RMT_Specification_V11

Functional Specification

System Operator

Transpower New Zealand Limited

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Keeping the energy flowing

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Version	Date	Author	Change
4.0	29 September 2016	Andrew Paver	Introduction of NMIR
5.0	17 December 2017	Richard Sherry	Revisions to section 3.2 for new NI AUFLS scheme
6.0	12 September 2018	Richard Sherry	Updated section 2.2 and added section 3.4 to include AOPO calculations. Other minor corrections to include SI ECE 47 Hz / 30 sec window. Revision to AUFLS to allow for block4 without df/dt (block10) Revised HVDC model description
7.0	26 August 2019	Richard Sherry	Added section 5.7 Added HVDC FIR sharing limits.
8.0	14 May 2021	Richard Sherry	Addition of sections 3.3 to 3.6 to clarify functionality within RMT Section 3.7 : clarification for AOPO charges that ‘larger’ = larger cost RMT Enhancements Project additions : 3.2.5 Intermittent variability parameter 3.2.8 FIR feasible from schedule 3.3.1 Series Solve (CE before ECE) 3.4.2 Untripped AUFLS for NFR SIR 3.5 SIR model for CE 3.6.2 Untripped AUFLS for NFR FIR 3.6.3 Removal of limit of NFR at Risk MW values
9.0	2 Sept 2022	Richard Sherry	Section 3.2.8 inserted for non-specific generation reserves (BESS)
10.0	8 Nov 2024 (issued Mar 2025)	Richard Sherry	update Fig. 1 (128 MW SI) update of 2.3.4 for BESS update 3.6.1 for multiple risk changes minor clarification updates (3.2.5, 3.3.2 and 3.5) updated obsolete EA website links
11.0	1 Feb 2026	Richard Sherry	Updated to reflect completion of North Island AUFLS transition to 4 blocks update Fig 1 - removed MW value of island risks

	Position	Date
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IMPORTANT

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1 INTRODUCTION

This document is the functional specification for the System Operator's Reserve Management Tool (RMT). RMT is implemented by RMTSAT application software. This application software is used by the System Operator to calculate the instantaneous reserves required to meet the **Reserve Management Objective**.

RMT provides an automated process for reserves management within the New Zealand power system, able to represent it in considerable detail.

This document provides a background to the characteristics of the New Zealand power system modelled by RMT. A description of the use of RMT to manage reserves follows.

Section 3 provides a functional specification for the **RMT Solver** and associated external calculations, as set out in section 1.1 and depicted diagrammatically in Figure 2. Section 4 provides the validation requirements. Section 5 provides a summary of the assumptions inherent in RMT.

1.1 SCOPE OF RMT CERTIFICATION

RMT certification covers the following described components as depicted in Figure 2:

- RMT Solver
- HVDC Model calculations within the RMT User Interface program
- Database calculations relating to variable reserve requirements
- Database calculations relating to Asset Owner Performance Obligations
- Key Input Parameters:
    - Load inertia
    - Load damping
    - Frequency standards
    - Safety margins
    - AUFLS settings
    - AC loss model assumptions
    - Free Reserve modelling limits
    - HVDC settings

1.2 FUNCTIONALITY NOT INCLUDED IN RMT

The functionality of RMT does not cover the following features:

- Detailed modelling of **Sustained Instantaneous Reserve**
- Modelling of uncleared reserve
- Modelling of AC transmission constraints
- Enhanced economic dispatch (Five minute reserve modelling)
- Generator compliance monitoring and associated cost allocation

2 Reserves management in New Zealand

2.1 The New Zealand Electricity System

The management of generation reserves in the New Zealand electricity system poses significantly different problems to the management of reserves in larger 'continental' systems, consisting of large synchronous interconnected areas. On a large continental system each large generating unit typically represents a small portion of the total generation and consequently the tripping of a large unit generally results in a minor frequency fluctuation. In contrast the largest generating units or the HVDC Bipole in the New Zealand system represent a relatively large portion of the total generation and a generator or Bipole trip can result in a relatively large frequency fluctuation.

For the purpose of analysing the management of reserves, the New Zealand electricity system is represented by Figure 1.

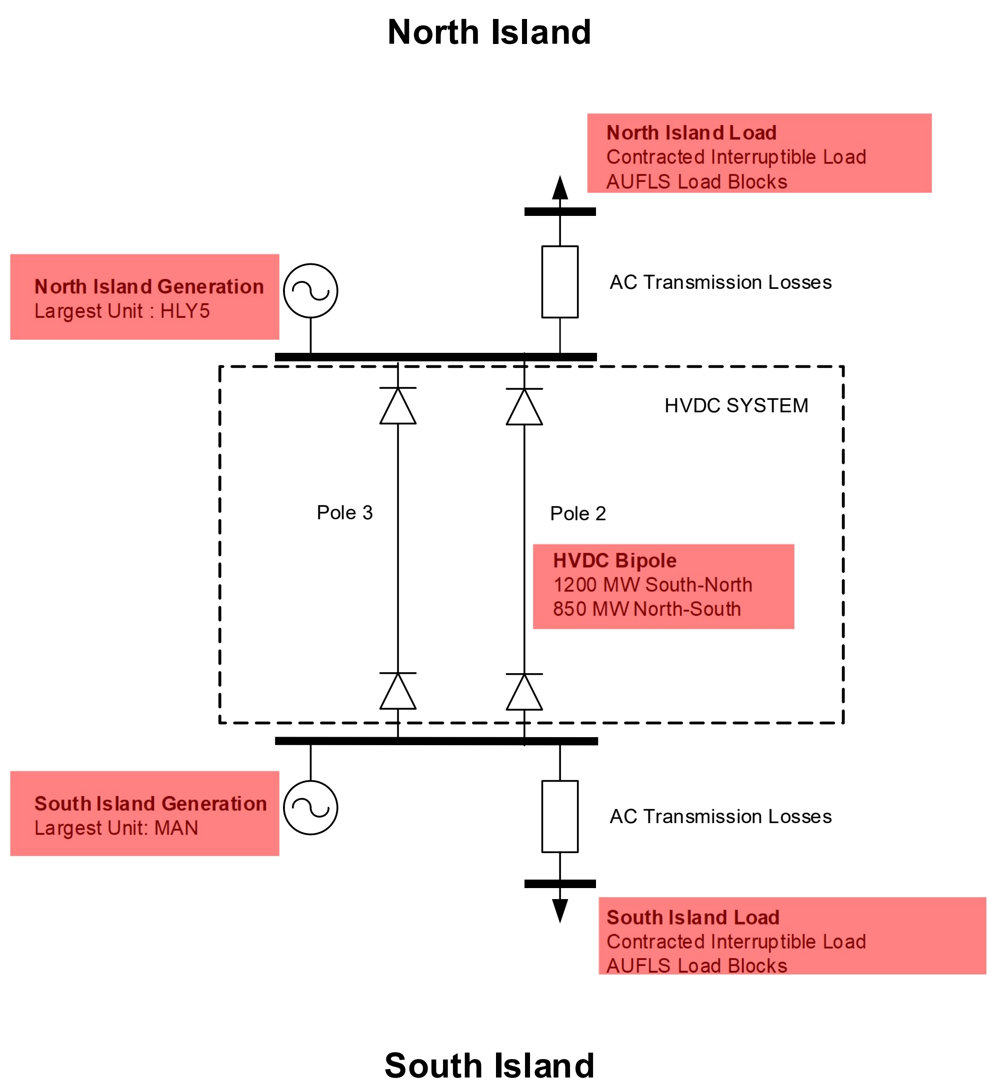

Figure 1. New Zealand Electricity System

In RMT the North Island and South Island networks are each represented by a 2 bus system with generation and the HVDC Bipole connected to one bus and load connected to the other bus. The AC transmission loss in each island is represented by a resistive loss component.

The AC networks within each island are not represented as it is assumed that the network topology is irrelevant to reserves management.[1]

The North and South Islands are linked by a two pole (often described as Bipole) HVDC Link. The HVDC link is, at the time of publication, rated to transfer 1200 MW from South to North or 850 MW from North to South. AC transmission constraints prevent the HVDC Link from operating at its rated maximum in some circumstances.

The tripping of an HVDC pole or the tripping of the largest generating unit in the North Island represents a significant power loss. Both Islands have a load shedding scheme to compensate for the potential loss. The load shedding schemes include 'Interruptible Load' and 'Automatic Under-Frequency Load Shedding'.

To model AUFLS and Interruptible Load, RMT includes separate independent blocks of load (in each Island) that trip at predefined frequencies.

2.2 ELECTRICITY INDUSTRY PARTICIPATION CODE 2010

The steady state operation of the New Zealand power system is based on the Scheduling, Pricing, and Dispatch (SPD) model. The SPD application takes generation offers and load bids as inputs into a linear programming algorithm which determines a clearing price for electricity at each of approximately 550 nodes in the power system. Constraints are included within the SPD model to represent contingent and dynamic power system operating limits.

As part of the scheduling and dispatch process, reserve offers are co-optimised with the energy offers from generators. The requirement for reserves is defined by Part 7 and Schedule 8.4 of the Electricity Industry Participation Code 2010 (Code). These rules require that for a Contingent Event (CE) the frequency fall to no less than 48 Hz and recover to no less than 49.25 Hz within 60 seconds (in both islands). The Code also requires that for an Extended Contingent Event (ECE) the frequency fall to no less than 47/45 Hz (North Island/South Island) and recover to no less than 49.25 Hz within 60 seconds. In the North Island it is also required that the frequency does not stay below 47.3 Hz for longer than 20 seconds or below 47.1 Hz for longer than 5 seconds.

On the New Zealand power system the tripping of a large generating unit or HVDC pole will generally result in a large frequency fluctuation whose magnitude is dependent on the size of the tripped unit or pole and the response characteristics of the remaining units. The frequency-oriented requirements of the Code are intended to prevent excessive load shedding and the cascade tripping of other generators due to low frequency operation.

Part 8 Sub Part 2 of the Code specifies Asset Owner Performance Obligations (AOPO) for generators. Clause 8.19 specifies that a generator is required to remain connected and provides an envelope of the frequency and duration requirements for each AC island. Reserves management will aim to ensure the frequency stays above these quoted envelopes.

