NTESMO

Scheduling and Dispatch Guidelines

May 2026

Version 1

Contents

1.Scope and Purpose

The System Control Technical Code prescribes the issuing of various procedures and guidelines by the Power System Controller[1]. Should any conflict arise between this document and the System Control Technical Code, the System Control Technical Code shall prevail.

The Interim Northern Territory Electricity Market (**I-NTEM**) commenced operation in 2015 following amendments to the System Control Technical Code. The set of original procedures constituted six individual procedures with varying degrees of overlapping concepts and operating requirements. The I-NTEM functions as a virtual wholesale market for the Darwin-Katherine Power System, providing a framework to facilitate the wholesale exchange of electricity between Generators and Retailers. Under current arrangements, generating units are committed/decommitted according to the relative participant price submissions as per the market rules described in this procedure, but the commercial settlements of the energy generated are determined by bilateral contractual agreements between Generators and Retailers. This review of the set of individual Scheduling and Dispatch guidelines has been undertaken to enhance the ease and effectiveness of operational application by the Power System Controller and clarity for Market Participants. In addition, the revised dispatch procedure facilitates optimised solar farm dispatch within defined network and system constraints, ensuring secure and stable power system operation.

The Scheduling and Dispatch Guidelines sets out the principles and associated methods determining:

a. The pre-dispatch schedule based upon the array of inputs required to determine the pre-dispatch merit order;

b. The real-time unit commitment and dispatch determined by the necessary inputs on a near-real-time basis including the discretion of the Power System Controller; and

c. The determination of virtual market pricing utilised to inform licensed system participants

For further clarification, understanding or resolution of issues relating to this document, please refer all matters to the Market Operator.

Where commercial-in-confidence information is necessary to ensure the Scheduling and Dispatch Guideline are sufficiently clear or practically applicable, the relevant information will be specified in confidential Participant-specific documents held by NTESMO.

It is anticipated that the Scheduling and Dispatch Guideline will evolve because of the introduction of reforms that are part of the Territory Electricity Market Reform Program and will require further revisions. However, the set of current guidelines have not been updated since 2020 and there has been significant change in the characteristics and entry of new supply technologies and the underlying operating environment of the wider power system to ensure alignment with current operational practices. The creation of amended, and to a degree, consolidated procedures provide a sound basis for the accommodation of future reforms. Consequently, the reasons that the Scheduling and Dispatch Guideline is being revised now are:

a. Consolidate into a single guideline to reduce duplication, address overlapping themes, and improve efficiency through a more streamlined and consistent structure.

b. Enhance operational consistency for controllers and market participants.

[1] System Control Technical Code, Version 7.0, February 2024, Section 3.5.1, page 22 of 94

c. Ensure effective accountability of the Power System Controller in adherence to the appropriate standard of procedure and ensure repeatability of operational performance.
d. Provide a basis to accommodate future change required because of the TEM Reform Program to identify a clear representation of the necessary amendments.
e. Replace obsolete procedures with Proportional Energy Dispatch (PED) to ensure more equitable, transparent, and efficient renewable energy maximisation. This will provide updates on real-time system operations to maximise renewable energy dispatch through the PED tool.
f. Improve the efficiency of system dispatch through automated management of transmission line constraints and optimisation of renewable generation, while maintaining system security.

2. Definitions

Terms defined in the System Control Technical Code[2] and Network Technical Code[3] have the same meaning in this guideline unless specified in this section. Terms defined in the System Control Technical Code and Network Technical Code are intended to be identified in this Procedure by italicising them, but failure to italicise a defined term does not affect its meaning. In addition, the words, phrases and abbreviations in the table below have the meanings set out opposite them when used in this guideline. Where a conflict arises in definition or meaning, the System Control Technical Code definition and meaning prevails.

TERM	DEFINITION
Automatic Generation Control (AGC)	A generating unit which responds to the regulating signals from the Power System Controller SCADA computing system.
Band 1	Band 1 for each *generating unit* comprises a quantity and a price. The Band 1 quantity is to reflect the *minimum stable load* recorded in the Generator Registration standing data of the *generating unit* or such increased amount where the increase has been notified to the Power System Controller via a formal Generator Outage / Test Request submission. The Band 1 price is to be zero for a self-committed *generating unit* and is to be not less than zero for a fast start *generating unit*.
Band 2	Band 2 for each *generating unit* comprises a quantity and a price. Band 2 can only be scheduled if *Band 1* is fully scheduled. The Band 2 incremental quantity (beyond the Band 1 quantity) is to reflect the nominal dispatchable range of the *generating unit*. Any output that can only be dispatched because of an additional manual action is not part of Band 2. For a synchronous *generating unit,* the quantity provided from *Band 1* and Band 2 combined must be equal to or greater than the Base Maximum Capacity recorded in the Generator Registration standing data of the *generating unit*, or such reduced amount where the reduction has been notified to the Power System Controller via a formal Outage and Testing Request submission. The Band 2 price is not to be less than the *Band 1* price, except for fast start *generating units* in which case the Band 2 price is to equal the Band 1 price.
Band 3	Band 3 for each *generating unit* comprises a quantity and a price. Band 3 can only be scheduled if *Band 2* is fully scheduled. The Band 3 quantity is only to be used to reflect the incremental increase in the *generating unit's* dispatchable range because of an additional manual action such as activation of wet mode or sprint capacity. The Band 3 price is not to be less than the *Band 2* price.

2 System Control Technical Code, Version 7.0, February 2024

3 Network Technical Code and Network Planning Criteria, Version 4, 30 March 2020

TERM	DEFINITION
Base Maximum Capacity	The lowest maximum capacity of a *generating unit* when environmental operating conditions are most unfavourable. Any output above the capacity recorded through Generation Registration standing data is regarded as a real time extension of the *Band 3* offer. Refer to Secure System Guidelines Section 4 Determining Base Capacity.
Closed Cycle Mode	A mode of operation of a *generating unit* where either it must be running to allow another *generating unit* to operate, or another *generating unit* must be operating for it to operate.
Decommitment Order	The order in which a *Generator* nominates to have its fast start *generating units* come off-line after 18:00 on a given trading day. If there are any other on-line *generating units* belonging to the same *Generator* identified in the decommitment order, then the *generating unit* with the lowest decommitment order that is not required to remain on for security reasons is to be decommitted. The order is applied until all the *generating units* identified have been decommitted (or prevented from being taken off-line by security requirements), with any *generating units* with no number specified being decommitted based on normal bid prices. Notes: This feature effectively moves these *generating units* to the top (what would normally be the highest price end) of the merit order for units to come off. Where a generating unit would, if not for the application of the decommitment order, be decommitted, that unit will not be able to set price. Normal scheduling and tie-break logic operates without regard for this order and will identify the next *generating unit* that would normally be taken off-line.
Default Offer	The Default *Generator* Offer that is approved from time to time by the Market Operator as part of the *Generator's* registration standing data. Note that the *Generator* may revise the Default Offer at any time by submitting a revised Default Offer to the Market Operator for approval. The Market Operator, in conjunction with the Power System Controller, will advise of the approval (or otherwise) of the Default Offer. The Default Offer commences from the day immediately following the date of approval by the Market Operator.
Dispatch and Pricing Tool (DPT)	The Dispatch and Pricing Tool, a software program that converts (for each trading day) *commitment and dispatch submissions* into a *pre-dispatch schedule* and *dispatch instructions* for *NTESMO*, calculates the *Market Price*, and sends relevant outputs to nominated stakeholders.
Dispatch process	A process that includes forming a pre-dispatch schedule or determining the real-time dispatch.

TERM	DEFINITION
Energy tie	An *energy tie* exists where one of two or more *generating units* are to adjust their output based on their Band 2 prices, but each of these *generating units* have the same Band 2 price. An *energy tie* is to be resolved using the *proportional energy dispatch process*, where this can be achieved without violating other constraints.
Essential System Services (ESS)	Refers to the following services provided by Generators or other System Participants: voltage control, reactive power control, frequency control, and black start capability.
Fast-start-commitment tie	A fast-start-commitment tie exists where either: • one of two or more fast start *generating units* from more than one *Generator* is to be started based on Band 2 (long run) prices and the *generating units* all have the same Band 2 (long run) price. or • one of two or more fast start *generating units* from more than one *Generator* is either to be started or to have Band 3 scheduled, based on any combination of Band 2 (short run) prices (for those units to be started) and/or Band 3 prices (in the case of scheduling Band 3) which all have the same value. A fast-start commitment tie is to be resolved using the *random day selection process*, where this can be achieved without violating other constraints. NOTE – The units are to come off in reverse of the order that they are started.
Gate closure	1230 hours on the last business day before the nominated trading day.
Generator	A Market Participant who engages in the activity of owning, controlling or operating a generating system that is connected to a Network and, in respect of a generating system connected to the Darwin-Katherine power system, is either registered by the Market Operator as a Generator or, intends to register with the Market Operator as a Generator.
Generator Offer	The information recorded on the Generator Offer template by a *Generator* for any one day of its proposed operation in the *I-NTEM*. For anyone trading day, prior to *gate closure*, the *Generator* may progressively submit one or more versions of the Generator Offer to correct a previous version. The last version prior to *gate closure* is the active Generator Offer.
Generating Unit tie break	Generating unit tie break is the term given to the methodologies used to resolve *self-commitment ties, fast-start commitment ties,* and *energy ties*.
The Interim Northern Territory Electricity Market (I-NTEM)	The Interim Northern Territory Electricity Market, as applied to the Darwin Katherine Power System.

TERM	DEFINITION
load forecast	A forecast of the total system demand for a period of at least 96 hours commencing from the half hour ending 1630 hours on the day that it is scheduled to be published.
market timetable	The timetable that governs the operation of the *I-NTEM*, the timing of commitment *and dispatch submissions*, and the provision of *market information*.
Minimum Stable Load	The lowest MW output at which a *generating unit* freely operates before it is taken off-line. This is to be based on installed technology / plant performance characteristics and is not to be adjusted to optimise a *generator unit's* dispatch in the market offer process.
Network Operator	A person defined as a "network provider" under section 4(1) of the Electricity Reform Act as in force on 1 June 2019.
Network technical Code (NTC)	The Code specified in the Electricity Reform Act and prepared by Power and Water in accordance with the Electricity Reform (Administration) Regulations.
the Northern Territory Electricity System and Market Operator (NTESMO)	The entity licensed to perform the functions of system control and market operations in accordance with the *Electricity Reform Act* and the *Electricity Reform (Administration) Regulations.*
Off-load order	The term specified in the relevant column of the commitment and dispatch template shown in Attachment 4 of the System Control Technical Code, as superseded by the Generator Offer procedure.
Open Cycle Mode	A mode of operation of a *generating unit* where it operates independently of other *generating units*.
Generator Outage/Test Request	*Electronic form required to be completed by Generators to request approval from the System Controller to schedule an outage on generator plant or equipment.*
Power System Controller	The entity licenced by the Utilities Commission pursuant to section 30 of the Electricity Reform Act.
Power and Water Corporation (PWC)	The body corporate established under the Government Owned Corporations Act.
Proportional Energy Dispatch (PED)	Proportional Energy Dispatch adjusts the output of tied generating units in proportion to their forecast available capacity so that, where system constraints permit, their combined response meets the required change in demand without compromising system security.
Random day	The trading day assigned to a specific *Generator* for assigning a marginal price priority order, as nominated in the *random day selection process.*

TERM	DEFINITION
Random day selection process	The process where each *Generator* is assigned a series of trading days in a period and on any one of those trading days, that *Generator's generating units* whose offer price is greater than zero and marginal will be dispatched by the *Power System Controller* before any other *Generator's generating unit* with an equal marginal price is dispatched.
Random period	The period allocated to a specific *Generator* for assigning the off-load priority order, as nominated in the *random period selection process*.
Random period selection process	This process is where each Generator is assigned a period (consisting of multiple consecutive trading days) where the Generator's generating units, with an off-load order, may be instructed to be taken off-line by the Power System Controller before any other Generator's generating unit, with an identical off-load order.
Security Constrained Economic Dispatch (SCED)	Economic low-cost dispatch which achieves a secure operating state.
Security Constrained Unit Commitment (SCUC)	Unit commitment optimisation which achieves a secure operating state.
System Control Technical Code	The Code specified in the Electricity Reform Act and prepared by Power and Water in accordance with the Electricity Reform (Administration) Regulations.
Self-commitment tie	A self-commitment tie exists where either: • one of the self-committed *generating units* from more than one *Generator* must be taken off-line because of the total of all Band 1 quantities exceeding system load, but these *generating units* have the same *off-load order*. or • one of the self-committed *generating units* within a congested area of the network from more than one *Generator* must be decommitted as a result of the total of all Band 1 quantities of *generating units* within that area breaching the network or system constraints that give rise to the congestion in that area, but these *generating units* have the same *off-load order*. A self-commitment tie is to be resolved using the *random period selection process*, where this can be achieved without violating other constraints.

3. Introduction

3.1. Background

3.1.1. Development of the Scheduling and Dispatch Guideline

The Scheduling and Dispatch Guideline has been developed through the consolidation of related procedures into a single document that brings together several existing procedures in a practical and easy-to-follow manner as presented in Table 1. The review of consolidation has resulted in the following procedures to remain stand-alone:

a. Generator Forecast Compliance Procedure – given effect under the Network Technical Code and subject to a separate review and redevelopment of the code, and
b. The System Control Plant Outage Procedure – represents the methodology for plant outage management that, whilst directly impacting scheduling of supply side resources, covers the entire range of outages for assets that extends well beyond scheduling and dispatch.

