ELECTRICITY AUTHORITY
TE MANA HIKO

Proposed real-time pricing amendments to the policy statement

Consultation paper

Submissions close: 5:00pm, 30 August 2022

Executive summary

The Electricity Authority (Authority) is consulting on a draft policy statement which is proposed to replace the policy statement that is currently part of the Electricity Industry Participation Code 2010 (Code).

The current Policy Statement, effective from 1 August 2022, is the result of the system operator's periodic review of the policy statement under Clause 8.10A of the Code. That review was due before the final review of the real-time pricing (RTP) impacts on the system operator's processes were known and so could not incorporate them. This consultation uses the 1 August 2022 Policy Statement as the baseline for the RTP changes.

Clause 8.11A(2) of the Code allows the Authority or a participant to request that the system operator proposes a change to the policy statement under clause 8.11A(1). The Authority has requested the system operator propose a change to the policy statement to align with the decision to implement the RTP changes to the wholesale market, and the accompanying Code amendments.

In addition to a number of relatively minor changes proposed to align the policy statement with the intent of the real time pricing Code amendment, the proposed amendments seek to:

- further detail the circumstances in which adjustments are made to the forecast and dispatch schedules, as provided for under Clause 12 of Schedule 13.3 of the Code,
- reform the Dispatch Policy to incorporate the production of Dispatch prices in the dispatch process
- describe the criteria the system operator will use to assess eligibility of market participants as Dispatch Notified participants.

Before deciding whether to approve the draft policy statement, the Authority must consult on the proposed amendments. This consultation complements the Authority's final consultation on the revised RTP Code Amendment. As these changes are required as part of the RTP market changes, the costs and benefits of these changes are deemed to be included in the Authority's assessment of the costs and benefits of the RTP project, and no further information is provided as part of this policy Statement consultation.

The Authority will consider all submissions received, including the system operator's cross submission. If accepted, the policy statement will take effect when it is adopted by the Authority by giving notice in the Gazette.

Contents

Executive summary ii

1 What you need to know to make a submission 4
What this consultation paper is about 4
How to make a submission 4
When to make a submission 4

2 The system operator has proposed amendments to the policy statement 5
The policy statement is prepared by the system operator 5
The system operator has submitted a draft policy statement following a request by the Authority 5
The Code prescribes a process for amending the policy statement 6
The system operator proposes amendments to the dispatch policy of the policy statement 6

The system operator has provided supporting information 6
There are three requirements for supporting material 6
The objective of the proposed amendment is to amend the policy statement to reflect the Authority's real-time pricing project Code amendments 7
The real-time pricing project has evaluated alternatives, costs and benefits 7

4 The Authority intends to adopt the system operator's proposed amendments 7

Appendix A Format for submissions 9

Appendix B Proposed amendment to the policy statement 10

Appendix C The system operator's assessment of the proposed amendments 11

Appendix D GL-OC-984 Dispatch schedule load input guideline 12

Appendix E GL-DP-983 Post schedule check summary 13

Glossary of abbreviations and terms 14

1 What you need to know to make a submission

What this consultation paper is about

1.1 The purpose of this paper is to seek comments on amendments proposed to the policy statement, from participants and persons that the Authority thinks are representative of the interests of the persons likely to be affected by the amendments.

1.2 The proposed changes to the policy statement are set out in Appendix B.

How to make a submission

1.3 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to policyconsult@ea.govt.nz with "Consultation Paper—proposed amendments to the policy statement" in the subject line.

1.4 Clause 8.12(4) of the Code requires that the Authority provide all submissions to the system operator and publicise them on the Authority's website.

1.5 If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider that part should not be published

(c) provide a version of your submission that can be published (if the Authority agrees not to publish your full submission).

1.6 If you indicate there is part of your submission that should not be published, staff will discuss with you before deciding whether to not publish that part of your submission.

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

When to make a submission

1.8 Please deliver your submissions by **5pm** on Tuesday **30 August 2022**

1.9 The Authority will acknowledge receipt of all submissions electronically. Please contact the policyconsult@ea.govt.nz if you do not receive electronic acknowledgement of your submission within two business days.

2 The system operator has proposed amendments to the policy statement

The policy statement is prepared by the system operator

2.1 The system operator policy statement plays a key role in the set of Code provisions, contracts and other arrangements that collectively deliver common quality and orderly system operation.