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[1] *Assuming that the AC network topology is irrelevant to the calculation of reserve requirements is not valid under circumstances where the generation reserves cannot be supplied to the load without overloading transmission circuits. However, these circumstances occur rarely and are not included in the design of RMT.*

Asset owners that do not comply with Clause 8.19 may be granted a dispensation – which gives that asset an exclusion from the requirement. However as noted in Clause 8.31 the system operator should charge any readily identifiable and quantifiable costs resulting from a dispensation to the asset owner. Costs are therefore charged for each trading period where the reserves requirement is increased by the dispensation. The formula for the cost per half hour trading period is specified in the Code as :

DispCostGENxt = 0.5 * QGENxt * PIRt

Where :

DispCostGENxt :	is the cost payable by a generator for generating unit x in any trading period t in which a class of instantaneous reserves is procured as a direct result of that generating unit's dispensation to ensure that the frequency does not fall below 47 Hertz or, in the South Island, below the minimum South Island frequency
QGENxt :	is the MW amount by which generating unit x is unable to sustain pre-event output in trading period t with reference to clause 8.19(1) or (3) (as the case may be) as determined from the capabilities specified in that generating unit's dispensation (different amounts may be specified with respect to each class of instantaneous reserves)
PIRt :	is the final reserve price for fast instantaneous reserves or sustained instantaneous reserves (as the case may be) in trading period t in the relevant island.

Contingent Event (CE) and Extended Contingent Event (ECE) are Risk Event types used in the Policy Statement to categorise and manage levels of risk. Part 8 does not specify in any detail how the risk of the North Island frequency falling below 47Hz (or the South Island below 45 Hz) is to be managed; this is left to the System Operator. The costs of procuring reserves to manage either a CE or an ECE Risk Event are captured by this definition as they are necessary contributions to ensuring that the frequency does not fall below the stated values. An identified risk under a dispensation may contribute to the frequency falling to below these stated levels. It is not considered dependent on the risk being an ECE risk, if additional reserves need to be procured for a CE risk due to a dispensation then the charges are applicable.

Within RMT any dispensation granted for non-compliance of a generator with Clause 8.19 is modelled and the reduction in MW from that generator (i.e. QGENxt) is calculated for each Event type and for each class of instantaneous reserves.

For each trading period, for the binding reserve risk, any MW reductions for generators with dispensations are output as the AOPO MW output for each class of instantaneous reserves. The market system then determines the corresponding financial charges to that generator.

The AOPO MW output is based on the reduction in output of the generator with the dispensation and not on the additional reserves required to compensate this reduction. The reduction is assessed over the duration of the RMT simulation (60 seconds). The AOPO MW output is the full MW output of the generator if it disconnects from the network, or if reserves are procured to avoid it disconnecting, due to a non-compliance.

Not all generation is required to meet the AOPOs in the Code. If the system operator knows that such generation will trip during contingency events then this is also modelled in RMT to ensure sufficient reserves are procured. No AOPO MW outputs (or subsequent costs to that generator) result from this.

2.3 THE ROLE OF RMT IN THE SPD PROCESS

Figure 2 shows how RMT interacts with the SPD application. The SPD application is used in 3 different modes:

- Scheduling Mode
- Dispatch Mode
- Pricing Mode

2.3.1 SPD Scheduling Mode

The Scheduling Mode of SPD is used to forecast a schedule for generation for 13 to 35 hours ahead of time. Market Participants (Generators and Loads) make offers and bids for each half-hour trading period to inject or take off power at each node in the system. Reserves are also offered by generators and contracted interruptible load providers.

The SPD application takes the offers and bids (or load forecast) for each trading period and employs a linear programming solution to match generation to load at minimum cost, subject to constraints in the network. Forecast information on cleared generation and load (those that have had successful offers and bids) as well as nodal prices is then fed back to the market participants. The participants may then choose to alter their offers and bids and resubmit these for a subsequent scheduling solution. By the time that each actual trading period comes to pass the participants will have had the opportunity to resubmit offers and bids up from 6 to 17 times, which is generally a sufficient number of iterations to result in a satisfactory solution to all participants.

2.3.2 SPD Dispatch Mode

The Dispatch Mode of SPD is used to determine dispatch instructions in near real time. The valid offers from the forecast schedule are finally used by the SPD application to provide a dispatch schedule for the current demand conditions. The SPD application runs every 5 minutes to keep pace with the changing load.

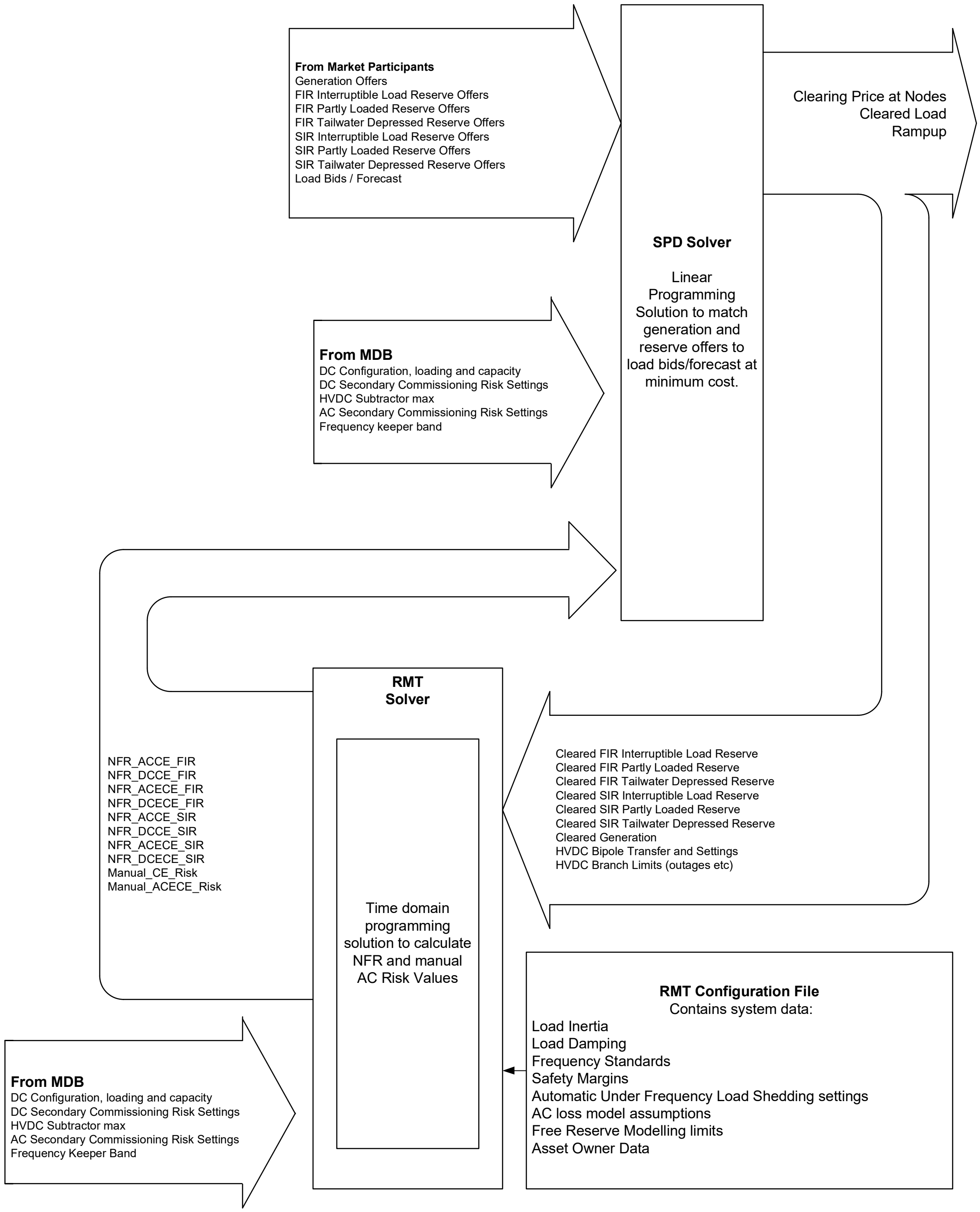

Figure 2. Role of RMT in the SPD Process. (See key on next page)

Key to Figure 2.

Term	Explanation
Generation Offer	Refer “Offer”, the Code, Part 1. Defined Terms.
Reserve Offer	Refer “Offer”, the Code, Part 1. Defined Terms.
FIR	Fast Instantaneous Reserve, refer Glossary.
SIR	Sustained Instantaneous Reserve, refer Glossary.
Interruptible Load Reserve	Refer Interruptible Load, the Code, Part1. Defined Terms.
Partly Loaded Reserve	Refer Partly Loaded Spinning Reserve, the Code, Part 1. Defined Terms.
Tailwater Depressed Reserve	Refer Tail Water Depressed Reserve, the Code, Part 1. Defined Terms.
Load Bids	Refer “Bid”, the Code, Part 1. Defined Terms.
Load Forecast	The estimated load forecast given for each trading period.
Manual_ACCE Risk	The Island manually entered min ACCE risk MW. If both the ACCE FIR and ACCE SIR primary risk plant are known risk units then this value is set to zero. A fixed risk that cannot be optimised by the SPD solver; it applies to ACCE events
Manual_ACECE_Risk	This is the island manual AC ECE risk MW. If both the AC ECE FIR and AC ECE SIR primary risk plant are known risk units then this value is set to zero. Otherwise it is set to the maximum of AC ECE FIR MW and AC ECE SIR MW that are not known risk units; the manually entered risk cannot be optimized by SPD solver; it applies to ACECE events
FIR_MW	The required FIR. Applies to ACCE, DCCE, ACECE, and DCECE
SIR_MW	The required SIR. Applies to ACCE, DCCE, ACECE, and DCECE
NFR	Net Free Reserve. The offset from the risk, applies to CE and ECE events. Can be negative indicating more reserves MW are required than the MW loss. Can exceed the Risk MW indicating sufficient reserves are available to cover a larger MW loss.
ACCE	AC Contingent Event, refer Glossary
ACECE	AC Extended Contingent Event, refer Glossary
DCCE	DC Contingent Event, refer Glossary.
DCECE	DC Extended Contingent Event, refer Glossary
Clearing Price at Nodes	Refer “clearing auction price”, the Code, Part 1. Defined Terms.
Cleared Load	Load that will be connected at a cleared price.
Cleared Reserve	Reserves that will be connected at a cleared price.
Cleared Generation	Generation that will be connected at a cleared price.
HVDC Bipole Transfer	The MW transfer of the HVDC link.
Commissioning Risk	Flag added to generator to indicate that it may be a secondary commissioning risk for ECE and CE risk events. If defined as a risk then it is tripped for the requested risk events.
Secondary DCCE_MW	DC secondary risk MW to be applied as an additional risk on ACCE and ACECE risk events for receiving island
Secondary DCECE_MW	DC secondary risk MW to be applied as an additional risk on ACECE risk events for receiving island
Frequency Keeper Band	MW band in which the frequency keeper could be generating, relative to its set point.

