NTESMO

Scheduling and Dispatch Procedure Development

Discussion Paper
3 November 2025

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1 Introduction

1.1 Purpose

Power and Water Corporation (Power and Water), in its capacity as the Power System Controller, is seeking to update and amend the suite of procedures governing scheduling and dispatch of generators and dispatchable supply side resources in the Darwin Katherine Power System (DKPS).

The System Control Technical Code (SCTC)[1] prescribes obligations on the Power System Controller in relation to the development of, and consultation on, guidelines and procedures governing the scheduling and dispatch of generators in various locations. The SCTC requires consultation with System Participants prior to publishing such documents.

The purpose of this paper is to facilitate consultation with System Participants and Interested Persons on the amendment and consolidation of the full suite of drafted and published procedures governing scheduling and dispatch of generators in the DKPS. The review of the set of procedures pertaining to scheduling and dispatch is timely having last been reviewed over 5 years ago for a relatively simple power system, coupled with the significant evolution of the DKPS regarding supply-side technologies that now includes a substantial grid-connected inverter-based generator capacity and battery energy storage systems (BESS). The technology and tools[2] developed or now being developed to manage these resources has evolved, affording more efficient management thereof.

NTESMO invites participants and interested parties to make submissions and potentially influence the amendment of scheduling and dispatch methods and procedures to secure the optimal outcome for the industry and consumer. It is important that each proposal for amendment is backed by clear rationale that includes evaluating the impact upon the participants arising from these amendments.

The Northern Territory Electricity System and Market Operator (NTESMO), a stand-alone business unit within Power and Water, fulfils Power and Water's role of the Power System Controller. NTESMO will undertake the consultation process and update the relevant procedures.

1.2 Approach and schedule

NTESMO will conduct a standard consultation aligned with clause 8.9.2 of the National Electricity Rules (NER) (NT). NTESMO encourages stakeholders to submit responses to this paper no later

[1] System Control Technical Code

[2] That includes the Transitional Tools and the Territory Dispatch Engine consulted on and forming part of the NTESMO regulatory submission FY24-27 and furthermore to be consulted on and forming part of the NTESMO regulatory submission FY28-32. The initial submission for the NTESMO regulatory submission FY28-32 will be provided to the Utilities Commission by NTESMO in early 2026.

than 1st December 2025 so that proposed amendments can be developed, reviewed, updated, finalised and published in accordance with the indicative schedule below in

Table 1.

Table 1 - Scheduling and Dispatch standard consultation timetable

Stage	Commence	Complete	Explanation
Release of consultation pack	3 November 2025	1 December 2025	Provides stakeholders at least 20 business days as per clause 8.9.2(a) of the NER (NT)
Review and consolidation of responses	8 December 2025	02 January 2026	50 business days to draft amendments to procedures
Develop and review amended procedure/s	05 January 2026	13 February 2026	Sufficient time to review and draft amendments taking into consideration stakeholder's first round submissions
Publish responses and commentary Publish amended procedure	16 February 2026	13 March 2026	Publication of response to stakeholder's first round submissions and amendments via notification on NTESMO's website
Review and draft response to submissions by System Participants	16 March 2026	30 April 2026	Sufficient time to update proposed amendments taking into consideration stakeholder's second round submissions
Publish responses and commentary Publish final amended procedure	1 May 2026	1 May 2026	Final publication, including notification of date of effect
Date of effect of amended Procedure	1 July 2026	1 July 2026	Date of effect may be brought forward contingent upon outcomes of stakeholder consultation
Industry updates regarding implementation	2 March 2026	To be determined	Updates to be published on NTESMO's website until post final transition

1.3 Scheduling and dispatch overview

An overview of the scheduling and dispatch process is presented in Figure 1 with a more detailed description of each element provided in the subsequent sections.

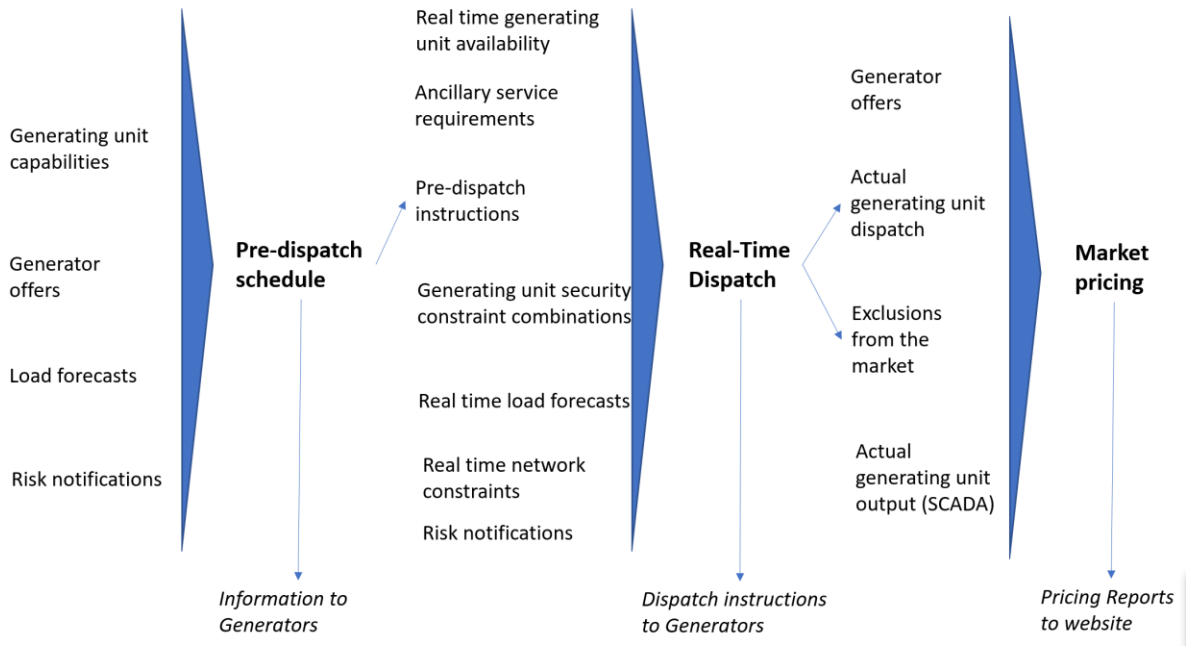
Under clause 4.7(c) of the SCTC, the Power System Controller must assess the need for increasing the output of self-committed generating units, or committing and dispatching fast start generating units, to meet total demand based on the primary principle of Security Constrained Economic Dispatch. This principle requires the dispatch of generating units to meet total demand while