The basis for consolidation is combining a number of existing procedures into a single, unified guideline. This consolidation reduces duplication, supports consistent interpretation, and provides a centralised reference for Market Participants.

Table 1: Scheduling and Dispatch suite of procedures

Procedure	Version	Date Effective	Review Period	Scheduling and Dispatch Guideline consolidated or Standalone
1. Market Timetable Procedure	1.0	July 2016	Subject to System Control Technical Code changes	Consolidated
2. Generator Forecast Compliance Procedure	1.1	July 2020	Subject to Network Technical Code and System Control Technical Code changes	Stand-alone
3. Generator Offer Procedure	2.0	September 2020	Subject to System Control Technical Code changes	Consolidated
4. Generator Unit Tie Break Procedure	2.0	September 2020	Subject to System Control Technical Code changes	Consolidated
5. System Control Plant Outage Procedure	1.0	October 2020	Subject to System Control Technical Code changes	Stand-alone
6. Dispatch and Pricing Procedure	Draft	Not yet released	To be determined	Consolidated

3.1.2. Review period for the Scheduling and Dispatch Guideline

Whilst the Scheduling and Dispatch Guideline will likely require continuous review as the application of scheduling and dispatch principles evolve over time; the guideline is intended to be comprehensively reviewed as a minimum on a 5-yearly basis.

3.2. Scheduling and dispatch process

3.2.1. Overview

The Power System Controller is obligated by Section 4.7(c) of the System Control Technical Code to conduct generating unit commitment and dispatch processes in the I-NTEM The Power System Controller must assess the need for increasing the output of self-committed generating units, or committing and dispatching fast start generating units, to meet total demand based on the primary principle of Security Constrained Economic Dispatch (**SCED**). This principle requires that generating units are dispatched to meet total system demand in a way that considers the Dispatch Principles and Dispatch Criteria outlined in clauses 4.3 (a) and 4.3(c) of the System Control Technical Code. The objective of these principles and criteria is to deliver secure and reliable operation of the power system.

Generator offers are then used to establish the merit order and to support the selection of the lowest cost combination of available generating units, provided that all applicable principles, security requirements, and operational criteria have already been satisfied.

The Dispatch Principles give priority, within the overarching principle of Security Constrained Economic Dispatch, to several system reliability and system security considerations. Implicit to these principles is the concept that, during normal operation, if practicable, scheduling ancillary services from generating units should result in an equivalent or increased dispatch level where practical.

The Dispatch Criteria include power system security, frequency control and dispatch of ancillary services, energy market dispatch, unplanned generation and network outages, overall efficiency of energy production, minimum/maximum load limits of individual generating units, ramp rate of individual generating units, and voltage support.

At all times, the Power System Controller is required to prioritise its obligations for the management of system security while managing the commitment, de-commitment, and dispatch of generating units.

The activities consolidated within this guideline are required for the operation of the Interim Northern Territory Electricity Market (I-NTEM)

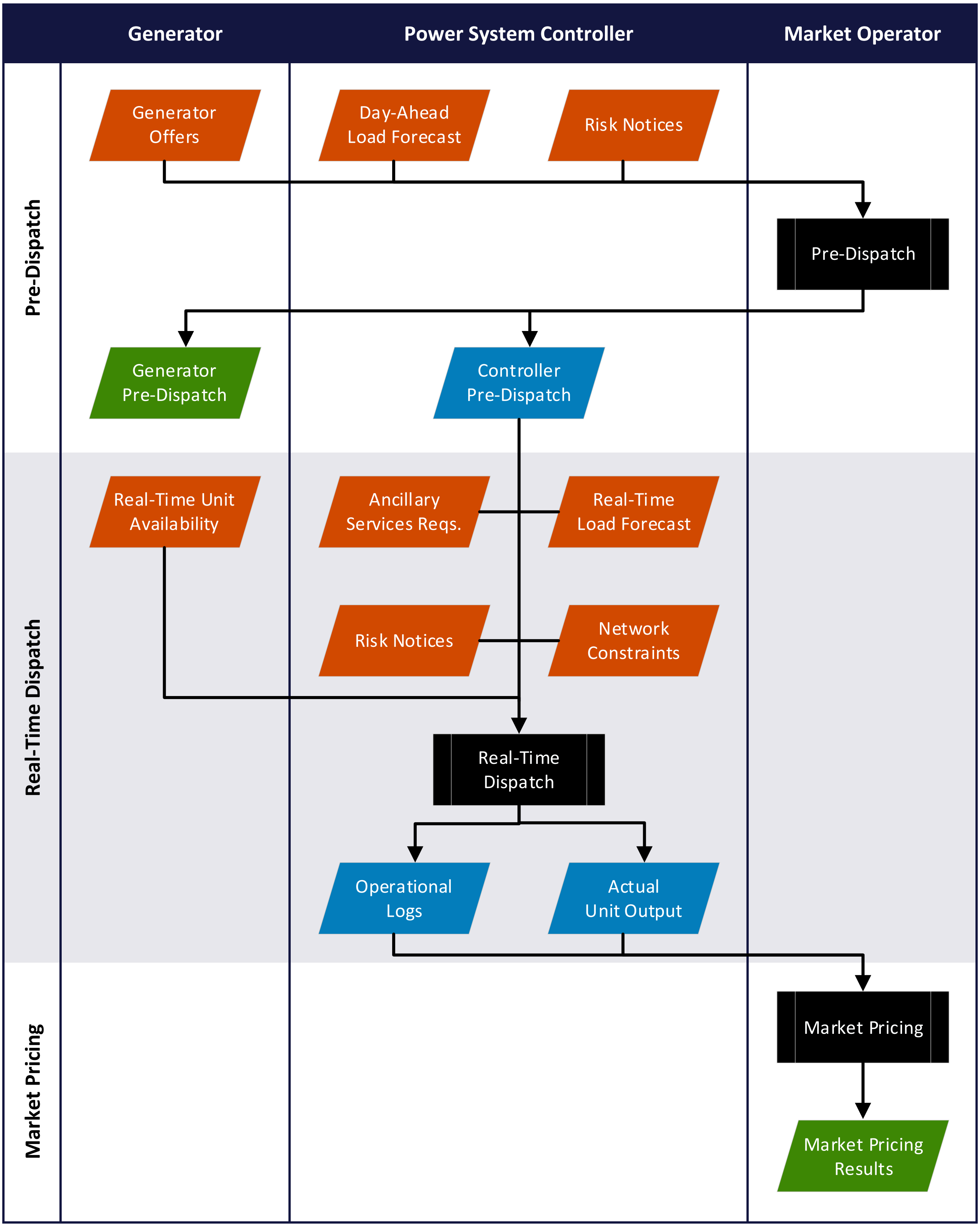
3.2.2. Scheduling and dispatch process explained

The process of scheduling and dispatch has been segregated into three distinct stages, namely:

- Pre-dispatch,
- Real-time dispatch, and
- Market Pricing

The stages are interdependent upon one another and culminate in the market settlement process that occurs after the scheduling and dispatch process monthly. The segregation of scheduling and dispatch activities underpin regulatory obligations of power system licenses participants.

Figure 1: Scheduling and Dispatch process



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3.3. Wholesale market timetable

The *I-NTEM market timetable* for the *Dispatch and Pricing* process is presented in Table 2.

The periods are described as follows:

Day -1 means on the *day* before a *trading day* commences; and
Day +1 means on the *day* after a *trading day* commences

Table 2: I-NTEM Market Timetable

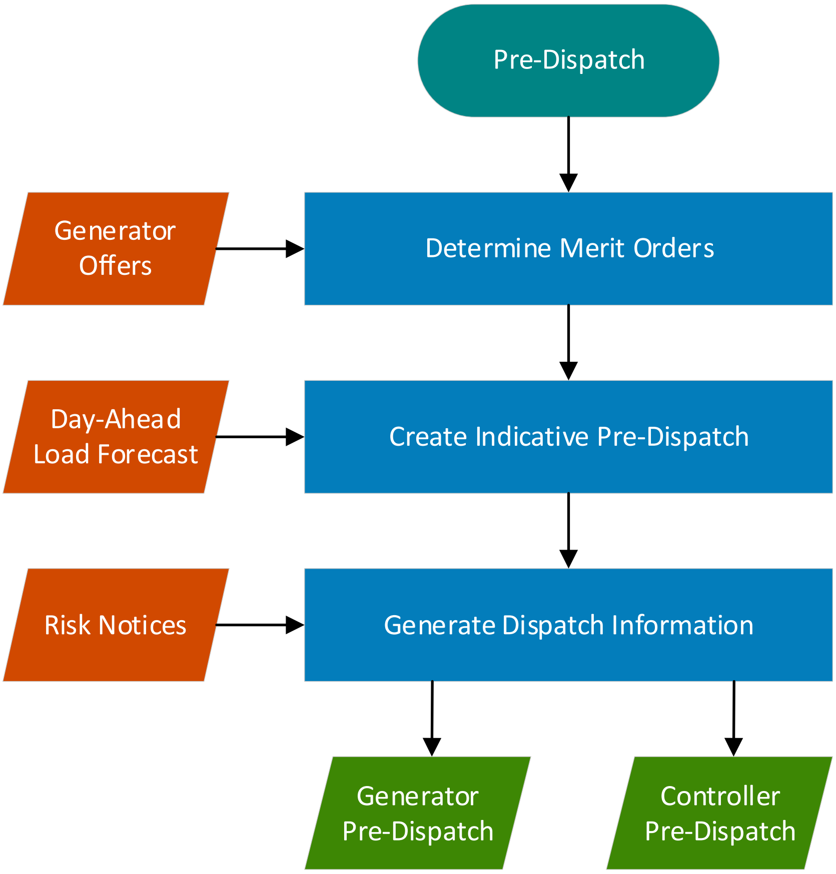
Period	Action
Day -1	*NTESMO* must prepare and publish the *Load Forecast* to be used in the commitment and dispatch process for the future 96 hours (or longer if necessary) no later than 0900 hours on the *day* prior to commencement of the *trading day*.
By Day -1	*Generators* must make *commitment and dispatch submissions (Generator Offer)* for a *trading day* no later than 1230 hours on the *day* prior to commencement of the *trading day*.
Day -1	*NTESMO* must consider Risk Notices issued before 1230 on the day prior to commencement of the trading for the purpose of pre-dispatch processing
Day -1	NTESMO must provide each Generator with the relevant pre-dispatch information for its generating units by no later than 1700 hours on the *day* prior to commencement of the *trading day*.
Day +1	NTESMO must *publish* the *market information* by 1700 hours on the *day* after commencement of the *trading day*. If this time can't be achieved in any one day, NTESMO must publish a notice advising of the delay in accordance with clause 4.8(f) of the System Control Technical Code.

4. Pre-dispatch

4.1. Overview

Pre-dispatch encapsulates the initiation of the scheduling and dispatch process whereby the pre-dispatch schedules are derived from day ahead and pre-emptive inputs related to the current state of the power system taking account of known aspects affecting the power system. The pre-dispatch schedules represent credible scenarios derived the day ahead of real time Security Constrained Unit Commitment (**SCUC**) and associated Security Constrained Economic Dispatch (**SCED**). The pre-dispatch process is illustrated in Figure 2.

Figure 2: I-NTEM Pre-Dispatch process



4.2. Standing Data

- The email address to be used to send the Offers will be nominated at the time of Registration.
    - The email address from which an Offer was sent will be used to relate the Generator to the Offer.
    - The Market Operator will assign a Generator ID at the time of Registration.
- Standing Data is to be provided to the Market Operator at the time of Registration.
    - If a generating unit is temporarily unable to meet its Standing Data specifications (e.g. the combined Band 1 and Band 2 capacities do not meet the base maximum capacity), then its updated specifications are to be provided in an Outage / Test Request.

- A special one-off Default Generator Offer (the Default Offer) is to be provided to the Market Operator at the time of Registration.
    - The Default Offer will be used if a valid Offer is not received in the designated System Control email inbox by gate closure (1230 hours on a business day). In this situation, the Default Offer to be used for a trading day will be the Default Offer held by System Control at the time of gate closure for that *trading day*. However, if the default offer has not been updated in the last six months, the generator offer from the previous *trading day* will be used as a valid offer for the next *trading day*.
    - The Default Offer can be updated at any time after the initial Default Offer is registered by sending a new Default Offer to the Market Operator.

4.3. Inputs

4.3.1. Bids and offers – Generator Offer Procedure

The following principles and key processes apply to the preparation and submission of *Generator Offers* before gate *closure*:

- A Generator Offer is to be prepared using the template shown in Section 4.3.1.1 The template presented in Figure 3 replaces the template shown in Attachment 4 of the System Control Technical Code, as described in clause 4.4B(f) of that Code.[4]
- A Generator must submit an Offer to the System Controller before gate closure.
- In the first instance, the Generator Offer is to be submitted to the Power System Controller's nominated email address no later than gate closure, as detailed in 4.3.1.2
- If the Generator Offer is not received in the Power System Controller's mailbox by gate closure, then the Default Offer will be used in the commitment and dispatch process.
- To be valid, a Generator Offer or Default Offer must comply with the instructions provided on the Read Me tab of Generator Offer Template consistent with this procedure
- If any submitted Generator Offer or Default Offer fails to conform to the requirements of this procedure, the Generator Offer or Default Offer will be rejected by the Power System Controller.