2.3.3 SPD Pricing Mode

The Pricing Mode of SPD is an ex-post solution used to determine nodal prices after the event. These prices may differ from ex-ante dispatch prices because the load bids do not exactly match the load off-take.

RMT is not actively used in the SPD Pricing Mode although the historical RMT inputs to the SPD solution are retained for the pricing solution.

2.3.4 Reserves Modelled

<u>Fast and Sustained Instantaneous Reserve</u>

The reserve offers are categorised as Fast Instantaneous Reserves (FIR) and Sustained Instantaneous Reserves (SIR). These terms are defined by the Code for the convenience of classifying the variety of reserve responses from different plant on the system.

For spinning reserve, FIR refers to the fast initial response to a frequency fall and is defined as the additional reserve capacity in MW provided at 6 seconds in relation to a standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds. This standard frequency excursion is described in section 7.

For spinning reserve, SIR refers to the relatively slow but sustainable response to a frequency fall and is defined as the average additional capacity in MW provided between 0 and 60 seconds in relation to the standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds and where the total output provided at 60 seconds is to be sustained until 15 minutes after the event.

For interruptible load, FIR refers to the fast initial response to a frequency fall and is defined as the drop in MW that occurs within one second of the grid system frequency falling to or below the trip frequency (49.2 Hz) and which is sustained for a period of at least 60 seconds.

For interruptible load, SIR refers to the sustainable response to a frequency fall and is defined as the average drop in MW that occurs between 0 and 60 seconds of the frequency of the grid system falling to or below the trip frequency (49.2 Hz) and which is sustained until advised by the system operator.

Note that a generator (or other reserve provider) that offers an amount of FIR will also generally offer the same amount or a greater amount of SIR as the fast initial response at 6 seconds will typically be sustained or increased over 60 seconds.

The FIR and SIR offers are also sub-categorised as Interruptible Load Reserve Offers (ILRO), Partly Loaded Reserve Offers (PLRO), and Tailwater Depressed Reserve Offers (TWRO).

- ILRO refers to load that is contracted to be tripped when the frequency falls below an agreed value – currently 49.2 Hz for most ILRO.
- PLRO refers to the reserve that is offered by partly loaded generators which are not running at their maximum output limits.
- TWRO refers to the reserve offered by hydro generators that are running as synchronous compensators with pressurised air excluding water from the turbine. In New Zealand this mode of operation is termed ‘Tailwater Depressed’ due to the depressed tailwater level caused by the pressurised air.

In all there are 6 different types of reserve offer that can be made, each type representing a significantly different type of response:

1. FIR ILRO

2. FIR PLRO
3. FIR TWRO
4. SIR ILRO
5. SIR PLRO
6. SIR TWRO

Battery Energy Storage Systems (BESS) can offer reserves into the market. These offers are entered either as ILRO (for response while in a charging state) and/or as TWRO (for response that involves MW injection). Both types of BESS reserve response are expected to be delivered in a similar way to conventional PLRO response. Further details are in section 3.2.7 below.

2.3.5 Risk Adjustment

In addition to offers and bids the SPD application also requires Net Free Reserve (NFR's) which are used to determine the amount of reserve that should be carried in order to cope with the under frequency effects of a CE (AC or DC) or ECE (AC or DC). The NFR's are provided by RMT.

The NFR's are calculated according to the risk in each island. This risk is the largest power loss that may result from an ACCE, DCCE or ACECE or DCECE. NFR's represent the reserve requirement offset from the risk.

Commissioning risks are not included in the size of the Risk MW but are included in the assessment of the NFRs.

There are potentially eight different types of NFR for each island:

- NFR for FIR ACCE.
- NFR for FIR DCCE.
- NFR for FIR ACECE.
- NFR for FIR DCECE
- NFR for SIR ACCE
- NFR for SIR DCCE.
- NFR for SIR ACECE.
- NFR for SIR DCECE

DC solutions are not always carried out for both islands, this depends on the scheduled DC power transfer.

SPD procures FIR as required for all risks and will not procure FIR to cover a risk at a generator which is part of that risk. As an example, if the current CE risk in the North Island is the Huntly 5 generator running at 350 MW and carrying 20 MW FIR then an NFR of 50 MW would indicate that FIR of:

(350-50) = 300 MW should be procured to cover that risk, at sites other than Huntly 5.

Note that NFR's can be larger than the Risk MW, indicating that the solution identifies reserves are available to cover a larger Risk MW.

Note that NFR's can be negative as well and that not all stations are cleared for reserve and/or frequency keeping.

2.3.6 NFR's provided to SPD by RMT

RMT calculates a set of NFR's that will ensure that the Code under frequency requirements are fulfilled.

Specifically, RMT calculates NFR's that will ensure that the frequency minimum is 48 Hz for a CE and 47/45 Hz for an ECE (North Island/South Island). There is an additional Code requirement that the frequency return to at least 49.25 Hz after 60 seconds. The specified ECE frequency envelope consists of up to 6 rectangular segments that the frequency must stay above. The North Island envelope is currently specified as follows - the frequency must not go below:

- 47.3 Hz for more than 20 seconds.
- 47.1 Hz for more than 5 seconds.

The South Island envelope is currently specified as - the frequency must not go below :

- 47.0 Hz for more than 30 seconds.

To calculate the NFR's, RMT uses the following data from the SPD solution[2]:

- Cleared Generation
- Cleared HVDC transfer
- Cleared FIR and SIR Interruptible Load Reserve
- Cleared FIR and SIR Partly Loaded Reserve
- Cleared FIR and SIR Tailwater Depressed Reserve

(Note that the SPD application creates this solution data partly based on the NFR's provided by RMT on the previous iteration.)

To calculate the NFR, RMT uses the following data calculated by MDB based on SPD solution data:

- DC configuration
- DC capacity
- DC subtractor max
- DC secondary commissioning risk setting
- Additional frequency keeper MW band, if the risk setter is also a frequency keeper

Ideally, after the NFR's are calculated by RMT, the SPD application should be re-run and the NFR's recalculated until the cleared generation, reserves, and load for a trading period are sufficient to meet the under frequency requirements. However, to avoid time-consuming SPD and RMT iterations, the NFR's calculated by RMT are used directly in the next SPD solution. This is justified by the experience that the NFR's generally change only slowly from trading period to trading period.

If a major tripping does occur then the current SPD solution will be invalid and the NFR's from RMT will also be invalid (although RMT will have already performed its function of determining the reserves necessary to cover the tripping). In this situation the Dispatcher uses discretionary action to recover the system by which time the SPD solution and RMT NFR's are generally valid again. During this recovery period, a scaling factor between 0% and 100% can be applied to the reserve requirement (using the risk adjustment factors (RAF)) to allow SPD to meet the energy demand while partially or totally ignoring reserves.[3] The system operates with reduced security until recovery is complete.

[2] *Note that the nodal prices and cleared load are not required to be used by RMT.*

[3] *The NFR's calculated by RMT are used by the SPD solver but SPD will procure proportionately less reserves if RAF scaling has been applied.*

3 RMT FUNCTIONAL SPECIFICATION

3.1 INTRODUCTION

The foregoing sections described the context within which RMT functions as a part of the whole application software. This section specifies the functional requirements of the RMT Solver and the other important functional components, as explicitly defined in Section 1.1 "Scope of RMT Certification". All references to RMT within this section specifically refer to this group of functional components.

The types of plant that are modelled by RMT are as set out in Table 1.

Table 1.

	Generic Model Type
1.	HVDC Bipole
2.	Partly Loaded Hydro (Hydro plant that may offer FIR when partly loaded)
3.	Tail Water Depressed Hydro[4] (Hydro plant that may offer FIR when operated in TWD mode)
4.	Steam Turbine[5]
5.	Geothermal[6]
6.	Gas Turbine
7.	Combined Cycle Mitsubishi
8.	Combined Cycle ABB
9.	Ungoverned Generator (includes Windfarms)
10.	Non-Specific Generator (includes Batteries)
11.	Sheddable Load
12.	Uncontrolled Load

3.2 TRANSLATION BETWEEN SPD DATA AND SIMULATION DATA

The SPD process and the RMT simulation process represent generation and reserves in quite different ways. A translation is required to transfer information between the two processes.

The SPD application handles generation in terms of MW and reserves in terms of FIR and SIR MW for interruptible load, partly loaded units, and tail water depressed units. Generation and reserves may be handled at either a station level or unit level. Large thermal plant is typically offered and cleared as individual units whilst smaller thermal plant and hydros are offered and cleared as a station block. RMT is capable of receiving offers in either form.

The RMT time domain solution is required to represent generators by their control system block diagrams (which for conventional generation are the speed governor controls and the turbine systems). The translation process converts the SPD generation and reserves associated with each station into

[4] *Includes stations that do not require TWD to be able to motor as their tailwater level is already below the turbine runner.*

[5] *Used for large steam turbine machines handled on a unit basis by SPD.*

[6] *Also used for smaller steam turbine machines handled on a station basis by SPD.*

the appropriate operating conditions for the simulation model. The different types of model have been listed in Table 1.

3.2.1 Translation for Loads (AUFLS schemes)

Error! Reference source not found. and Figure 4 show how the North and South Island loads are allocated to the different load models.

In the North Island the total load is taken to be the sum of the cleared generation and HVDC Bipole injection (referred to as the North Island Power Supply or NIPS) minus the fixed and variable transmission losses. The transmission losses are calculated from the SPD solution data and are not dynamically altered during the simulation.

The total load is then allocated between models for AUFLS, the scheduled Interruptible Load and Uncontrolled Load. Note that only the cleared Interruptible load will be tripped in a study, but the scheduled value is used to determine the size of the Uncontrolled Load.

The North Island model applies a 4 block AUFLS scheme. The Block 4 AUFLS load will also trip if the rate of change of frequency exceeds -1.2 Hz/s for 100ms and the frequency is below 48.5 Hz.

Certain connected parties (e.g. North Island distributors) provide a specified percentage of their load as AUFLS. The model allows a quantity of load to be exempt from this requirement. Such loads may still offer interruptible load but are otherwise unaffected by load shedding schemes. Exempt loads not offered as Interruptible Loads are added to the Uncontrolled Load.

Provision is made for the operator to specify that non-compliant generators (generators that trip on under frequency) must trip along with some embedded load. Three of the North Island AUFLS blocks (5 through 7) are required for tripping embedded load at non-compliant generators when the generator trips.