minimising costs as defined by generating offers, and having regard to the Dispatch Principles and the Dispatch Criteria, as set out in clauses 4.3(a) and 4.3(c) of the SCTC, respectively:

- The **Dispatch Principles** give priority, within the overarching principle of Security Constrained Economic Dispatch, to a number of system reliability and system security considerations. Implicit to these principles is the concept that, during normal operation, if practicable, scheduling ancillary services[3] 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.

Figure 1 - Scheduling and Dispatch Process Overview

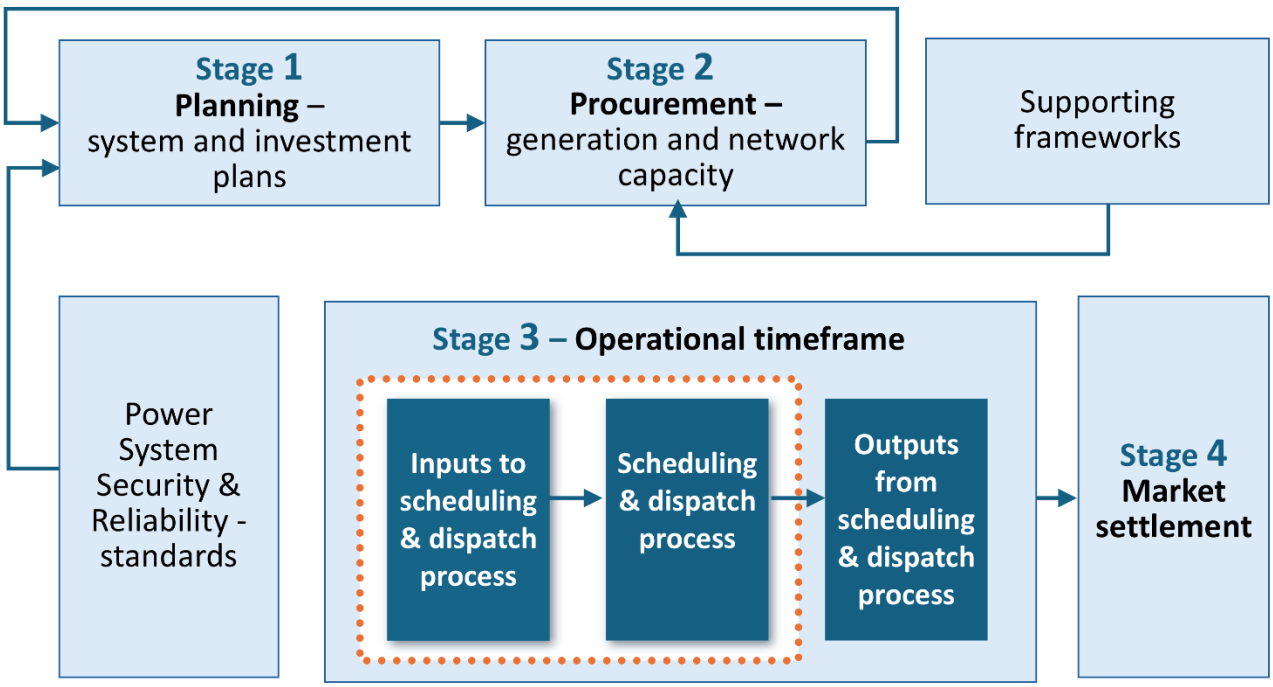


[3] Now commonly referred to as Essential System Services.

1.4 Consultation in the context of the TEM Reform Program

The Northern Territory Government is currently progressing reforms to the Territory Electricity Market (TEM), including a new Public Procurement Model (PPM) for the DKPS, which will come into effect over the next couple of years. A simplified overview of the operation of the DKPS following the implementation of the TEM Reform Program is provided below in Figure 2. The most significant changes are in relation to Stage 1 – Planning, Stage 2 – Procurement, and the Power System Security and Reliability standards.

