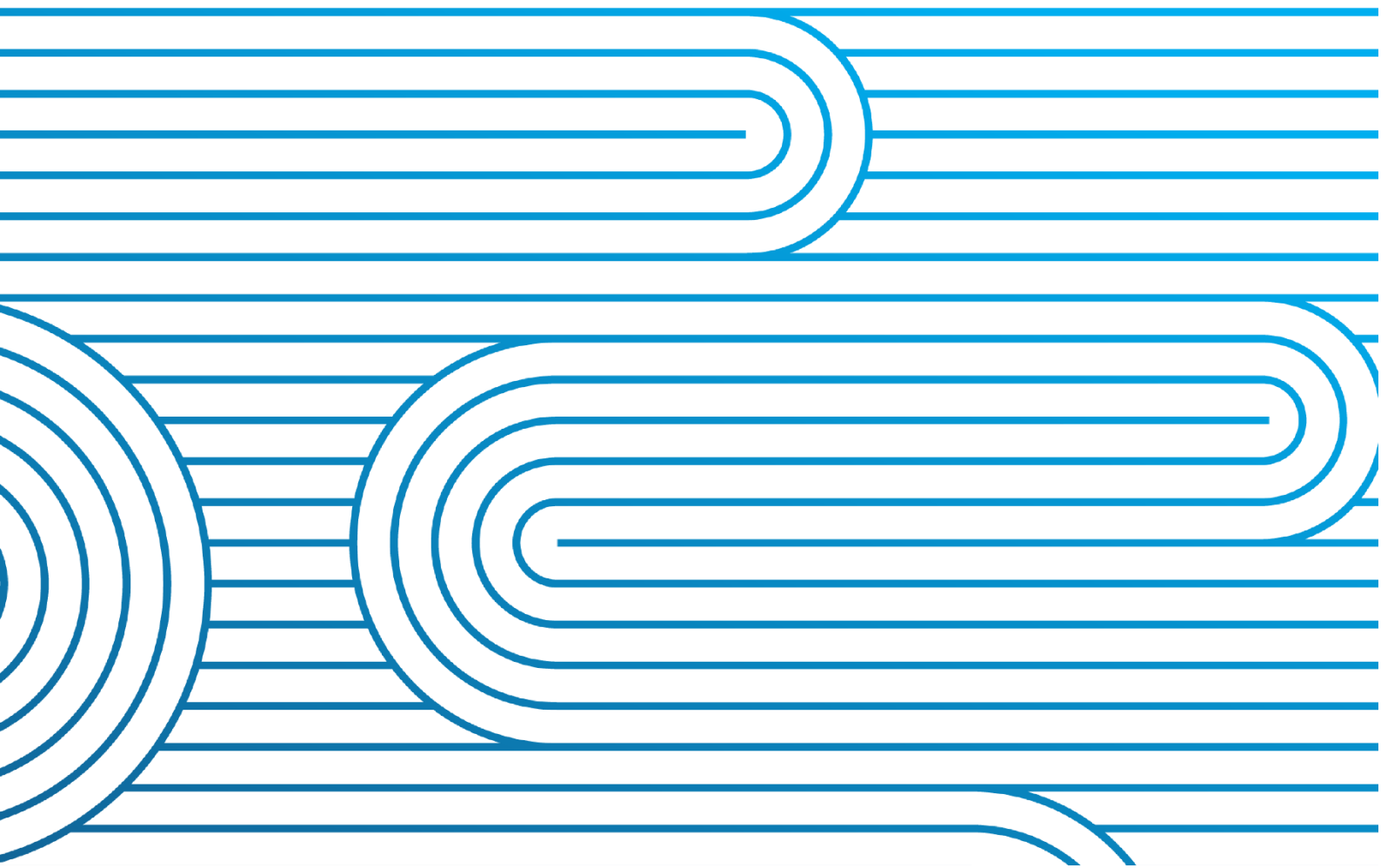


IMPROVING OFFER ARRANGEMENTS FOR BATTERY ENERGY STORAGE SYSTEMS

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

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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.



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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 Objective⁴, 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 generators⁷ 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.