The Interruptible Load model is allocated the Interruptible Loads that have been cleared as FIR.

The South Island model is similar to the North Island, but no AUFLS blocks are currently required for tripping embedded load at non-compliant generators.

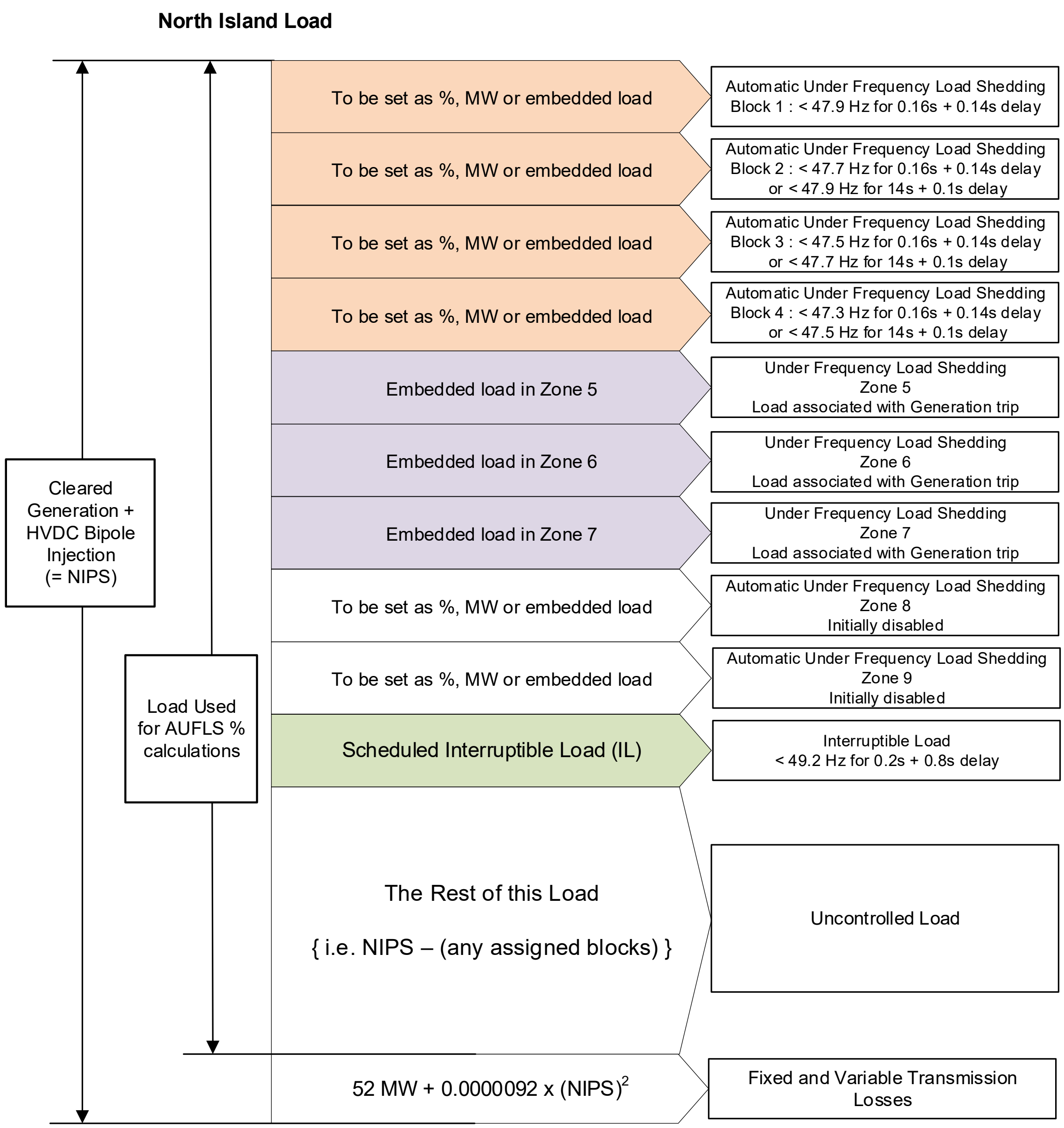

Figure 3. Allocation of Load to Models for the North Island 4 block scheme

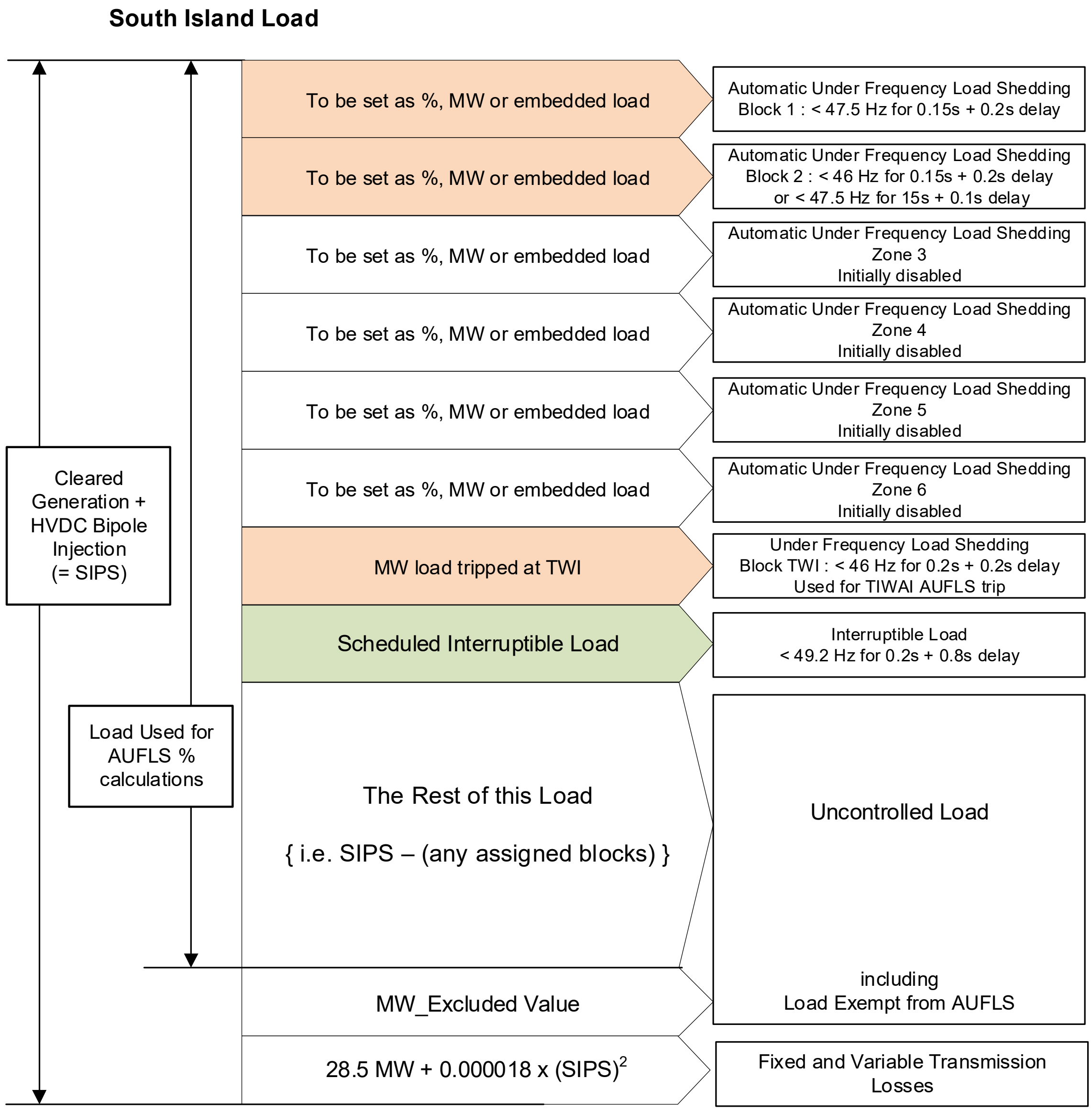

Figure 4. Allocation of Load to Models for the South Island.

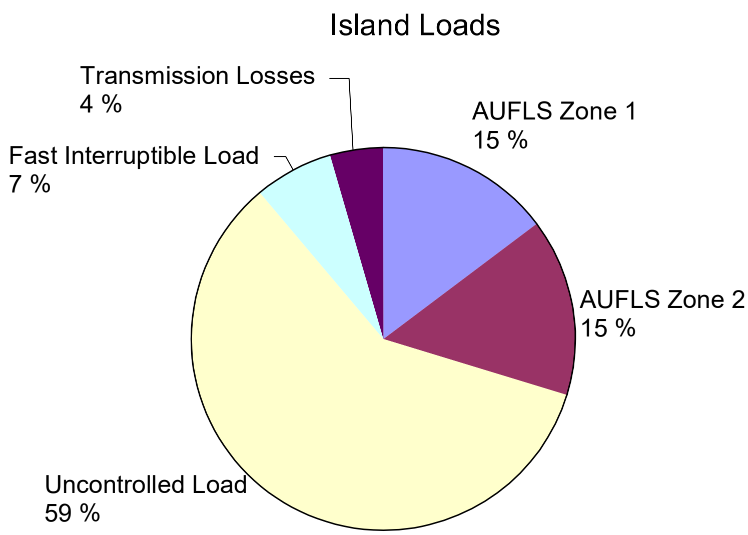

Figure 5. Example of Load Allocated to Model

As an example Figure 5 shows typical % quantities of load allocated to different load models for the following hypothetical scenario:

- Island Generation 2400 MW
- HVDC Injection 600 MW
- Fast Interruptible Load 200 MW

3.2.2 Translation for Hydro, Gas Turbine, and Geothermal Stations

For most Hydro, Gas Turbine, Geothermal, and small steam turbine stations the SPD process handles generation and reserves on a station basis rather than as individual units. Consequently the cleared generation and reserves information from the SPD solution is generally insufficient to determine exactly how many units will be on-line, or what their individual unit loading will be at these stations.

The RMT simulation model assumes that the station will run the minimum number of units necessary to provide the cleared generation and FIR, and that all on-line units will have identical loadings[7]. These assumptions allow the on-line units at a station to be represented by a single lumped model. (The exception to this is for stations which are cleared for tailwater depressed FIR. These stations are represented by two lumped models, one lumped model for the partly loaded units and another lumped model for the tailwater depressed units).

