to how much the BESS will charge or discharge in the given trading period.

(b) If a BESS is conservative with quantities, this will reduce the potential variation in output from expected.

6.60. Trading at full capacity would mean there is more chance that the outcome for a BESS turns out differently from the expected one because it would lead to greater quantities being priced close to the marginal price.[46]

6.61. However, it is worth noting that:

(a) uncertainty of dispatch outcomes applies for any generator or purchaser pricing their offers or bids close to the marginal price

(b) the same situation applies if trading conservatively in quantities, the only difference is the total quantity traded at prices close to the marginal price will be higher if not needing to be conservative

(c) state of charge constraints would help provide visibility of potential future outcomes.[47]

Maintaining one-hour gate closure for BESS would support system security

6.62. As part of our preferred solution, we suggest that gate closure should be 1-hour for BESS. We consider this would help ensure the System Operator can assess system security risks and prepare mitigations. It would also limit any gaming opportunities associated with shorter gate closure.

6.63. We consider our preferred solution provides a better balance between the various needs compared to trading:

(a) conservatively with reduced gate closure

(b) at full capacity with state of charge constraints and reduced gate closure.

The System Operator advised that reducing gate closure for BESS may cause difficulties in maintaining power system security

6.64. Reducing gate closure for BESS would provide the System Operator with less time to assess system security risks and put in place mitigations.

6.65. The System Operator develops constraints and other mitigations to system risks ahead of gate closure for use in the forecast schedules. After gate closure, the System Operator uses advanced applications to validate whether the mitigations are sufficient and, if not, to refine them or develop new ones.[48]

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[46] The marginal price is the offer price of the highest priced offer dispatched (or lowest priced bid dispatched). If quantities are priced close to the marginal price, it is more uncertain whether they will be dispatched if demand varies from expected.

[47] This is described further in paragraph 6.69.

[48] The System Operator refers to this process as schedule security assessment, as described in section 3.1 of the System Operator's report at Appendix E.

6.66. In summary, the System Operator advised that reducing gate closure to 30 minutes or less:

(a) 'could potentially lead to an inability to manage the grid within the security standards' in some situations

(b) would make the schedule security assessment process near impossible for 30-minute gate closure as more BESS enters the market. It would also be impossible for gate closure of 15 minutes or less as more BESS enters the market. The Authority understands this means there is an increased risk of damage to grid assets and disruption to consumers' electricity supply. This is because the security standards are relied on to prevent cascade failure of the power system[49]

(c) would further exacerbate issues in managing an increasingly intermittent power system

(d) would cause greater difficulties for power system management than intermittent generation. This is because the System Operator 'has reference to weather forecasts to assure the probability of realising the offered capacity' of intermittent generation.

The Authority is concerned about the system stability risks of reducing gate closure and is not contemplating reducing gate closure to less than 30 minutes at this stage

6.67. We believe it is important to consider the increased risk of damage to grid assets and disruption to consumers' electricity supply caused by reduced gate closure. Damage of grid assets could:

(a) reduce the resilience of the grid, further increasing the risk of disruptions to consumer's electricity supply

(b) require grid upgrades, the majority cost of which would likely be passed through to consumers, resulting in less affordable electricity.

6.68. In particular, we consider that reducing gate closure to less than 30 minutes could cause significant risks. For this reason, we believe this option is not worthy of further consideration at this stage.

The Authority considers its preferred option would reduce risks to system stability compared to conservative trading with 30-minute gate closure

6.69. We consider it would be more difficult to assess system security and prepare mitigations with conservative trading and 30-minute gate closure compared to our preferred option. This is because there will be times when this process will be difficult with 30-minute gate closure. We also acknowledge the System Operator's view that reduced gate closure for BESS may cause greater difficulties for power system management than intermittent generation.

6.70. By contrast, under our preferred solution, the System Operator would have greater visibility of potential dispatch outcomes at one hour out from dispatch time. With

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[49] See the policy statement incorporated by reference into the Code by clause 8.10, effective 14 March 2025. In particular, see the security management section of Chapter 1 - Security Policy, as well as Chapter 2 - Dispatch Policy.

state of charge constraints, the System Operator would have visibility of the expected outcomes, and could gain visibility of a range of potential outcomes by applying price sensitivities. This would be similar to how weather forecasts and their sensitivities provide this visibility for intermittent generation.

The Authority acknowledges that reduced gate closure would be more efficient for BESS

6.71. Reducing gate closure would enable BESSs to take advantage of new information of expected future prices to reset their trades. This would be an advantage over our preferred solution. However, unexpected outcomes would still arise after gate closure.

6.72. We consider the efficiency advantages of our preferred solution would outweigh those of conservative trading with reduced gate closure. We consider conservative trading can be very limiting, especially when trading to take advantage of unexpected opportunities. In our view, BESSs are likely to be operating with this strategy most of the time. Moreover, we consider that the importance of this strategy will become more prominent over time as supply becomes more intermittent.

The Authority considers reducing gate closure could create gaming opportunities

6.73. Reducing gate closure for BESSs could provide them with gaming opportunities as they would have greater power to set prices compared to participants with longer gate closure periods. This would be especially true while BESS penetration is low as there would be less competition between BESSs in setting prices.

6.74. In particular, a BESS may be inclined to limit the decrease in prices caused by its injections or to increase prices for the benefit of a wider generation portfolio. This would limit the reduction in wholesale costs that BESSs can provide through energy arbitrage. In turn, this would limit BESSs' benefits to consumers of more affordable electricity.

6.75. It may also be difficult for the Authority to monitor and enforce potential breaches of trading conduct provisions in the Code due to the complexity of trading considerations for BESSs.

6.76. BESSs' trades may be complex to monitor and assess because they depend on:

(a) an evolving view of the cost of charging as new information comes to light on expected future prices

(b) an evolving view of the future prices at which they could discharge

(c) an evolving view of the potential variability of expected prices from dispatch

(d) their appetite for risk and opportunities.

Overall, the Authority considers its preferred solution provides a better balance of gate closure objectives compared to reducing gate closure with conservative trading

6.77. In summary, the Authority considers, compared to conservative trading, its preferred solution:

(a) improves the System Operator's ability to assess and manage system risks, helping to ensure a continuous supply of electricity to consumers

(b) improves arbitrage opportunities, helping to ensure affordable electricity for consumers

(c) limits gaming opportunities, helping to ensure affordable electricity for consumers

The Authority considers the additional risk of reducing gate closure with flexible trading is not worth the gain it will bring

6.78. The Authority considers allowing flexible trading with state of charge constraints would provide significant benefits to consumers. While we acknowledge that further material benefits could be gained by reducing gate closure, we think these are unlikely to outweigh the costs of increased risk of supply disruptions. We consider the potential for gaming with reduced gate closure further strengthens our opinion.

6.79. If the Authority decides not to reduce gate closure following consultation, we will reconsider this decision at a later date, once the System Operator has gained experience using new tools it is planning to implement. In the 2026/27 financial year, the System Operator is intending to update its operational tools to better account for schedule sensitivities and scenarios.[50] We consider this could enable a reduction in gate closure without compromising the System Operator's ability to assess system risks.

The Authority has done some preliminary modelling of the arbitrage benefits of different options

6.80. We have done some preliminary modelling of arbitrage benefits from our preferred option compared to:

(a) trading at full capacity with state of charge constraints and 30-minute gate closure

(b) trading conservatively with prices and one hour gate closure

(c) trading conservatively with prices and 30-minute gate closure

6.81. These results demonstrate the potentially significant increase in benefits from our preferred option compared to trading conservatively with prices at one-hour or 30-minute gate closure. They also demonstrate that there may be little benefit gained by reducing gate closure if trading at full capacity with state of charge constraints. Further details can be found in Appendix D.

6.82. Before consulting on any proposed Code amendments, we will consider whether these models need to be refined and new ones added, based on stakeholder

[50] The purpose of this project is to address the limitations of the current tool suite for running real-time scenario analysis. An enhanced real time scenario analysis tool will allow operators to run market schedule-based power system studies with customisable inputs, resulting in timely and consistent analyses and probability-based decision-making for the control room and operational support teams. The project is underway with an initial concept study having been completed middle of 2025. Further investigation is scheduled in early 2026, followed by planned implementation in FY27 contingent on the outcome of the investigation phase.

feedback to this consultation. This could include modelling options where trades are conservative in quantities, or accounting for probabilities of different outcomes.

The Authority is considering whether an interim option is required to enable more efficient use of BESS

6.83. The implementation of our preferred option depends on introducing state of charge constraints. The System Operator has estimated this would take approximately 17 months following a decision by the Authority to implement the changes. For this reason, we are also considering whether an interim solution would be needed.

6.84. An interim option we are considering would enable BESS to trade based on their expected capability and to revise quantities after gate closure if their state of charge differed from expected.

6.85. This option would enable more efficient use of BESS in the interim period. However, it would also make it more difficult for the System Operator to assess system security risks and prepare mitigations.

Questions:

Q11. Do you agree the issues identified by the Authority are worthy of attention? If so, do you agree with our framing?

Q12. Do you agree that BESS should have the same arrangements when charging and discharging, and that embedded BESS should have the same arrangements as grid connected BESS?

Q13. Do you agree with our preferred new arrangements for BESS?

Q14. Do you see any issues with how we have defined state of charge constraints?

Q15. Do you agree that the benefits of state of charge constraints likely outweigh the costs?

Q16. Do you agree with how we have characterised the differences between various options?

Q17. Are there any other options that you think would better achieve the gate closure objectives?

Q18. Do you consider an interim solution is necessary? If so, do you agree with the potential solution we suggested?

Q19. Do you have any information that can help us better understand the benefits and costs of different options? This includes, for example, substantiating the system risks, and how to improve our modelling of benefits.

7. Issue 4: Constrained off payments

7.1. This section considers the issue of 'constrained off' payments and whether BESS should receive this compensation when charging.

7.2. We consider that BESSs should not receive constrained off compensation because the rationale for paying it to dispatchable purchasers does not apply to BESSs.

The existing arrangements

Constrained off payments compensate dispatchable purchasers when dispatch outcomes differ from final prices

There are different kinds of 'constrained situations' but only some are compensated

7.3. 'Constrained on situations' and 'constrained off situations' occur when there is a discrepancy between dispatch outcomes and what dispatch would be if based on final prices. Participants are sometimes compensated for these situations.

7.4. Constrained on or off situations can occur when:

(a) there are several dispatch prices across a trading period but only one final price[51]

(b) the System Operator dispatches plant out of merit order[52] to maintain system security.

7.5. Constrained on and off payments are made, where applicable, for each dispatchable bid or offer tranche in each trading period.

Dispatchable purchasers and generators receive constrained on compensation, but only dispatchable purchasers and frequency keepers receive constrained off compensation

7.6. As shown in Table 3, constrained off payments are made to dispatchable purchasers but not generators, except when selected for frequency keeping.

Table 3 Constrained-on and off amounts and payments

Category	Constrained Off	Constrained On
Situation for generator	Occurs when a generator has been dispatched to generate less than they would have been willing to generate based on the final price. This is because the final price	Occurs when a generator has been dispatched to generate more than they would have been willing to generate based on the final price. This is because the final price

[51] Except in rare circumstances, this is the only reason for constrained off payments to dispatchable purchasers, as described in in Appendix C.

[52] Merit order means dispatching generators on and loads off in order from lowest to highest priced bids and offers

	turned out higher than their offered price.	turned out lower than their offered price.
Payment to generator	Only made when frequency keeping.	To compensate for costs incurred (eg, fuel costs) that was not compensated through prices.
Situation for Dispatchable Load purchaser	Occurs when a dispatchable load purchaser has been dispatched to consume less than they would have been willing to consume based on the final price. This is because the final price turned out lower than their bid price.	Occurs when a dispatchable load purchaser has been dispatched to consume more than they would have been willing to consume based on the final price. This is because the final price turned out higher than their bid price.
Payment to dispatchable load purchaser	To compensate for profits they could have made if not dispatched down.	To compensate for financial losses they incurred by paying more than they were willing to pay.

Constrained off payments for load were introduced to incentivise demand response participation

7.7. We introduced dispatchable demand to facilitate efficient price response by purchasers. This directly benefits dispatchable purchasers if they are able to respond to dispatch. It also benefits other consumers through more efficient pricing and by helping the System Operator manage the power system.

7.8. However, the efficiency gains depend on bid prices being set at efficient levels. This means bidding at the maximum price the purchaser is willing to pay, representing the price at which they would be indifferent about consuming electricity.

7.9. When the Authority introduced dispatchable demand, we decided dispatchable purchasers would receive constrained off payments (see Appendix C for more details). This is even though generators are not eligible for constrained off payments. This was done to incentivise:

(a) **participation in dispatchable demand**. This was a response to feedback from industry, who told us constrained off compensation would be required for purchasers to participate

(b) **efficient dispatch and pricing**. Dispatchable purchasers would be incentivised to bid at the maximum price they are willing to pay for electricity.

7.10. Constrained on and off costs are paid by wholesale purchasers in proportion to their total purchase quantity.

Issues with existing arrangements

BESSs do not need constrained off payments to incentivise submitting dispatchable bids

7.11. As discussed in section 4, the Authority considers BESSs should be required to submit dispatchable bids. We consider they should have the same requirements as generators when charging because:

(a) they have the same capabilities whether they are charging or discharging

(b) like generators, their purpose is to sell electricity. They should therefore have the same responsibility as generators to ensure a functioning market and power system.

7.12. Therefore, we consider there is no need to provide a separate incentive for BESS to be dispatchable when charging.

7.13. Authority data shows that constrained off payments represent a small part of existing New Zealand BESSs' revenue streams.[53]

BESSs do not need constrained off payments to incentivise bidding prices that reflect their willingness to pay for electricity

7.14. Whether it is efficient for BESSs to receive constrained off payments also depends on how BESSs change their bidding behaviour and how that affects overall electricity dispatch and prices.

7.15. By submitting bid prices at the maximum price they are willing to pay for the given bid quantity, BESS would:

(a) not get dispatched if the dispatch price turns out higher than they are willing to pay. In most cases this would mean final prices were below what they were willing to pay

(b) get constrained on payments if final prices turned out higher than they were willing to pay.

7.16. Theoretically, BESSs could offer at higher prices than they were willing to pay to help ensure they did not lose profit opportunities due to constrained off situations.

7.17. However, in doing so, they may end up being dispatched when the final price turned out higher than what they were willing to pay. Moreover, they could put upward pressure on prices by bidding this way. This could result in prices being higher than they would be if BESSs bid what they were willing to pay.

7.18. We therefore consider BESSs are likely to submit bid prices as the maximum price they are willing to pay for electricity.

[53] We have estimated that constrained off payments represent less than 1% of the total energy and reserve revenue of the first BESS connected to the system.