Where a *Generator Offer* is rejected under this situation, the *Generator* may submit a revised *Generator Offer* until *gate closure*.

4.3.1.1. Generator Offer Template

A *Generator Offer* is to be submitted using the following pre-prepared template as presented in Figure 3, available from the Power System Controller.

[4] Generator Offer Template, 29/01/2026, D2026/31252 see Section 7

Figure 3: Generator offer template

Template Version 12 - (03/07/2020)

For trading day commencing

Issuer

Date of issue

Issue Version

Company

	Self-commitment units										Fast start units											Merit			
Standard Unit ID	off-load order	Time of sync (on-line)	Time of de-sync (off-line)	B1: minimum stable load	B1 OFFER	B2: incremental capacity	B2 OFFER	B3: incremental capacity	B3 OFFER	total offered capacity (check)	T1: Time to start	T2: Time to reach min load	Offload Order (after 1800 Hours)	T4: Time to reduce to zero	B1 minimum stable load	B2: incremental capacity	B2 OFFER - LONG RUN (Set 1)	B2 OFFER - SHORT RUN (Set 2)	B3: incremental capacity	B3 OFFER	total offered capacity (check)	Machines Offered	B2 - LONG RUN Merit	B2 - SHORT RUN Merit	B3 Merit
	Number	hhmm	hhmm	MW	$/MWh	MW	$/MWh	MW	$/MWh	MW	mm	mm	Number	mm	MW	MW	$/MWh	$/MWh	MW	$/MWh	MW	Unit ID	Number	Unit ID	Number
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Band totals				0.0		0.0		0.0		0.0					0.0	0.0			0.0		0.0				

4.3.1.2. Completing the Generator Offer Template

The following guidelines are to be observed for completing the Generator Offer Template:

- General:
  - A blank field means that no Offer is made – no entry is otherwise required in that field.
  - The Unit IDs to be used in column C of the Offer template are listed in template data.
  - The trading day is the 24-hour period commencing half hour ending 0430 hours on day 1 and ending 0400 hours on day 2.
  - The Offer must only nominate one mode of operation for any one unit in a trading day. The choices are either self-committed mode or fast-start mode. The mode of a unit can change from one trading day to the next.
  - Units that can operate in combined cycle mode and/or in open cycle mode are to be offered as individual units. The recognition of their combined cycle relationship will be recorded in the standing data.
  - The total capacity offered for any one synchronous generating unit must be equal to or greater than the base maximum capacity quantity registered in the standing data with the Market Operator unless the Generator has submitted a Generator Outage / Test Request advising of the temporary reduction in capacity.
  - The unit prices for capacity above minimum stable load "must approximate the dispatch cost that would have been incurred or avoided as appropriate by such dispatch", in accordance with the provisions in clauses 4.4B(g) and (h) of the System Control Technical Code.

- Self-committed generator units:
  - For self-committed *generating units*, the *Band 1* quantity is to represent the *minimum stable load* of the unit. The *Band 2* quantity is to be incremental on the *Band 1* quantity. The *Band 3* quantity (if any) is to be incremental on the *Band 2* quantity.
    - *Band 3* capacity is to be zero (blank) if no separately dispatchable capacity is available.
    - *Band 2* capacity is not required if all capacity is allocated to *Band 1* for a special purpose (e.g. testing).
  - For self-committed *generating units*, the *Band 1* price is to be zero $/MWh. The *Band 2* price is to be greater than or equal to the *Band 1* price. The *Band 3* price, if applicable, is to be greater than or equal to the *Band 2* price.
    - A *Generator* may offer multiple self-committed *generating units* with the same *Band 2* prices. However, this does not apply to the *Band 3* prices.
  - For all self-committed *generating units* with a *Band 1* quantity exceeding zero, the order for taking the unit off-line is to be provided in column E (the 'Off-Load Order').
    - The Off-Load Order is an ascending numeric sequence 1, 2, 3, …, n, which denotes the first, second, third, …, nth units to be taken off-line.
    - For *generating units* operating in the *closed cycle mode*, the units are to be ordered to ensure that steam units are taken off-line prior to taking off-line any final coupled unit(s) whose removal would render the steam unit unable to remain on-line.
  - For self-committed *generating units*, the times of synchronisation and de-synchronisation may be provided in columns G and H, respectively.

        - The time of synchronisation is the time of day by which point the unit should have just finished being bought on-line and ramping up to its *Band 1* level.
    - The time of de-synchronisation is the time of day by which point the unit should have just finished being bought off-line.
    - Both times are to be aligned to the end of a trading interval.
    - Both times are to be left blank if the unit is on-line prior to the *trading day* and is offered for all 48 intervals in the nominated *trading day*.

4.3.1.3. Submitting offers

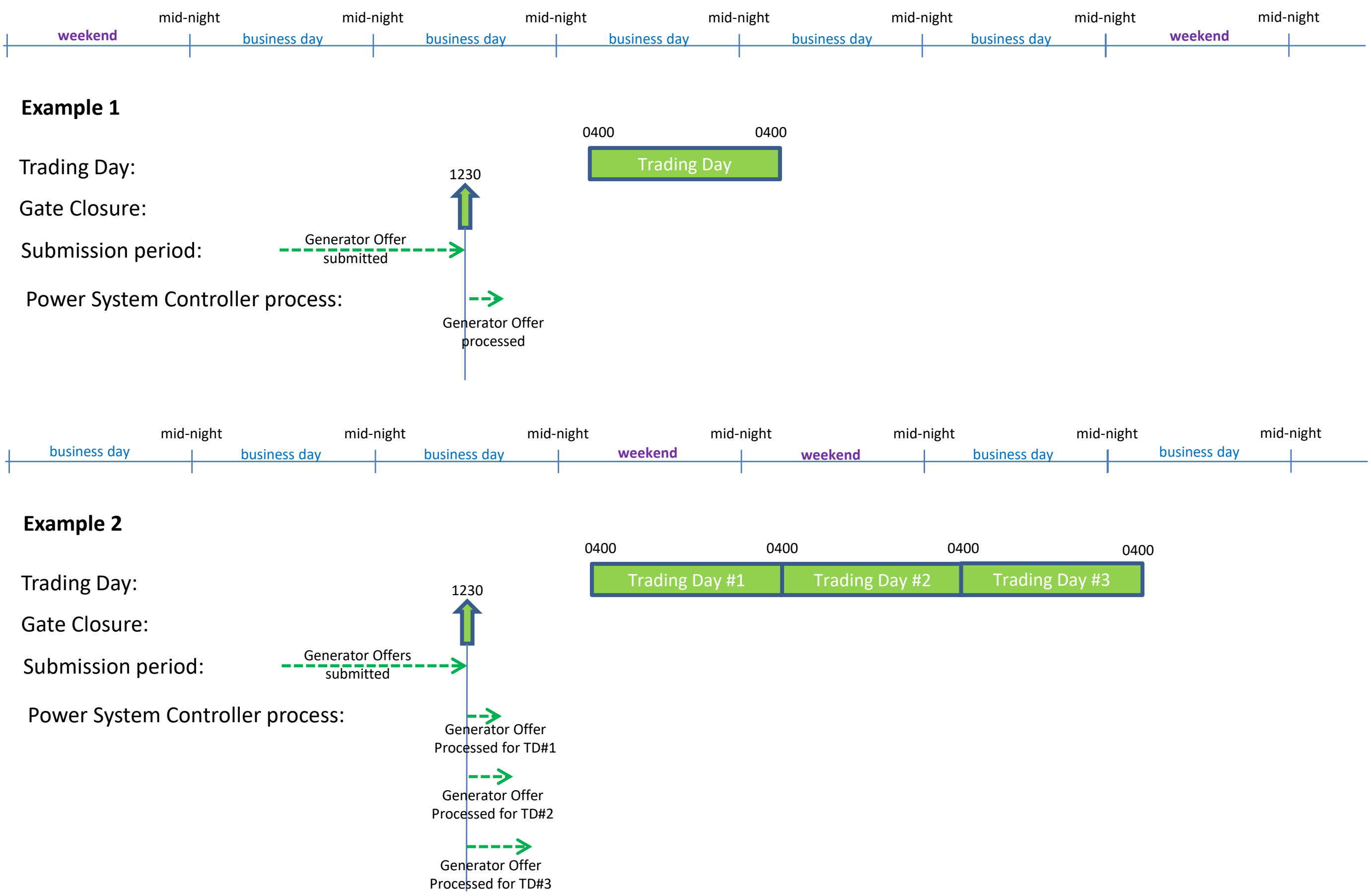
- The completed Offer must be emailed to: systemdispatch.PWC@powerwater.com.au
- The email subject line must begin with the text "Generator Offer". There are no restrictions on any subsequent text.
- The Offer must be attached to the email as an Excel Workbook file (.xlsx). There are no restrictions on the file name.
- The Offer date is the date shown in cell C3 in the offer tab of the attached file.
    - The Offer date is the date of the trading day, NOT the date of the email submission.
    - If the Offer date is missing, the email will be rejected.
- The email must be submitted by no later than 1230 hours on any one business day.
    - Note that Offers for days in advance may be made on the last business day in the week, provided the Offers are correctly dated.
- Only one Offer is required for each trading day.
    - If two or more Offers are submitted for the one trading day, only the latest Offer prior to 1230 hours will be processed for that trading day.
- An Offer will be rejected if it contains an error. Examples of errors include:
    - Email subject lines that do not start with "Generator Offer".
    - Emails that do not have an ".xlsx" attachment.
    - An Offer date is not provided or relates to a past trading day.
    - A generating unit is included in the Offer, but its ID has not been registered with the Market Operator.
    - The offered Band 1 + Band 2 capacity for a generating unit exceeds that unit's registered standing data for Base Maximum Capacity.

4.3.1.4. Gate closure

An explanation of the *gate closure* arrangements is provided in Figure 4

- A *Generator Offer* must be submitted by email prior to 1230 hours on the day ahead of the nominated trading day in which *gate closure* applies. If no *Generator Offer* is received by the System Controller for the nominated trading day, the commitment and dispatch process will automatically select that default *Generator* Offer as its replacement.
- Whilst it would be expected that *Generator Offer* would be made relatively close to the time of *gate closure*, there is no earliest time specified for the transmission of the Offer.

Figure 4: Examples of Offers submissions before gate closure



- More than one *Generator Offer* may be submitted prior to the *gate closure* time. Each of the *Generator Offers* must be sequentially incremented in their version number. At *gate closure*, System Control will only use the *Generator Offer* with the highest version number for the pre-dispatch process.
- The latest *Generator Offer* to be received prior to *gate closure* will be treated as the active *Generator Offer* by System Control.
- System Control will use the active *Generator Offer* in the pre-dispatch process.

4.3.2. Load Forecast

The Power System Controller is required by clause 5.11 of the System Control Technical Code to determine, by 1600 hours on each business day and at least 72 hours ahead of the trading day, a load forecast representing the total system load forecast for each half hour of the trading day. This load forecast is used in the pre-dispatch process and is only produced on business days.

4.3.3. Generating unit capacity limits

The minimum and maximum capacity of each generating unit for the trading day is set using the Generating unit standing data captured in the Market Participant registration process, which is administered by the Market Operator.[5]

4.3.4. Risk notifications

Risk notifications provide information on existing approved Outage and Testing Requests [6] and the generation or generic system constraints[7] that arise from them for the trading day. Risk notifications record the impact of outages on generating units and any applicable limits on the operation of one or more generating units for one or more trading intervals during the trading day. Some of these constraints may specify, for example, a particular generating unit or a minimum or maximum number of generating units in a group of generating units to be committed or decommitted and may place additional upper or lower energy output limits on the dispatch of generating units.

4.3.5. Network constraints

Network constraints, which are defined in clause 3.9 of the System Control Technical Code, are applied by the Power System Controller if actions are required to maintain the power flow through a network element within limits. These actions include ensuring secure operation of the power system following a contingency event.

Network constraints are not applied in the pre-dispatch schedule, being only applied in the real-time commitment and dispatch.

In the real-time commitment and dispatch process, the Power System Controller will operationally endeavour to reconfigure the network via switch activities to manage both generic system constraints and network constraints as a priority. However, where it is not possible to manage by network switching alone, adjustments to generating unit commitment and dispatch will be made. Much the same as generic system constraints, network constraints may specify a generating unit or a minimum or maximum number of generating units in a group of generating units to be committed and may place additional upper or lower energy output limits on the dispatch of generating units that are committed.

4.3.6. Essential System Services requirements

Essential System Service (**ESS**) requirements (previously referred to as ancillary services) to manage system security are accounted for in the real-time commitment and dispatch process only.

The requirements for each of the services are currently translated into either a set of constraints currently limited to Territory Generation generating units that must be committed or an additional minimum capacity that must be available from the Territory Generation portfolio Generating unit availability.

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[5] While the Band 1 quantities and the Band 2 or Band 3 (if non-zero) quantities in generator offers respectively imply minimum stable load and maximum capacity the Power System Controller will still use standing data quantities, or adjusted values under an approved Outage and Testing Request reflected in a Risk Notification, if there is a conflict.