The RMT simulation model allows turbine gate or valve limits to be applied to limit the amount of FIR that the generators can deliver. Gas Turbine, Geothermal and generic generator models also allow the available FIR to be restricted to the cleared quantity. The partly-loaded hydro model provides a

[7] The assumption that the minimum number of units will be run is based on the principle that generators are usually most efficient at high loading. The assumption that all on-line units will have identical loadings will not be valid if units are physically different or if some units have been derated due to mechanical problems.

configuration setting (the free modelled fraction) that specifies the percentage of free FIR (if any is available) to be modelled.

RMT determines how much free FIR could be available based on a lookup table of the pu MW loading of the generator and the FIR that can be provided at that power output level (this lookup table is created from the generator test results).

A setting of 0% permits the model to only deliver the amount of FIR cleared by the SPD solution[8]. Conversely, a setting of 100% permits all the free FIR available from the online units to be delivered.[9]

3.2.3 Translation for Tailwater Depressed Hydro Plant

Some hydro stations are capable of offering both partly loaded reserve (PLSR) and tailwater depressed reserve (TWD). In these cases the partly loaded reserve is represented in the same manner as described in Section 3.2.2 which determines the number of units necessary to deliver the cleared generation and cleared partly loaded reserve.

It is assumed that the:

- the generation is run as offered. SPD clears PLSR and TWD offers but only dispatches the total reserve quantities not the PLSR/TWD split
- remaining units are available for tailwater depressed operation
- available FIR is the power output defined in section 2.3.4
- number of units running to provide tailwater depressed reserve will be the minimum number necessary to provide the cleared FIR
- turbine gate limits will be set to restrict the available FIR to the amount of cleared FIR.

3.2.4 Translation for Ungoverned Generation

Conventional synchronous or induction generators that do not employ a governor speed control (such as some co-generation plants), are represented in RMT by the Ungoverned Generator Model. Generators not modelled in SPD but which will have an impact on frequency are also represented in RMT by the Ungoverned Generator model, with the quantity of generation being assumed. The SPD process handles ungoverned generators on a station basis rather than as individual units. The RMT simulation model assumes that the station will run the minimum number of units necessary to provide the cleared generation, and represents the on-line units at each station by a single lumped model. The Ungoverned Generator model for a rotating machine generator contributes only inertia and turbine damping.

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[8] *The assumption that generator operators will apply turbine gate or valve limits to restrict available reserve to the cleared reserve is recognised to be very unlikely. The usual practice is to set these limits to slightly above the generator rating unless there are specific mechanical limitations. This assumption is made in RMT in an attempt to be consistent with an electricity market principle that only cleared generation, load, and reserves should be connected to the system. Uncleared reserve that remains connected is 'free' and not paid for.*

[9] *There is a risk associated with the modelling of free reserve. The Code allows generators to meet their total energy and reserve dispatch across the whole block (e.g. river chain), so the actual number of machines connected, and hence the free reserve capability, can vary from what was assumed in the model. Choosing a factor between 0% and 100% allows a more realistic assumption, providing a safety margin to help mitigate this risk.*

Inverter connected generation (e.g. Wind, Solar, Battery) are (or will be) represented in RMT as ungoverned generation. No inertia or turbine damping contribution is modelled from these.

No reserve is usually offered, cleared or modelled on ungoverned generation, but RMT has this capability if it is ever required.

Ungoverned generation such as (but not limited to) windfarms do not follow dispatch as smoothly as conventional generation due to their intermittent fuel supply. RMT has functionality to add a proportion of the plant rated MW to the scheduled energy MW when modelling the trip of such generation. For generation that is known to trip for certain events this allows RMT to model this loss of infeed at any level between the scheduled energy MW and the maximum output of the generation. The functionality is at a station level allowing different factors to be applied to different generator stations.

Analysis of generic wind variability suggests a 30 minute variability setting of 80% could be used with minimal risk, and a much smaller % could be used for a 5 minute variability, however the parameter will be initially set to 100% (i.e. no change from existing modelling) pending a more detailed assessment.

3.2.5 Translation for Steam Turbine Plant

The large steam turbine units are offered and cleared in SPD for generation and reserve on a unit basis. Consequently there is no requirement for RMT to estimate the number of units that are online at these stations. However, the FIR available from the steam turbines is dependent on their generated power and the boiler pressure.

RMT models the initial boiler pressure required to produce the cleared generation and FIR according to the simulation model.

If the steam turbine is a frequency keeper, it generates higher and lower than its dispatch setpoint to maintain frequency. If the turbine is the risk setter in addition to being a frequency keeper, an additional set of equations is required to add the frequency keeping band to the risk. The frequency keeping band is provided by MDB.

3.2.6 Translation for Combined Cycle Plant

The large combined cycle generators are also offered and cleared in SPD on a unit basis so there is no requirement to estimate the number of units that are online at these stations.

If these stations are not cleared to provide FIR then the speed governor control is disabled in the models. However, the rest of the model continues to model the effect of frequency on the combined cycle operation. If the stations are cleared to provide FIR then the speed governors are enabled, and simulated valve limits are imposed to restrict the available FIR to the cleared value.

If the combined cycle plant is a frequency keeper, it generates higher and lower than its dispatch setpoint to maintain frequency. If the plant is the risk setter in addition to being a frequency keeper, an additional set of equations is required to add the frequency keeping band to the risk. The frequency keeping band is provided by MDB.

3.2.7 Translation for Non Specific Generation

Following the EIPC code changes to enable energy storage systems to offer instantaneous reserve[10] which became effective 3rd May 2022, RMT now has a category of Non-Specific Generation reserve providers.

Non specific generation models allow for reserve provision from any source using a general purpose generator model. The non specific generation models do not require a traditional speed governor.

For a single source energy storage system in particular – such as a grid connected battery energy storage system (BESS) - the modelling will allow for reserves to be provided in the following operating modes, where the response in each mode can be different :

1. As a load reduction when the energy storage is re-charging from the grid
2. As an injection from the stored energy

Reserves provided as a load reduction, from a single source, can only be provided from an initial load state (i.e. Market Energy Offer = 0, and the storage system is drawing load).

Reserves provided as an injection, from a single source, can be provided from any initial state (i.e. by increasing an initial Energy output, by injection from a 0 MW (idle) state, or by injection from a load state subsequent to the reduction of that load to 0 MW)

For a single source, if reserves are cleared for both modes simultaneously, RMT will model the load reduction occurring first, followed by the injection response.

For an aggregated source, accurate identification of the initial state may be unavailable. Reserve response would therefore be modelled conservatively based on the information provided by the Market Participant.

3.2.8 Translation errors for FIR procurement

For a number of generating stations, there can be discrepancies between their energy and reserve offers that have cleared in the market system and the plant capability at the station. This happens most commonly (but not solely) at stations that are part of a hydro scheme which is block dispatched. The asset owner has the flexibility to meet the cleared energy and reserve offers from other stations within the block but RMT does not do this. RMT can therefore have more FIR scheduled at a station than it is capable of delivering given its scheduled energy output and its models based on its reserve test results. This additional FIR can not be delivered in the simulation. RMT determines the feasible FIR from the model of the station and this value is used (rather than the scheduled FIR) in the FIR required calculations.

3.2.9 Translation of Generator Commissioning Risk

AC plant set as a commissioning risk is added to either the ECE Event solutions or all the CE and ECE Event solutions. If the risk is for ECE only, the plant is considered not to be a trip risk for a CE event which can involve an excursion close to 48 Hz.

The commissioning risk type and MW output of the AC plants is passed on from the MDB.

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10 https://www.ea.govt.nz/documents/1216/EIPCA_Enabling_Energy_Storage_Systems_to_Offer_Instantaneous_Reserve_2022_-_Ce_Oq8AkFL.PDF

The model in RMT applies a trip frequency at which the plant trips with a default of 49.9 Hz in all cases. RMT includes functionality to allow, via parameter changes :

- the 49.9 Hz value to be altered
- the ECE-only risk to have a different trip frequency.

3.2.10 Translation for HVDC Bipole

The HVDC Bipole data that RMT receives from SPD includes the pole power transfers and losses.

RMT takes the expected HVDC plant configuration, frequency control mode, and the capability of each pole from MDB.

3.2.11 Translation of DC Secondary Commissioning Risk

MDB provides the following two factors for RMT to calculate secondary DC risk to be applied to ACCE and ACECE event solution of the receiving island.

HVDCAsACSecondaryRisk:	0 – No Secondary Risk 1 – Bipole as secondary risk 2 – Pole 2 as secondary risk 3 – Pole 3 as secondary risk
HVDCCommissioningLevel:	This is the MW level that the commissioning plant identified by the previous factor has been commissioned to be as a CE Risk

The DC secondary risk for the receiving island is added to the primary AC risk for the associated event solution. When calculating the NFR value for these event solutions this DC secondary risk is removed from the primary risk.

If there is either a DC secondary CE or ECE risk defined then the DC model will be turned off as the RMT wrapper will set the DC reserve sharing limits to zero. This does result in a conservative approach when DC plant is only defined as a secondary ECE risk.

3.3 Calculation of Required FIR

The RMT solution is a time domain simulation representing as closely as possible the physical response of the generation connected to the system.

The solution timeframe (t) is up to 60 seconds corresponding to the sustained duration required for FIR. The simulated response up to t = 60s is therefore fully representative of the FIR being delivered from the dispatched reserve-providing generation.

The required FIR is determined using these equations :

$$FIR\ feasible = FIR(Island) - FIR(undeliverable)$$

Where FIR(undeliverable) is as described in section 3.2.8. Required FIR is then calculated depending on whether the solution has island reserve sharing :

$$FIR\ required(1\ island) = Factor(RiskIsland) * FIRfeasible(RiskIsland)$$

$$\begin{aligned} FIR\ required&(2\ island) \\ &= Factor(RiskIsland) * FIRfeasible(RiskIsland) + EffectivenessFactor \\ &* FIR(OtherLimited) \end{aligned}$$

Where :

$$FIR_{OtherLimited} = \min(Reserve_{SharingLimit} - 0.01 * Load_{OtherIsl} + Comm_{RiskOtherIsl}, Factor * FIR_{OtherIslFeasibl}\ )$$

For the 2 island solution, RMT applies the DC sharing limit to the FIR that can be provided from the other island. If a commissioning risk exists on the Non-Risk island additional FIR can be modelled above the DC sharing limit, this is to ensure solution convergence.

As FIR from the other island is delivered with a delay compared to FIR from the Risk Island, an effectiveness factor is applied. For FIR the Effectiveness Factor used presently is 0.8 for both CE and ECE events for both islands.