Option

The Authority considers that BESSs should not receive constrained off payments when charging

7.19. In line with our objective of promoting competition in the industry, the Authority wants to ensure a level playing field for different technologies. This includes removing barriers to entry for BESSs and helping ensure its capabilities can be realised. However, it also means ensuring they do not receive greater compensation than other technologies where it is not justified.

7.20. The Authority considers that BESSs should not be entitled to constrained off payments when charging, because:

(a) these payments would not be appropriate for an entity participating in the market for the purposes of selling energy, especially when it has the ability to follow dispatch

(b) we expect it would not result in inefficient bidding behaviour by BESSs.

7.21. The Authority considers removing constrained off payments for BESS when charging would meet our main statutory objective to promote competition because it would help ensure consistent compensation across different technologies participating in the market for the purpose of selling electricity.

7.22. The Authority is currently working with the System Operator to investigate improvements to the frequency keeping arrangements. This includes enabling BESSs' participation across their full operational range. We are also investigating changes that would remove constrained compensation for frequency keeping. Whatever changes we decide to make, we will want to ensure consistency of any constrained payment compensation across all frequency keeping providers. We would consult on any proposed changes to frequency keeping.

Questions:

Q20. Do you agree the issues identified by the Authority are worthy of attention?

Q21. Do you agree with our framing of the issue?

Q22. Do you consider having constrained off payments would affect bidding and offering behaviour from BESS?

Q23. Do you agree with our preferred solution?

8. Next steps

8.1. The Authority will consider submissions to this consultation before deciding how to progress.

8.2. We will model the energy arbitrage benefits of various solution options for the gate closure problem and present these when consulting on any proposed Code amendment. This will help us to substantiate our choice.

8.3. If we decide to propose any Code amendments, we will consult on these in the first half of 2026.

Appendix A Electricity and ancillary service market basics

The electricity market and ancillary services help ensure consumers have electricity when they need it

A.1. It is important that the supply and demand for electricity are closely balanced at all times, and any temporary imbalances are quickly restored. This ensures a stable and resilient power system that delivers electricity to consumers when they want it.

A.2. The supply-demand balance is maintained by various means. These include wholesale electricity market dispatch, Code requirements on industry participants, and ancillary services procured by the System Operator.

- The wholesale electricity market creates dispatch instructions for generation, and some demand response, to match supply with demand. The System Operator sends dispatch instructions at least once per half hour and up to every 5 minutes, as needed.
- The 'frequency keeping' ancillary service helps ensure supply and demand remain closely balanced between wholesale market dispatches.
- The 'instantaneous reserve' ancillary service helps ensure the supply-demand balance can be restored following the sudden and unexpected loss of injections into the power system (a 'contingent event').
- For the purposes of this consultation, it is not critical to understand how Code requirements on participants or other ancillary services help maintain the balance of supply and demand.

Generation reserve or interruptible load can provide fast and sustained instantaneous reserves

A.3. Instantaneous reserves can be either

- 'Generation reserve' (GR): Spare generation capacity that is injected into the power system in a contingent event
- 'Interruptible load' (IL): Consumption that is reduced in a contingent event

A.4. The System Operator procures two types of instantaneous reserves

- 'Fast instantaneous reserve' (FIR), which acts quickly to arrest a fall in system frequency
- 'Sustained instantaneous reserve' (SIR), which does not need to act as quickly but must be sustained for 15 minutes

The System Operator's market system is used to produce dispatch schedules and prices as well as forecast schedules and prices

A.5. The System Operator dispatches generators and dispatchable loads using its market system. This system matches supply with demand using 'offers' from large generators, 'bids' from some wholesale purchasers, and demand forecasts.

A.6. Dispatch instructions are created by selecting the least cost combination of offers, dispatchable bids, and instantaneous reserve offers. The quantity a given generator or load can be dispatched to will be subject to constraints that ensure the power system remains stable and resilient to shocks.

A.7. A ‘dispatch price’ is also created through this process as the cost of meeting an additional MW of demand. This creates an efficient price signal as to the value of extra generation.

A.8. Prices differ across different locations to reflect the differing costs of supplying electricity. This reflects any transmission constraints. It also reflects that more generation is required the further away the demand, as more electrical energy is lost as heat on transmission lines.

A.9. The final spot price for a given trading period and location is calculated by the clearing manager as the time-weighted average of dispatch prices.

Appendix B Description of BESSs' benefits

BESSs support a stable and resilient power system by providing ancillary services

B.1. BESSs support a stable and resilient power system by providing ancillary services. This reduces the risk of disruption to consumers' electricity supply.

BESSs help ensure sufficient capacity in times of tight supply

B.2. As more intermittent generation is built, there will be an increasing need for flexible generation to meet electricity demand when the wind is not blowing and the sun isn't shining. BESSs can provide that flexibility, ensuring that electricity demand can be met whatever the weather conditions. This helps ensure consumers' electricity demand can be met at all times.

BESSs reduce dry year risk by enabling intermittent generation overbuild

B.3. Without BESSs, there will be a limit to how much intermittent generation (IG) can be built before IG would need to be dispatched off at times of high wind and sunshine to ensure the total supply did not exceed demand. BESS could enable such 'over-build' by soaking up the excess generation at these times and discharging it back into the power system at times of low wind and sunshine.

B.4. Hydro generators could conserve more of their energy, as more energy would be utilised from IG. This would reduce the risk of energy shortfalls during 'dry years' – when climate conditions lead to especially low inflows into hydro storage lakes.

B.5. This would benefit consumers by keeping prices low during dry years and helping ensure their supply did not need to be disrupted due to an energy shortage.

BESSs can be built in the locations where it is needed most

B.6. Most generation needs to be built close to its fuel source. For example, near gas networks for gas-fired generation, where there is geothermal activity for geothermal generation, where the water flows for hydro generation, where the wind blows or sun shines for intermittent generation. In some cases (eg, for wind farms and geothermal sites), land availability can also be a constraint on what locations the generation can be built.

B.7. The location of large loads is also often constrained, for example because of the need to access shipping for the raw materials used in a manufacturing process, or for a dairy processing factory to be close to where the milk is sourced.

B.8. BESSs isn't as constrained as most generation or some large loads on the location it can be built. This means it can be built where it is needed most.

B.9. By building in the right locations, BESSs can:

- provide alternatives to network assets. For example, BESSs can help avoid or defer transmission upgrades by reducing transmission flows on constrained lines. This can reduce the cost of transmission upgrades that are ultimately passed through to end consumers.
- ease transmission constraints by generating downstream of the constraint or consuming upstream of the constraint. This reduces wholesale prices downstream of the constraint. It also helps ensure a continuous supply of electricity to consumers downstream of the constraint.
- reduce the cost of transferring electricity across the High Voltage Direct Current (HVDC) link by providing lower-cost instantaneous reserve in the

receiving island. As energy and reserve prices are interrelated, this can reduce both the wholesale spot price and the reserve price.

- reduce transmission losses by generating closer to demand. This means less generation is needed to meet the same volume of demand and can reduce wholesale purchase costs.

B.10. BESS operators are broadly incentivised to build in the right locations through locational pricing in the wholesale market, contracts with network owners, and transmission pricing.

BESSs can reduce financial risk for participants

B.11. BESSs can reduce financial risks for generators and purchasers when built as part of a portfolio of assets, or when providing hedge contracts with other asset owners. In particular, BESSs can help to balance variable revenues from intermittent generation, manage locational price risk, and manage price volatility.

B.12. This benefits consumers by:

- reducing financing costs on wholesale purchasers to manage cash flow volatility
- reducing the costs to finance investments in new generation or large loads, by creating greater cash flow certainty. This benefits the new large consumers directly. It also benefits all consumers by bringing efficient generation to market earlier, reducing wholesale prices, and helping to ensure there is enough generation to meet demand at all times.

Appendix C Description of constrained off situations for purchasers

Constrained off situations for purchasers mainly occur due to variability in dispatch across a trading period

C.1. A purchaser will get dispatched for some but not all of a trading period if their bid prices are below some dispatch prices in the period but above others.

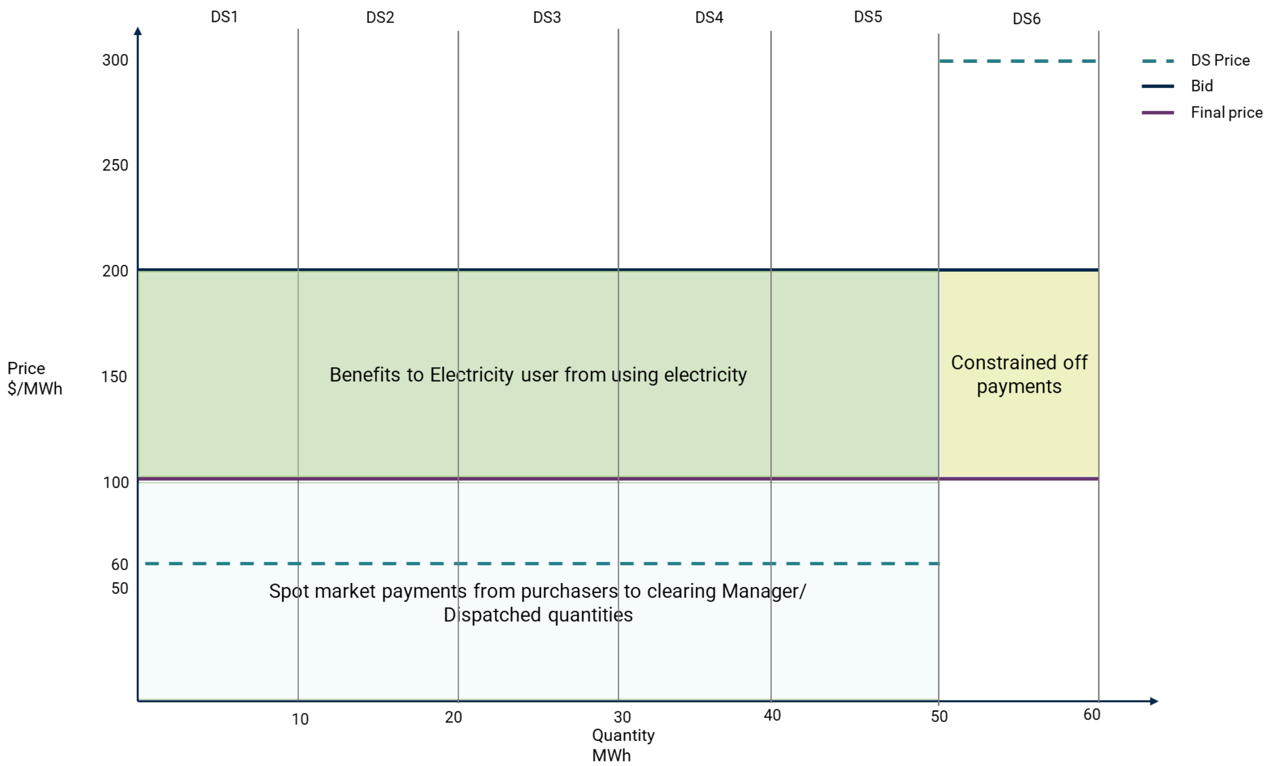
C.2. Sometimes when this occurs, it will cause a constrained off situation for one or more purchasers. This could lead to constrained off payments in some such occurrences simply due to how final prices are created as the time-weighted average of dispatch prices. This is more likely to occur the greater the variability of dispatch prices across the trading period.

Example of a constrained off situation and payment for a dispatchable purchasers

C.3. For example (Figure A1),

- A dispatchable purchaser bids 120MW at $200/MWh (representing the maximum price they are willing to pay).
- Suppose there are six dispatch schedules in a half hour trading period, one every 5 minutes. This means the final price will be the simple average of the dispatch prices.
- The prices for the first five are $60/MWh, the price for the last one is $300.
- This means the BESS would have been dispatched to 120 MW in the first five dispatch schedules, and 0MW in the final schedule
- The final price will be $100/MWh.
- At that price, the purchaser would have been willing to consume for the entire trading period.
- They will have consumed 42MWh across the half hour trading period (100MW for 25 minutes) but would have been willing to consume 50MWh (100MW for the full half hour).
- They would therefore receive constrained off payments for the 8MWh they were unable to consume.
- The payment would represent the additional profit they could have made if they consumed for the entire trading period. Because their bid price represents the price at which they would be indifferent about consuming, it is assumed that their electricity dependent profit per MWh of energy consumed will be zero at this point. Therefore, their profit per MWh in general will be equal to the difference between the price their bid price and the final price.
- Their constrained off payment would therefore be equal to 8MWh*($200/MWh - $100/MWh) = $800.
- Note, the constrained off payment calculation will use the MWh consumed in place of the average dispatch volume, if it was a larger value.

Figure A1: How constrained off payments work for BESS



Note: *In the figure above DS stands for dispatch schedule.*

Some constraints that are applied in rare situations lead to constrained off payments to purchasers

C.4. Constrained off situations can also occur in rare circumstances when the System Operator applies constraints that directly limit the purchaser's dispatchable capacity. These constraints can lead to constrained off situations because they can result in purchasers being dispatched out of merit order.

C.5. These constraints are applied after unexpected failure of load plant, as a temporary measure before the purchaser has updated their bid.

C.6. They could also be applied in other unexpected events requiring quick action from the System Operator to alleviate a localised threat to power system stability. In such events the System Operator may need to use a simple constraint so it can alleviate the situation quickly. Once the System Operator has managed the immediate threat, it should be able to develop a more appropriate constraint that does not lead to constrained off situations.

Most constraints do not lead to constrained on or off payments

C.7. Most constraints applied by the System Operator are reflected in the dispatch prices. This means most constraints don't cause generators and dispatchable purchasers to be dispatched out of merit order and, therefore, do not result in constrained payments.

C.8. For example, if the System Operator applies a transmission constraint to a specific region, a dispatchable purchaser might be constrained (meaning that it would have been dispatched to consume had the constrained not been applied). However, this constraint also results in in lower electricity prices in the affected region. This ensures an efficient price signal to encourage new loads to connect in the region and new generation to connect elsewhere. In this case providing constrained off payments would distort this signal and, therefore, be inefficient.

Appendix D BESS modelling

.

Preliminary modelling of BESS gate closure options

11 November 2025

Contents

1. Overview

1.1. We have undertaken preliminary modelling of different trading strategies and gate closure arrangements to help us understand the differences in:

(a) consumer benefits from energy arbitrage, and

(b) BESS profitability.