Figure 2 – TEM Reform and scheduling and Dispatch Process Overview



This consultation is focussed on amendments to various procedures that define the way scheduling and dispatch is conducted by the Power System Controller, in terms of the inputs to the process and the process itself (highlighted by the dotted red line in Figure 2). The types of inputs to the process, and the requirement for Security Constrained Unit Commitment and Security Constrained Economic Dispatch principles have been established as foundational policy settings of the TEM Reform Program.[4] The changes that are discussed in this paper are required for the operation of

[4] While the TEM Reform Program will not change the types of inputs required for the Scheduling and Dispatch process, they may change the actual inputs to the Scheduling and Dispatch process. For example, the Ancillary Service (or Essential System Service) requirements will be updated as part of the TEM Reform Program.

the Interim Northern Territory Electricity Market (I-NTEM) and also enable the implementation and operation of the PPM.

In some areas, this paper proposes to amend the procedures to align them with current operational practices. *For these reasons, NTESMO is of the view that these changes should be made now and should not be deferred until further detail on the PPM and other reform workstreams that form part of the TEM Reform Program is made publicly available.*

When enacted, the *Electricity Legislation Amendment (Market Reform) Act 2025* is expected to repeal the requirement for a SCTC and replace it with the TEM Rules. Throughout this consultation process, NTESMO will monitor the development of the TEM Rules. At this stage, NTESMO expects that any changes that are made to the suite of procedures governing scheduling and dispatch will align with the new TEM Rules.

Changes recently made to the Secure System Guidelines come into effect on 1 November 2025. There are no further changes proposed to these guidelines in this paper.

2 Procedural evolution

There are currently five approved procedures that define the way scheduling and dispatch is conducted by the Power System Controller, with an additional procedure that has been drafted but not released as final. These procedures are tabulated below in Table 2.

Table 2 - Scheduling and Dispatch suite of procedures

Procedure	Version	Date Effective	Review Period
Market Timetable Procedure	1.0	July 2016	Subject to SCTC changes
Generator Forecast Compliance Procedure	1.1	July 2020	Subject to NTC and SCTC changes
Generator Offer Procedure	2.0	September 2020	Subject to SCTC changes
Generator Unit Tie Break Procedure	2.0	September 2020	Subject to SCTC changes
System Control Plant Outage Procedure	1.0	October 2020	Subject to SCTC changes
Dispatch and Pricing Procedure	Draft	Not yet released	To be determined

The purpose of this discussion paper is to:

1. describe the current scheduling and dispatch procedures, and operational challenges experienced, to be able to identify the updates and amendments required to the

procedures to better align them with current real-time operational practices, and improve the scheduling and dispatch process so as to leverage a contemporary set of tools and systems being developed for future implementation

2. seek input from System Participants and Interested Parties regarding the proposed amendments to the method of enabling scheduling and dispatch for the DKPS
3. propose consolidating some or all of the existing procedures into a single, consistent and succinct procedure that sets out the way the System Controller schedules and dispatches all System Participants in the most economical manner for the Power System while respecting security constraints within the context of the I-NTEM and the foreshadowed introduction of the PPM.

Participant Question 1: What are your views on consolidating some or all of the existing procedures into a single procedure / reference guide governing the scheduling and dispatch of System Participant Facilities? Which procedures should be consolidated into a single procedure, and which (if any) should not? Please provide clear rationale for not including any of the existing procedures into a single consolidated procedure.

3 Inputs used in the pre-dispatch and real-time scheduling and dispatch processes

The inputs that are used in the scheduling and dispatch process are described in this section. This section provides information to assist Market Participants make are submission to this consultation process being undertaken by NTESMO.

3.1 Generator offers

Generators are obligated by clause 4.4B of the SCTC to make generator commitment and dispatch submissions ("offers") for each trading day. The information to be provided is described in the Generator Offer Procedure and includes the classification of generating units as either self-committed generating units or fast start generating units. These submissions contain the Generator's preferences for how its portfolio of units are committed and decommitted.

Generator's submissions also currently provide the offer prices for each generating unit, including band 2 short run price, band 2 long run price and band 3 price for a fast start generating unit. With the foreshadowed introduction of the PPM in the DKPS, the offer prices for each generating unit contracted to NTESMO under the PPM will be as set out in the relevant contract.

3.2 Load forecast

The Power System Controller is required by clause 5.11 of the SCTC 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 are only produced on business days.

In the operational time frame, the Power System Controller uses dynamic tools to update the total system load forecast at a 5-minute resolution, which accounts for weather data, solar data, and historical patterns of behaviour. The 5-minute resolution near real-time forecasts are published and updated every 5 minutes on the NTESMO Website.

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]

3.4 Risk notifications

Risk notifications provide information on existing approved Outage and Testing Requests (OTRs)[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.

3.5 Network constraints

Network constraints, which are defined in clause 3.9 of the SCTC, 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.

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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 OTR processes refer to the Plant Outage Procedure.

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

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.

3.6 Essential system service requirements

Essential System Service 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 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. With the foreshadowed introduction of the PPM, all generators that are accredited to provide Essential System Services will be able to tender to supply essential system services.

3.7 Real-time generating unit availability

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]

3.8 Pre-dispatch schedule outputs

The process of determining the pre-dispatch schedule determines a number of inputs to the real-time dispatch process, including pre-dispatch instructions and feasible combinations of generating units to satisfy system security considerations.