3.3.1 Required FIR for CE

For CE events, the solution scales the scheduled FIR reserves to the minimum value required to meet the frequency recovery criteria. This scaling may be up or down from the initial scheduled values, and FIR from the other island is limited based on the HVDC sharing capability as described in section 0.

Each CE risk event then has a required FIR MW value. For CE events this is used directly for NFR FIR calculations.

3.3.2 Required FIR for ECE

With the default ‘series solve’ option in use, CE events are solved first and the largest relevant FIR requirement is used as a minimum FIR procurement for solution of ECE events. For DCECE events, only the DCCE FIR procurement is used as the minimum FIR procurement.

Normally, the ECE events are then secure with this FIR procurement (along with any AUFLS load shedding occurring within the simulation if there is a larger MW loss occurring with the ECE event). In these cases FIR required for ECE is less than FIR required for CE and is not specifically known.

If the ECE event requires additional FIR (i.e. it becomes the binding FIR event), the solution will scale FIR up from the binding CE solution. The required FIR for ECE is then known and is used directly for the NFR FIR calculations.

The series solve option can also be limited to use only for ACECE solutions, this allows for solutions ensuring that the actual FIR volume required for a DCECE event is reported in the solution. This option is intended for use when there are shortages expected in the provision of reserves, under these conditions FIR reserves for the DCECE event must still be procured so the volume required must be known even when it is lower than the FIR required for the DCCE event.

The FIR required is determined by the time domain solution and is likely to be lower if AUFLS blocks have tripped. For the required FIR for ECE, the AUFLS blocks are not included in the FIR required value. Required FIR for ECE therefore has a minimum of 0.

The AUFLS blocks may be included in the NFR FIR calculation step depending on the solution. The NFR FIR calculations are detailed in section 3.6.

3.4 Estimate of Required SIR

In general the SIR MW available from a reserve provider is not the same MW value as the FIR MW at each operating point. As RMT models the FIR response, the specific SIR response can not also be modelled on an individual generator or station basis.

RMT estimates the required SIR so that SIR NFR's can be fed back to the SPD application along with the FIR NFR's derived from the simulations. This SIR estimate covers the net power lost which is expected to ensure that the frequency will recover to 49.25 Hz within 60 seconds as required by the Code.

Each risk event has a required SIR MW value as detailed below.

Required SIR is calculated in this way :

$$SIR_{Required} = Event\ Risk + Conseq_{MW} + Conseq_{SIR} - AUFLS_{event}$$

Where: Conseq(uential)MW is the net sum of all generation and embedded load which trips in the simulation and Conseq(uential) SIR is the sum of any SIR scheduled on those generators.

AUFLS tripped on the non risk island is included but only up to the MW limit specified for the DC sharing to the risk island.

The required SIR MW is then used for NFR SIR calculations as detailed in section 3.6.

3.4.1 Required SIR for CE

A CE is expected to result in the frequency remaining above 48 Hz so cascade generator tripping should have only a minor impact (it only includes generators with a trip frequency higher than 48 Hz).

For CE events the AUFLS term is zero.

Consequently the SIR required to cover a CE is assumed to be equal to:

- the CE risk
- plus any cleared SIR carried on the risk unit
- plus any generation or SIR lost in the simulation due to cascade tripping.

3.4.2 Required SIR for ECE

An ECE may result in the frequency falling as far as 47 Hz in the North Island or 45 Hz in the South Island with consequent cascade generator tripping and under frequency load shedding from the AUFLS scheme.

For ECE events, the AUFLS term is the sum of all AUFLS blocks that trip in the simulation plus the MW of the first untripped AUFLS block on the risk island. The untripped AUFLS block to include in the NFR is determined from the AUFLS zone parameters (which are ordered by the highest frequency trip setting).

The SIR required to cover the ECE is assumed to be equal to:

- the ECE risk
- plus any cleared SIR carried on the risk unit
- plus any generation or SIR lost in the simulation due to cascade tripping
- minus any AUFLS load shed in the simulation
- minus an allowance for untripped AUFLS block/s on the risk island

For the required SIR for ECE, unlike the required FIR, the AUFLS blocks are included in the SIR required value, rather than the NFR calculation step. SIR required for ECE therefore can be negative.

3.5 MODELLING OF SIR FOR CE SOLUTIONS

RMT has functionality to model the additional SIR MW delivery in the CE solutions and this can be enabled or disabled via an RMT parameter.

It should be noted that this functionality is presently only used for event analysis and is not part of the Market System RMT solution passed back to SPD. Changes in how RMT models SIR would need to be reflected in appropriate and quite significant changes to SPD. Presently this is part of potential future work, but is not being progressed yet.

SIR is procured in the Market System based on the risk and consequential loss of infeed experienced by the system as detailed in section 3.4 above. For CE events there is no AUFLS load tripping, so all SIR is procured to cover CE events as an ancillary service, similar to FIR procurement.

As SIR is defined and procured as an average output over the initial 60 seconds which is then sustained for a longer period, SIR procured and delivered has an impact on the 60 second period simulated by RMT.

The modelling of SIR that will be procured for each CE risk event improves the match of the RMT result with the actual system behaviour.

The SIR model response is configurable within these requirements :

- The SIR generator is modelled on the Risk Island to avoid any interaction with any reserve sharing limits or other HVDC limits in the case
- The SIR generator is a model in the simulation and can be disabled or modified as required
- The SIR generator is not associated with any market generation, It does not add inertia or turbine damping (the reserve providers for SIR are assumed to be already modelled as generators in the simulation)
- The SIR generator has a start time specified for its power delivery. This is conservatively selected to avoid impacting unrealistically on the solution for the FIR required – by default this is done by starting the SIR MW injection at t =10s which is beyond the 6s requirement for FIR and from historical CE events is after the time the minimum frequency will have occurred
- SIR generation is a specified power injection - by default a simple ramp reaching its final value in 30 seconds (i.e. at t=40s)
- The SIR generator maximum output is calculated as the required SIR MW minus the present solutions FIR MW (including any free modelled fraction and as scaled during the solution). This is a conservative assumption that the SIR MW at t =60s is the average value and no larger.
- The required SIR MW includes generation and SIR modelled as a commissioning risk but, conservatively, does not include generation (or SIR) lost due to a frequency related tripping.
- SIR generation has a 1.5% droop setting with frequency, providing its full response for any frequency below 49.25Hz. SIR procurement is assessed with an injection signal that recovers to 49.25 Hz, the droop in the model ensures that the SIR generator provides no more than the expected performance of the SIR providers.
- The SIR generator has a minimum output of 0 MW (for unusual occasions when FIR required exceeds the SIR required).

The RMT simulation for CE events with the SIR model is expected to exhibit a frequency recovery but is not constrained to recover to 49.25 Hz as this would introduce a risk of over-constraining the solution.

A SIR generator is not applied to ECE solutions.

3.6 CALCULATION OF NFRS BY RMT

The NFRs calculation by RMT is aligned with how SPD sees the event risk MW.

SPD knows the primary risk plant output and will include any Frequency Keeping band or HVDC modulation band in the primary Risk MW assumption. SPD will then procure reserves based on these relationships :

$$FIR\ to\ be\ procured\ = Event\ Risk\ MW - NFR\ FIR\ (for\ the\ binding\ FIR\ event\ )$$

$$SIR\ to\ be\ procured\ = Event\ Risk\ MW - NFR\ SIR\ (for\ the\ binding\ SIR\ event)$$

SPD will not make any allowance for reserves providers being part of the primary risk or for generation that will be tripped because of the frequency excursion. RMT models these effects and in order to ensure SPD procures appropriate reserves these are subtracted from the relevant NFR value.

RMT provides NFRs for all risks and for both islands, SPD applies the necessary island constraints to ensure that sufficient reserves are then procured for each risk.

3.6.1 Event Risk MW

The event risk MW used by RMT depends on the case parameters as shown below :

- ACCE: _ACCE Risk_MW + Single_FIR_FKBand_MW*
- ACECE: ACECE Risk_MW + Multiple_FIR_FKBand_MW*
- DCCE receiving island: DC_CE_MW
- DCCE sending island: DC_CE_MW_Sent
- DCECE receiving island: DC_Received_MW
- DCECE sending island: DC_ECE_MW_Sent

*A non-zero value for the Frequency Keeping MW (the FK_Band_MW parameter) is an input provided if the risk plant also has MW assigned as a Frequency Keeping plant.

For AC risks if it is the DC receiving island and the Secondary_DC CE (or ECE as appropriate)_MW is nonzero, then (DC_Received – DC_Secondary_Risk_Subtractor) is added to the risk.

For AC risks, the risk can be made up of multiple generating stations. This is used to represent generation connected to the same circuit and also wider area risks where the loss of connection to the region is being treated as a risk. All generating stations identified as part of the risk will be tripped in the solution. The MW risk is determined by SPD and passed to RMT, it may be smaller, equal to, or larger than the sum of the risk generation energy dispatch,

DC risks on the sending island are included at nominal MW values when the DC power transfer is low. This ensures SPD has valid NFR results if the DC power direction changes between solves.

3.6.2 NFRs for FIR

For CE events the NFR for FIR is the difference between the event risk and the FIR required.

For ECE events :

(1) If the ECE solution is secure with the binding CE solve, the actual FIR required for ECE is not determined in the solution. In this case the NFR FIR is calculated as shown below :

Secure ECE Solution	NFR FIR
No AUFLS tripped in risk island	Max (Risk MW, next untripped AUFLS block in the risk island)
Some but not all AUFLS tripped in risk island	Max (Risk MW, {tripped AUFLS block(s) - consequential generator tripping + 50% of the next untripped AUFLS block in the risk island})
All AUFLS tripped in risk island	Max (Risk MW, {80% of the tripped AUFLS - consequential generator tripping})

(2) If the ECE solution is not secure with the binding CE solve, the FIR required for ECE will be higher than is required for CE. In this case the FIR required is calculated from the ECE solution (which will include the effect of tripped AUFLS blocks) and the NFR for FIR is the difference between the event risk and the FIR required (as for a binding CE event) - with no increase for untripped AUFLS blocks.

3.6.3 NFRs for SIR

The NFR for SIR is the difference between the event risk and the required SIR.

The SIR required is not limited at 0 which means the NFR SIR for ECE can exceed the Event Risk.

Within SPD there are SIR effectiveness factors related to the island location for SIR procurement but these are not passed to RMT. RMT presently makes no island-specific assessment in determining the SIR required.