1.2. The different strategies and gate closure options are described in detail in section 7 of the paper.

1.3. As a reminder, consumers benefit from energy arbitrage through reductions in wholesale purchase costs.

1.4. For simplicity, we have modelled a single BESS of medium size (50MW/100MWh).

1.5. We have modelled each of the following trading scenarios with both one-hour and 30-minute gate closure periods:

(a) **Full capacity with state of charge (SoC) constraints**: This means trading at full capacity, at all times, with SoC constraints. With one-hour gate closure, this represents our preferred option described in section 7. Under this scenario, bids and offers are given economic prices based on predictions of future prices. For example, offer prices would reflect the opportunity cost of discharging in that period compared to discharging in a later period.

(b) **Conservative pricing**: This means trading only at times when profits are expected, with conservative prices.[1] This represents our trading conservatively option described in the body of the paper, but assuming the BESS always trades conservatively in prices rather than quantities.

1.6. We tested the scenarios in a historical market setting over a full year (1 July 2024 to 30 June 2025).

1.7. Our results from this preliminary modelling indicate:

(a) Trading at full capacity with SoC constraints and one-hour gate closure (our preferred option) can provide significantly greater wholesale purchase cost savings, and more profits to BESS owners, compared to conservative pricing with either one-hour or 30-minute gate closure.

(b) There is little difference in consumer benefits or a BESS' profits between one-hour and 30-minute gate closure if trading at full capacity with SoC constraints.

(c) When trading conservatively with prices, 30-minute gate closure enables BESS to earn materially greater profits than one-hour gate closure as it helps prevent financial losses.

1.8. We will gain a better view of the differences between various policy options by refining our models and running new scenarios, eg, to represent a conservative in quantities strategy. Feedback from this consultation will improve our understanding of how BESSs are likely to operate in the market. This will help us to further develop our models ahead of consultation on any proposed Code amendments.

1 SoC constraints are not applied in this scenario.

2. Description of battery model parameters

2.1. We model different BESS strategies in vSPD[2]. We have chosen these parameters to balance the need to replicate the parameters we expect to see in BESSs entering the market over the next few years, with the need for simplicity in our modelling.[3]

Battery setup

2.2. We modelled one BESS located at the BRB2201 market node. This is the same site as Meridian's Ruakākā BESS.

2.3. In the model, the battery can charge and discharge up to 50MW.

2.4. It can store up to 100MWh of electricity.

2.5. We have chosen a single BESS to simplify the optimisation model we use.

2.6. We have chosen a moderately sized BESS as we consider it is big enough to have an impact on the market without significantly changing trading strategies of other market participants. This ensures the historical trading data we use is relevant to our simulation.

Battery cost and lifespan

2.7. The battery costs $1,000,000 per MW of capacity.

2.8. It is expected to last for 8,000 charge-discharge cycles.

2.9. This gives a degradation cost of $62.50 per MWh which is applied every time the battery discharges, including self-discharge.

Efficiency and energy loss

2.10. The battery is assumed to have a 90% roundtrip efficiency. This is assumed to be symmetrical, meaning there are about 5.13% of energy losses when charging and again when discharging.

2.11. It also loses 2% of its stored energy every 30 days due to self-discharge. This works out to about 0.0014% per trading period. Again, this small loss is included in the degradation cost.

Operating limits

2.12. The battery's state of charge is kept between 12.5 MWh and 87.5 MWh. This may help extend its battery life and meet warranty conditions, and also ensures it can provide both fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) at any time.

Simplifications in the model

2.13. This is a simplistic battery model and does not include things like:

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2 vSPD is a replica of the System Operator's market dispatch and pricing tool. It is available at https://github.com/ElectricityAuthority/vSPD

3 We have researched the possible parameters of existing and future BESS by talking to participants, and online research.

(a) power used by support system like cooling or controls

(b) effects of temperature on battery degradation

(c) aging over time even when not used

(d) changes in performance as the battery ages

(e) limits on how fast the battery can charge or discharge

(f) efficiency changes based on energy level, power, or temperature

3. Battery optimisation and simulation method

Forecasting spot prices

3.1. Both strategies require predictions of electricity prices:

(a) trading at full capacity with SoC constraints requires price predictions to determine bid and offer prices (described in detail further below).

(b) conservative pricing requires price predictions to decide when the battery should charge or discharge.

3.2. We predict prices using historical forecast schedules available at gate closure adjusted for the impact of the BESS.

3.3. We start with forecast prices from the price-responsive schedule short (PRSS) and price-responsive schedule long (PRSL).[4] We use the most up-to-date forecasts available at gate closure.[5] This gives us about 1.5 days of forecast prices to use in the battery optimisation.

3.4. We then estimate the impact of BESS use on prices to get the price predictions we use in our various models.

Estimating price impact from battery use

3.5. In the market, BESSs will be able to estimate their impact on prices by looking at results of forecast schedules that include their bids and offers, and by assessing price sensitivities published on WITS. It is therefore important that our model accounts for the impact of BESS on prices.

3.6. We use price sensitivity tests in vSPD[6] to see how battery charging and discharging might affect prices. To do this, we:

(a) interpolate the sensitivity tests to estimate what prices would be if national demand was 50MW lower. We repeat this for the case where it is 50MW higher.

(b) calculate the gradient between -50MW and +50MW. This creates the red line in Figure 1.

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4 Selected schedules are available at: https://www.emi.ea.govt.nz/Wholesale/Datasets/ForecastPrices

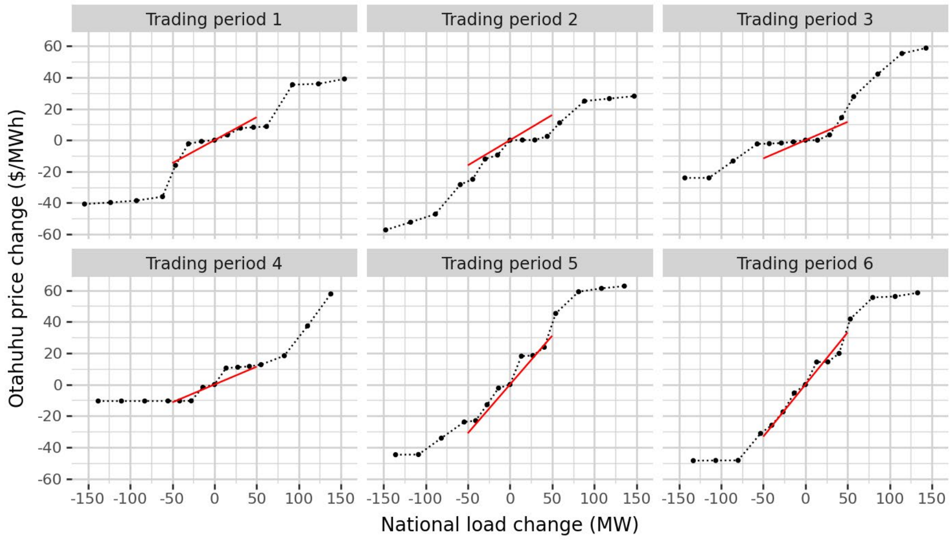
5 We determine this by looking at the run time of historical schedules

6 We used price sensitivities we had previously simulated off the last price responsive schedule runs for each trading period. These tests provided price sensitivities for various percentage changes in demand. We then applied the price changes from those tests to the most recent PRS schedules available at gate closure.

(c) adjust the result to prevent negative price values when demand drops.

3.7. This price gradient for each trading period is internalised within the BESS optimisation model and applied to all forecast prices.

Figure 1: Sensitivity runs of vSPD and BESS price gradient.



Battery optimisation

3.8. We run a profit maximisation model just before gate closure, which chooses the optimal times and quantities to charge and discharge, subject to state of charge limits.

3.9. One limitation is that the model does not account for how other market participants might change their bids or offers in response to the battery.

3.10. Another limitation is that the optimisation model doesn't consider instantaneous reserves. We excluded instantaneous reserves from the model for simplicity.

We apply SoC constraints to dispatch outcomes

3.11. Just before gate closure, we finalise the BESS's bids, offers, and reserve offers (described in detail in the next section).

3.12. We simulate dispatch and apply SoC constraints to ensure dispatch remains feasible given potential outcomes after gate closure.[7]

3.13. This should typically only be needed for the trading at full capacity strategy. This is because the conservative pricing strategy is designed to ensure SoC limits are only exceeded in reasonably unforeseeable circumstances. We applied SoC constraints for this strategy to replicate the trade revisions that would occur should such circumstances occur.

3.14. Example:

(a) at midnight, the battery has 15MWh stored.

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7 The state of charge constraints are applied by adjusting the bids and offers in the vSPD input file.

(b) it has bids to charge 5MW in trading periods 1 and 2.

(c) we create an offer to discharge 10MW in trading period 3.

(d) if the earlier bids do not clear, the battery will fall outside its ideal operating range and not be able to meet its SIR requirements.

3.15. We adjust bids and offers to make sure they are feasible. Any bids or offers that would push the battery outside its ideal operating range (12.5MWh to 87.5MWh) are removed.

3.16. If the battery is close to falling outside this range due to self-discharge, we add a small, high-priced bid to prevent this.

Quantity and pricing strategies

Conservative pricing

3.17. Under the conservative pricing strategy, we determine bid and offer quantities using the profit maximisation model run at gate closure. The most profitable times and quantities are chosen based on what is achievable given state of charge limits.

3.18. We set bid prices at $6,499 per MWh and offer prices at $0 per MWh. This guarantees the battery is fully dispatched (unless a transmission outage or scarcity situation occurs).

3.19. We determine generation reserve offer quantities for FIR and SIR in each trading period as the remaining MW capacity after accounting for the quantity of energy offered. We do this because we expect that it will generally be more profitable for the BESS to be dispatched for energy rather than instantaneous reserve, noting that energy prices tend to be higher than instantaneous reserve prices.

3.20. We offer generation reserve at $0 for both FIR and SIR.

3.21. A limitation of our models is that interruptible load is not offered in either strategy. We considered it would be simpler to model and assess results without interruptible load included at this stage.

Full capacity with SoC constraints

3.22. Under the full capacity with SoC constraints strategy, we bid and offer the full charge/discharge capacity in every trading period, with SoC constraints ensuring dispatch is achievable.

3.23. To determine bid and offer prices, we split the battery into five 10MW bid blocks and five 10MW offer blocks.

3.24. For each block, we re-run the profit maximisation model and compare to the original result. This enables us to calculate the price at which the owner would be indifferent to being dispatched at the full 10MW.[8]

8 The state of charge constraints remove infeasible quantities starting at the highest priced offer tranches and lowest priced bid tranches.

3.25. For simplicity, we offer generation reserve in full as FIR and SIR at all times, with $0 prices.[9]

4. Simulation results and insights

4.1. We tested both strategies over a full year (1 July 2024 to 30 June 2025), using both one-hour and 30-minute gate closure times.

4.2. Figure 2 shows the wholesale purchase cost savings (excluding purchases from our simulated BESS) from each scenario. These savings are the difference between wholesale purchase costs without our BESS and the wholesale purchase costs with our BESS.

4.3. To calculate the wholesale purchase costs without BESS, we:

(a) get the final energy price at each node

(b) multiply it by reconciled demand at each node to get each market node's retail cost in each trading period[10]

(c) add up the cost across all market nodes and trading periods.

4.4. For the wholesale purchase costs with BESS, we repeat this, using instead the modelled prices from vSPD with the battery included.

4.5. Wholesale purchase costs are significantly reduced in all scenarios. Some of the cost reductions are likely due to the steady, low-cost source of instantaneous reserves.[11]

4.6. We note that some differences between scenarios will be attributable to chance.

4.7. The full capacity with SoC constraints strategy leads to the largest wholesale purchase cost savings, likely because it helps to limit unforeseen price spikes. This may in part be due to this strategy including full generation reserve offers at times when it expects it would be profitable for the BESS to generate. This allows the market dispatch engine to determine the optimal combination of energy and generation reserve to dispatch at these times.

4.8. In our models, the wholesale purchase cost reductions are similar across different gate closures for both trading strategies. Slightly greater reductions occurred with the longer gate closure in the conservative pricing strategy. This may be because, at shorter gate closure, the strategy is more able to avoid trading at times when the BESS ends up losing money but reducing wholesale purchase costs. For example, the BESS could create wholesale purchase cost savings by reducing wholesale prices when discharging by more than it increases prices when charging. However, in doing so, they may at times not earn sufficient revenue to recover degradation costs.

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9 vSPD will determine the optimal dispatch of energy and generation reserve within the MW discharge limit.

10 We use reconciled data that was used bey the clearing manager at the time.

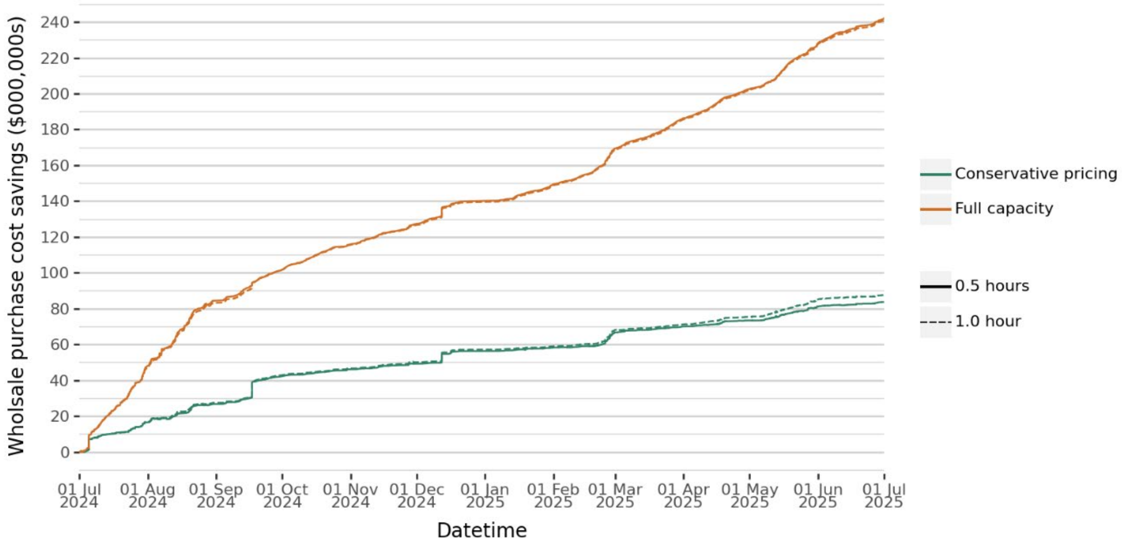
11 By providing instantaneous reserves, this frees up generation capacity from other generators that would otherwise be providing reserves, potentially leading to lower energy prices. Also, if the price of energy is being set by the risk setter (the plant setting the instantaneous reserve demand), then the cost of reserve is included directly in the energy price. Providing low-cost reserve in this scenario would therefore reduce the energy price.