[6] For further information on Outage and Testing Request processes refer to the Plant Outage Procedure.

[7] Generic system constraints, which are defined in clause 3.9 of the System Control Technical Code, are applied by the Power System Controller where a system limitation exists as the result of a planned or unplanned network outage.

Information on the real-time availability of generating units is available to the Power System Controller to indicate limitations on generating units in the real-time commitment and dispatch process. This information includes unplanned forced or performance issue outages, as well as generator firm offers and forecasting compliance monitoring.[8]

4.3.7. Outage Plan

Plant and network availability as presented in the ongoing power system plant outage plan that considers long-term, medium, and short-term outage planning is accounted for in determining the pre-dispatch schedule. The content of the power system outage plan serves as an input to the determination of the pre-dispatch schedule. The power system outage plan may inform where parts of the power system there may be pre-existing constraints and unavailable resources such as generators and BESS that may impact the stability, security, and reliability of the system. The process for determining the power system outage plan is contained in a separate System Control Plant Outage Procedure.[9]

4.4. Pre-dispatch process

4.4.1. Overview

This section describes the pre-dispatch process – the inputs used, the preparation of commitment and dispatch merit orders, other pre-dispatch data, the pre-dispatch solution process and an indicative commitment and dispatch schedule.

Each generator is provided with a generator pre-dispatch schedule, and the Power System Controller is provided a pre-dispatch schedule and merit orders as shown in the I-NTEM Pre-Dispatch process in section 4.1, Figure 2.

4.4.2. Inputs used in the pre-dispatch process

The inputs used for a pre-dispatch for a trading day are described in Section 4.3 are:

- generator offers
- generating unit capabilities
- load forecasts
- risk notifications.

4.4.3. Preparation of commitment and dispatch merit orders

Merit orders are developed in the pre-dispatch process to determine the pre-dispatch schedule, which is a single schedule determined once for the full trading day. The merit orders described in this section are:

- self-committed commitment merit order
- energy and tie break merit order
- short run commitment merit order
- decommitment merit order
- first off decommitment merit order (only applies after 1800 hours).

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[8] For further information refer to the Plant Outage Procedure and Generator Forecast Compliance Procedure.

[9] System Control Plant Outage Procedure V1.0 2020

The merit orders are defined by using generator offer data across all Generators. The generator offers include information that defines the order in which units should be committed or decommitted and the order in which energy output should be increased or decreased within the portfolio of units of an individual Generator.

The same merit orders inform the real-time commitment and dispatch process. However, the interpretation of the merit orders in real-time is more dynamic as the merit orders are applied to the prevailing system conditions, including the mixture of units running, the order of commitment and decommitment of units from the past, and constraints that impact generation commitment and dispatch decisions.

4.4.4. Pre-dispatch generating unit tie break

Where required to develop the merit order, tie-breaking is applied in accordance with the *generating unit* tie-break methods presented in Section 5.4. These methods consider the following scenarios:

- Ties between self-committed *generating units* with respect to commitment or decommitment when energy output is already at minimum stable load, or the units are offline. These ties are resolved using the random period selection process.
- Ties between fast start *generating units* with respect to commitment or decommitment when energy output is already at minimum stable load, or the units are offline. These ties are resolved using the random day selection process.
- Ties between *generating units* with respect to their energy output above their minimum stable loads, requiring some combination of generating units to adjust energy output while remaining on. These ties are resolved using the proportional energy dispatch process.

4.4.5. Self-committed commitment merit order

The self-committed commitment merit order is the order in which self-committed generating units are to be committed. In practice, as per System Control Technical Code clause 4.7(b), a self-committed generating unit will be committed unless this is not possible for reasons of system security.

The self-committed commitment merit order is the reverse of the order of the decommitment off-load orders specified by the Generator in their generator offers, considering tie break rules. In particular:

- The off-load order for self-committed generating units in the generator offer of a Generator defines the order in which its self-committed generating units are to be decommitted. Different configurations of combined cycle units are also specified within these off-load orders.
- Commitment ties between self-committed generating units arise because non-zero band 1 quantities are offered at a band 1 price of zero. These generating units are decommitted according to the Generating Unit Tie Break Procedure as their band 1 prices are always tied.

4.4.6. Energy and tie-break merit order

The energy and tie-break merit order is the order in which generating units are to be committed and/or scheduled to produce energy, where that energy is expected to be required for a duration greater than four hours. It applies once all self-committed generating units have been committed.

The energy and tie-break merit order is constructed by arranging the band 2 (long-run) prices of both the fast-start and self-committed generating units in ascending order, that is, from the cheapest to most expensive units. Where energy ties exist, the tied generating units are to be listed as jointly occupying the same place in the merit order. The dispatch of these tied units in real-time will be determined by the random-day selection process and proportional energy dispatch process, as appropriate.

Where fast-start units are required to be committed to provide band 2 energy, their band 1 quantity will be automatically supplied in making it possible for the *generating unit* to provide band 2 energy.

4.4.7. Short run commitment merit order

When a fast start generating unit is to be committed to run for a period of less than four hours, the choice of which fast start generating unit to commit is based on the short run commitment merit order. Generators have the option to specify a short run price for each fast start generating unit band 2 quantity.

The short run commitment merit order is compiled by ordering the band 2 short run prices of fast start generating units and the band 3 prices from fast start generating units from the cheapest to the most expensive.[10] The merit order does not distinguish between band 2 and band 3 offers so each compete directly. A tie occurs whenever two or more units have the same price within bands 2 and 3 for an available dispatchable quantity. In the event of a tie, section 5.4 Unit Tie Breaking and Proportional Dispatch process is applied, subject to maintaining system security and not violating any system or network constraints.

4.4.8. Decommitment merit order

Self-committed generating units will only be decommitted after any operating fast start generating units have been decommitted unless security reasons prevent this.

If fast start generating units are to be decommitted or band 3 capacity is to be dispatched off-line prior to 1800 hours in a trading day, the Power System Controller must select the most expensive generating unit to decommit first (except, where prevented for security reasons). Where a tie exists, section 5.4 Unit Tie Breaking and Proportional Dispatch process as such that the capacity is selected in the reverse of the order in which Generators were instructed to commit that tied capacity online (except where prevented for system security reasons).

After 1800 hours on each trading day, and where a generating unit is to be decommitted, the first off decommitment merit order may modify the selected capacity, as described in section 4.4.9.

The next generating unit to be decommitted is determined by repeating the process with the remaining units.

Where self-committed generating units are to be decommitted, the Power System Controller follows the order specified in the Generator’s generator offer for the trading day. Where ties exist with generating units of other Generators, the Power System Controller follows the reverse order in which the tied Generators were instructed to commit generating units, unless prevented for system security reasons.

4.4.9. First off decommitment merit order (post 1800 hours)

The first off decommitment merit order modifies the decommitment merit order from 1800 hours to the end of each trading day when energy use typically begins to decrease. This provides flexibility to Generators to control which fast start generating units are selected for decommitment. A Generator shall specify a decommitment order to apply post 1800 hours in its generator offer for the trading day. The first off

[10] The nature of *band 3* quantities is that they are available for only a short period, so this procedure does not consider the situation of ties between *band 3* quantities and *band 2 long run prices*.

decommitment merit order has no impact on the self-committed generating units in the decommitment merit order.

The first decommitment merit order modifies the normal decommitment merit order by factoring in the information from the decommitment order that may be specified in generator offers by Generators for fast start generating units.

When the process identifies a particular fast start generating unit to be decommitted and the off-load order for that Generator has not been exhausted, the next fast start generating unit in the Generator’s decommitment order that is currently online will be decommitted ahead of the initially selected fast start generating unit. If a fast start generating unit in the decommitment order was required to remain online for security reasons, then the next unit in decommitment order is selected instead.

It should be noted that this option does not allow a Generator to replace fast start generating units in the order, only rearrange fast start generating units to be decommitted prior to other units owned by the same Generator.

Where Generators do not have, or they have exhausted preferences for the order of decommitting within their own portfolio, the decommitment merit order reverts to the standard decommitment merit order.

Table 3 illustrates the effect of decommitment orders on the decommitment merit order to produce the first off decommitment merit order. Units A1, A2, A3 and A4 are part of Generator A’s portfolio, while B1, B2, B3 and B4 are part of Generator B’s portfolio. For simplicity we assume that all units are fast start generating units. Generator A has specified A2 as the first unit in the decommitment order and A3 as the second unit. The right column shows the first decommitment merit order. Comparing the two tables below, we see that because of the decommitment order, the decommitment merit order has been rearranged to form the first off decommitment merit order.

Table 3: Illustrative effect of decommitment orders on the decommitment merit order

Decommitment Merit Order	Decommitment Order
B2	
A3	2
A2	1
B1	
B4	
A1	
B3	1
A4	

First Off Decommitment Merit Order
B3
B2
A2
A3
B1
B4
A1
A4

This flexibility enables the Generator to efficiently manage resources, although it comes with pricing exclusion implications where the substituted generating unit is more expensive. In the example above, B2 would be a higher cost generating unit than B3, but B3 goes offline while B2 remains online.

The market pricing process excludes generating units from the same Generator that remain on because of this feature from setting the market price i.e. it is a market exclusion reason. This would apply for the remainder of the trading day or until the same generating unit was committed in the same trading day, having previously decommitted. Due to the first off decommitment merit order it follows that when B3 is decommitted instead of B2, then B2 is not allowed to set the market price for the remainder of the trading day. The market price should therefore be no more than it would otherwise have been.

The decommitment order does not change the tie break logic. As an example, consider the case where unit B2 is tied with unit A3 and the normal tie breaking logic picks unit B2 to decommit. Because Generator B has specified that B3 is to come off before B2, then unit B3 would be taken off-line first (subject to system security constraints). That is, B3 is treated as being at the top of the merit order. The units involved in the tie break would then be taken off in the order that the tie break logic requires, namely B2 first, followed by A3. However, Generator A's off load order results in A2 taking the place of A3.

In practice, the first decommitment merit order seen by the Power System Controller lists the generating units compiled from all the decommitment orders across all Generators. Whenever the Power System Controller identifies a fast start generating unit is to be decommitted for a given Generator, it will decommit the fast start generating unit first online for that Generator (if any) in the first decommitment merit order unless prevented from doing so for security reasons.

4.4.10. Pre-dispatch solution process

Figure 5 provides an illustrative example of a pre-dispatch schedule. It provides a conceptual view of the pre-dispatch solution process, covering 20 trading intervals (10 hours) rather than the full 48 trading intervals in a trading day. The example assumes the band 2 long run cost of all fast start generating units exceeds the band 2 long run cost of all self-committed generating units, this being the normal case.

The 5-step process to determine the pre-dispatch schedule is described in the following sections.

Step 1 – Dispatch self-committed units to minimum stable load

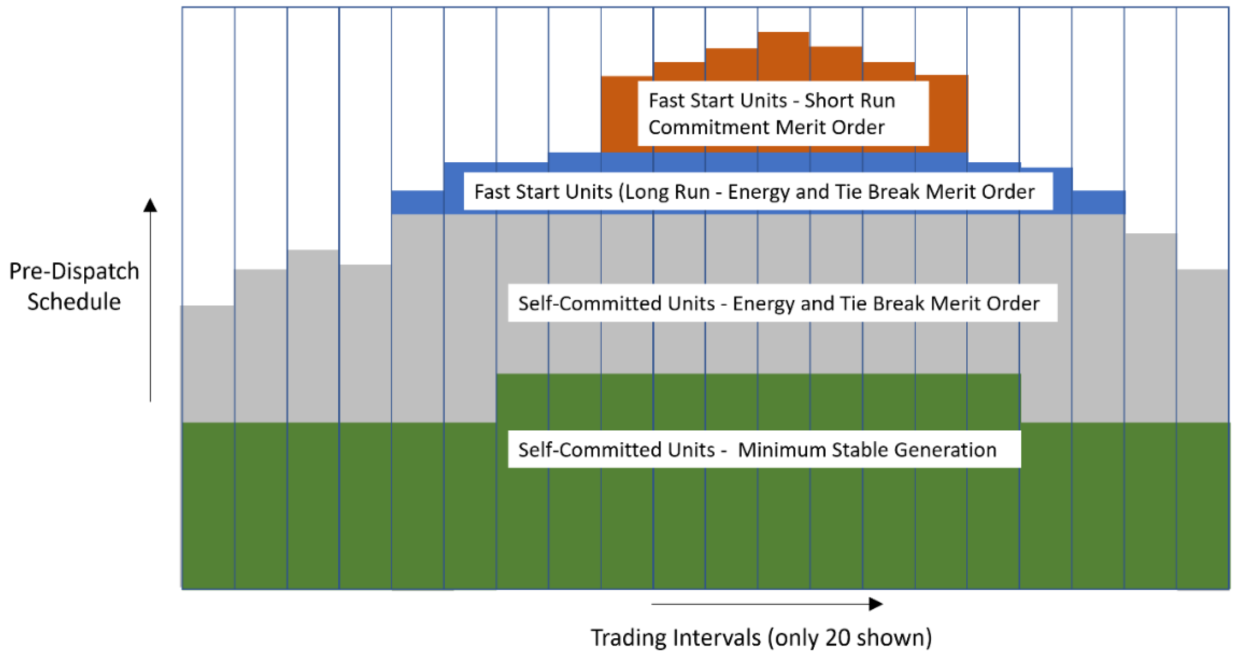
The first step is to dispatch all self-committed generating units to their minimum stable load (i.e. fully dispatched band 1 capacity). Where there is not enough system load to support this, the self-committed commitment and decommitment orders will be used to guide commitment choices.