3.7 Calculation of AOPO MW values by RMT

As described in section 2.2, RMT creates an AOPO output (which is a value in MW) for any generator that has a dispensation for the relevant clauses in the Code. Each dispensation is represented within RMT as one of five types - the first five entries shown in the table below :

Type	Unit behaviour	Output AOPO MW value (equals MW loss modelled in RMT)	For Events	Trigger
1	Unit reduces MW	Reduction in MW output	Any	Modelled
2	Unit trips	Dispatched MW	Any	Modelled
3	Unit reduces MW and/or trips	Reduction in MW output / or Dispatched MW, if it trips	Any	Modelled
4	Unit trips	Gross Machine Rating MW	ECE only	None
5	Unit trips	MW Maximum	ECE only	Frequency
6*	Unit trips	MW Maximum	ECE only	Frequency
7*	Unit trips	MW Maximum	DCECE only	Frequency

* 6, 7	are used to trip generation that does not have a dispensation – the functionality is the same but these types do not raise AOPO MW outputs

The triggers are defined as follows :

"Modelled" the dynamic model used by RMT for the generator includes the reduction in power output or trip behaviour. This can be speed related terms within a governor model or a protection relay model. An AOPO output is generated if any reduction occurs for the specified binding risk event.

"None" the AOPO output is generated if the binding risk event is of the specified type.

"Frequency" the AOPO output is generated if the binding risk event is of the specified type and the frequency falls below a specified value (in the input data file)

Types 4 and 5 are used to provide an AOPO output MW value for intermittent generation where the actual MW generation level for the trading period is variable. These types are also used where the actual generation output is unknown or is limited by the asset owner to a Maximum value (Max_Stn_MW) which is submitted with their market system offer. For intermittent generation the MW value tripped can be reduced if the variability factor (as described in section 3.2.4) allows a reduction.

Generators being modelled as tripping at Gross Machine Rating or MW Maximum are usually modelled in RMT as the tripping of a (negative) load component. This method is chosen because the schedules which generate the input data file in real time operation will include an estimate of the actual generation MW output of any dispatched generator, but the calculation of the reserves that need to be procured is done on the maximum potential risk MW.

Generators modelled as tripping from a specified or dispatched MW value (provided in the input data file) may have auxiliary loads (which do not trip when the machine trips) and also related embedded load (which does trip with the machine). They would record an AOPO MW output as :

- Dispatched MW + Auxiliary Load (if any) – Embedded_Load_Max (if any)

AOPO outputs are calculated for both FIR and SIR. The FIR value used is for the FIR binding risk. The SIR value used is for the SIR binding risk; a generator with a dispensation may have AOPO outputs for both.

If a unit with a governor is not cleared to provide FIR and reduces power output, the FIR AOPO MW output recorded is the maximum reduction in generation occurring during the simulation. This can occur at the end of the simulation (i.e. at t=60 seconds, the end of the fast reserve response period) but when SIR is modelled in the CE solutions (section 3.5) this is likely to occur earlier. This is calculated within the RMT software based on the model of the governor – which includes the power reduction as frequency reduces - and the actual frequency excursion seen in the simulation. This method uses the modelled reduction in the pre-event output which has been used in determining the required system FIR reserves.

If a generator reduces output this only results in a FIR AOPO output. It is assumed that as the reserve procurement will return the frequency to at least 49.25 Hz the generator's drop in output will recover to some extent and not be significant for SIR.

The best solution is the one which the FIR NFR results are produced from and is above the specified frequency criteria and within the solution tolerances.

For CE events, the FIR AOPO outputs are from the simulation iteration which is the best solution. For ECE events, the FIR AOPO outputs are from the simulation iteration which is closest to the best solution but does not meet the frequency criteria (i.e. the last non-compliant result). This is required because the ECE solution will normally – in order to meet the frequency criteria - procure sufficient reserves to avoid a large generator with a dispensation from tripping.

The SIR AOPO outputs are from the simulation iteration which is the best solution.

For generators that trip in the last non-compliant result but not in the best solution - because reserves are procured to prevent that trip - the FIR AOPO output will be the MW trip level, and the SIR AOPO output will be zero - this avoids a SIR charge being created when sufficient FIR was procured to prevent the generator actually tripping[11]. For generators that trip in the best solution, the FIR and SIR AOPO outputs will both be the MW trip level.

With the National Market for reserves enabled, if a generator is attributed an AOPO output for the same reserve category for both islands, for example NI CE FIR and SI CE FIR, the AOPO output used is the one which results in the larger cost[12].

As described in section 2.2 other generation which is not charged an AOPO cost may also be known to trip and modelled in RMT to avoid under-procurement of reserves. The way this generation is modelled is specific to the generation and the circumstances for which it is at risk of tripping. Usually these generators are not in the Market System and the trip is modelled as the MW maximum with a frequency level trigger using type 6. However, it is also possible for generation to be modelled at their expected or dispatched MW output levels, and as tripping for just some of the event types.

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[11] This method was adopted following a breach notification issued in April 2014: *https://eacorpsitelegacy.z8.web.core.windows.net/operations/market-operation-service-providers/system-operator/monthly-reports/2014/*

[12] This approach was adopted following consultation in 2016.

https://eacorpsitelegacy.z8.web.core.windows.net/development/work-programme/risk-management/national-instantaneous-reserves-market/development/decision-charges-for-generating-units-holding-dispensation/

4 OUTLINE OF VALIDATION OF SYSTEM MODELS

The time domain simulation model in RMT is both complex and critical to the management of reserves in the New Zealand power system. In order to ensure an acceptable accuracy a number of validation tests are required to be performed on the model.

The generator models are largely based on data provided by the generating companies as part of their compliance testing required under the Code. Data from regular required compliance tests is used to validate generator governor models.

Validation tests are summarised as follows:

4.1 SIMULATION OF INJECTED FREQUENCY TESTS

Generators are required to perform regular governor tests and submit the test data to the system operator along with associated governor models. The first step in the validation process requires the standard under-frequency curve to be injected at several levels of generator output with the test results recorded. The simulated model response is matched with the actual response from the test data. The simulated under-frequency injection test enables the asset owner to provide validation of the governor speed control loop.

To confirm the modelling of possible non-compliant power reductions with system frequency the injection test is usually insufficient as the power reduction is often a consequence of actual shaft speed reduction which is not changed in the injection test. To validate the provided models for the purposes of a dispensation, asset owners can provide data from specific drop-load tests (where another generator is deliberately tripped to disturb system frequency) or from system events that have occurred during normal operation.

4.2 SIMULATION OF HVDC BIPOLE TRIP AND SEVERAL GENERATOR TRIPS

After each generator model has been tested the remaining modelling uncertainty lies with the characteristics of the load – specifically the load frequency damping coefficient and the load inertia (H) constant.

Unlike the generators, which mostly have test data for each unit, there is no test data available for the system loads. However, RMT calibration is verified every time a significant under-frequency event happens on the system. Using actual generation and load data just prior to the event, RMT is run and results are compared with actual system data recorded during the event.

These comparisons include:

- Generator behaviour
- IL behaviour
- Rate of change of frequency
- Magnitude of drop in frequency
- Load behaviour.

5 Summary of Assumptions Inherent in RMT

The present version of RMT incorporates a number of assumptions that have been described at various points in this specification. These assumptions are also summarised in this section.

5.1 Network Model

The North Island and South Island networks are each represented by a 2 bus system with generation and the HVDC Bipole connected to one bus and load connected to the other bus.

The AC transmission loss in each island is represented by a resistive loss between the buses. This loss is calculated from the cleared generation and Bipole power and remains fixed throughout the simulation.

The AC networks within each island are not represented as it is assumed that the network topology is irrelevant to reserves management. This assumption is not valid under circumstances where the generation reserves cannot be supplied to the load without overloading transmission circuits. However, these circumstances occur rarely and have not been considered in the design of the present version of RMT.

5.2 Minimum Frequency Targets

RMT determines the FIR required to meet the Code requirements, Schedule 8.4, that the frequency minimum is 48 Hz for a CE and 47/45 Hz for an ECE (North Island/South Island). The additional Code requirement that the frequency return to at least 49.25 Hz after 60 seconds is not specifically handled by the present version of RMT but is expected to normally be met in any case.

RMT ensures that the North Island ECE frequency will not go below:

- 47.3 Hz for more than 20 seconds
- 47.1 Hz for more than 5 seconds

RMT ensures that the South Island ECE frequency will not go below:

- 47.0 Hz for more than 30 seconds.

5.3 Iterative Relationship between SPD and RMT

There is an iterative relationship between the SPD application and RMT. Ideally, after the NFR's are calculated by RMT, the SPD application should be re-run and the NFR's recalculated until the cleared generation, reserves, and load for a trading period are sufficient to meet the under frequency requirements. However to avoid time consuming SPD and RMT iterations the NFR's calculated by RMT are used directly in the next SPD solution. This is justified by the experience that the NFR's generally change only slowly from trading period to trading period.

If a major tripping does occur then the current SPD solution will be invalid and the NFR's from RMT will also be invalid (although RMT will have already performed its function of determining the reserves necessary to cover the tripping). In this situation the Dispatcher uses discretionary action to recover the system by which time the SPD solution and RMT NFR's are generally valid again. During this recovery period, the NFR's may be increased to allow SPD to meet the energy demand while partially or totally ignoring reserves. The system operates with reduced security until recovery is complete.

5.4 TRANSLATION FROM SPD TO RMT SIMULATION

The translation from the SPD process to the RMT process is required because the two processes represent generation and reserves in different ways. The SPD application handles generation in MW and reserves in terms of FIR and SIR. On the other hand RMT represents both generation and reserves by detailed simulation models.

The translation between SPD and RMT involves a number of assumptions, the most significant of which are summarised here.

RMT assumes a relationship between generation, FIR, and the number of units connected at a station. This relationship is based on the characteristics of the plant models used in RMT and the expectation that the generator operators will load units based on cleared generation, maximum efficiency, and maximum availability. However there is no explicit agreement with the generating companies that the RMT assumptions are correct (although the model data is derived from information provided by the generating companies).

For some types of generator, only cleared reserve is represented in the simulation. Gate or valve limits are imposed so that generators cannot provide more reserve than they have been cleared for. For partly loaded hydro generators, the percentage of free reserve to be modelled is configurable.

The assumption that generator operators will apply turbine gate or valve limits to restrict available reserve to the cleared reserve is recognised to be very unlikely. The usual operating practice is to set these limits to slightly above the generator rating unless there are specific mechanical problems. This assumption is made in RMT in an attempt to be consistent with an electricity market principle that only cleared generation, load, and reserves should be connected to the system. Uncleared reserve that remains connected is ‘free’ and not paid for.