4.9. This logic is consistent with what we observe in the results. Figure 2 shows the difference in wholesale purchase cost savings between 30-minute and one-hour gate closure gradually increasing form the start of April 2025 to the end of June. Figure 3 shows the conservative pricing strategy consistently making financial loses over this time, but with slightly greater losses occurring in the one-hour gate closure scenario.

4.10. We expect if financial losses were consistently occurring in real life, the trader would adapt by removing trades where expected profits were less certain. If so, more trades would likely be removed at longer horizons when price uncertainty is greater. This may lead to smaller wholesale purchase cost savings at longer gate closures.

4.11. Finally, if we modelled a strategy where the BESS traded conservatively in quantities, it would likely show significant reductions in wholesale purchase costs from reducing gate closure. This is because the total quantities traded would be more restricted the longer the gate closure period. However, as explained in the body of the paper, the reduction in wholesale purchase costs from this strategy at 30-minute gate closure would likely be much less than from our preferred option.

Figure 2 Cumulative wholesale purchase cost savings



Battery profitability

4.12. Figure 3 compares how much profit each strategy makes in the wholesale energy market.

4.13. As can be seen, the BESS owner’s profit is much smaller than the savings it creates for wholesale purchasers.

4.14. Both strategies earn greater profits with shorter gate closure, when more accurate price forecasts are available.

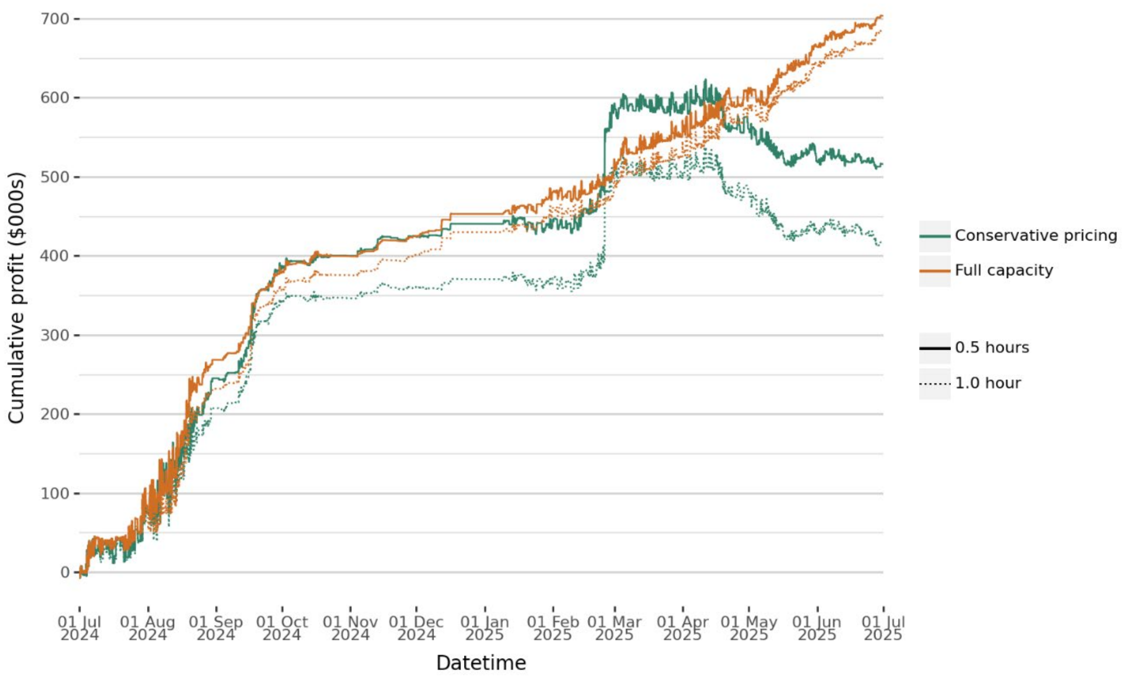
4.15. The strategy, however, makes a much bigger difference to profitability than the gate closure period.

4.16. Trading at full capacity with SoC constraints delivers greater profits compared to conservative pricing. This is what we would expect because it enables the BESS to take advantage of more opportunities and avoid financial losses.

4.17. There are many times when the conservative pricing strategy loses money. This shows there can be a big gap between expected prices and the actual market prices.

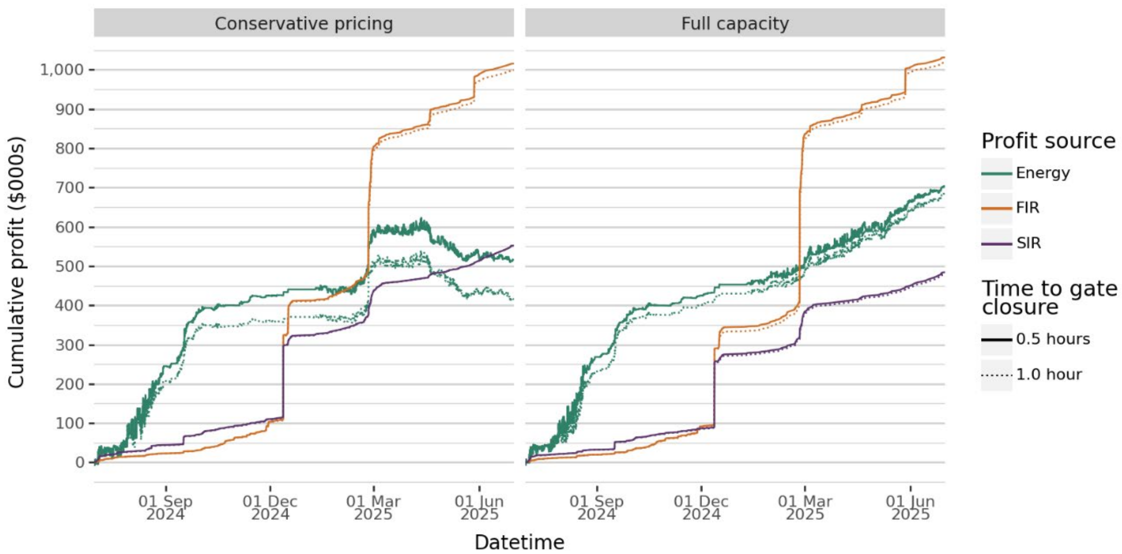
4.18. As with wholesale purchase cost savings, we note that differences in profitability between different scenarios may at times be attributable to chance.

Figure 3 Cumulative wholesale energy profit for BESS



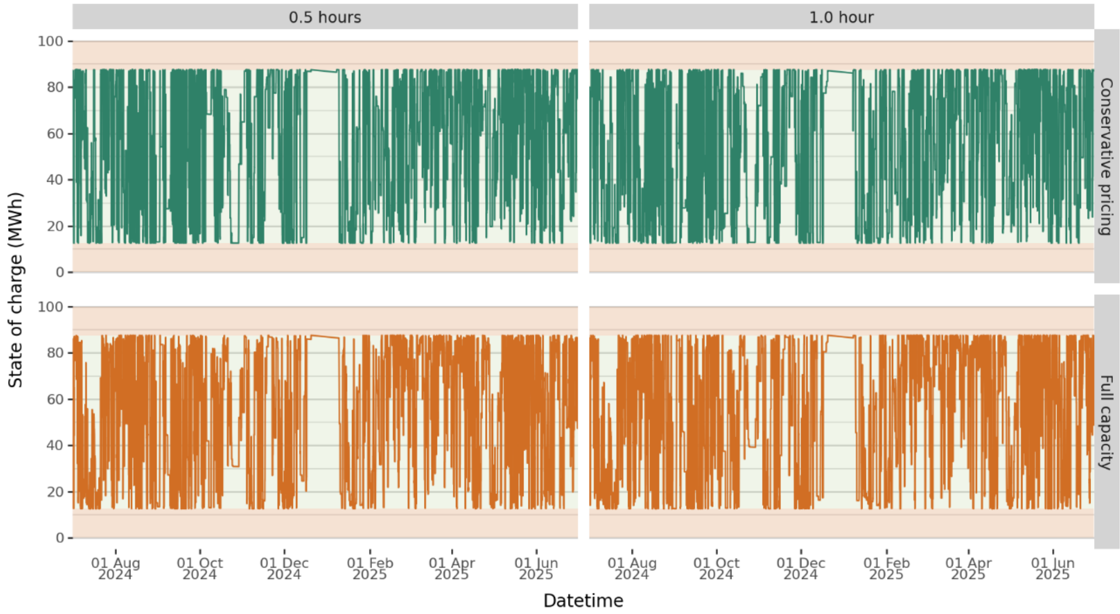
4.19. Figure 4 shows that most of the revenue comes from reserves. The amount earned from reserves is similar across both strategies and gate closure times.

Figure 4 Cumulative wholesale energy and reserve profit



4.20. Figure 5 shows that the battery was used actively throughout most of the year. However, in mid to late December and early January, usage dropped due to consistently low prices.

Figure 5 BESS state of charge



5. Potential further work

5.1. There are several different types of models and refinements to our current models that would be useful to run.

5.2. It would be useful to model further conservative trading strategies at both one-hour and 30-minute gate closure. This would more clearly demonstrate the impact of reducing gate closure if conservative trading was required under the Code. It would also more clearly demonstrate the difference between these policy options and our preferred option.

5.3. In particular, it would be useful to model a conservative in quantities strategy. It may also be useful to model a strategy that was a mixture between being conservative in prices and being conservative in quantities. This would enable charging and discharging in full when profit was expected, while being able to take advantage of limited unforeseen opportunities at other times. This might better replicate how traders would behave if conservative trading was required.

5.4. It would also be useful to have the same reserve offer strategies between the different scenarios to help us better understand the differences between energy offer strategies.

5.5. We intend to add interruptible load offers to any options we model in the future.

5.6. So far, we have used historical energy prices, adjusted for the effect of BESS energy dispatch. It may be worth rerunning vSPD with the FIR and SIR offers included, as this could lead to a better forecast of energy prices within the optimisation model.

5.7. We are also considering modelling a larger BESS. We are mindful, however, that traders would be more likely to change their bids and offers in response to larger BESS. This means our historical data may be less applicable to the situation we are modelling.

5.8. Finally, we are also considering whether to use a probability-based optimisation method, like SDDP.[12] This might improve the profitability and consumer benefits of all options.

5.9. We will consider all feedback received in submissions about our modelling as well as how BESS are likely to operate in the market. This will inform any further modelling we do should we proceed to consultation on proposed Code amendments.

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12 A Julia package for SDDP is available in: https://sddp.dev/stable/

Appendix E System Operator's report

IMPROVING OFFER ARRANGEMENTS FOR BATTERY ENERGY STORAGE SYSTEMS

TAS 113 REPORT

Transpower New Zealand Limited

April 2025

Version History

Version	Date	Change
0.1	November 2024	Initial draft
0.2	February 2025	Updated draft with design elements for delivery
0.3	March 2025	Updated draft for internal review
0.4	April 2025	Updated draft following EA review
1.0	April 2025	Final Version

Document Review and Approval

	Name	Position
Prepared By:	Alan Ching	Senior Business Analyst
	Cara Dunford	Energy Co-ordinator
	Connor McCarthy	Power System Engineer
	Hamish McKinnon	Principal Advisor
	Marije Postma	Project Lead
	Oliver Wilson	Market Analyst
Reviewed By:	Matthew Hansen	Operations Manager
	Murray Henderson	Principal Advisor
	Vong Nyuk-Min Vong	Principal Engineer
Approved By:	Rebecca Osborne	Head of Market Services
	Matthew Copland	Head of Grid and System Operations

Document Glossary

Term / Abbreviation	Description
BESS	Battery Energy Storage Systems
CAISO	California Independent System Operator
Code	The Electricity Industry Participation Code 2010 and her amendments
DCLS	Dispatch-capable Load Station, the physical asset(s) providing a dispatchable demand resource
DD	Dispatchable Demand
DSA	Dynamic Stability Analysis, in reference to a suite of software tools
EA	Electricity Authority aka the Authority
ESB	Enterprise Service Bus, the internal communications network which transfers data between different market system components
IBR	Inverter-based Resources
MDAG	Market Development Advisory Group, a now-disbanded advisory group for the Electricity Authority
MBL	Market Business Logic, the logical components of the market system
MDB	Market Database, the data store for the market system
MDS	Market Dispatch System
MOI	Market Operator Interface
NCC	National Coordination Centre
NEM	(Australian) National Electricity Market – comprising Queensland, New South Wales, Victoria, South Australia and Tasmania power systems
NFR	Net Free Reserve, a MW-equivalent quantity of governor response that is modelled to occur in a contingent event
NZX	New Zealand's Exchange (NZ's national stock exchange)
PPOs	Principal Performance Obligations
RMT	Reserve Management Tool – the software used for calculating instantaneous reserve requirements used in market schedules
ROM	Rough Order of Magnitude (an approximate estimate of the cost of a project, aiming for an accuracy of -25%/+75% at this stage of the investigation
SDC	Southern Data Centre
SO	System Operator
SOC	State of Charge – the quantity of stored energy of a battery relative to its storage capacity

Term / Abbreviation	Description
SPD	Scheduling Pricing and Dispatch – the software used to solve the Objective Function in market schedules
TAS	Technical Advisory Services
VRE	Variable Renewable Energy, often synonymous with “Intermittent Generation”
WITS	Wholesale Information and Trading System

EXECUTIVE SUMMARY

The Electricity Authority has commissioned this Technical Advisory Services (**TAS**) scope #113 to seek advice from the system operator on options to improve offering arrangements for Battery Energy Storage Systems (**BESS**). This work considered:

1. Operational impacts from potentially reducing the gate closure period for BESS (for both energy and instantaneous reserve).
2. Options for mitigating any risks arising from reducing the gate closure period.
3. Offering enhancements that facilitate BESS trading.
4. A Rough Order of Magnitude (**ROM**) estimation for recommended changes.

The system operator is facing an increasingly challenging operating environment, driven by many factors including increasing intermittent generation penetration (wind and solar) and a proliferation of inverter-based resources, which include BESS. Its principal process for ensuring power system security is preparing effective market schedules – determining the expected schedule of generation output for every trading period in the near future. Increasing intermittent generation penetration is increasing the uncertainty of those generation schedules, meaning more and more contingency planning must be executed to remain confident of being able to operate the power system security in real-time.

At the same time, investment in BESS is increasing. BESS are unique power system assets in that they operate with limited state of charge – effectively, their stored "fuel" is only available in small quantities. This presents an interesting scheduling challenge – how to make the best use of this limited resource? From the BESS trader's perspective, the ability to change the offered BESS capacity close to real-time enables the greatest value from this resource. However, this presents a significant operational challenge for the system operator, which relies on certainty of energy commitment within the gate closure period. Essentially, maximising the value of BESS through near real-time offer changes creates significant additional risk that those changes results in an insecure system, exacerbating the existing underlying issue of increased uncertainty from increasing intermittent generation penetration.