Step 2 – Dispatch self-committed units to provide energy above minimum stable load

This step entails determining the energy output from band 2 of each self-committed generating unit in each trading interval (allowing for system security and essential system service requirements). The generating units are dispatched based on the energy merit order subject to tie-breaking rules.

If system load is insufficient to require all self-committed generating units to have band 2 fully dispatched (within the availability of the generating unit and generator or generic system constraints) in some trading intervals, then only the most economic (based upon their offers) self-committed units will be committed and/or dispatched.

Figure 5: Illustrative example of pre-dispatch schedule



Step 3 – Commit and dispatch fast start units

It can be seen from the diagram above that, at times, system load is at a level such that all self-committed generating units are running at maximum usable capacity based on system security requirements. To meet the remaining system load, it is necessary to commit fast start generating units.

There is a choice between committing fast start generating units based either on the short run price commitment merit order or the energy and tie break merit order. The offered prices for committing and running generating units for a short run (≤ 4 hours) will be greater than those for a long run. This is because generating unit offer prices are currently expected to be set to recover the generating unit's start-up costs, and there is less time to recover start-up costs for a short run, requiring higher offer prices.

It transpires that as there is enough system load over the 14 consecutive peak system load trading intervals (7 hours) to support the commitment of fast start generating units based on the energy and tie break merit order. After committing these generating units and dispatching them to the point where they either serve the remaining load or reach their capacity, there is still additional system load over the peak seven trading intervals (3.5 hours) which, being less than 4 hours in duration, will be served by committing the next available generating units from the short run merit order.

Step 4 – Indicative pre-dispatch clearing prices

The highest priced offer cleared in each trading interval defines the indicative clearing price for that trading interval. The methodology used to set this price is conceptually the same as that used in determining market prices after the trading day but without the application of market exclusions.

Step 5 – Overlay known risk notification

The published risk notifications that are likely to be applied on the trading day, and which will alter generation commitment and/or dispatch, are identified to inform likely generating unit availability and hence constrain the pre-dispatch solution.

Decommitment of generating units

When system load drops, it may be necessary to decommit generating units. This could happen in the middle of the day due to higher behind the meter solar generation or at the end of the day as actual customer consumption declines.

Each Generator specifies its preferred order for decommitting its generating units, but for fast start generating units, a Generator must also specify an alternative first off decommitment merit order to apply from 1800 hours to the end of the trading day, refer to section 4.4.9. The logic described for these merit orders will apply between 1800 hours and the end of the trading day to determine the order in which generating units decommit, including changes in order due to tie-breaking and restrictions arising for reasons of security.

Dispatch of fast start generating units

Fast start generating units have the same price for band 1 and band 2.

If the band 2 price of a fast start generating unit were to be less than the band 2 price of a self-committed generating unit, then the self-committed generating unit would still be committed first as the Power System Controller is required to commit self-committed generating units and dispatch them up to their minimum stable loads wherever system security constraints allow it.

In this situation, the self-committed generating unit would be dispatched to minimum stable load, then the fast start generating unit would be dispatched to minimum stable load, then the generating units would increase output with increasing load based on their band 2 prices. This would mean that the fast start generating unit would be dispatched for energy ahead of the self-committed generating unit due to the fast start generating unit having a lower band 2 price.

4.4.11. Indicative commitment and dispatch schedule

The Power System Controller must provide pre-dispatch targets (expected outputs for each trading interval) and the pre-dispatch indicative clearing prices to the Market Operator each business day for publication.

The Power System Controller will provide to each Generator via e-mail:

- the pre-dispatch schedule specific to that Generator's generating units
- the indicative clearing prices for each trading interval of the trading day
- for each generating unit participating in the pre-dispatch process, its minimum capacity, its maximum capacity, and the trading intervals it is available
- a list of security constraints and essential system service requirements applied.

The information provided to Generators is issued to provide guidance to the Generators as to how their generating units could expect to be committed and dispatched. The actual commitment and dispatch on the trading day may differ due to real-time considerations.

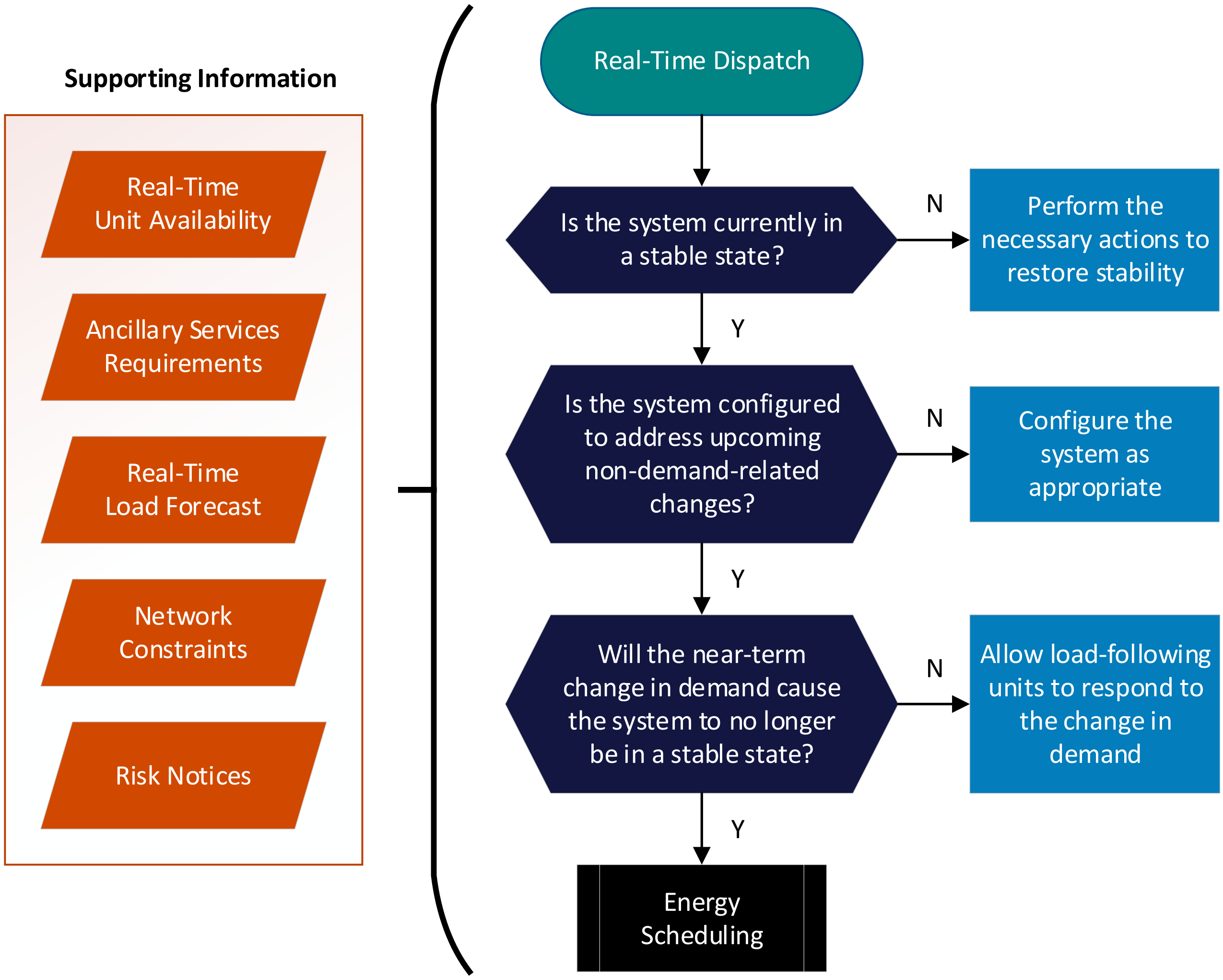
A set of pre-dispatch instructions are developed for use in the real-time commitment and dispatch process, by Power System Controller staff, as described in the next section.

5. Real-time commitment and dispatch

5.1. Overview

This section is focused on providing a summary of the process for unit commitment and dispatching the power system in (and leading up to) real-time. The real-time commitment and dispatch process is illustrated in Figure 6.

Figure 6: I-NTEM real time scheduling and dispatch process



The real-time commitment and dispatch process is based upon the principles of SCUC and SCED . In performing real-time commitment and dispatch, the Power System Controller must focus on simultaneously:

- Balancing instantaneous energy generation with system load
- Ensuring that sufficient generation capacity with sufficient flexibility is online to:
  - Respond to near-term fluctuations in system load
  - Respond to contingency events
  - Meet ESS requirements
- Anticipating demand changes and preparing to commit/decommit generating units according to the relevant merit orders
- Respecting constraints on how the system can be operated
- Identifying required deviations from the merit order when considering operational requirements (reliability, performance, unit starts and stops, rated capacity, minimum stable load requirements)

In managing power system constraints, the Power System Controller will first seek to manage constraints within the current commitments. If this is not sufficient, the Power System Controller will then modify the scheduling and dispatch solution of the transmission network and assets connected to the transmission network (and potentially the distribution network) to ensure ESS to operate the power system within technical operating limits.

The Power System Controller can control the dispatch output of generating units to regulate frequency via Automatic Generation Control (**AGC**). Generally, only Territory Generation generating units are under AGC control, with the settings related to regulating ranges set to allow the units to increase or decrease output within limits in controlled economic dispatch to follow the changing load of the power system, as well as provide frequency error correction to the frequency set point and time error correction.

5.2. Inputs used for real-time dispatch

The inputs used for real-time dispatch during a trading day are:

- a set of pre-dispatch instructions determined in the pre-dispatch process, which serve to provide information relevant to the commitment and dispatch process, including:
  - a graphical representation of the pre-dispatch solution
  - generating unit capacities and availabilities
  - generator aggregate capacities and availabilities
  - a pre-dispatch table providing a simpler ordering of generating units that covers system load plus covers other capacity requirements
  - various merit orders, tied units, and information on feasible combinations of the minimum set of units that must be committed
- Standing notes and guidance to provide additional information for system controllers
- real-time generating unit availability[11]
- total system demand forecast
- Long Term Risk Notices
- Outage Specific risk notifications

[11] For further information refer to the Plant Outage Procedure and Generator Forecast Compliance Procedure.

- network constraints
- real-time system configuration and system security considerations
- real time operational requirements of the load following generators

5.3. Real-time dispatch process

The approach to real-time dispatch is illustrated in Figure 7 and 8 and described in the following sections.

The pre-dispatch schedule provided to Generators is indicative only. The generating units must instead operate in a manner consistent with the commitment and dispatch instructions issued by the Power System Controller in real-time. The instructions issued by the Power System Controller will deviate from the pre-dispatch schedule as required to respond to changing system load, changing Generator and network availability, and to reflect planned and unplanned outages, and real-time security constraints.

5.3.1. Actions when the generation requirement for energy or capacity increases

5.3.1.1. Unit commitment

Priority 1 – Security Constraints

All generating units required to be online under any system security or essential system service requirement are committed first. This factors in both generic system constraints and network constraints. This scheduling provides protection against any credible contingencies, whether they involve the loss of generation or load, by distributing the essential system service requirements (voltage control and frequency control services including reserves associated with both) across multiple generating units.

Where there is flexibility within a security constraint or Essential System Service requirement to choose which generating unit or units to commit, the Power System Controller selects the lowest price generating unit or units to commit as per the Economic Commitment and Dispatch Arrangements (see below), unless this would unnecessarily delay addressing the security constraints which may occur if there is a state of emergency within the system.