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

4 Pre-dispatch processes

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.

4.1 Inputs used in the pre-dispatch process

The inputs used for a pre-dispatch for a trading day are:

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

These were described in more detail in the previous section.

4.2 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).

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.

4.2.1 Generating unit tie break procedure

Where required to develop the merit order, tie-breaking is applied in accordance with the Generating Unit Tie-Break Procedure. The Generating Unit Tie Break Procedure considers two separate scenarios:

- 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.
    - This is covered by clause 5.8 of the Generating Unit Tie Break Procedure.
- Ties between generating units with respect to commitment or decommitment when energy output is already at minimum stable load, or the units are offline.
    - The former is covered by clauses 5.1 to 5.4 of the Generating Unit Tie Break Procedure, while the latter are covered by clauses 5.5 to 5.7 of the Generating Unit Tie Break Procedure.

The Generating Unit Tie Break Procedure applies to ties in commitment and energy decisions using either a random period or random day selection process, depending on the situation, that allocates the order in which generating units will be selected to respond.

In all cases, tie-breaking is conditioned by the requirement to maintain system security. The selected generating unit, taking whichever action is required, must not violate other system or network constraints. In practice, it may be necessary to skip generating units in the merit order to satisfy these requirements.

4.3 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 SCTC 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, taking into account tie break rules. In particular:

- The off-load order for self-committed generating unit 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.

Where self-committed generating units have been decommitted earlier in the trading day (primarily in real-time) and it is now possible to recommit some of these generating units, the

Generator for each generating unit has the right, but not an obligation, to have that generating unit committed in the same order in which it was decommitted (first off / first on). If all impacted Generators exercise this right for all impacted generating units, the merit order will remain the same. Where a Generator declines the option to be re-committed, that generating unit is moved down to the end of the merit order for the remainder of the trading day.

4.4 Energy and tie break merit order

The energy and tie break merit order is constructed in two steps.

- The band 2 long run and self-committed band 2 prices are arranged from the cheapest to the most expensive.
- An energy tie exists where there are equal priced offers from band 2 from two or more self-committed or fast start generating units. Clause 5.8 of the Generating Unit Tie Break Procedure determines the order in which to increase or decrease generating unit output.
    - The tie-breaking process applies up to 5 MW increments of increase or decrease rather than the full capacity of the band 2 offer. Each tied band 2 offer is partitioned into 5 MW increments (or less where there is not enough remaining capacity in the band to support this).
    - The first increment of each tied generating unit is ordered in the merit order based on the tie-breaking order of the generating unit. This process is then repeated to order the next 5 MW increments from those same tied generating units within the remaining band 2 capacity. This process repeats for all generating units until their band 2 offer capacities are exhausted.

The energy and tie break merit order considers the band 2 long run price of fast start and self-committed generating units. Further, if the fast start generating unit is not currently committed it will be committed based on this merit order unless prevented for system security reasons.[9] As with commitment ties, the tie-breaking procedure is sensitive to system and network constraints.

Current operational practice differs from the tie-breaking procedure as written for self-committed units due to system security requirements. Implementing the 5 MW increments requires many manual actions from the system controllers, which are difficult to apply in conjunction with system and network constraints. Therefore, to mitigate system security risks, the current practice is to dispatch self-committed units via proportional energy dispatch (PED).

[9] This will mean that the *band 1* quantity will be supplied automatically in making it possible for the *generating unit* to provide *band 2* energy.

In PED, where a constraint exists in a region that does not allow all self-committed generators to be dispatched to their full offered capacity, each self-committed generating unit in the region is allocated a proportional share of the capacity required to meet demand or satisfy the constraint.

PED is currently applied pre-emptively via a manual calculation process. With the development of more sophisticated dispatch tools and automation of the energy management system (EMS), it is becoming increasingly possible to amend the Generating Unit Tie Procedure and adapt to proportional dispatch. NTESMO intends to investigate options for automating the PED process in due course with the implementation of these tools.

Participant Question 2: Do you support amending the Generating Unit Tie Break Procedure to more accurately reflect the current operational practice of proportional energy dispatch process?

4.5 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, clause 5.8 of the Generator Unit Tie Breaking Procedure is applied, subject to maintaining system security and not violating any system or network constraints.

4.6 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

[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*.

generating unit to decommit first (except where prevented for security reasons). Where a tie exists, clauses 5.1 to 5.4 of the Generator Unit Tie Breaking Procedure require 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 below.

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 Generator Unit Tie Breaking Procedure requires that 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.

4.7 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 has the option, though is not required, to specify a decommitment order to apply post 1800 hours in its generator offer for the trading day as described in the Generator Offer Procedure. The first off 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.

The following table 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 (this order is denoted by the 1 and 2 in accordance with the Generator Offer Procedure). The right column shows the first decommitment merit order. Comparing the two tables below, we see that as a result 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.

Participant Question 3: Do you have any material observations and recommendations regarding the decommitment merit order post 1800 hours? Please provide clear rationale for your recommendations.

4.8 Other pre-dispatch data

4.8.1 Overnight generating units

The Power System Controller prepares a list of Overnight generating units to use in the real-time commitment and dispatch process, based on the expected number of generating units required to be on overnight and the preferred order of decommitment specified by Generators. The list identifies specific generating units expected to be online based on the load forecast, with some generating units being required on due to specific security requirements, with the rest determined based on commitment merit orders.