Mitigating this risk requires a comprehensive approach to managing commitment uncertainty near real-time. As relates to increasing BESS penetration, we recommend the following measures:

1. Enhancing scheduling to include state of charge in forward and dispatch schedules, which constrain scheduled BESS energy output or consumption to predicted physical capability.
2. Incorporating rules into the scheduling and dispatch processes which permit the system co-ordinators to constrain BESS charging and discharging out of merit for managing likely system events.

The estimated ROM capital delivery investment envelope (-25%/+75%) to implement the above changes in our market system tools and applications is between $1.2M and $2.7M, and to be implemented over an estimated 13-month period. In the event the Authority determines the above measures are to be delivered separately, the capital delivery investment envelope for delivering BESS state of charge in the forward and dispatch schedules and bi-directional offering is between $0.81M – $1.90M, and between $0.96M – $2.25M respectively.

Other potential mitigations relate to increasing the overall effectiveness of the system co-ordinators' situational awareness and intelligence. These include but are not limited to easy and effective scenario analysis, sensitivity scheduling, intelligent alarming and enhanced contingency analysis. We recommend considering these initiatives as part of a wider package of enhancements that address increasing operability risks generally.

At the same time, the current scheduling paradigm for BESS is operationally ineffective for both system co-ordinators and traders and can result in non-physical outcomes where BESS can be scheduled to both charge and discharge at the same time. To mitigate these issues, we recommend enhancing BESS wholesale market participation through establishment of "bidirectional offers". This unique offer type would permit BESS to offer as a single asset within the market system and constrain the system to only output physically coherent solutions. This would also support future participation of BESS in the frequency keeping market.

Table of Contents

1 BACKGROUND

1.1 Purpose of TAS 113

Battery Energy Storage Systems (**BESS**) are a novel and unique class of power system asset, capable of providing short-term energy storage and potential for arbitrage. When integrated with the wider power system, BESS have the potential to revolutionise provision of system services and improve reliability, particularly in systems with high penetration of Variable Renewable Energy (**VRE**) generation (known in the New Zealand context as "**intermittent generation**").

The Electricity Authority (**the Authority**) commissioned TAS 113 seeking advice from the system operator on options to improve offering arrangements for BESS.[1] This work considered:

1. impacts from potentially reducing the gate closure period for BESS (for both energy and instantaneous reserve)
2. options for mitigating any risks arising from reducing the gate closure period
3. offering enhancements that facilitate BESS trading, and
4. providing a Rough Order of Magnitude (**ROM**) estimation for recommended changes.

1.2 Purpose of this report

The content in this report is provided by the system operator in response to the TAS request from the Authority.

The Authority's request was to consider what are the "*operational and system security risks… of greater uncertainty in final dispatch of BESS*" and what safeguards are necessary to mitigate these risks, and to elaborate on the details for implementing the identified mitigations and other enhancements to enable BESS participation in the market. The report also steps through options for solving the problem of the market system being able to dispatch physically impossible solutions and provides solution concepts and ROM costing for implementation of these changes to the system operator's systems.

1.3 Next Steps

The system operator understands progressing any of the proposed changes documented in this report to an implementation phase will be subject to the Authority's decision to proceed and funding approval.

[1] This advice is delivered under Technical Advisory Services (TAS) contract number 113.

2 INTRODUCTION

2.1 The system operator co-ordinates electricity supply

The principal role of the system operator is the real-time co-ordination of the power system, to ensure its ongoing operation at stipulated levels of quality. These quality levels are defined by the Principal Performance Obligations (**PPOs**) in the Electricity Industry Participation Code 2010 (**the Code**),[2] with the relevant obligations being:

1. The need to avoid cascade failure of assets resulting in a loss of electricity to consumers.
2. The need to maintain the relevant frequency standards for normal operation and post contingent events.[3]

The system operator must also meet the Dispatch Objective[4], which requires dispatch of power system resources, for each half hour, in a way that maximises the gross economic benefits to purchasers, subject to meeting the PPOs and the requirements of restoration.

In practice, achieving these obligations requires significant technical risk assessment and planning, beginning with system resource adequacy assessments and security assessments years ahead of real-time. Within one week of real-time (known as "scheduling time") the system operator has sufficient information about pending generation and transmission outages that half-hourly co-ordination can occur. This involves creating economic schedules of generation based on matching generation offers with system needs for locational demand and transmission constraints, and frequency regulation and contingency reserve ("**instantaneous reserve**" in the New Zealand market).

This process relies on the information input to the forecast schedules being sufficiently accurate to be adequately representative of real-time system conditions. However, real-time conditions always diverge to some extent from those modelled in scheduling time. System operator staff (principally the real-time co-ordinators on shift) maintain situational awareness and look for deviations from modelled parameters, such as changes to generation offers and availability of transmission assets. The system operator's capacity to manage variations to system conditions is currently appropriate for the number and magnitude of variations observed.

2.2 The power system is changing rapidly

The system operator's systems and processes for scheduling and dispatch have evolved incrementally over time. Recently, the evolution of the power system has accelerated with increasing difficulty in forecasting future system conditions. In twenty years, the amount of VRE on the system, principally wind but more recently solar generation as well, has increased from tens of MW to over 1,200 MW, around 12% of installed generation capacity. Penetration of intermittent generation is planned to increase significantly as electrification of emissions-intensive sectors of the economy continues at pace, while additional demand is met by lower-cost generation options. More detail on these changes is provided in the system operator's strategic plan.[5] Increasingly, new solar and wind installations are being planned to include BESS.

[2] Refer clause 7.2A – D of the Code.
[3] Contingent events are defined by the Risk Management Policies in the Policy Statement.
[4] Refer clause 13.57 of the Code.
[5] Found here.

All other things being equal, this changing power system landscape places increasing burden on the system co-ordinators in executing their near real-time security assessments, as there is a wider range of possible power system outcomes. For example, forecast intermittent generation may not eventuate, or may be more than forecast, changing modelled power-flows and possibly resulting in operational exceedances on transmission assets.

2.3 BESS are unique power system assets

BESS have unique characteristics that can both help, and hinder, system security. BESS offer capacity for short-duration storage of low-cost energy (often abundant in high VRE systems), improving the ability to manage peaks in electricity demand. As inverter-controlled devices, BESS can change their consumption of energy (charging) or injection into the grid (discharging) very rapidly, making them very well suited to sub-second frequency regulation, and capable of providing nearly all other system needs.[6] It is therefore desirable, from the system operator's perspective, to reduce any barriers for BESS connecting to the power system or participating in the electricity market.

However, the short-duration storage attribute of BESS is unique among power system assets and not well suited to current scheduling and security checking processes. BESS operational storage is quantified as the "state of charge" (**SOC**) which represents the amount of stored energy compared to the BESS asset's storage capacity. As current generation offering obligations require certainty within the **gate closure period** of available capacity from resources which are not intermittent generation, BESS of limited energy (MWh) storage must offer their MW capacity conservatively so as to be able to reasonably be confident of honouring their offer, being cognisant of their current and planned SOC. Outside of the gate closure period, BESS traders must continually update their offers based on their SOC which varies according to previous trading periods' dispatches.

Given the highly dynamic nature of the electricity market, BESS SOC is uncertain more than a few trading periods ahead of real-time, i.e. within scheduling time, depending on dispatch outcomes in preceding trading periods. This means while BESS offered capacity in real-time ought to be secure and able to be relied upon, it is difficult for the system operator to know what that capacity is any more than one or two trading periods ahead of time. Therefore, in the absence any other rules or incentives, the system operator may not be able to rely on BESS capacity in planning to meet its PPOs. This could have detrimental market impacts – generation scheduling either may not include BESS capacity that is available in real-time, which could drive overly conservative price signals, or if BESS capacity is included and is inaccurate, then this may result in capacity shortfalls in real-time. Current Code obligations (placed on generators[7] and purchasers) for offer accuracy drives conservative offering behaviour.

[6] The Global Power System Transformation Consortium (G-PST) provides a useful summary of system needs in their publication "System Needs and Services for Systems with High Inverter-Based Resource Penetration", found here.

[7] At time of writing BESS are effectively considered as generating stations, pending further consideration of defining a unique asset type within the Code for the purposes of mandating bespoke asset owner performance obligations.

2.4 Many jurisdictions internationally are seeing increasing BESS capacity

While in New Zealand only 35 MW / 35 MWh of market-offered BESS capacity is operational at the time of writing this report, that capacity is forecast to increase rapidly. Several jurisdictions overseas have already seen significantly increasing penetration of BESS capacity, notably the Australian National Energy Market (**NEM**), California, Chile and Hawaii, among others. In these jurisdictions regulators and system operators have deployed operational changes and amendments to market rules that clarify BESS obligations without stifling investment. Indeed, in jurisdictions with high VRE penetration BESS have become indispensable in providing the levels of system services required to operate systems with high penetration of inverter-based resources (**IBR**).

Developments to accommodate BESS are varied, depending on these jurisdictions' prevailing market rules and operational paradigms. In the NEM, BESS have been incentivised to participate through mechanisms such as bidirectional offering (offering both charging and discharging capacity as one continuous offer, discussed later in this report), five-minute electricity market settlement and causer-pays arrangements for system services.[8] In California, BESS have been integrated into a complex market which already had multiple settlement timeframes and multi-period unit commitment. Further, the Californian system operator (**CAISO**) has operational discretion to schedule BESS out-of-merit to ensure availability for system security.[9] While useful and perhaps reassuring to consider other jurisdictions' approaches, it is important that modifications to New Zealand market rules and operating processes are designed in the context of the New Zealand power system and electricity market.

[8] See numerous rule changes from the Australian Electricity Market Commission: Integrating energy storage systems into the NEM; Implementing integrated energy storage systems; Clarifying mandatory primary frequency response obligations for bidirectional plant.
[9] CAISO publishes regularly a market monitoring special report on battery storage.

3 OPERATIONAL PROCESSES

3.1 Background – Scheduling and Security Checking Processes

In considering the level of uncertainty in dispatch, we need to assess impacts to the system operator's scheduling and security checking processes.

"Scheduling" describes the preparation of the market schedules as detailed in the Code and the Policy Statement. It involves the automated gathering of input data, assessment of the validity and quality of that data, execution of the economic optimisation solution, and presentation and publishing of the schedule outputs.

"Security checking" describes verifying that the generation schedule, when dispatched, will not exceed physical transmission asset tolerances or system stability limits. This assessment includes post-event contingency analysis, it is not just steady state analysis. The speed with which power system events play out means, in order to meet our PPOs, the system operator's security checking must also include post-event analysis e.g. to ensure remaining in service assets operate within their offered limits following the sudden unplanned tripping from service of another asset. Security checking relies on use of the simultaneous feasibility test (**SFT**) application, which runs automatically with market schedules to dynamically constrain generation across monitored transmission assets, and the dynamic stability assessment (**DSA**) suite of tools, which identify dynamic stability risks.

An automatic outcome of the scheduling process is the assignment of frequency keeping plant, determined by least-cost offer selection. The selection of specific frequency keeping plant can have an impact on managing short-term capacity in periods of system stress.

3.1.1 Assessing Schedule Security

SFT runs as part of every NRSL and NRSS case. SFT checks for N-1 security risks arising from the optimised SPD solution, for example voltage violations or circuit overloads (thermal offload violations). N-1 security risks are the result of the loss of any piece of equipment considered to be a credible risk, such as transmission circuits, and generating units. If the SFT power flow solution results in violations, it may create constraints to resolve these.

After each schedule is produced, co-ordinators will carry out a security assessment. Since several inputs of forward schedules are forecasts, (for example conforming load forecasts, intermittent generation offers, voltage equipment profiles, block dispatches), there is a potential degree of inaccuracy in the schedule which must be assessed. For this reason, any security constraints built must be checked closely for validity. This assessment can be time consuming and may involve comparison with contingency analysis run on modified SCADA data from the live system.

The security assessment may indicate that one of a number of remedial actions need to be taken. These include:

1. modifying schedule inputs such as voltage profiles, load forecasts, or numerical constraint values and rerunning the forward schedule
2. analysing potential reconfiguration of the grid area to N security (e.g. putting in Northland splits to avoid potential N-1 overload of 110 kV circuits)
3. taking action to manage voltage by dispatching reactive power assets

4. issuing formal notices requesting changes to bids or offers, and/or
5. managing demand.

3.1.2 Frequency Keeper Lockdown

The frequency keeping selection and constraint process runs off the completion of NRSS and NRSL schedules. Frequency keeping selection and constraint generation re-runs at 15 minutes into every trading period.

The frequency keepers selected for the current plus one trading periods are locked down when the frequency keeper selection re-runs. Lockdown prevents any frequency keeper re-selection from being applied in the lockdown period. Lockdown enables advance notice of frequency keeping dispatch to be issued to the selected frequency keeping providers 15 minutes prior to the start of the trading period. This provides sufficient lead time for frequency keeping providers to enable their frequency keeping control systems. The lockdown also provides time for assessing the risk of a frequency keeping band in the reserve requirements for any frequency keeping provider that is also an AC risk setter.