Figure 7: Illustration of the approach to real-time energy scheduling

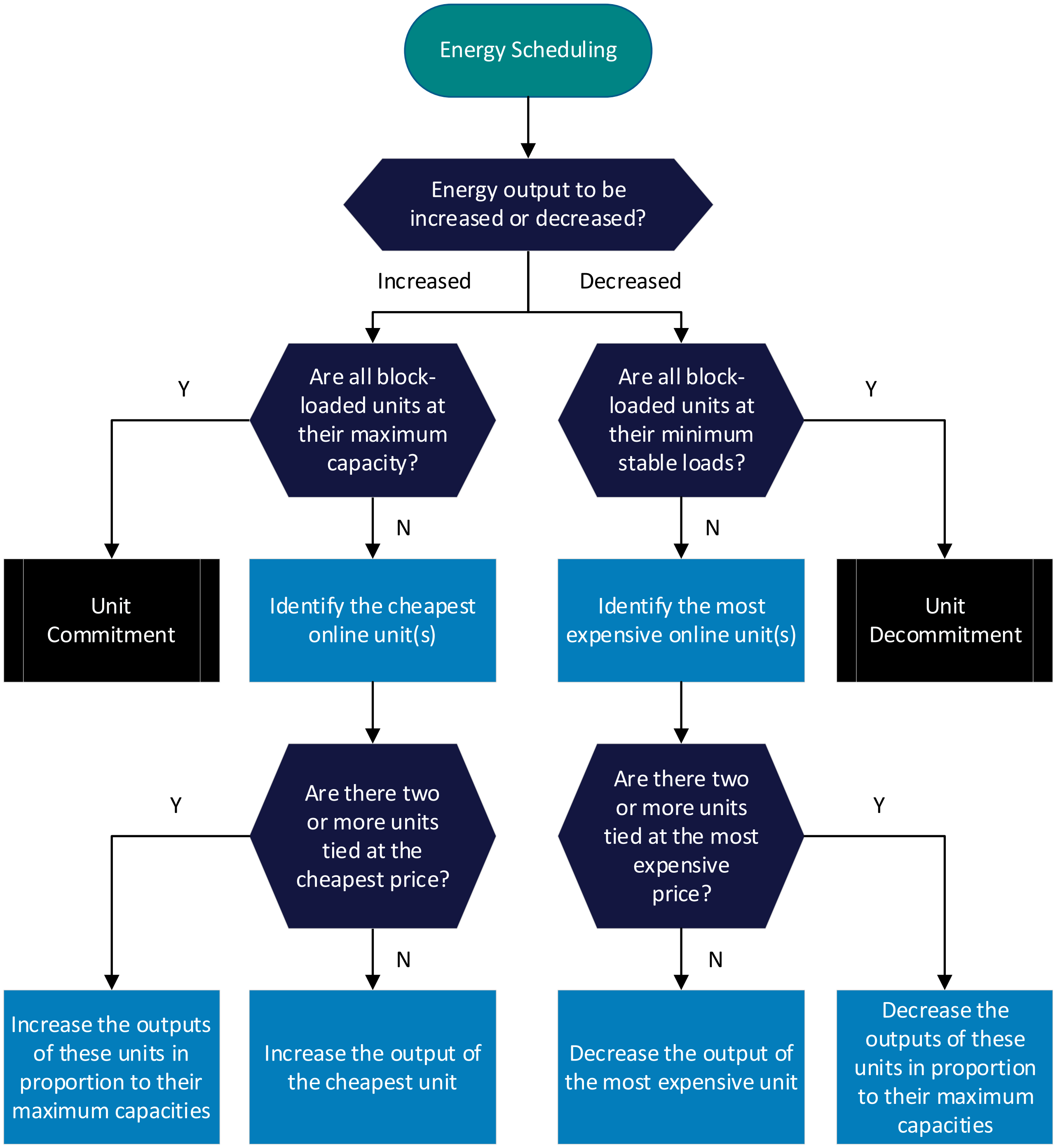
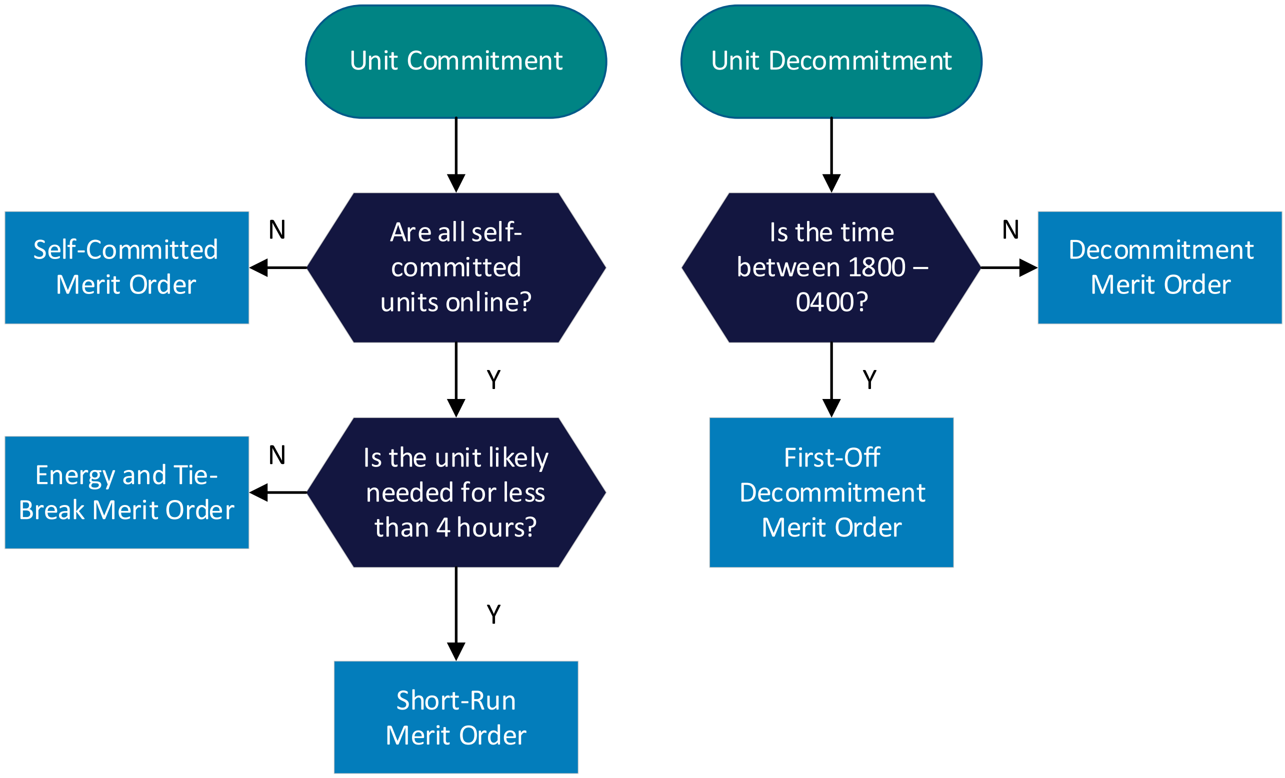


Figure 8: Illustration of the approach to real-time commitment and dispatch



Priority 2 - Economic Commitment and Dispatch Arrangements

Self-committed generating units

All self-committed generating units are committed as practicable prior to the commitment of any fast start generating units, except where prevented by security reasons. Self-committed generating units will always be committed and dispatched to their minimum stable load, where practical, with the aim of having all self-committed units online at any given time in accordance with the self-committed commitment merit order.

The self-committed generating units online will be dispatched above their band 1 quantities to match the load or to provide regulation under AGC control (as described above).

Fast start generating units

Fast start generating units are committed if and only if more capacity is required above the amount supplied by the self-committed generating units or if they are required for system security reasons. When there is a need to commit a fast start generating unit, the Power System Controller will assess the likely duration for which the additional generation capacity is needed. If the assessment is that the additional capacity is likely required for no more than 4 hours, this will be considered a short run. If the assessment finds that the additional capacity is needed for more than 4 hours, this will be considered a long run.

In the case where it is determined that a fast start generating unit is required for a **short run**, the Power System Controller will commit the next generating unit (or dispatch the incremental band 3 capacity if the associated unit is already online) from the short run commitment merit order that is not presently online.

In the case where it is determined that a fast start generating unit is required for a **long run**, the Power System Controller will commit the next generating unit (or dispatch the incremental band 3 capacity if the associated unit is already online) from the energy and tie break merit order that is not presently online.

Adjustments to reflect operational requirements and economic considerations

When performing economic commitment and dispatch, operational requirements may result in situations where strictly following the merit order results in suboptimal economic outcomes due to factors not accounted for in the pre-dispatch. In these situations, it may be possible to alter the dispatch order to create a more economic outcome in which no participant is negatively affected compared to the base case.

As set out in the scope of this procedure, it is noted that the I-NTEM is currently a virtual market where the offer prices are not used in any commercial settlement process. However, the relative offer prices do influence the relative dispatch of the *generating units* and therefore the total energy generated by each Generator, which does have commercial implications. As such, alterations to the dispatch order should always conserve the dispatch quantities allocated to each Generator by the defined merit orders so that no Generator is disadvantaged.

Alterations to the dispatch order may be performed considering, but not limited to, factors such as unit reliability, performance, minimum stable load requirements, regulating reserve levels, unit size, and the required number of units starts. Any alterations to the dispatch order not made explicitly for system security reasons must be performed with the consent of the relevant Generator, and the units will be treated as out-of-merit for the purpose of market pricing.

5.3.1.2. Energy scheduling

Generating units providing regulating reserves will have their dispatch level determined by the Power System Controller's AGC to meet their ESS obligations in the most economically efficient manner. Regulating reserve generating units may have their outputs increased or decreased in real time to accommodate other changes.

Other generating units will have their band 2 and/or band 3 dispatch level set by the Power System Controller based on the energy and tie break merit order.

5.3.1.3. Participant communication

The Power System Controller must provide the actual dispatch schedules for the trading day to the Market Operator for publication.

5.3.2. Actions when the generation requirement for energy or capacity decreases

5.3.2.1. Unit decommitment

Fast start generating units

The decommitment of fast start generating units is undertaken prior to any decommitment of self-commitment generating units unless prevented by security considerations or operational requirements.

Prior to 1800 hours fast start generating units will be decommitted, or band 3 capacity removed from the schedule, based on the decommitment merit order.

Between 1800 hours and the end of the trading day, the first off decommitment merit order is used in priority to the decommitment merit order.

Self-committed generating units

Once all fast start generating units that can be decommitted have been decommitted, and the load on the system decreases, all online self-committed generating units will have their outputs dispatched to minimum stable load (plus any required reserve margins). Once all self-committed generating units have been dispatched to their minimum stable load (allowing for any required reserve margins), the next generating unit, according to the self-committed offload order, that is currently online (or mode of operation with regards to combined cycle units) will be decommitted unless prevented for security reasons.

5.3.2.2. Energy scheduling

This is an identical process to that presented for the load increasing case, but working down the energy and tie break merit order given the generating units committed rather than working up it. Regulating reserve generating units may have their outputs increased or decreased to accommodate other changes.

5.4. Unit tie-breaking and proportional dispatch

5.4.1. Overview

This section specifies the principles and associated methods in applying a *tie-break* to competing *generating units* when operating in the *I-NTEM* to ensure an orderly merit order *dispatch process* by the *Power System Controller*.

The method applied is prepared under the authority of Section 4.4B(e) of the System Control Technical Code and covers those parts of the commitment and dispatch process that covers:

- The dispatch of generating units from two or more Generators when the offer prices are equal at the Pool Price Point.
- The priority of the off-load order when comparing generating units (whose offer price is zero) from more than one *generator*.

5.4.2. Generator selection process

The *Generator selection process* assigns each *Generator* a priority ranking. This ranking determines the order in which the *Generators* will be instructed to take actions in the event of a tie. Each *Generator* is assigned a specific period, consisting of multiple consecutive *trading days*, during which time it will have the highest priority. The remaining *Generators* are then assigned priorities based upon the sequence in which they are allocated the subsequent periods. Once a *Generator's* period has ended, it moves to the lowest priority for the next period.

The initial allocation of periods is determined by the order in which the *Generators* registered with the Market Operator.

When a *Generator* registers with the Market Operator:

- That *Generator* will be assigned a four-week period commencing on the first Monday after its commencement date (or if the commencement date is a Monday, that day) and finishing on the Sunday four weeks later.
- The first *Generator* to have registered will be assigned the four-week period commencing on the trading day after the last *Generator* completes its period.

- The subsequent *Generators*, if any, will be assigned the subsequent four-week periods in the order of their registration dates until all *Generators* have been allocated a period.
- Once a *Generator's* allocated period has ended, it will then be assigned to the next available four-week period that has not yet been allocated to any *Generator*.
- The periods continue rotating in this manner until the next *Generator* registers.

For the removal of doubt, all registered *Generators* are included in the priority rankings for any given period. When resolving a tie, only the *Generators* with *generating units* involved in that tie will be instructed to take actions based on their relative priorities.

5.4.3. Self-committed generating unit ties – off-order commitment

During the *dispatch process*, if the *power system* load falls to the level where a self-committed *generating unit* must be decommitted, the *Power System Controller* is to:

- select the online *generating unit* that has the lowest *off-load order* in accordance with the *Generator selection process*; and
- instruct that *generating unit* to be taken offline and decommitted.

When selecting the online *generating unit* that has the lowest *off-load order*, if the *Power System Controller* identifies *generating units* from two or more *Generators* that have the same *off-load order*, then a *self-commitment tie* exists. The *Power System Controller* must resolve this tie by selecting a *Generator* according to the *Generator selection process* and instructing them to take offline their *generating unit* that has the lowest *off-load order*. If more *generating units* are required to be decommitted, this process will repeat with the remaining tied *generating units* until the tie is resolved.

Once the *power system* load reaches start increasing, the *Power System Controller* must request the *Generator(s)* to commit their *generating units* in the reverse order to how the *Generator(s)* were instructed to take them offline.

5.4.3.1. Example self-commitment tie resolution

Table 4 and Table 5 is provided as an example to demonstrate how the *decommitment merit order* is constructed from the *off-load orders*.

On the trading day 29 April 2017, the most recent *Generator* to register is GEN_Z on Friday 6 January 2017. Therefore, the first random period was allocated to GEN_Z on Monday 9 January 2017, and by 29 April 2017, the period is allocated to TGEN. The next periods will be assigned to GEN_A and GEN_Z in that order. Therefore, the unit decommitment order for these *generating units* is as follows:

T1, A2, Z1, T2, A1, Z2, T3, T4

Table 4: Example Generator *commencement dates.*

Generator	Commencement Date	Commencement Order
GEN_A	27 May 2015	1
GEN_B	30 July 2016	2
GEN_Z	6 January 2017	3

Table 5: Example Generator Offers *containing tied* off-load orders

Gen_A Units	Offload Order		GEN_B Units	Offload Order		GEN_Z Units	Offload Order
T1	1		A1	2		Z1	1
T2	2		A2	1		Z2	2
T3	3						
T4	4						

The *Power System Controller* will instruct the *Generators* to take their *generating units* offline in this order, that is, moving from left to right. Once the *power system* load reaches its nadir and starts increasing, the *Power System Controller* will request the *Generators* to commit their *generating units* in the reverse of the decommitment order, that is, moving from right to left.