2.2 The policy statement is a document prepared by the system operator and incorporated by reference into the Code by the Authority in accordance with Schedule 1 of the Electricity Industry Act 2010 and clause 8.10 of the Code. The policy statement must include:

(a) the policies and means that the system operator considers appropriate for the system operator to observe in complying with its principal performance obligations

(b) the policies and means by which scheduling and dispatch are adjusted to meet the dispatch objective and must include the provision of a dispatch process statement. The dispatch process statement must contain the details of the processes that enable the system operator to meet the dispatch objective, including the methodologies to be used by the system operator for planning to meet the dispatch objective during the period leading up to real time and meeting the dispatch objective in real time

(c) a policy setting out how the system operator will manage any conflict of interest that arises in the performance of its obligations under the Code

(d) a statement of the reasons for adopting the policies and means set out in the policy statement (which statement must be regarded as an explanatory note only and does not form part of the policies itself)

(e) a statement of how future policies and means might be formulated and implemented.

2.3 The Authority has requested the system operator propose a change to the policy statement to align with the decision to implement the real time pricing (RTP) changes to the wholesale market, and the accompanying Code amendments. The Authority and the system operator have complied with the requirements under Clause 8.11A of the Code in producing this version of the Policy Statement.

2.4 The current policy statement came into effect on 01 August 2022.

The system operator has submitted a draft policy statement following a request by the Authority

2.5 The system operator provided a draft policy statement to the Authority on 29 June 2022. This resulted from the system operator's full review of the RTP Code amendment and development workshops with the Authority project team.

2.6 The current Policy Statement, effective from 1 August 2022, is the result of the system operator's periodic review of the Policy Statement under Clause 8.10A of the Code. That review was due before the final review of the RTP impacts on the system operator's processes were known and so could not incorporate them. This consultation uses the 1 August 2022 Policy Statement as the baseline for the RTP changes.

2.7 The amendments to the policy statement proposed by the system operator seek to:

(a) further detail the circumstances in which adjustments are made to the forecast and dispatch schedules, as provided for under Clause 12 of Schedule 13.3 of the Code

(b) reform the Dispatch Policy to incorporate the production of Dispatch prices in the dispatch process

(c) describe the criteria the system operator will use to assess eligibility of market participants as Dispatch Notified participants

(d) make a number of minor clarifications to the policy statement text.

The Code prescribes a process for amending the policy statement

2.8 Before deciding whether to approve the draft policy statement, the Authority must consult on the proposed amendments, in accordance with clause 8.12 of the Code and clause 5 of Schedule 1 of the Electricity Industry Act 2010 (Act).

2.9 The consultation process for a policy statement is different from the process for making a Code amendment because:

(a) it is specified in the Code, not the Act

(b) at the end of the process, if the Authority approves the changes to the policy statement, they are adopted by the Authority incorporating the replacement document into the Code by reference by notice in the Gazette to this effect.

2.10 In preparing this consultation paper, the Authority has drawn on the material provided by the system operator in support of the draft policy statement.

The system operator proposes amendments to the dispatch policy of the policy statement

2.11 The system operator states in its proposal that the most significant amendments to the dispatch policy include the following items:

(a) The load (demand) input that SPD uses to schedule generation

(b) The automated post-schedule check process that assures a valid dispatch solution, and

(c) The use of discretion – manual interventions made by the system co-ordinators in real time to adjust the dispatch schedule for changes in system conditions.

2.12 The dispatch Policy has been re-drafted to improve clarity

2.13 The full set of amendments are included in tracked change format in Appendix B.

The system operator has provided supporting information

There are three requirements for supporting material

3.1 When submitting a draft policy statement to the Authority, the system operator is required to provide the following information on the proposed changes (clause 8.11A(1)):

(a) an explanation of the proposed change and a statement of the objectives of the proposed change

(b) an evaluation of alternative means of achieving the proposed change

(c) an evaluation of the costs and benefits of the proposed change.

3.2 The system operator provided a document with its draft policy statement, ”Real time pricing – changes to the Policy Statement”, that includes the information described in paragraph 3.1. This is attached as Appendix C. Further clarification of the dispatch schedule load input and post schedule checks are included in Appendices D and E respectively.

The objective of the proposed amendment is to amend the policy statement to reflect the Authority’s real-time pricing project Code amendments

3.3 The Code requires the system operator to provide a statement of the objectives of the proposed amendments. The system operator has met this requirement by setting out the objective of each proposed amendment individually in supporting material (Appendix C).

3.4 Drawing on this supporting material, the Authority’s summary of the objective of the proposed amendments is to describe the system operator policy changes necessary to implement the Code requirements of the real-time pricing project.

The real-time pricing project has evaluated alternatives, costs and benefits

3.5 The Code requires the system operator to provide an evaluation of alternative means of achieving the objectives, and of the costs and benefits of the proposed amendments.