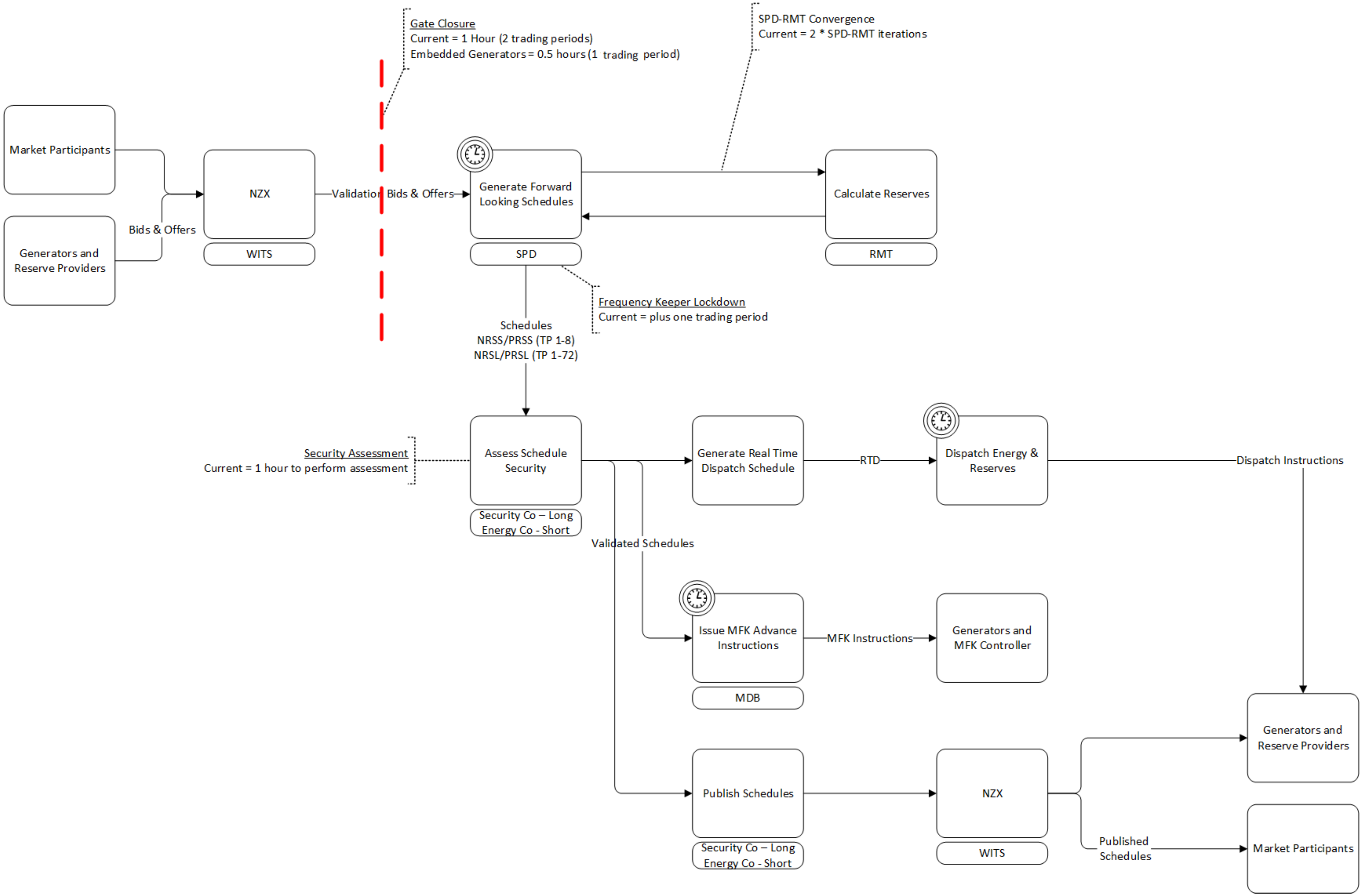

Figure 1 – Overview scheduling and security checking processes within gate closure

3.2 Impact of BESS flexibility on scheduling and security checking processes

The Authority requested the system operator to assess the operational and security risks associated with three options of reduced gate closure timeframes, and associated safeguards. The impact assessment is summarised in table 1 below. This assessment considers the security and operational impacts of a reduction in gate closure generally, not necessarily in relation to BESS alone.

In general, the system operator's ability to plan to operate the power system in real-time is directly impacted by the level of certainty in generation offers and the load forecast (including bids). Reducing gate closure for any or all asset classes would increase scheduling uncertainty, at a cost of increased operational risk.

Gate closure rules strongly improve certainty near real-time for both system co-ordinators and market participants. However, reduced certainty created by a 30- minute or less gate closure causes several concerns:

1. If issues arose after final offer changes, the time available for the security co-ordinator to assess and decide on a course of action would be a maximum of less than 15 minutes. This would be a tight timeframe at the best of times for deciding and implementing a remedial course of action. In busy periods, such as during the start and end of planned outages, and at times of stress on the system (low residual, unplanned events such as transmission asset, generation or load trip, software malfunctions etc) the lack of available time would make appropriate assessment and action unachievable. This could potentially lead to an inability to manage the grid within the security standards.
2. With the rapid increase in new, primarily intermittent, generation on the grid, in the near future, the power system we manage is likely to be less stable, and less predictable. Reducing gate closure would further exacerbate the difficulties in managing such a system.
3. A second iteration of SFT to generate security constraints may not be possible post gate closure (based on the current half hour regularity of forward schedules).

All these concerns are observed during current operations in managing intermittent generation uncertainty. For instance, if the projected system adequacy for generation is secure, but relies on several hundred MW of wind generation, the system co-ordinators assess the likelihood of the wind generation being unavailable within the assessment period and prepare for the contingency where this occurs – they may run test cases which produce (unscheduled) transmission constraints reflecting the scenario, which can then be studied and contingency plans put in place to remove assets, recall outages or in the worst case, manage demand. However with intermittent generation, this has a measure of reliability in that the accuracy of the weather forecast driving the expected generation quantities can be assessed, and the likelihood of a significant change influences the degree of forward contingency planning that occurs.

Consider a similar scenario, but with BESS. In the near future we expect an installed capacity of BESS on the system of 400 MW or more. Reducing gate closure for these assets would essentially drive them towards being treated as “intermittent” in the context of security planning, but without the associated reference to weather forecast to assure the probability of realising the offered capacity. This is a step-change increase in uncertainty of ***double*** the BESS installed capacity, given the BESS may not only elect to (fail to) discharge but could elect to charge at the same rate. Allowing BESS to change offers close to real-time injects a step-change in overall uncertainty into the security checking process; the BESS trader may choose to offer full capacity, or none, or choose to charge at full load. Either each of these outcomes would need to be considered for contingency planning, driving operation of the system to a more conservative state, or significant investment would be required to shorten the security checking and contingency planning processes.

These issues are somewhat exacerbated from current uncertainty around performance obligations for BESS, in particular. Conventional synchronous generation and inverter-based intermittent generation both have performance obligations to support frequency and voltage and ride through faults. Consequently, these obligations (or dispensations from these obligations) are modelled in power system assessment tools. The uncertainty around these obligations mean behaviour of BESS assets during faults or power system events is not currently well understood, which would drive a need for more comprehensive studies (ie more time required) to assess security.

Table 1 – Summary of impacts of reduced gate closure on system operator processes

Step in Process	1-Hour Gate Closure (Status Quo)	30-Minute Gate Closure (Status Quo for embedded generation)	15-Minute Gate Closure	No Gate Closure
Produce Forward Schedules	Produced every 30 minutes.	Could continue with current process. May have future issues with >30-minute forward visibility as the BESS capacity and number of providers increases.	Frequency of short schedule production would have to increase to consider any potential change in offers. As volume of BESS increases this would be more and more impactful. If frequency of schedule production did not increase, PRSS as the “backup” pricing schedule would begin to suffer from misalignment between most recent schedule and more recent offer changes – introducing (limited) potential for gaming.	More reliance on manual schedule production to dynamically build transmission constraints. Strong possibility of being unable to manage the grid through dynamic constraint build and could need to revert to static constraints.
Calculate Reserves	Takes about 5 minutes to produce an RMT case.	Likely no initial impact, but as the volume increases this may generate unforeseen issues further on in scheduling and security checking processes.	Potential impact on ability to accurately calculate net free reserve (NFR), leading to impact on the system operator’s ability to minimise the amount of instantaneous reserve scheduled and ultimately meet the PPOs.	As for 15-minute gate closure.

Step in Process	1-Hour Gate Closure (Status Quo)	30-Minute Gate Closure (Status Quo for embedded generation)	15-Minute Gate Closure	No Gate Closure
Assess Schedule Security	Initial assessment takes about 5 minutes. Can take much longer if there are security violations requiring constraints or other responses, usually resolved within half an hour.	Possible to do, but timeframe for checking accuracy of constraints and responses is very tight. Initially the impact is likely to be low, but as volume of BESS increases the disparity between the differing gate closures for differing generation types would make this near impossible. Further detail is provided in section 3.2.	Timeframe to resolve security violations will not be possible. The same volume statement for the 30-minute gate closure applies here.	Would have no knowledge of potential security violations requiring constraints, system would become unmanageable without increased conservatism in scheduling and constraint management.
Generate Real-Time Dispatch Schedule	Uses the latest RMT and runs every 5 minutes during the trading period.	Would continue to run using the latest forward-schedule constraint set and NFRs. Dispatch is impacted by the accuracy of those inputs, described above.		
Issue MFK Advance Instructions	Relies upon the 1-hour gate closure. Frequency keepers cannot change their offer electronically after MFK instructions issued. Frequency keepers have the ability to make a bona fide offer verbally inside gate closure.	Shortened gate closure would require revisiting business rules for frequency keeping scheduling, if BESS were able to offer frequency keeping. Further details are provided in section **Error! Reference source not found.**.		
Publish Schedules	System operator has a requirement to produce accurate forward schedules.	Forward price accuracy is impacted by increasing levels of uncertainty closer to real-time.		

3.3 Shortening gate closure for BESS provides uncertain market benefit

Given the assessment in section 3.2, a shortening of gate closure period for BESS or otherwise increases the risk for the system operator to plan for and be able to manage its PPOs within the current environment and market arrangements. As the power system transition proceeds and more intermittent generation connects to the system, managing security uncertainty in the near real-time timeframe will become more difficult. This would be exacerbated by allowing greater offering flexibility for BESS, and in our view the benefits of a shortened gate closure period seem not to outweigh these risks at first glance.

BESS asset owners can mitigate their risks in failing to honour offers outside gate closure through other means, principally, ensuring adequate storage capacity is installed that meets gate closure requirements. This position is supported through conversations the system operator has had with international BESS owner/operators who operate in jurisdictions with more stringent gate closure requirements than New Zealand.

Essentially, storage capacity should be sized to be double the gate closure period, so a grid-connected BESS with 1-hour gate closure would self-cover their offering risk with a 2-hour storage capacity. At one hour before real-time, the SOC of the battery is known and the average MW output of the BESS for each trading period can be offered with surety. Managing the potential output of the BESS for any particular trading period is then a financial decision best made by the asset owner.

However, when at lower states of charge, longer duration batteries are still able to submit offers that may not be deliverable. For example, a 2-hour-duration battery at 25% state of charge will take approximately half an hour to drain its remaining capacity, so offering risk will still exist at times. If the obligation is on the battery operator to deliver the injection they have offered, then to ensure security there will need to be robust measures to respond to dispatch non-compliance, as battery operators may have a greater incentive than existing generators to submit offers that risk non-deliverability.

We note that some BESS systems will operate with 30-minute gate closure, as this is the gate closure period for embedded generators[10]. Shorter gate closure may create an arbitrary incentive for BESS developers to build embedded BESS rather than grid-connected BESS. While this incentive also exists for other forms of dispatchable generation, this is a particular issue for BESS because:

1. BESS is more sensitive to gate closure as its injection capability will often change during the gate closure period based on dispatch outcomes.
2. there are more BESS projects in the pipeline than other dispatchable generation types (e.g. hydro, thermal).

[10] Definition of "gate closure period" in the Code

3.4 There is little operational benefit to allowing BESS to increase offered capacity within gate closure (except in grid emergencies)

We considered what operational benefit there might be to allowing restricted reoffering within the gate closure period. A BESS trader may find itself in the position where dispatch in preceding trading periods has resulted in a higher-than-expected state of charge, meaning they would be able to offer additional capacity at short notice.

Operationally, there is little benefit in additional short-notice capacity unless energy or instantaneous reserve are scarce. In extreme cases, this would result in a grid emergency, which relaxes gate closure rules and would permit a BESS trader to offer any excess capacity to mitigate a security situation.

We expect any economic rationale supporting short-notice offer changes to be a complex trade-off of considerations including the value of forward price certainty, potential for gaming real-time dispatch outcomes, and interactions within a generator's portfolio. This investigation has limited its scope to operational issues and not considered these elements directly.

3.5 What constitutes a reasonable offer for BESS?

3.5.1 Current offering/bidding arrangements for generators/DCLS appear sufficient for BESS

It is useful conceptually to compare potential offering[11] arrangements for BESS to existing power system assets, particularly (non-intermittent) generating units and intermittent generating stations. Essentially, offering arrangements consider non-intermittent generators as having "infinite" fuel availability—the time scales and operating conditions for exhausting a conventional generator's available fuel is well beyond near real-time half-hourly scheduling consideration. At the other end of the scale, intermittent generators' scheduled offers are not considered in real-time,[12] as it is understood that the intermittent generators' fuel sources are variable, but also reasonably forecastable.

BESS sit somewhere in between these two paradigms; their "fuel" is stored chemical energy, which is measurable and knowable before real-time, but also prone to be exhausted in the scheduling timeframe. Modern energy trading also makes use of automated, algorithmically-determined price quantity setting, which updates energy offers regularly in response to changing system conditions.

In the absence of any clear and compelling reason for putting in place different arrangements, we expect BESS owners have sufficient information and capability to be able to reasonably offer injection (and bid offtake) within the same framework as existing generation.

[11] In New Zealand's energy market "offering" refers specifically to energy injection into the system, whereas "bidding" refers to offtake. For BESS, both are relevant. "Offering" is used generally here to mean "making trades in the energy market, whether for injection or offtake". In the absence of bidirectional offering (discussed in section **Error! Reference source not found.**) equivalent Code provisions should be developed for bidding energy offtake, particularly, we consider BESS should also be required to bid for dispatchable offtake as a dispatch-capable load station (**DCLS**). Further consideration of this is outside the scope of this report.
[12] Except in requiring curtailment.

Existing generation is required to offer according to a reasonable estimate of their operational capability and update these estimates if their capability changes. For example, generating units with extended startup and shutdown periods will offer quantities and prices according to their per-trading period capabilities in these operating ranges. Similarly, BESS traders should be able to offer injection and bid offtake in a way which is consistent with their per-trading period capabilities and update these offers regularly based on recent dispatch outcomes which impact the BESS SOC.

3.5.2 BESS frequency support obligations may require bona fide offer changes

Concurrent with this investigation is another TAS investigation underway (TAS 112) considering potential asset owner performance obligations for BESS. If it is decided BESS should continue to have frequency support obligations like the current obligations for generators,[13] this could result in a bona fide physical reason to change offered capacity within the gate closure period. The magnitude of this risk is highly variable and dependent on a number of parameters such as *inter alia* the time of the day, the proportion of dispatched intermittent generation, and the status of the HVDC link. There is also an apparent disproportionate opportunity cost borne by BESS that are subject to a frequency support obligation, as it is possible (likelihood as yet unknown) that the frequency support obligation could have a significant impact on SOC. Trading arrangements and common quality obligations should be mutually supportive of maintaining stable system operating conditions.

[13] Refer Part 8 of the Code, including consideration of future obligations for providing frequency support while in charging and idle states.

4 OPTIONS FOR MITIGATING SCHEDULING-TIME SECURITY RISKS

We have considered several process and system enhancements which would contribute to improving near-term operational security and mitigate risks associated with increasing BESS uptake. These options are not mutually exclusive, and some should be implemented to support BESS market participation, regardless of any changes to gate closure rules.