5.4.4. Fast start units subject to fast-start-commitment

During the *dispatch process*, if the *power system* load increases to a level such that additional fast start *generating unit* capacity is required, and:

- that capacity will be required for greater than four hours such that the *Power System Controller* must commit fast start *generating units* based on Band 2 (long run) prices; or
- that capacity will be required for less than four hours such that the *Power System Controller* must either commit fast-start *generating units* based on Band 2 (short run) prices or schedule Band 3 capacity for fast-start *generating units* based on Band 3 prices; and
- two or more fast start *generating units* belonging to two or more *Generators* could address the identified need,

then a *fast-start commitment tie* exists.

The *Generator* to be instructed to perform the relevant action is to be chosen in accordance with the *Generator selection process*. For the removal of doubt, once the first *generating unit* has been committed or instructed to supply Band 3 capacity in accordance with the *Generator selection process*, its full Band 1, Band 2, and if applicable Band 3 capacity is applied to the price stack. If more capacity is required, this process will repeat with the remaining tied *generating units* until the tie is resolved.

If *power system* load starts decreasing, the *Power System Controller* requires *Generator(s)* to decommit, or stop supplying Band 3 capacity from, their *generating units* in the reverse order to how the *Generator(s)* were instructed provide this capacity, or where applicable decommit a replacement *generating unit* determined through the application of the *first-off decommitment order*.

5.4.4.1. Example fast-start commitment tie resolution

The following example scenario is provided to demonstrate how the *energy and tie-break merit order* and the *short-run merit order* are constructed from the Band 2 and Band 3 prices. It uses the same example *Generator* commencement dates given by Table 6 in the previous example.

Table 6: Example Generator Offers *containing tied fast start* generating units

TGEN Units	B2 Long Price	B2 Short Price	B3 Price	GEN_Z Units	B2 Long Price	B2 Short Price	B3 Price
T1	$40	$240	$140	Z1	$50	$250	$150
T2	$50	$250	$150	Z2	$60	$260	-
T3	$60	$260	-				
T4	$70	$270	-				

On the trading day 29 April 2017, the most recent *Generator* to register is GEN_Z on Friday 6 January 2017. Therefore, the first period was allocated to GEN_Z on Monday 9 January 2017, and by 29 April 2017, the period is allocated to TGEN. The next periods will be assigned to GEN_A and GEN_Z in that order. However, since GEN_A does not provide any fast start *generating units* on this *trading day*, it is not included in the priority rankings. Therefore, the *energy and tie-break merit order* for these *generating units* is as follows:

T1, T2, Z1, T3, Z2, T4

The *short-run merit order*, where "B3" denotes Band 3 capacity, is as follows:

T1 (B3), T2 (B3), Z1 (B3), T1, T2, Z1, T3, Z2, T4

The *Power System Controller* will instruct the *Generators* to commit or schedule their *generating units* in the relevant order depending on the length of time the capacity is required for. If the next *generating unit* in merit is the Band 3 capacity of a *generating unit* that is currently offline, it will be skipped until such time that the *generating unit* is brought online.

5.4.5. Equal Band 2 price offers subject to an energy tie

During the dispatch process, if the *Power System Controller* identifies the need to adjust output of a self-committed *generating unit* in response to a change in demand, but there is more than one self-committed *generating unit* that could address the need, such that an *energy tie* exists, the *Power System Controller* must apply the *proportional energy dispatch process* defined in Section 5.4.5.1 below to each of these *generating units.*

The *proportional energy dispatch process* involves dispatching each tied *generating unit* in proportion to their share of *forecasted capacity* as specified below, where this can be achieved without violating other constraints, and such that the combined change from the tied *generating units* addresses the required demand change.

The share of *forecasted capacity* for each *generating unit* shall be calculated based on its *forecasted capacity* as a share of the total *forecasted capacity* of all *generating units* with the same Band 2 offer price:

- The *forecasted capacity* for an inverter-based *generating unit* is the expected minimum output that it will be able to provide at the time for which the *proportional energy dispatch process* is being applied.
- The *forecasted capacity* for a synchronous *generating unit* is equal to its available capacity at the time for which the *proportional energy dispatch process* is being applied, that is, its offered capacity less any system security constraints.

If necessary to avoid breaching network constraints, *the Power System Controller* may group *generating units* into defined regions upon which the proportional energy dispatch calculation shall be calculated on a regional basis, considering the imported and/or exported power along with relevant constraints.

The regions are intended to group *generating units* around a common load centre that are not separated by constrained network elements. However, other groupings may be made for reasons of system security and economic dispatch.

The *Power System Controller* may include or exclude any *generating units* from the proportional energy dispatch for reasons of system security.

In the application *proportional energy dispatch process* and only for *generating units* with a zero Band 1 quantity, the *Power System Controller* may, at its discretion, treat a small increment of the Band 2 quantity as not being part of the price stack where required to allow the *generating unit* to be available for dispatch if the alternative is to isolate it from the power system.

5.4.5.1. Proportional energy dispatch process

The exact implementation of the *proportional energy dispatch process* depends on the tools available to the *Power System Controller* and the capabilities of the generators. Nevertheless, the *proportional energy dispatch process* will always adhere to the concept of proportionality as far as practicable within the available capabilities. This method will be updated over time as these capabilities improve.

In a constraint or low-load management situation, the dispatch of synchronous generators will be performed at the *Power System Controller's* discretion for the purpose of maintaining system security. Where this is not necessary, the *Power System Controller* will endeavour to manually dispatch synchronous generators simultaneously with solar generators in a proportional manner whilst respecting each units' limits.

The dispatch of solar generators depends on the nature of the constraint being addressed. Where the proportional energy dispatch process involves dispatching each tied generating unit in proportion to their share of forecasted capacity, and this can be achieved without violating other constraints, and such that the combined change from the tied generating units addresses the required demand change, the entire power system is considered as one region, and all solar generation in the power system will be dispatched in proportion.

Otherwise, where it is necessary to avoid breaching network constraints, the Power System Controller may group generating units into defined regions upon which the proportional energy dispatch calculation described can be calculated on a regional basis, considering the imported and/or exported power along with relevant constraints. Where the power system is split into regions, all solar generation within a given region will be dispatched in proportion.

In general, for a given region:

$$D_{region} = (L_{region} + P_{export}) - \left(\sum G_k + \sum_{Constrained} S_k\right)$$

$$S_{i_{PED}} = D_{region} \times S_i \, / \sum_{Unconstrained} S_k$$

In these equations:

k is an index that iterates through each relevant generator in a summation, based on the unit type, constraints, and system / region.

L_{region} is the forecasted total load in the system or region, as applicable.

P_{export} is the power exported from the region, as defined by the network constraint(s). This is negative if the network constraint(s) requires import, and zero if considering the whole system.

G_i is the output of synchronous generating unit G_i

S_i is the constrained / *forecasted capacity* of solar generating unit S_i

D_{region} is the required generation to be met by PED.

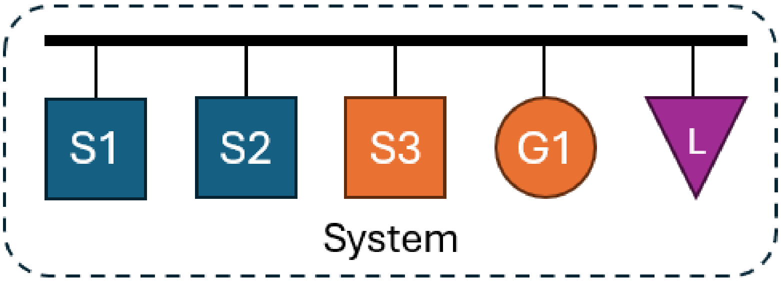
$S_{i_{PED}}$ is the PED dispatch level that is to be applied to solar generating unit S_i

Derivations and examples for each scenario are provided in the following sections.

Proportional energy dispatch applied to a system without network constraints

Consider the simplified diagram presented in Figure 9 of a power system with solar generators $S1$, $S2$, and $S3$, a synchronous generator $G1$, and a load L. There are no network constraints in this power system, as represented by each element being connected to an infinite bus.

Figure 9: Simplified power system



Assume $S3$ and $G1$ are constrained on for testing purposes and system security, respectively, and that load L is increasing such additional generation will be required. It is desired to find the PED dispatch levels of the tied solar units $S1$ and $S2$.

The load balance for the system can be written as follows:

$$S1 + S2 + S3 + G1 = L$$

To find the demand to be met by the tied solar units, the above equation can be rearranged to the following:

$$S1 + S2 = L - (S3 + G1) = D$$

Next, the total *forecasted capacity* is simply the sum of each tied units' *forecasted capacity*:

$$T = S1 + S2$$

The dispatch of the tied generators can then be calculated by the following:

$$S1_{PED} = S1 \times D/T, \qquad S2_{PED} = S2 \times D/T$$

Worked example:

As per Figure 9, Table 7 presents the parameters for each of the power system elements:

Table 7: Proportional dispatch parameters

PARAMETER	TYPE	VALUE (MW)	PRICE
Load	Load	55	N/A
S1 Forecasted Capacity	Solar	14	$0.00
S2 Forecasted Capacity	Solar	19	$0.00
S3 Forecasted Capacity	Solar	10	Constrained On
G1 Output	Synchronous	20	Constrained On

Demand to be met by proportional dispatch:

$$D = L - (S3 + G1) = 55 - (10 + 20) = 25\ MW$$

Total capacity available for proportional dispatch:

$$T = S1 + S2 = 14 + 19 = 33\ MW$$

Allocation to each tied generator:

$$S1_{PED} = S1 \times D/T = 14 \times 25/33 = 10.6\ MW$$

$$S2_{PED} = S2 \times D/T = 19 \times 25/33 = 14.4\ MW$$

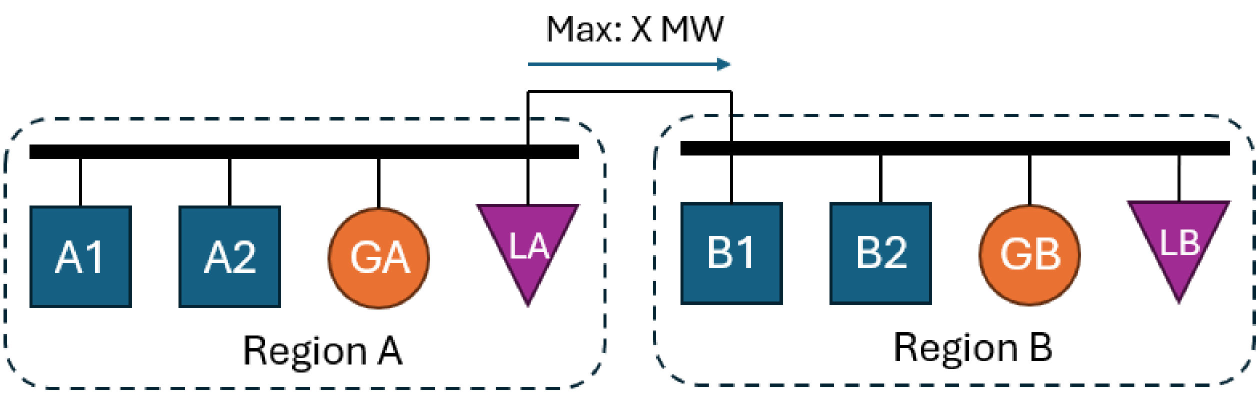
Check:

$$L = S1 + S2 + S3 + G1 = 10.6 + 14.4 + 10 + 20 = 55\ MW$$

Proportional energy dispatch applied to a system with network constraints

Consider the simplified diagram presented in, of a power system split into two distinct regions, A and B, by a transmission line that has a restriction X on the amount of power exported from A to B. Region A contains generators $A1$, $A2$, GA and a load LA, while Region B contains generators $B1$, $B2$, GB and a load LB.