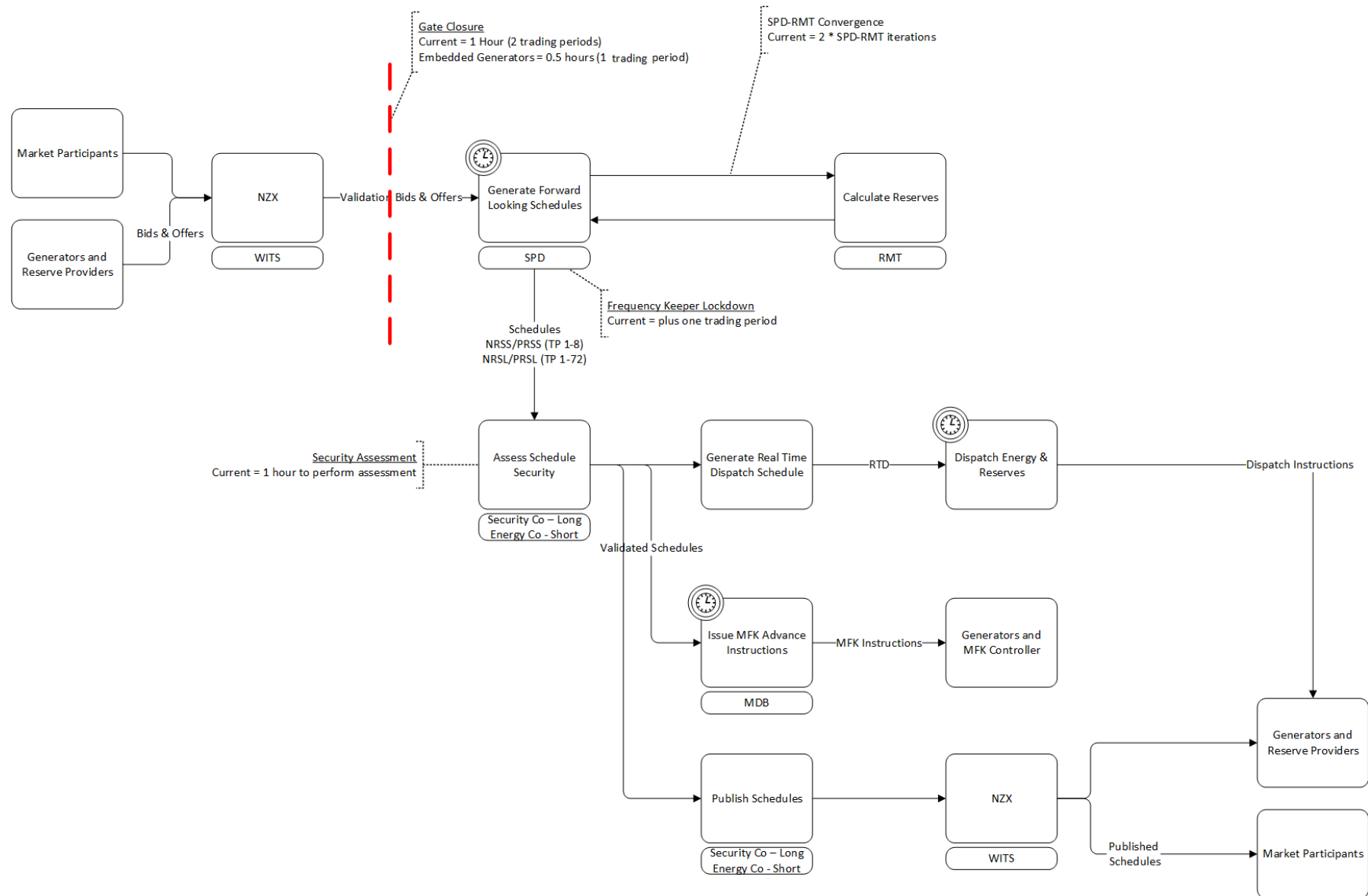


Figure 1 – Overview scheduling and security checking processes within gate closure

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 generators¹⁰. 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 offering¹¹ 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 Function¹⁴, 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 asset 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 CONTROLMIN¹⁸ value. The current convention assumes the minimum CONTROLMIN value that can be offered is zero, as no generator is also a consumer of electricity¹⁹, 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 schedules²⁰, 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.