Implementation of these changes may in the future allow for shortened gate closure for BESS and other assets. We recommend exploring a plan to implement some or all of these changes and then assess whether improved operational security permits increased market flexibility in the future.

4.1 Incorporating State of Charge into scheduling and dispatch processes

To improve the accuracy of both forward schedules and dispatch schedules, the market system should be enhanced to incorporate state of charge constraints that moderate the offered discharge capacity. This ensures that forward schedules have a physically coherent generation schedule for each trading period which accounts for changes in the BESS state of charge as a result of their scheduled output or consumption in prior periods.

In practice this could mean:

- For the dispatch schedules, measuring the current state of charge of each offered BESS and limit the sum of energy offers MW quantities to either the offered MW Max (the offered maximum output of the inverter) or the MW power level expected to be able to be maintained for 5 minutes based on the SOC.
- For the forward schedules, incorporating the current SOC at the time of schedule commencement and estimating the end-of-period SOC based on the scheduled injection/offtake, then carrying that value into the next trading period. The initial SOC for each trading period should inform the scheduled injection such that injection is limited by the SOC where necessary.
- In both cases, SOC constraints should apply for both energy and sustained instantaneous reserve (**SIR**) scheduling. Fast instantaneous reserve (**FIR**) is not impacted as providing FIR only requires one minute of response.

Although providing real-time SOC information would incur a small cost to BESS asset owners (the incremental cost of an additional SCADA point in their real-time telemetry), we believe this information is vital for ensuring market schedules are accurate and in practice, this information is not costly to provide if incorporated into the initial data specification at commissioning. Other system operator processes such as engineering and ancillary service compliance monitoring would greatly benefit from receiving SOC telemetry.

Note this change does not incur a change to the Objective Function[14], which is solved for each interval independently. It is analogous to using initial output and ramp rates for scheduling generation within their expected physical constraints. A further significant enhancement for maximising the value of BESS within market scheduling would be to incorporate an intertemporal (unit commitment) solution.

4.2 Employ rules to allow constraining BESS to charge when anticipating capacity shortfalls

In the absence of intertemporal market solutions (optimising for multiple trading periods simultaneously), the current market optimisation logic will fail to schedule BESS when they are most needed – it will only schedule BESS to discharge once marginal prices exceed their offer. This could mean BESS are discharged prior to peak periods when they would be most valuable. This presents a lost opportunity to manage capacity adequacy risk if forward schedules signal BESS capacity is available and then is depleted prematurely through real-time prices being higher than forecast.

Other jurisdictions (notably CAISO) employ market rules allowing the system operator to constrain-off BESS discharge, and constrain-on BESS charging, to ensure adequate states of charge for the anticipated peak periods where there is a risk of a supply shortfall. Such rules could be applied in the New Zealand market to improve supply reliability. We recommend developing policy for application of discretionary constraints to circumstances agreed with BESS asst owners to mitigate the risks of breaching asset warranties. This policy may be permitted by current market rules, however we recommend engaging proactively with affected participants to manage expectations around what would constitute reasonable justification for using this discretion.

4.3 Enhanced sensitivity scheduling and improved situational awareness

One of the key issues for the co-ordinators managing the power system is the ability to prepare the generation schedule for an anticipated system state. We operate a highly dynamic market with security constraints and instantaneous reserve requirements being constantly re-optimised. This is feasible as we expect convergence to a system state within the gate closure period. After gate closure we can expect the security constraints and reserve requirements calculated by the market system to reflect system needs (based on a high-confidence generation schedule).

With increasing uncertainty of generation output (or BESS injection/offtake) within the gate closure period comes increasing likelihood that modelled security constraints or reserve requirements will be insufficient for real-time. Within gate closure this is managed through discretion to manually update market modelling and re-run market schedules, which is then used for assessing voltage and power system stability.

[14] Refer the Code, clause 13.3 (8).

Sensitivity schedules – running production-like market cases which are effectively "what-if" assessments – could enhance co-ordinator decision-making in the near-real-time timeframe by providing optional, pre-built, easily applied security constraints or reserve requirement schedules to the co-ordinators for selection. In theory this would allow co-ordinators to accelerate decision-making in the gate closure period if and when system conditions varied significantly from those expected in scheduling time.

Following the Winter 2023 Initiative work sensitivity schedules are provided to the market specifically showing anticipated price impacts from graduated increases and decreases in load. For operational utility, other sensitivities could be run routinely, possibly based around a "forecast uncertainty measure" methodology as used by the Australian Energy Market Operator (**AEMO**). This could calculate generation schedules given an accepted uncertainty in demand and intermittent generation output, which would inform whether additional security constraints or other operational mitigations are likely to be needed in real-time.

We have also provided the Authority advice for incorporating the current "minimum viable prototype" solution into the market system proper for heightened reliability. We would seek to leverage this market-system based solution (not yet implemented) for any operationally focussed sensitivity schedule solution. There is also a significant risk of information saturation for the co-ordinators from indiscriminately running too many sensitivities. Implementing this option would require considerable care in user experience design and change management to avoid these down-sides.

4.4 Structural market enhancements

Ultimately the current self-commitment energy-only market may not be the most efficient way of scheduling significant quantities of resources that have limited storage. The current market constraint of solving for each trading period independently will not make best use of short-duration storage and could cause greater uncertainty and conservatism in scheduling, to the detriment of market efficiency.

The wider question, considering BESS participation among many other drivers, is whether structural changes should be made to improve market efficiency. As this question relates to BESS, options such as intertemporal scheduling (unit commitment) in the forward scheduling timeframe, 5-minute settlement, an ahead market that reduces commitment uncertainty, and higher granularity forward scheduling all could contribute to varying degrees to incentivising BESS participation. The benefits of these options have been considered generally in other forums, notably the Market Development Advisory Group's (MDAG) recommendations.[15]

[15] Found here: Pricing in a renewables-based electricity system

5 NON-PHYSICAL SOLUTIONS AND FREQUENCY KEEPING

5.1 Currently SPD can schedule non-physical solutions for BESS

The current market modelling for BESS requires separating the asset's capability into two notional dispatch nodes, one representing the injection capacity of the BESS ("generation") and the other representing its potential to reduce charging load ("dispatchable demand, **DD**"). In addition to the operational difficulties this presents to both BESS traders and system co-ordinators, this also creates the potential for SPD to schedule non-physical solutions under certain system conditions. In particular, when energy prices are high and instantaneous reserve is relative scarce, the SPD solution could schedule the generation side of the BESS to inject while also scheduling the BESS to charge, so that it may enable scheduling interruptible load (**IL**)[16]. This is currently managed through bid/offer changes in scheduling time, and through the dispatch process in real-time.

We expect this current scheduling arrangement to continue to cause difficulties to traders and co-ordinators, and the difficulties are likely to be exacerbated by increasing numbers of BESS being traded in the market.

5.2 Options exist to mitigate non-physical solutions and operational issues

Two options have been identified to prevent SPD from scheduling non-physical solutions: Option A – Bidirectional offers, and Option B – Associated nodes. These options are described briefly below.

Of the two options, Option A remedies the operational difficulties faced by traders and co-ordinators and is the clear preference for implementation. The current BESS modelling within the market system (a pair of dispatch nodes, one for discharging charging/injection and one charging/offtake) causes significant additional modelling complexity, opportunity for modelling error, and risk of confusion around interpreting dispatch targets and telemetered values. Traders have described anecdotally that maintaining independent sets of bids for charging and offers for discharging is complex to implement in software logic and causes issues around offering instantaneous reserve capacity. Bidirectional offering is also considered an enabler for rapid implementation of BESS offering in frequency keeping.

5.2.1 Option A – Bidirectional offering

In this solution, the BESS is offered at a single dispatch node using a single offer form for energy, with the charging load being offered as "negative generation". This is distinct from the current arrangement where charging load is bid separately as DD. The BESS would also submit a single instantaneous reserve offer, where applicable, that offers its total contingency response capacity as the sum of reduction in charging load (currently offered as IL) and increase in energy injection (currently offered as generation reserve).

[16] For IL offers from DD providers, where the IL is physically located at the dispatch-capable load station (**DCLS**) (ie is not an aggregation) the IL is constrained against the scheduled DD quantity, such that if SPD schedules the DCLS to reduce consumption, that load is automatically no longer available to provide IL.

This solves the problem of SPD scheduling non-physical solutions as SPD would inherently recognise the BESS as a single asset. When calculating the scheduled quantity for a given asset, SPD sums the cleared (or partially cleared) offer tranches associated with that asset. When implemented for BESS, SPD would net the cleared charge and discharge offer tranches resulting in a single output (being either negative, representing charging, or positive, representing discharging.)

Bidirectional offering for energy could facilitate simplifying the way BESS offer instantaneous reserve. Currently BESS may offer both interruptible load reserve when charging, and generation reserve when charged. The proposed solution with bidirectional offering is to allow for a single instantaneous reserve injection response, analogous to generation reserve, but allowing the full capacity of the BESS to be offered as a single capacity value. For example, a BESS owner may offer a reserve MW capacity of double its rated capacity, provided it can move seamlessly from full charging, through idle to full discharging within the reserve product response time. This can be represented as a single reserve offer, which will be co-optimised with the energy offer. Co-optimisation is ensured by SPD using the net scheduled quantity and comparing it to the BESS offered maximum MW to determine its reserve capability.[17]

To be clear, implementing a bidirectional offer form does not preclude a BESS asset owner from alternatively offering both charging and discharging separately if they wish to do so. The manner of reserve response implied by a single reserve offer and bidirectional energy offer is a continuous response through zero (idle). If the asset does not operate in this fashion, it may be more appropriate to offer separate reserve responses based on different characteristics while in charging and discharging modes.

This solution has moderate confidence for implementability, noting there is significant similarity between this solution and the implementation of difference bids in the market system. There remains significant investigation work to determine whether changes to the dispatch system would be required to facilitate this solution; for the purposes of this report, we have assumed a detailed investigation and solution engineering phase would mitigate the need for dispatch system changes.

The high-level technical attributes considered for the solution are documented in Appendix A.

5.2.2 Option B – Associated nodes

This option considered a minor change to SPD, making use of the current two-node modelling arrangement. We would introduce a constraint to SPD that prevented scheduling both energy (injection) and load (offtake) at the same time from a given BESS asset. All other arrangements would remain the same. To enable this, we would need to incorporate into the market model an association between the injection node and offtake node, so SPD would be able to recognise that both nodes 'belonged' to the one physical asset.

The system operator recognised that Option B would likely lead to future issues with anticipated market changes (particularly around integration of hybrid generating plant) which were not included in the scope of TAS. In addition, while Option B would technically solve the non-physical solution problem, it does not mitigate operational difficulties. Recognising these detriments, this option was not progressed to cost assessment.

[17] SPD performs a similar calculation in determining the reserve sharing capability of the HVDC link. For instance when the HVDC Link is sending power from North Island to South Island in Roundpower mode, SPD can determine the ability of the HVDC to ramp up northward flow in response to a North Island contingency, even though its pre-contingent transmission is southward.

5.3 Implementing bidirectional offering supports future frequency keeping participation

Notwithstanding potential future developments of the frequency keeping ancillary service, the current frequency keeping arrangements do not well support BESS. Under current system constraints, BESS may currently only provide frequency keeping while discharging, which in turn requires sufficient SOC to provide the service for a given trading period. This is a perverse barrier to participation as BESS are technically very capable of providing frequency regulation in both charging and discharging modes and are expected to be able to do so at significantly lower costs compared to conventional generation plant.

Incorporating BESS participation in frequency keeping has two technical challenges:

1. Allowing negative offered CONTROLMIN[18] value. The current convention assumes the minimum CONTROLMIN value that can be offered is zero, as no generator is also a consumer of electricity[19], in the way BESS is. It is unclear whether the market system currently supports frequency keeping offers with negative CONTROLMIN.

2. Calculation of constrained costs. The frequency keeping selection tool accounts for an estimate of constrained costs when assessing the least-cost provider from the set of offers. When considering constrained costs for BESS, under current arrangements a BESS offering both energy (discharging) and DD (charging) would be entitled to both constrained-on costs while discharging out of merit, plus constrained-on *or* constrained-off costs if charging out of merit. If the constrained cost assessment is retained as part of frequency keeping selection, this introduces significant modelling and logical difficulties for the tool, which is already performance constrained. A simpler consideration might be to stop paying constrained costs for frequency keeping, and hence remove consideration of constrained costs from frequency keep selection. Traders may incorporate expected costs from not clearing energy into the frequency keeping offer price.

Implementing bidirectional offering by itself would not solve these problems, and depending on system constraints, could prevent BESS from participating in frequency keeping at all until a remediation of the frequency keeping selection tool was undertaken. However, the problems would be exacerbated somewhat by persisting with a two-node model. Conceptually the logic for managing frequency keeping selection for a single asset using separate injection offers and offtake bids is very difficult to formulate, particularly in needing to compare BESS asset offerings with other generators.

To facilitate frequency keeping participation for BESS, we recommend:

- implementing bidirectional offering described in section 5.2.1,
- further investigations into the market system behaviour for offered CONTROLMIN and scope system changes to enable this, and
- removing consideration of constrained costs from the Code and thereby the frequency keeping selection logic.

[18] Note the frequency keeping offer form is not specified in the Code. CONTROLMIN is the attribute of the offer which is the lowest output the generator can sustain while frequency keeping. The generator scheduled for frequency keeping will have its energy dispatch constrained to greater than or equal to a value equal to (offered CONTROLMIN MW + FK BAND MW).
[19] In the sense that a generator may not seamlessly move between injection and consumption.

6 RECOMMENDATIONS

Based on the preliminary assessment into options for managing reduced certainty near real-time from BESS market participation, the system operator recommends the following:

Market rules

1. Maintain the current 1-hour gate closure period for BESS or any other assets. On balance, the system operator considers the detriment to our ability to operate the power system would likely outweigh any benefit from allowing greater flexibility in BESS offering. BESS asset owners also seem to have sufficient ability to manage gate closure related risks. Any reduction in gate closure period from the current situation would require significant automation of our scheduling processes to mitigate operational risks.

System enhancements

2. Regardless of the gate closure period, to manage increasing volumes of BESS we recommend investment to accommodate enhanced scheduling, particularly including SOC and discretionary constraint rules into the scheduling and dispatch processes (described in sections 4.1 and 4.2).
3. To mitigate the risk of non-physical SPD solutions, improve trader and system co-ordinator operational processes, and enable future BESS participation in frequency keeping, the system operator recommends bidirectional offering for BESS (described in section 5.2.1) is progressed into an implementation phase.
4. To enable BESS participation in the frequency keeping market, it is recommended the Authority consider removing constrained costs from the frequency keeping selection logic and considers further investigations and system changes to enhance the frequency keeping selection tool (described in section 5.3).
5. The system operator recommends the Authority commission the system operator to further investigate enhanced sensitivity scheduling and alignment with existing sensitivity schedules (described in section 4.3).