Figure 10: Power system split into two regions



The system can be defined by the following two equations:

$$A1 + A2 + B1 + B2 = (LA + LB) - (GA + GB)$$

$$(A1 + A2 + GA - LA) \leq X$$

In the first instance, the *proportional energy dispatch process* will be applied as shown in the previous example. However, if this results in a breach of the line constraint, then $A1$ and $A2$ must constrained down to their highest permissible output, which is:

$$(A1 + A2 + GA - LA) = X$$

$$A1 + A2 = X + LA - GA = D_A$$

Similarly, the constraint for region B can be found by:

$$(B1 + B2 + GB - LB) = -X$$

$$B1 + B2 = -X + LA - GA = D_B$$

Next, the total *forecasted capacity* in each region is simply the sum of the *forecasted capacities* for each tied unit in that region:

$$T_A = A1 + A2, \qquad T_B = B1 + B2$$

The dispatch of the tied generators can then be calculated by the following:

$$A1_{PED} = A1 \times D_A/T_A, \qquad A2_{PED} = A2 \times D_A/T_A$$

$$B1_{PED} = B1 \times D_B/T_B, \qquad B2_{PED} = B2 \times D_B/T_B$$

Worked example:

As per Figure 10: Power system split into two regions

, Table 8 presents the parameters for each of the power system elements:

Table 8: Regional Proportional dispatch parameters

PARAMETER	TYPE	VALUE (MW)	PRICE
LOAD A	Load	15	N/A
LOAD B	Load	70	N/A
Line Constraint X	Constraint	30	N/A
A1 Forecasted Capacity	Solar	24	$0.00
A2 Forecasted Capacity	Solar	20	$0.00
B1 Forecasted Capacity	Solar	17	$0.00
B2 Forecasted Capacity	Solar	20	$0.00
GA OUTPUT	Synchronous	15	Constrained On
GB OUTPUT	Synchronous	10	Constrained On

Demand to be met by proportional dispatch:

$$D = (L_A + L_B) - (GA + GB) = 60\ MW$$

Total capacity available for proportional dispatch:

$$T = A1 + A2 + B1 + B2 = 24 + 20 + 17 + 20 = 81\ MW$$

Check line constraint:

$$(A1 + A2) \times (D/T) + GA - L_A = 32.6 \leq X = 30:\ False$$

Since the line constraint would be breached by this dispatch, *the proportional energy dispatch process* must be applied to each region individually.

Demand to be met by proportional dispatch in each region:

$$D_A = L_A - GA + X = 15 - 15 + 30 = 30\ MW$$

$$D_B = L_B - GB - X = 70 - 10 - 30 = 30\ MW$$

Total capacity available for proportional dispatch in each region:

$$T_A = A1 + A2 = 24 + 20 = 44\ MW$$

$$T_B = B1 + B2 = 17 + 20 = 37\ MW$$

The dispatch of the tied generators can then be calculated by the following:

$$A1_{PED} = A1 \times D_A/T_A = 16.4\ MW \qquad B1_{PED} = B1 \times D_B/T_B = 13.8\ MW$$

$$A2_{PED} = A2 \times D_A/T_A = 13.6\ MW \qquad B2_{PED} = B2 \times D_B/T_B = 16.2\ MW$$

Check:

Load balance condition: $L_A + L_B = (A1 + A2 + B1 + B2)_{PED} + GA + GB = 85\ MW:\ True$

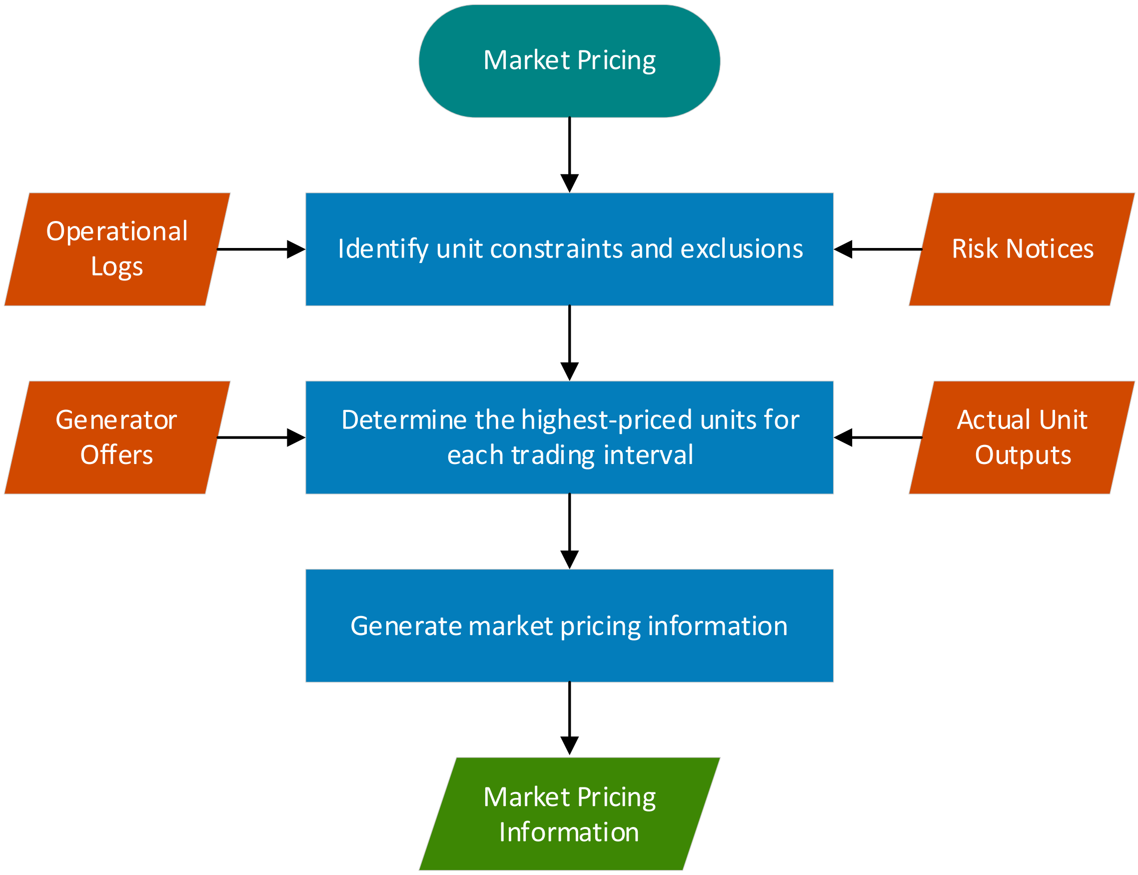
Line constraint: $(A1 + A2)_{PED} + GA - L_A = 30 \leq X = 30:\ True$

6. Market Pricing

6.1. Overview

The market pricing process, including processes to determine all after-the-event information about the dispatch, are only run on business days. In the event of an islanding situation, the market will continue to operate as normal, although it is expected that several generation units will need to be run out of merit for the duration of these events under system security. As a virtual market, there is no regulatory obligation upon participants to utilise the market pricing outcomes. The market pricing process is a regulated function of the I-NTEM that provides transparency of the post market interval pricing determined by the Market Operator to inform licensed participants. The market pricing process is illustrated in Figure11.

Figure11: Market pricing process



6.2. Inputs used to determine market prices

The inputs used in determining the market price for each trading interval are:

- The offer applicable to each generating unit, including long run and short run offers where applicable.

- The average Megawatt (**MW**) quantity provided by each generating unit in each trading interval, where this information is based on real-time SCADA data or, in the event of a SCADA issue[12], the set of dispatch instructions issued to each generating unit.
- The relevant operational logs, risk notices, and feedback from the real-time operation manager that reflect the reasons for deviations from the merit order, if applicable.

6.3. Method for determining market price

The market price for a trading interval is representative of the marginal cost of supplying system loads for that trading interval.

The market price for each trading interval is taken to be the offer price of the most expensive generating unit running for that trading interval taken from that the set of generating units that are running but which are not excluded from setting the market price for that trading interval.

The process for determining the market price for each trading interval is described in the following sections.

6.3.1. Step 1 – Process generating units to identify excluded units

This first step involves excluding generating units from setting the market price for a trading interval because of meeting criteria for such exclusions. The criteria broadly align with the following two areas:

System Security, where a generating unit must be committed for security requirements. Examples of this include, but are not limited to:

- when a risk notice forces a generating unit to be committed and/or dispatched out of merit
- where a performance issue is detected, and a Generator Outage / Test Request is requested
- where essential system service requirements force a generating unit to be committed and/or dispatched out of merit
- in post-contingent event management
- to support system voltage requirements
- to manage supply in islands
- when a generating unit that is not offered on a given trading day but is requested to be committed by the Power System Controller in an emergency scenario to meet load or system security requirements
- if a unit should be no longer required to be constrained for security and is committed in the merit order, the unit will be unconstrained to participate as per the merit order.

Out of Merit, where generating units are online in a manner inconsistent with security constrained economic dispatch. Examples of this include but are not limited to:

- generating unit changeovers at the change of trading day
- other events that may cause a generating unit to become out of merit, such as an error on behalf of one or more system participants other than the Power System Controller, or a real-time alteration to the dispatch made with the consent of the system participants.

[12] If SCADA data were unavailable for a generating unit (e.g. due to a communication failure) fall back strategies include dispatching the generating unit at constant output or decommitting it, while deducing any missing data based on dispatch instructions which have verbal confirmation, data requested from and provided by the Generator, or from state-estimator data.

6.3.2. Step 2 – Process the remaining generating units to identify the relevant price for each trading interval

This step is only performed if there are one or more generating units still able to set the market price for the trading interval after the completion of step 1.

It is first necessary to define which band a generating unit is deemed to be dispatched for the trading interval. If the generating unit is operating in the same band for the entire trading interval, this is straightforward, and the band can be deduced from its average MW output during the trading interval. If the generating unit is operating within more than one band during the trading interval, then the relevant band is the highest priced band the generating unit operated in during the trading interval as deduced from the dispatch instructions.

The price associated with a generating unit for the purpose of setting the market price is determined by the highest priced band for which it was dispatched at any point within a given trading interval, irrespective of the generating unit's output over that trading interval. If a generating unit is dispatched at band 1 for the entire trading interval, then its price will be set to its band 1 price. If a generating unit is dispatched as band 2 during a trading interval, then its price will be set as either its band 2 short run price or band 2 long run price, depending on the duration for which the generation unit was run. If a generating unit is dispatched as band 3 during a trading interval, then its band 3 price will be used in favour of the band 2 or band 1 price.

The band 2 short run price will only be used in cases where the generating unit is brought online and taken offline within a 4-hour period. This does not include cases where the generating unit was already committed and operating at its band 1 quantity, was then raised to band 2 for not more than 4 hours, before having its output returned to its band 1 quantity, where the entire duration of the commitment is greater than 4 hours.

6.3.3. Step 3 – Setting the market price for each trading interval

If all generating units were excluded in Step 1 from setting the market price for the trading interval, then the market price for that trading interval is the market floor price of $0/MWh.

If there is one or more generating units remaining that were not excluded in Step 1 from setting the market price for the trading interval, then the market price for the trading interval is the greatest value of the relevant prices identified at Step 2 for these generating units.

6.4. Publication of market prices

The Market Operator will post a report pertaining to the market price on the Market Operator website. This report contains system load, generating unit output and market price for each trading interval of the trading day.

These reports are available on-line at: https://www.powerwater.com.au/market-operator/daily-price-and-trading-data

6.5. Generator information

The following information is provided to Generators by the Power System Controller after each trading day:

- actual System Loads
- actual market exclusions arising from constraints on the commitment and dispatch process
- chart of the market price for each trading interval over the trading day
- the exact value of the market price for each trading interval

- generator offer file details:
    - generator name
    - offer version
    - start interval
    - trading day
- the pre-dispatch table defined in clause 5.11 of the System Control Technical Code.

This information is emailed to each Generator.

Where a System Participant wishes to query a market price for a given trading interval, they may contact the Market Operator via email at: SystemDispatch.PWC@powerwater.com.au

6.6. Pricing reviews

The Market Operator in concert with the Power System Controller will review pricing results that appear anomalous and will categorise them as being due to either:

- scheduling decisions that may not conform with expected practice
- the application of a previously undocumented security constraint, or
- an error in application of the pricing methodology.
- In any case, the Market Operator will issue a notice to Market Participants explaining the circumstances of the event and the outcome of the review within 10 business days of a System Participant querying a market price of the relevant trading day.

7. Related Records

Related records and procedures, referenced in Table 9, are stored in either:

- the System Control Operational Document Facility accessed through the intranet web site for Power System Control and Market Operations,
- Power and Water's Records Management System (CM9) in accordance with the Corporate Document and Record Control Procedure, or
- records are to be retrievable through Power and Water's Record Management System.

Upon request to the Market Operator, a record may be made available in part or full where appropriate.

Table 9: Related records

NO.	DOCUMENT	DATE	LOCATION/Reference no
1	Generator Offer Template (version 12)	29/01/2026	Content Manager – Reference: D2026/31252

8. Document history

As a minimum the Scheduling and Dispatch Guideline shall be reviewed every 5 years.

Table 10: Document history (including separate procedures)

PUBLICATION	REVISION	DATE	STATUS / CHANGE	UPDATE BY	REMARKS
Market Timetable Procedure	1.0	July 2016	Published	Market Operator	Procedure consolidated into Scheduling and Dispatch Guideline Version 1
Generator Offer Procedure	2.0	Sept 2020	Published	Market Operator	Procedure consolidated into Scheduling and Dispatch Guideline Version 1
Generator Unit Tie Break Procedure	2.0	Sept 2020	Published	Market Operator	Procedure consolidated into Scheduling and Dispatch Guideline Version 1
Dispatch and Pricing Procedure	1.0	2021	Draft	Market Operator	Procedure consolidated into Scheduling and Dispatch Guideline Version 1
Scheduling and Dispatch Guidelines	Version 1.00	May 2026	Issued as draft	Market Operator	Initial drafting of the Scheduling and Dispatch Guideline following consolidation of various scheduling and dispatch procedures as defined above

Contact

Power and Water – 1800 245 092 from 8am to 5pm weekdays.
Market Operator – 08 8985 8566
Email: market.operator@powerwater.com.au

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