This information is provided as a reference point. The Power System Controller may run a different set of generating units where the situation changes, for instance, if a new security requirement arises.

One trading day ends at 0400 hours and a new trading day starts. The generator offers applicable to the new trading day take precedence over a Generator's preference for how its generating units are decommitted for the previous trading day. This means that if a Generator does not want some of its generating units decommitted at 0400 hours and different generating units committed it needs to ensure consistency of its preferred order of decommitment on the previous trading day with prices and other data in its generator offer for the new trading day.

4.8.2 Frame 6 / FCAS units

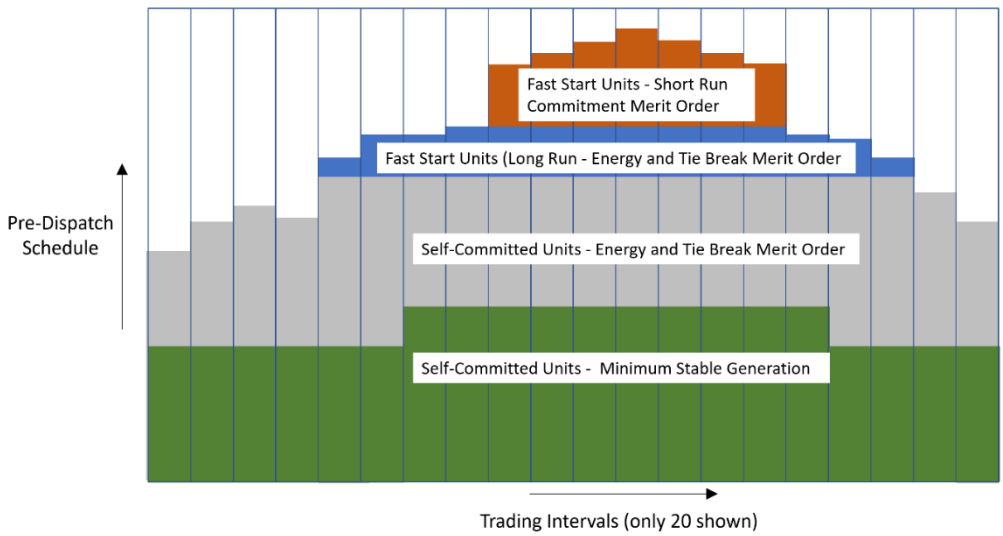
The Secure System Guidelines currently require the Power System Controller to maintain a minimum number of frame 6 generating units online at different nodes taking the recent addition of the Channel Island BESS into account. This requirement specifies the combinations of frame 6 generating units that can satisfy the guidelines. From this list of combinations, the controller must always select the cheapest two to be run, that includes the BESS, which may result in a single Frame 6 unit and the Channel Island BESS.

While a fixed number of generating units has been used to date to meet this requirement, the number is expected to become more dynamic over time with revised Secure System Guidelines (Version 5) coming into effect on 1 November 2025. This replaces the traditional static spinning reserve requirements with a more dynamic FCAS framework.

4.9 Pre-dispatch solution process

Figure 3 - Illustrative example of pre-dispatch schedule 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.

Figure 3 - Illustrative example of pre-dispatch schedule



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.

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. With the introduction of the PPM, start-up and shut-down costs are expected to be separately specified in the contract with NTESMO.

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 can also specify an alternative first off decommitment merit order to apply from 1800 hours to the end of the trading day (refer above). 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.

With the foreshadowed introduction of the PPM, this situation will not occur.

4.10 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.

Participant Question 4: Do you have any material observations and recommendations regarding the scheduling / pre-dispatch process? Please provide clear rationale for your recommendations.

5 Real-time commitment and dispatch

The previous section described obligations on the Power System Controller that apply during the pre-dispatch process and during real-time commitment and dispatch. Accordingly, this section is focused on providing a summary of the process for dispatching the power system in (and leading up to) real-time. It is focused on simultaneously:

- matching energy generated with system load
- ensuring that sufficient generation capacity with sufficient flexibility is online to give the power system the ability to react to changes in system load and contingency events while providing the required essential system services
- respecting constraints on how the system can be operated
- satisfying the economic and security requirements of a security constrained economic dispatch.

In managing power system constraints, the Power System Controller will first seek to manage constraints within the current commitments and 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 Essential System Services to operate the power system within technical operating limits.

The Power System Controller can control the dispatch of generating units via Automatic Generation Control (AGC). Generally:

- All Territory Generation generating units are under AGC control (noting that the Katherine Power Station Units cannot be placed in an 'economic dispatch' mode), 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.
- If further frequency control is required, generating units operate under primary frequency control in droop control mode to recover frequency to a normal frequency operating band.
- Where required, units are manually configured to produce or absorb reactive power in addition to producing active energy required by the market.

Following a contingency event, the Power System Controller has 30 minutes to restore a secure operating state and restore frequency within the normal operating band. During this period, generating units will be reacting, in many instances automatically under primary frequency control, to the event rather than in response to specific dispatch instructions (secondary frequency control) while the Power System Controller will be focused on taking actions, such as committing additional units, to restore a secure operating state. Consequentially, some Essential System Service requirements may not be satisfied until such time as the regulated power system has been restored to normal operation and the power system has resumed operating in the normal frequency operating band.