Future market changes

6. We recommended the Authority ensures consideration of BESS-related market participation in any existing work around structural market design investigations.

A.1 TECHNICAL DESCRIPTION OF PROPOSED SYSTEM CHANGES AND INVESTMENT ESTIMATES

A.1.1 Incorporating BESS state of charge into scheduling

Incorporating BESS SOC into scheduling, the aim of the solution is to incorporate constraints into scheduling that limit energy and instantaneous reserve (**IR**) dispatch by the storage capacity of the asset. The constraints would be applied in both scheduling time to the forward schedules[20], and in real-time to the real-time dispatch (**RTD**) schedule. In dispatch, this would ensure scheduled output (or consumption) and SIR provision from the BESS does not exceed SOC, which would otherwise result in additional burden on the frequency keeper.

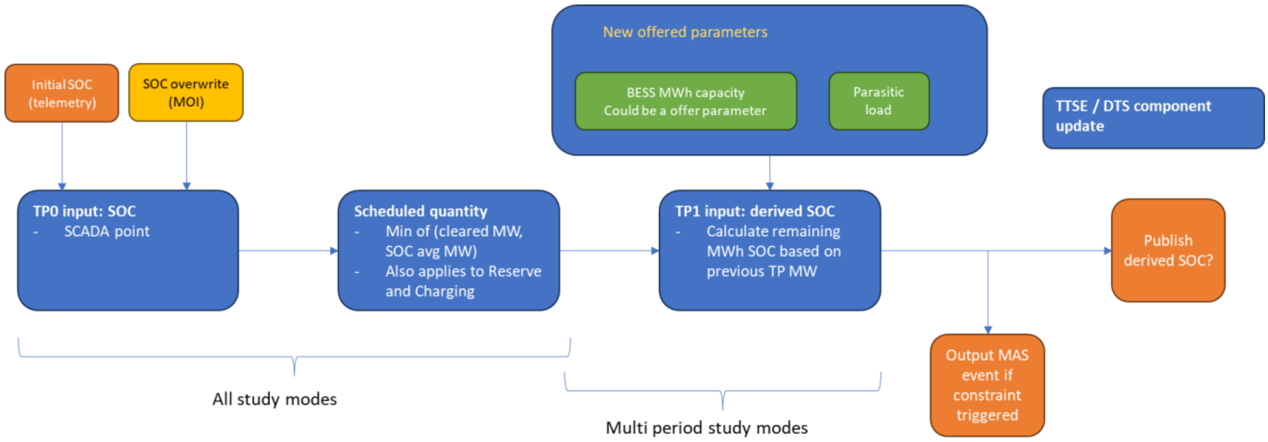

Figure A.1 – simplified block diagram of solution implementing SOC constraints in scheduling.

The implementation of the proposed system changes will require the following solution scope:

1. Modification of the BESS offer form to require MWh_max and MWh_min in a single form with the attributes, as well as a MW value for parasitic load[21].
2. Changes to incorporate a BESS SOC constraint that reads the initial SOC (for the current interval) or a derived SOC (for future intervals) and limits scheduled MW output or consumption based on the available energy storage capacity of the asset.
3. Updating market and SCADA models to receive BESS SOC telemetry information.
4. Updating elements of the Market Operator Interface (**MOI**) to allow presentation of SOC information.
5. Updating the information publication system (**WITS**) and integration changes to enable publication of the derived BESS SOC values in the forward schedules.
6. Updating the testing and training simulator environment logic to account for BESS SOC.

[20] Collectively the WDS, NRSL, PRSL, NRSS and PRSS. There may be merit in applying the constraints in a subset of these schedules; this will be considered this in the implementation phase.
[21] Parasitic load describes any constant MW consumption of the BESS while idle.

A.1.2 Bi-directional offers

Implementing a bi-directional offer form for BESS aims to resolve the current potential for SPD to schedule non-physical solutions (scheduling discharging at the same time as charging, to obtain IL through co-optimisation), as well as improve operability for both co-ordinators and traders. The following simplified block diagram presents the solution design elements:

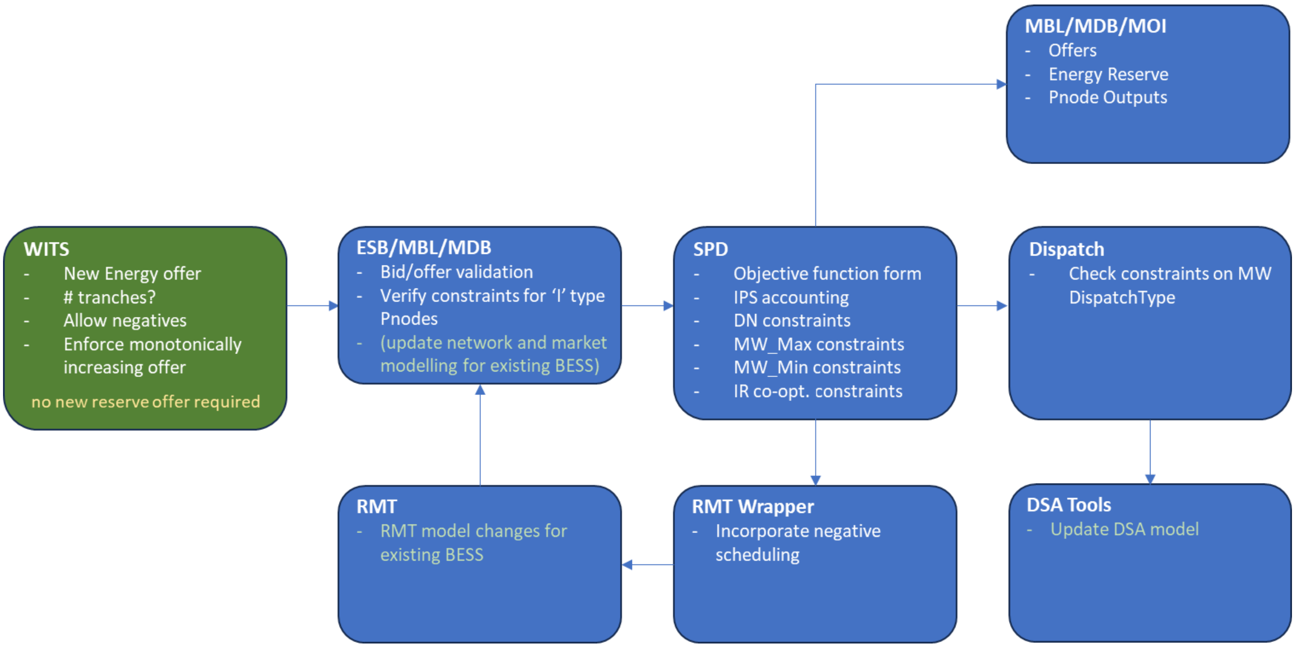

Figure A.2 – Simplified block diagram of implementation of bi-directional offering for BESS.

1. Provision of a new energy offer type for BESS that allows BESS traders to offer both charging MW and discharging MW in a single form.

2. Bid and Offer Validation (**BOV**) logic must be updated to screen the energy offer for validity.

3. Updating the MOI to allow presentation of new case data and control mechanisms for dispatch and enabling the BESS energy offer to be viewable within the MOI using the schedule inputs displays for offers and bid and offer changes. This will enable, amongst others, the system operator to intuitively interpret negative MW quantities presented for dispatch on the Energy Reserve display and dispatch these quantities using current automatic and manual processes as for energy and reserve dispatch.

4. Changes to our scheduling and dispatch tools that:
   - consume the energy offer treating the negative MW quantity offer blocks analogous to Dispatchable Demand (**DD**) bids
   - constrain the scheduled quantities according to known SOC variables (if applicable)
   - co-optimise generation reserve offers for the Pnode as the combined additional MW capacity from reduction in charging and increase in discharging.

5. The Market Dispatch System (**MDS**) must be able to dispatch negative MW quantities for BESS or provide an operable alternative through validation.

6. Changes to the modelling tools (RMT and RMT Wrapper) enabling the processing of negative MW scheduled quantities for BESS Pnodes.

7. Updating WITS and integration changes to enable relevant parameters and restrictions and to receive BESS bi-directional offers.

At the time of completing the TAS report, the following items were considered out of scope for the development of the ROM estimate:

- Completion of a separate RMT audit.
- Security and infrastructure changes, including and SCADA/market system integration.
- Drafting and/or reviewing Code amendment proposals and industry engagement.
- Changes to WITS. The estimate for changes to be provided by the WITS manager (**NZX**).

A.1.3 Estimated investment and implementation timeframe

At this initial planning stage, the investment envelope has a -25/+75 tolerance estimation range as per the agreed estimation methodology documented in the Integrated Project life Cycle (**IPLC**) framework. The system operator expects the project to be delivered over 13 months, preceded by an estimated 4-month investigation, which would be completed under the TAS delivery mechanism under the IPLC.

The ROM estimate for the respective investigation and implementation phases of the project delivering both scope items are documented in table 2 below.

Table 2 – ROM estimate including estimation tolerance range

Phase	Optimistic (-25%)	Expected	Pessimistic (+75%)
Investigation[22]	$240,256	$320,341	$560,597
Delivery	$1,160,603	$1,547,471	$2,708,074
Total	$1,400,859	$1,867,812	$3,268,671

At the request of the Authority, the system operator has completed an estimate for the separate scope items in the event the Authority decides these items are to be delivered separately. With an expected similar timeframe to a combined implementation, the ROM estimates for the separate scope items are shown in tables 3 and 4 below.

[22] Estimate is based on an estimated 1,906 hours of effort with budget estimate based on FY24/25 TAS base rate.

Table 3 – ROM estimate - Incorporating BESS state of charge into scheduling

Phase	Optimistic (-25%)	Expected	Pessimistic (+75%)
Investigation[23]	$169,919	$226,558	$396,477
Delivery	$642,383	$856,510	$1,498,893
Total	$812,302	$1,083,068	$1,895,370

Table 4 – ROM estimate – BESS bi-directional offers

Phase	Optimistic (-25%)	Expected	Pessimistic (+75%)
Investigation[24]	$214,592	$286,122	$500,714
Delivery	$748,209	$997,612	$1,745,821
Total	$962,801	$1,283,734	$2,246,535

The following delivery risks and considerations were identified during the definition of the solution design components and development of the ROM estimates.

Table 5 – Delivery Risks and Considerations

Ref	Item	A/R/C[25]	Mitigation/Comment
1	Instantaneous reserve offering process	A	Changes to the instantaneous reserve offering process are not required.
2	Pnode Type	A	A new Pnode type will not be required.
3	Existing BESS market modelling	A	The existing BESS market modelling will be transferred once the new modelling becomes available.
4	BESS energy offer type	A/C	The new BESS energy offer will be offered with monotonically increasing prices for each bid/offer tranche (block). The manner in which the offer form and SOC is incorporated into the schedules is dependent on the implementation of the bi-directional BESS offer changes.
5	BESS SOC telemetry	A	BESS SOC telemetry is available and able to be modelled through current business process (with some Market System modification).
6	Parasitic Load	A	Parasitic load can be modelled as a constant negative MW when the BESS is in idle / 'standby' mode.
7	Dispatch System	A	Dispatch system changes are not required.
8	DSA Tools	A	Integration changes are not required to DSA tools.

[23] Estimate is based on an estimated 1,348 hours of effort with budget estimate based on FY24/25 TAS base rate.

[24] Estimate is based on an estimated 1,702 hours of effort with budget estimate based on FY24/25 TAS base rate.

[25] Description A/R/C – Assumptions, Risks and Constraints.

Ref	Item	A/R/C[25]	Mitigation/Comment
9	WITS changes	A	It is assumed the information publication system (WITS) will be updated to enable publication of the derived SOC values in the forward schedules.
10	NZX resource availability	A/R	It is assumed NZX makes the necessary integration and WITS changes and is available to complete integration testing with the SO.
11	Transpower resource availability	A/R	This initiative is a Market Design initiative. Once this initiative receives approval to proceed, project resources and timeframes will need to be reviewed and (re)confirmed. Currently it is assumed resources will be available to progress the initiative. Due to the high demand for resources within the committed portfolio plan, there is a risk project delivery may be delayed.

A proof of concept will be completed during the investigation phase and will help support the validation of the identified risks and considerations and will inform the solution development approach.

Appendix F Format for submissions

Submitter	

Questions	Comments
Understanding the characteristics, benefits and future operation of BESS	
Q1. Do you agree we have sufficiently identified the unique characteristics of BESS to assist in developing appropriate arrangements?	
Q2. Do you have any views on how BESSs should be defined in the Code?	
Q3. Do you agree that BESS can deliver the benefits described? Are there any other benefits that will assist us in assessing the size of benefits of different arrangements?	
Q4. Do you agree with our description of how BESSs are likely to operate and how this will change over time? If not, why?	
Q5. Do you have any other insights about potential BESS operation that will help with assessing the benefits of our options?	
Dispatch requirements for BESS when charging	
Q6. Do you agree with the way we have framed the issues?	
Q7. Do you agree with the Authority's preferred option?	

If not, what are alternative options that would better address the issues? Are there any particular risks with our preferred option that you would like to identify?	
Bids and offers forms for BESS	
Q8. Do you agree with how we have framed the issues?	
Q9. Do you agree with out preferred options? If not what other options would better address the issues identified?	
Q10. Do you think further restrictions to BESS participation in MFK under the current arrangements would have any effect on their participation?	
Balancing flexible trading with security needs	
Q11. Do you agree the issues identified by the Authority are worthy of attention? If so, do you agree with our framing?	
Q12. Do you agree that BESS should have the same arrangements when charging and discharging, and that embedded BESS should have the same arrangements as grid connected BESS?	
Q13. Do you agree with our preferred new arrangements for BESS?	

Q14. Do you see any issues with how we have defined state of charge constraints?	
Q15. Do you agree that the benefits of state of charge constraints likely outweigh the costs?	
Q16. Do you agree with how we have characterised the differences between various options?	
Q17. Are there any other options that you think would better achieve the gate closure objectives?	
Q18. Do you consider an interim solution is necessary? If so, do you agree with the potential solution we suggested?	
Q19. Do you have any information that can help us better understand the benefits and costs of different options? This includes, for example, substantiating the system risks, and how to improve our modelling of benefits.	
Constrained off payments	
Q20. Do you agree the issues identified by the Authority are worthy of attention?	
Q21. Do you agree with our framing of the issue?	
Q22. Do you consider having constrained off payments would affect bidding and	

offering behaviour from BESS?	
Q23 . Do you agree with our preferred solution?	