3.6 In this case, the changes to the Policy Statement are required by the Authority’s real-time pricing project Code amendment. Where available, the Authority has consulted on alternative implementation options and decided on the preferred option. The Authority agrees that the cost-benefit analysis developed for the real-time pricing implementation demonstrates a net benefit for the associated policy Statement changes.

4 The Authority intends to adopt the system operator’s proposed amendments

4.1 The Authority proposes to replace the existing policy statement in its entirety with the draft policy statement the system operator has submitted, subject to any further amendments made following our consideration of feedback received from this consultation.

4.2 The Authority have considered the costs and benefits of the amendments proposed by the system operator, drawing on the supporting material provided with the draft policy statement (Appendix C). The Authority’s preliminary view is that the proposed amendments would support the implementation of the real-time pricing Code amendments.

4.3 The Authority accepts the system operator’s determination that the real-time pricing project cost-benefit analysis provides sufficient justification for the policy Statement changes.

Q1. Do you agree with the overall assessment of the proposal? If not, what alternative assessment would you make and why?

4.4 In Appendix C, the system operator has set out its view on alternatives to the amendments it has proposed to the policy statement.

4.5 The Authority acknowledges the system operator's views but understand that alternatives may exist that have not been identified, and therefore invite stakeholder comment on this point.

Q2. Is there an alternative to any of the individual amendments the system operator has proposed, that better meets the objectives of the proposal? If so, please describe the alternative and say why you prefer it.

4.6 The Authority invites participant comment on the drafting proposed by the system operator in Appendix B to give effect to the changes it identified in its review of the policy statement.

Q3. What comments do you have on the proposed drafting of the amendments, as set out in Appendix B? If you disagree with what is proposed, please provide alternative drafting.

Appendix A Format for submissions

Submitter	

Question	Comment
Q1 Do you agree with the overall assessment of the proposal? If not, what alternative assessment would you make and why?	
Q2 Is there an alternative to any of the individual amendments the system operator has proposed, that better meets the objectives of the proposal? If so, please describe the alternative and say why you prefer it.	
Q3 What comments do you have on the proposed drafting of the amendments, as set out in Appendix B? If you disagree with what is proposed, please provide alternative drafting.	

Appendix B Proposed amendment to the policy statement

Policy statement

Contents

Introduction ... 4
PURPOSE ... 4
SYSTEM OPERATOR POLICIES TO ACHIEVE THE PPOS AND DISPATCH OBJECTIVE ... 4
Avoid Cascade Failure ... 4
Frequency ... 5
Other Standards ... 5
Restoration ... 5
Dispatch Objective ... 5
INTERPRETATION ... 5
Chapter 1 - Security Policy ... 5
POLICY AND SCOPE ... 5
General Policy ... 5
RISK MANAGEMENT POLICIES ... 6
Identification and Application ... 6
Quality Limits Associated with Events ... 11
SECURITY MANAGEMENT ... 12
Security Constraints ... 12
Under-Frequency Management ... 15
Time Error Management ... 17
Over-Frequency Management ... 17
Rate of Occurrence of Frequency Fluctuations ... 17
Purchaser Step Changes ... 17
Voltage Management ... 18
Management of Quality ... 19
Regional long term contingency planning ... 20
Outage Planning ... 21
EMERGENCY PLANNING ... 22
General ... 22
Standby Residual Shortfall ... 23
Formal Notices ... 23
Demand Management ... 25
Allocation of Demand Reduction ... 29

Restoration 30
Chapter 2 - Dispatch Policy 32
DISPATCH POLICY & PROCESS STATEMENT 32
Software 32
The Scheduling Process 32
Security Assessment 32
Price-responsive schedule and non-response schedule 33
Dispatch Schedule 33
Week-ahead Dispatch Schedule 34
Frequency Keeping 35
Use of discretion to constrain generation or reserve 35
Adjustment of demand profile 35
Chapter 3 - Compliance Policy 36
POLICY AND SCOPE 36
General Policy 36
COMPLIANCE AND PERFORMANCE MONITORING 36
System Operator Compliance with Obligations under the Regulations and Code 36
Asset Owner Compliance and Performance Monitoring 37
Compliance with AOPOs and Technical Codes 37
Compliance with Dispensations and Equivalence Arrangements 38
Compliance with Alternative Ancillary Services Arrangements 38
Asset Owner Non-Compliance 38
Urgent Change Notice 39
ASSET CAPABILITY INFORMATION 39
General Policy 39
General Information Required from Asset Owners 39
ASSET CAPABILITY ASSESSMENTS 40
General Asset Capability Assessment 40
Asset Owner Protection Systems 40
Grid Owners 40
Generator Asset Capability Assessment 41
Voltage 41
Voltage Fault Ride Through 42
Frequency 42
Grid Owner Asset Capability Assessment 42
Voltage 42
HVDC Frequency Capability 42