5.5 HVDC BIPOLE MODEL

The HVDC Bipole model is presently capable of representing the effects of tripping either a single Pole or the Bipole. The model represents the various HVDC frequency keeping configuration modes such as ‘Frequency Stabiliser,’ ‘Spinning Reserve Sharing,’ and ‘Frequency Keeping Control.’ SPD calculates the DCCE risk using the HVDC risk subtractor and passes this value to RMT.

The HVDC modulation is limited by the minimum and maximum transfer limits.

The HVDC model enables reserve sharing modelled as part of the **National Market for Instantaneous Reserves** (NMIR). NMIR is designed to allow reserves to be procured in one island to cover generation risk in the other. As a result the quantity of reserves procured can be reduced.

NMIR RMT looks at the frequency in both Islands for AC risks, modelling a two-island HVDC response. Reserves are shared across the HVDC link. A portion of NFR (approximately 1% of the sending island’s load) is also shared. If sharing reserves across the HVDC link requires it to transition to the opposite power direction this can result in a short delay (3 seconds) in the response at 0 MW transfer. The bipole model includes modelling of this time delay.

5.6 Limits Applied in RMT Calculations

The RMT calculation applies various limits when carrying out its simulations and when formulating the results to be passed back to SPD. Some limits are variable and are provided from SPD within the input data file, these limits can affect the NFR values calculated by RMT.

5.6.1 DC Reserve Sharing Limit

In each dispatch solution, SPD determines on which island the reserves can be procured. To do this SPD applies forward and reverse FIR and SIR sharing limits to the solution depending on the initial HVDC MW value, the final HVDC MW and, for real time calculations, whether an HVDC pole is unavailable in either direction due to the cable discharge period. Details of how SPD determines the FIR and SIR sharing limits is detailed in the SPD specification.

The FIR sharing limits calculated by SPD are provided to RMT as the parameters :

"*Reserve Sharing Limit to NI*" and "*Reserve Sharing Limit to SI*"

RMT will use these values to limit the allowable change in the DC transfer. This restricts the ability to benefit from both NFR and FIR in the other island, and can significantly change the overall NFR result.

It should be noted that for any constrained condition SPD would procure reserves allowing for any DC sharing limit, however the relationship between the SPD and RMT solves described in section 5.3 means that the RMT constrained result for the NFRs would be used by SPD in the subsequent solve (where the constraint may not be needed).

And similarly the NFRs being used by SPD when such a sharing constraint initially arises may have come from a prior RMT run that did not apply a sharing constraint. This is an unavoidable consequence of the sequential solution approach.

5.6.2 Maximum reserve from the non-risk (other) island

When NMIR is enabled, for each risk on an island, RMT applies a limit to the FIR that can be provided from the other island (the 'Non-Risk' island).

This is achieved by limiting the FIR factor that can be applied to the Non-Risk island. The possible FIR shared from the Non-Risk island is therefore :

$$Factor(NonRiskIsland) * FIRfeasible(NonRiskIsland)$$

Where *Factor(NonRiskIsland)* is the same as *Factor(RiskIsland)* subject to :

$$Factor(NonRiskIsland) \leq \frac{Max((Reserve\ Sharing\ Limit\ to\ Risk\ Island\ -\ 0.01 * Load(NonRisk\ Island) + CommRisk(NonRiskIsl)),0)}{FIRfeasible(NonRisk\ Island)}$$

The combined effect being that the shared FIR cannot exceed the DC Reserve sharing limit to the Risk island (allowing a margin of 1% of the Non-Risk island load for NFR response to the Risk island), unless a commissioning risk exists on the Non-Risk Island.

5.7 Load Models

The loads are represented as lumped models for uncontrolled load, interruptible load, and AUFLS.

This lumped representation is necessary because little is known about the individual characteristics of each load.

5.8 Validation Tests

The generator models are largely based on data provided by the generating companies. This data includes manufacturer tests and governor test data. Tests are performed whenever generators make a change to governor settings or plant hardware which may affect under-frequency performance.

Routine performance tests are also compulsory for all generators above 30 MW. Drop load test results and frequency injection test results are used to check the response of each model.

The overall system response is verified and calibrated if necessary after each under-frequency event where the system frequency in either island falls below 49.2 Hz.

6 GLOSSARY

ACCE	**AC Contingent Event, caused by the loss of (usually) one generator unit**
AUFLS	**Automatic Under Frequency Load Shedding**
ACECE	**AC Extended Contingent Event, caused by the loss of (usually) an interconnected transformer or a bus bar.**
BESS	**Battery Energy Storage System.** Energy storage systems can provide reserves. The most common form of energy storage system being a battery.
CE	**Contingent Event**. This is an event for which, in the reasonable opinion of the system operator, resources are able to be economically provided to maintain the security of the grid system and power quality without the disconnecting of demand. (In practice this means that without resorting to AUFLS the system will tolerate the loss of either a single AC circuit (ACCE), or a single generating set (ACCE), or a single pole of the HVDC (DCCE).)
Code	**Electricity Industry Participation Code**
DCCE	**DC Contingent Event, loss of one HVDC Pole**
DCECE	**DC Extended Contingent Event, Loss of the HVDC bipole**
ECE	**Extended Contingent Event**. This is an event for which, in the reasonable opinion of the system operator, resources are able to be economically provided to maintain the security of the grid system and power quality **<u>with</u>** the disconnecting of demand. (In practice this means that by using Automatic Under Frequency Load Shedding the system will tolerate the relatively unlikely loss of the HVDC Bipole, an interconnecting transformer or a specific busbar).
FIR	**Fast Instantaneous Reserve**. As defined in Part 1 of the Electricity Industry Participation Code, and including but not limited to : **Spinning reserve**: The additional output in MW provided at 6 seconds in relation to a standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds. **Interruptible load**: The drop in MW that occurs within one second of the grid system frequency falling to or below the trip frequency (49.2 Hz) and which is sustained for a period of at least 60 seconds.
ILRO	**Interruptible Load Reserve Offer**
NFR	**Net Free Reserve.** Calculated by RMT to represent the net outcome of helpful and detrimental effects on the reserve required to cover a particular risk. Helpful effects include such things as uncleared or unoffered reserve capability from partly-loaded hydro machines (FIR only), AUFLS (ECE only), load damping associated with motors slowing down as frequency falls (FIR only), a limited allowance for HVDC reserve sharing (AC FIR only). Detrimental effects include cascade tripping of non-compliant generators (generators that do not remain connected to the grid or do not maintain output at frequencies down to the Code limits.) NFR's are calculated for AC and DC risks for two risk classes (CE and ECE) and two reserve products (FIR and SIR)

in each island. In SPD, the NFR is deducted from the risk MW associated with each event. The result of this calculation is the FIR or SIR that SPD must clear to cover the event.

NMIR **National Market for Instantaneous Reserve**

PLRO **Partly Loaded Reserve Offer**

Reserve Management Objective: Refer to the Code, Schedule 8.4.

RMT **Reserve Management Tool,** being the reserve management function which incorporates the whole software application including the **RMT Solver**, **RMT** user interfaces and system interfaces to **SPD**.

RMT Solver That part of the **RMT** application software that provides the model simulations and predicts reserve requirements.

RMTSAT A TSAT software application that allows complex control systems to be represented.

SIR **Sustained Instantaneous Reserve**
As defined in Part 1 of the Electricity Industry Participation Code, and including but not limited to :
Spinning reserve: The average additional output in MW provided between 0 and 60 seconds in relation to a standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds and where the total output provided at 60 seconds is to be sustained until 15 minutes after the event.
Interruptible load: The average drop in MW that occurs between 0 and 60 seconds of the frequency of the grid system falling to or below the trip frequency (49.2 Hz) and which is sustained until advised by the system operator.

SPD **Scheduling, Pricing, and Dispatch Software**

TWRO **Tailwater Depressed Reserve Offer**

7 STANDARD FREQUENCY EXCURSION CURVE

The standard frequency excursion curve represents the typical worst case under frequency that may occur in response to a contingent event. The curve has been chosen as the critically damped second order response that reaches a minimum of 48 Hz at 6 seconds and recovers to 49.25 Hz at 60 seconds:

Freq (t) = 49.25 + (0.75 – 0.8055t)e-0.1973t Hz

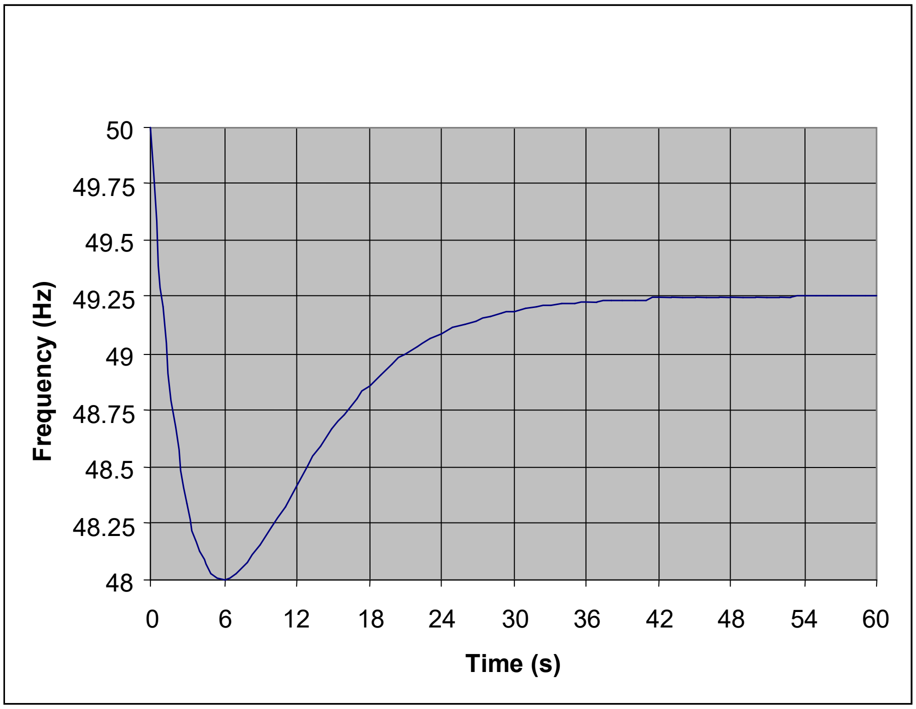

Figure 6 - Standard Frequency Excursion Curve