5.1 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 guidelines 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
- network constraints
- real-time system configuration and system security considerations.

5.2 Real-time dispatch process

The approach to real-time dispatch is illustrated in *Figure 4* 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.

5.2.1 Actions when the generation requirement for energy or capacity increases

Unit commitment

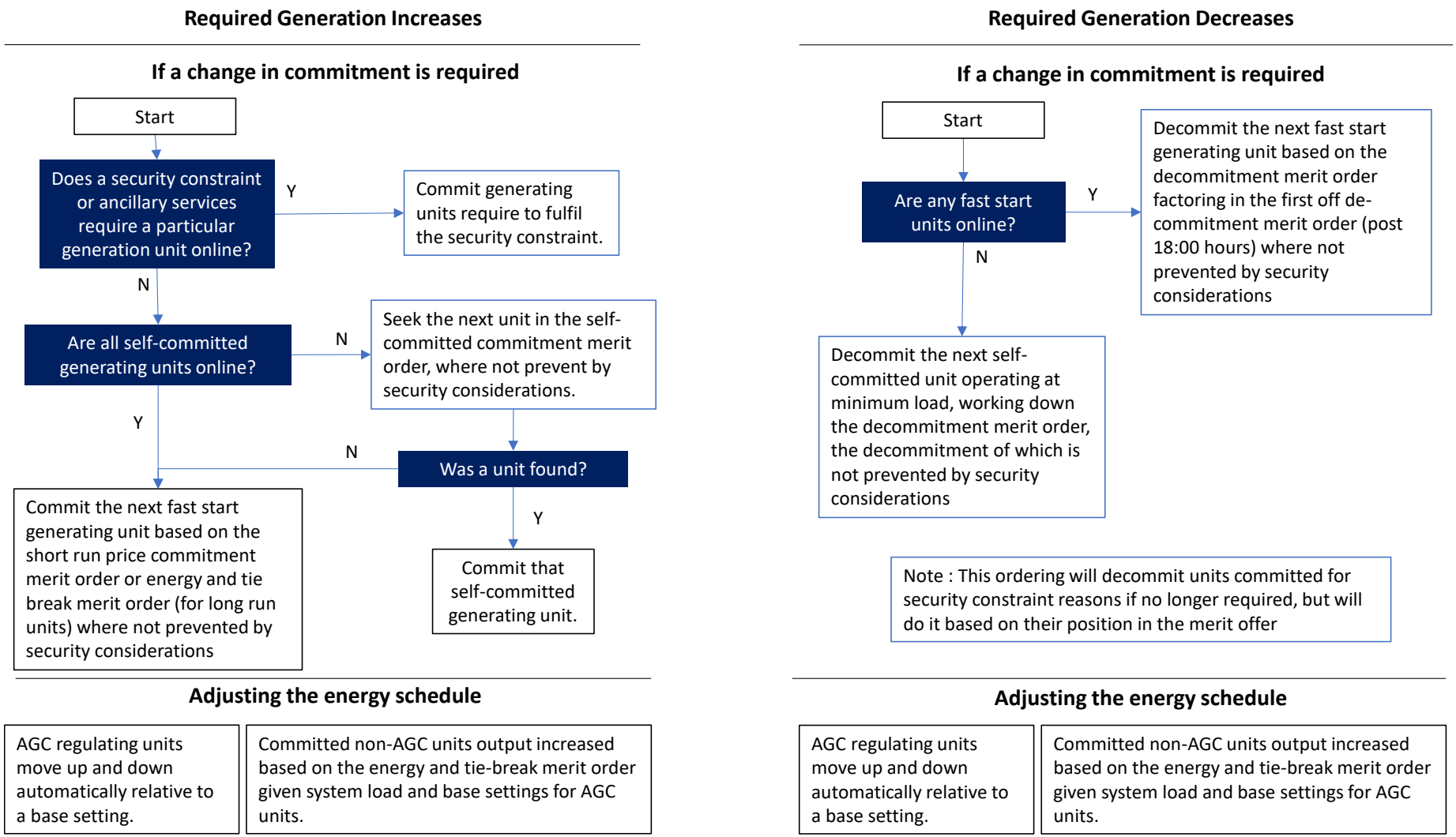
Priority 1 – Security Constraints

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 contingency whether it involves the loss of generation or load by balancing out all the essential system service requirements (voltage control and frequency control services including reserves associated with both) across more 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.

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

Figure 4 – Illustration of the approach to real-time 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 committing all self-committed units 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).

Where a self-committed generating unit was previously decommitted on the same trading day and it is now possible to recommit the generating unit based on the self-committed commitment merit order, the Generator has the option to recommit the generating unit when requested by the Power System Controller in the same order in which it was decommitted (first off/first on). Where a Generator declines the option to recommit the self-committed generating unit, that generating unit will be moved down to the end of the merit order for the rest of the trading day.

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.

When committing from either of these merit orders, the order will always be used regardless of the size of that quantity, including in the circumstance where multiple generating units may be required to be committed at the same time. That is, small generating units (or band 3 quantities) that are considered too small to likely cover the increase in load will not be skipped in favour of larger units, even if all the units belong to the same Generator. Due to system security requirements, this requirement is not always met. If a unit fails to start when needed, it poses a

system security risk. Therefore, in the event that a unit has recently been unreliable when starting, the next unit in the merit order may be dispatched first.