Automatic Under-Frequency Load Shedding (AUFLS) 43
Distributors Capability Assessment 43
Automatic Under-Frequency Load Shedding (AUFLS) 43
COMMISSIONING ASSETS 43
General Policy 43
Commissioning Plan 44
Dispatch for Commissioning 45
During Commissioning 45
Final Assessment 45
Test Plan 45
DISPENSATIONS AND EQUIVALENCE ARRANGEMENTS 46
General Policy 46
Terms and Conditions of Dispensations and Equivalence Arrangements 47
Dispensation, Equivalence Arrangement and Alternative Ancillary Service Arrangements Register 47
Cancellation of Arrangements 47

Chapter 4 – Conflict ~~Of~~of Interest Policy........................ 49

General Policy 49
GENERAL APPROACH 49
THE MEANS TO MANAGE CONFLICT OF INTEREST 50

Chapter 5 – Future Formulation and Implementation Policy 53

Policy and Scope 53

Chapter 6 - Statement of Reasons for Adopting Policies and Means 54

Glossary of Terms 55

Introduction

PURPOSE

1. This is the **policy statement**, referred to in part 8 of the **Code**.

1A. This **policy statement** takes effect from ~~dd MMM yyyy.~~01 Nov 2022

1B. References to the **system operator's** website in this policy statement refer to the system operator page on the **Transpower** website.

2. The **policy statement** also:

   2.1 Forms a transparent basis from which detailed procedures are developed to support compliance with the policy as well as a mechanism for continually improving existing practices.

   2.2 Clarifies the risks being managed by policy and the key assumptions made in managing those risks.

SYSTEM OPERATOR POLICIES TO ACHIEVE THE PPOS AND DISPATCH OBJECTIVE

3. The policies by which the **system operator** must seek to achieve the various **PPOs** (and other deliverables) are set out in the sections of the **policy statement** as follows:

Avoid Cascade Failure

4. The policies to be adopted in respect of avoiding cascade failure are set out in:

   4.1 The Security Policy that:

      4.1.1 Outlines how commonly occurring events are to be managed with the intention to avoid exceeding:

         (a) Frequency limits.
         (b) **Asset** capability (including voltage limits), normally without **demand shedding** being required.

      4.1.2 Outlines the use of **automatic under-frequency load shedding** to manage **extended contingent events**, where **demand** may otherwise be shed to maintain the security policies and the requirement for emergency management procedures to manage extreme events.

   4.2 The Emergency Planning section of the Security Policy that details the emergency arrangements required for extreme events (or where the event cannot be satisfactorily managed through the normal application of the Risk Management policies).

Formatted: Not Expanded by / Condensed by

Formatted: Not Expanded by / Condensed by

Formatted: Heading 1, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

Formatted: Font: Bold

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

4.3 The Dispatch Policy that details how the **system operator** intends to adjust scheduling and **dispatch** to maintain frequency and reserves for use in connection with the Security Policy.

Frequency

5. The policies to be adopted in respect of maintaining frequency are set out in:

5.1 The Security Policy, that:

5.1.1 Sets the overall objective for maintaining reserves for **contingent events** and **extended contingent events**.

5.1.2 Outlines the process for determining the required frequency reserves (as described in the sections on under-frequency and over-frequency management).

5.2 The Dispatch Policy, which describes the arrangements for **dispatching** these reserves.

6. The policies to be adopted for maintenance of the frequency within the **normal band**, and time keeping, are set out in the Dispatch Policy and the **procurement plan**.

Other Standards

7. The policies to be adopted in respect of the other **PPOs** are described in the Security Policy section on Management of Quality.

Restoration

8. The restoration process is described in the Emergency Planning section of the Security Policy.

Dispatch Objective

9. The Dispatch Policy describes the policies that must be adopted in respect of the **dispatch objective**.

9A The Dispatch Policy also describes the preparation and adjustment of the **dispatch schedule** for the purposes of producing **dispatch prices**.

INTERPRETATION

10. Any terms used in the **policy statement** which are defined in the **Act** or in Part 1 of the **Code** and which are not defined in the Glossary of Terms within the **policy statement**, have the same meaning as given to them in the **Code**. In the event of any inconsistency or conflict between the provisions of this **policy statement** and the rest of the **Code**, the rest of the **Code** shall prevail.