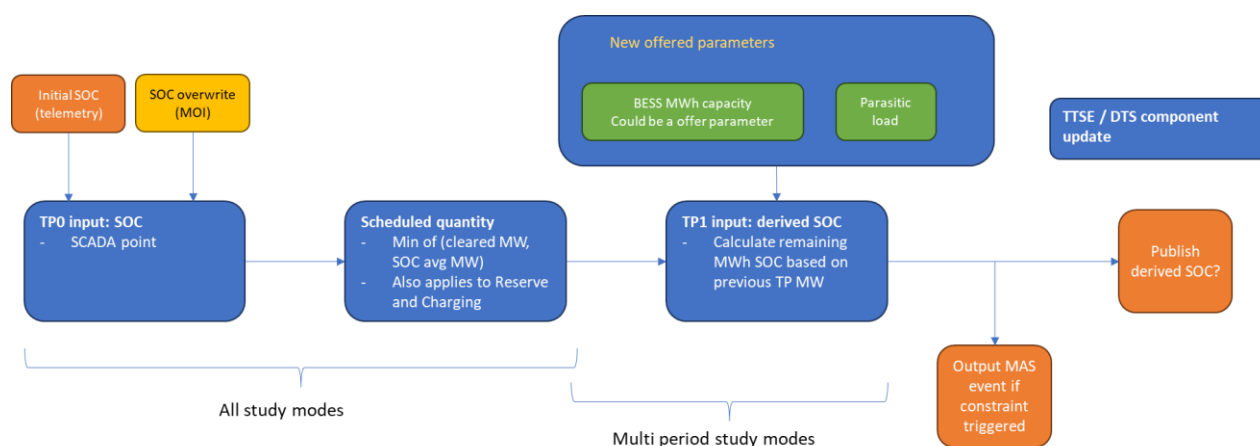


Figure A.1 – simplified block diagram of solution implementing SOC constraints in scheduling.

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 load²¹.
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:

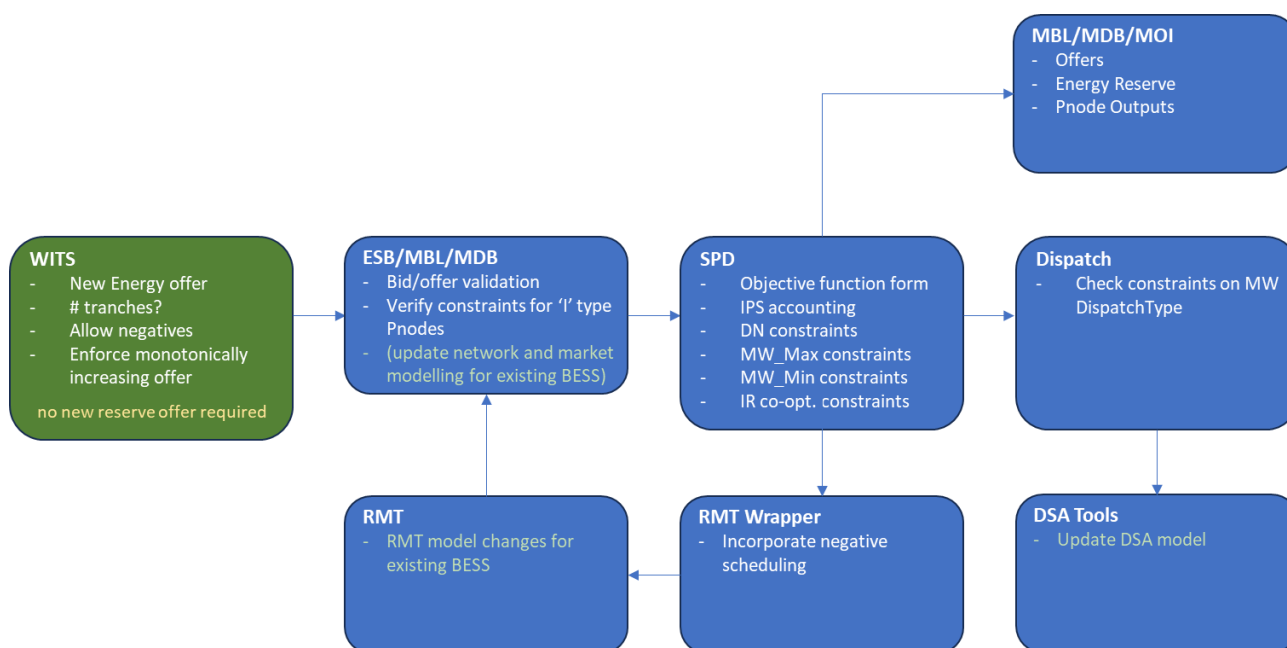


Figure A.2 – Simplified block diagram of implementation of bi-directional offering for BESS.

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-optimize 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.