Additionally, the merit order may not always be able to be followed if it would result in a lack of regulation draw down.

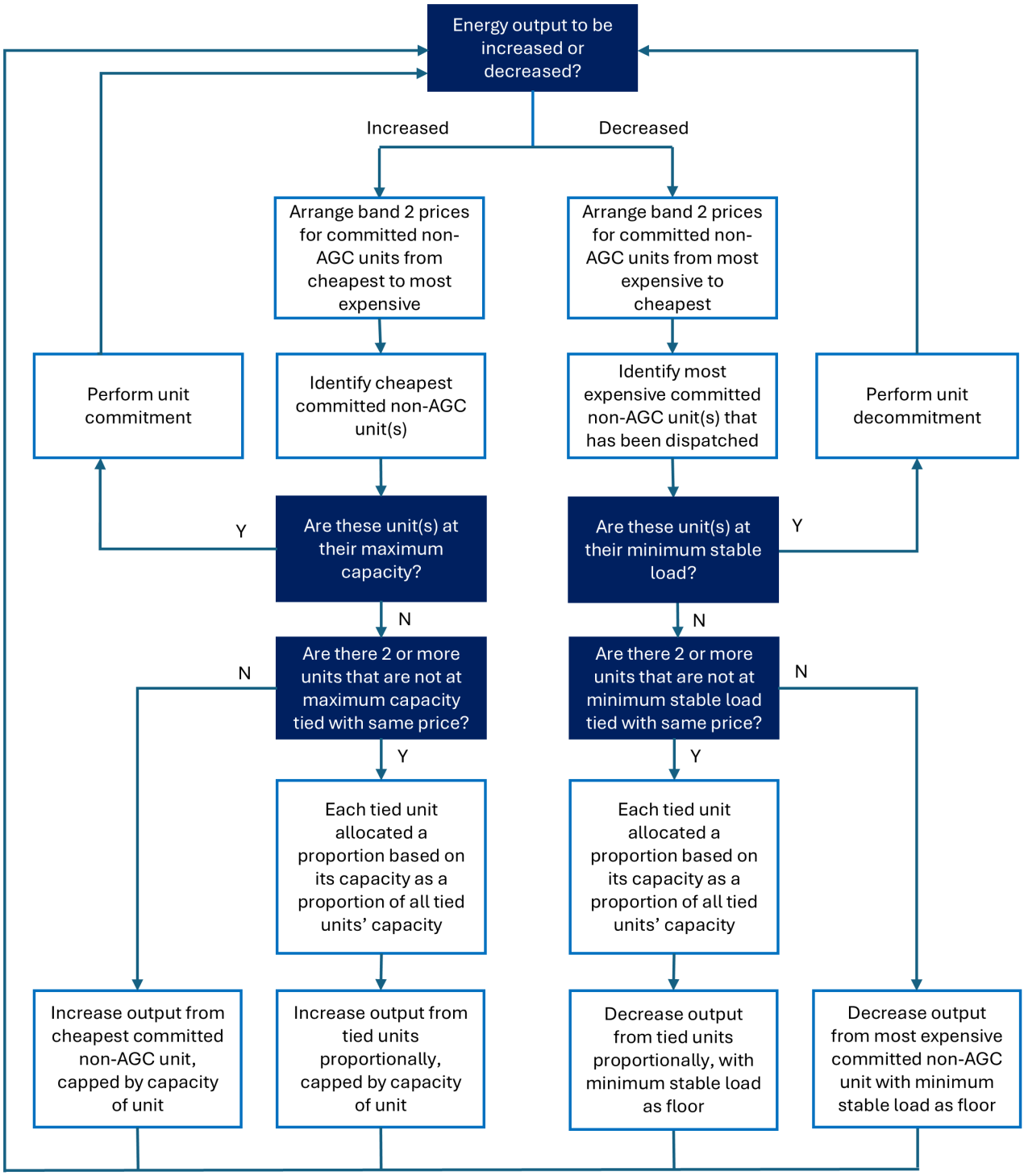
Energy scheduling

Generating units providing regulating reserves will have their dispatch level determined by the Power System Controller's AGC to meet their essential system service obligations in the most economically efficient manner. Regulating reserve generating units may have their outputs increased or decreased 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, as illustrated in Figure 5. The Power System Controller will employ reasonable efforts to dispatch generating units tied under clause 5.8 of the Generation Unit Tie Break Procedure in 5 MW blocks. Each tied unit-band is increased by 5 MW in turn in tie-breaking order. This feature is intended to minimise the impact of tie-breaking on Generators and (in the case of solar farms) aids geographic diversity of supply by spreading the reductions across solar farms manually in fairly large quantities.

As discussed above, current operational practice differs from the tie-breaking procedure as written due to system security requirements. To mitigate system security risks, the current practice is to dispatch self-committed units via PED.

Figure 5 – Illustration of the approach to real-time energy scheduling



5.2.2 Actions when the generation requirement for energy or capacity decreases

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.

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.

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.

Participant communication

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

Participant Question 5: Do you have any material observations and recommendations regarding the real-time scheduling and dispatch process? Please provide clear rationale for your recommendations.

6 Market prices – I-NTEM

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.

6.1 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 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
- list of criteria for excluding generating units from setting the market price, to be applied to the set of dispatch instructions.
    - The market exclusions are set by the Power System Controller to reflect dispatch actions taken that are deemed to preclude the generation unit from contributing to the marginal cost of serving system load. For example, a unit that is constrained to run out of merit order should not set the market price.

6.2 Method for determining market prices

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.

[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.

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 as a result 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 an OTR 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
    - generating unit changeovers when a lower cost generating unit becomes available
    - generating unit changeovers when essential system service requirements change
    - the application of the first-off decommitment merit order
    - 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.

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

This step is only performed if there is 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.

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.

6.3 Market pricing results

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

6.4 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 SCTC.

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

6.5 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.

Participant Question 6: Do you have any material observations and recommendations regarding the market price determination process? Please provide clear rationale for your recommendations.

7 Proposed amendments to procedures governing scheduling and dispatch

7.1 Market timetable procedure[13]

All timetables associated with the release of pre-dispatch and pricing information are governed by clauses 4.4B and 4.7 of the SCTC and summarised in detail in the Market Timetable Procedure.

The existing market timetable appears to be well suited to the I-NTEM (and may suit the PPM accordingly) and it is not intended to make any material changes to the procedure, except for consolidating the market timetable prescriptions into the proposed Scheduling and Dispatch procedure.

Participant Question 7: What amendments would you recommend to the existing market timetable as described in the Market Timetable Procedure? Please provide clear rationale for recommending such changes.

7.2 Generator forecast compliance procedure[14]

The generator forecast compliance procedure, which governs the automatic access arrangements for System Participants, is prepared under the authority of the Network Technical Code (NTC), rather than the SCTC.

It requires a comprehensive update. Presently inverter-based solar generators are subject to negotiated access that applies bespoke generator forecast compliance requirements. The intent is to revise the generator forecast compliance procedure with the advent of further applications under the automatic access arrangements as prescribed in the NTC.

Participant Question 8: What amendments would you recommend to the existing generator forecast compliance procedure based upon current negotiated access? Please provide clear rationale for recommending such changes. Do you support consolidation of the generator forecast compliance procedure into the proposed scheduling and dispatch procedure? If not, please provide a clear rationale for an alternative approach.

[13] Market Timetable Procedure
[14] Forecasting Compliance Procedure

7.3 Generator offer procedure[15]

The generator offer procedure is intended to be integrated into the recommended Scheduling and Dispatch procedure.

NTESMO intends to retain the current approach for generator offer and bid submissions, with the addition of a provision allowing participants to submit self-committed offers for multiple generating units at the same price. This enhancement supports the application of proportional dispatch, consistent with current operational practice.

Furthermore, NTESMO intends to segregate the generator offers to separate generator commitment offers (start/stop) and variable operating offers based upon short and long run duration. The segregation of bid structure would likely be considered once the requisite systems are established to manage these, including the advent of the Territory Dispatch Engine (TDE).

It is intended that the generator offer provisions will apply with the foreshadowed introduction of the PPM, noting that the offers by generators contracted by NTESMO will be in accordance with those contracts.

Participant Question 9: What amendments would you recommend to the existing generator offer procedure based upon prevailing market conditions? Please provide clear rationale for recommending such changes.

7.4 Generator unit tie break procedure[16]

The generator unit tie break procedure is intended to be integrated into the recommended Scheduling and Dispatch procedure.

As discussed in section 4, NTESMO intends to amend the existing method for unit tie breaking from 5 MW blocks to a proportional energy dispatch arrangement.

Participant Question 10: What amendments would you recommend to the generator unit tie break procedure based upon prevailing market conditions? Please provide clear rationale for requiring such changes.

Do you support centralised dispatch of all generating units to afford incremental proportioning of dispatch?

Can you recommend any alternative methods to be considered? Please present clear rationale for such.

[15] Generator Offer Procedure Version 2.0
[16] Generating Unit Tie Break Procedure

7.5 System Control plant outage procedure[17]

The System Control Plant Outage procedure is intended to be appended to the recommended Scheduling and Dispatch procedure. The procedure is currently 5 years old – it requires a review and minor updates before being included, but NTESMO is of the view that no substantial changes are required

Participant Question 11: What amendments, if any, would you recommend to the existing System Control plant outage procedure based upon prevailing market conditions? Please provide clear rationale for recommending such changes.

7.6 Dispatch and pricing procedure (draft)[18]

Industry feedback has indicated that a flexible process for dispatch of fast start units is required to enable real time dispatch commitment decisions to adapt to the real time circumstances. In practice we have many instances where circumstances at the time of dispatch are not suited to rigid merit orders that results from the draft procedure for fast start generating units. NTESMO is intending to incorporate flexibility into the procedure for generating units offered as fast start where this does not impact dispatch of generating units offered as self-committed.

The draft dispatch and pricing procedure is intended to be absorbed into the recommended Scheduling and Dispatch procedure. All industry responses to the draft procedure will be considered in the drafting of the Scheduling and Dispatch procedure.

Participant Question 12: Do you support the consolidation of the draft dispatch and pricing procedure into the proposed scheduling and dispatch procedure? Please provide clear rationale for any alternative approaches proposed.

[17] System Control Plant Outage Procedure
[18] Draft Dispatch and Pricing Procedure

Contact

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

NTESMO