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Font: (Default) Arial

Formatted: Indent: Left: 0.21 cm, Hanging: 1.25 cm, Right: 0.3 cm, Space Before: 0 pt, Line spacing: Exactly 12.6 pt, Tab stops: 1.45 cm, Left

Formatted: Expanded by 0.05 pt

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

Chapter 1 - Security Policy

POLICY AND SCOPE

General Policy

11. The general policies the **system operator** intends to use to meet the **principal performance obligations** are as follows:

11.1 Adopting processes intended to identify events, assess the risks of occurrence of those events in advance, categorise those event risks, and manage those defined events on the power system in real time in accordance with this **policy statement**.

11.2 Applying **security constraints** on **dispatch**, in accordance with the Security Policy, given the **assets** and **ancillary services** made available to the **system operator**.

11.3 Procuring, scheduling and **dispatching** reserves, where possible, with the **assets** and **ancillary services** made available to the **system operator**, to maintain the required frequency standards and to avoid cascade failure, for defined events.

11.4 Managing voltage and available reactive support during real time, where possible given the **assets** and **ancillary services** made available to the **system operator,** in a manner intended to avoid cascade failure for defined events.

11.5 Recommending and facilitating, to the extent considered to be reasonably appropriate and practicable by the **system operator,** co-ordination of advised planned **asset** outages to minimise the impact on security during **dispatch**.

11.6 If reasonably requested by a **participant**, investigating, identifying and, to the extent reasonably practicable, resolving the cause of a non-compliance with harmonic levels, voltage flicker or voltage imbalance standards (sections 4.7, 4.8 and 4.9 of the **Connection Code**).

11.7 Defining the circumstances under which **formal notices** must be sent in accordance with **Technical Code** B of Schedule 8.3 of the **Code** and, to the extent possible, determining the situations in advance that will potentially result in the initiation of **demand shedding**, including **unsupplied demand situations**.

RISK MANAGEMENT POLICIES

Identification and Application

12. The **system operator** must seek to manage the outcomes of events that may cause cascade failure by:

12.1 Identifying potential credible events (each an 'event') on the power system as a result of **asset** failure that may result in cascade failure. At the date of this **policy statement** the **system operator** has identified the following credible events that may result in cascade failure, due to these events causing quality and/or power flow outcomes exceeding **asset** capability:

Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Heading 1, Indent: Left: 0 cm, Right: 0 cm
Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm
Formatted: Indent: Left: 1.46 cm, Right: -0.04 cm, Line spacing: Exactly 12.6 pt
Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

12.1.1 The loss of one of the following power system components:

- a **generating unit**; or
- a **transmission circuit**; or
- an **HVDC link** pole; or
- an **interconnecting transformer** (110 kV or 220 kV); or
- a busbar (220 kV, 110 kV or 66kV); or
- large load or load blocks; or
- reactive injections, both when provided as an **ancillary service** or when available from transmission **assets**:

12.1.2 The loss of both transmission circuits of a double circuit line:

12.1.3 The simultaneous loss of two or more of any of the components in 12.1.1:

12.1.4 The close consecutive loss of two or more of any of the components in 12.1.1:

12.1.5 The loss of the **HVDC link** bipole:

12.1.6 Other credible events may be identified during the term of this **policy statement**. This may include events arising in particular temporary circumstances such as, for example, a credible event identified as potentially arising during commissioning:

12.1.7 If, during the term of this **policy statement**, the **system operator** identifies a further or other credible event then, subject to operational requirements and as soon as reasonably practicable, the **system operator** must:

- **advise** such further credible event to all **participants**;
- invite **participants** to comment on such credible event; and
- consider **participants'** comments prior to it implementing mitigation measures for such credible event.

12.2 Assessing each event, or category of events, to estimate the likely risks based on the potential impact on the power system (including on achievement of the **PPOs**), if the event or category of events occurs. Consequence assessment has taken and must take into consideration mitigating factors such as:

- **AUFLS**.
- The provision of levels of reserves.
- The provision of **constraints** on **dispatch**.
- The probability of occurrence based on historical frequency of

asset failure or other credible reliability information, provided that where the **system operator** has limited historical or other information for specific **assets**, it must consider generic information available to it regarding failure of that type of **asset**.

- The estimated costs and benefits of identified risk management.

- The feasibility and availability of other potential mitigation measures.

12.3 Assigning each of the assessed events to one of the following categories:

- **Contingent events:** Events where the impact, probability of occurrence and estimated cost and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and **dispatch** processes pre-event.

- **Extended contingent events:** Events for which the impact, probability, cost and benefits are not considered to justify the controls required to totally avoid **demand shedding** or maintain the same quality limits defined for **contingent events**.

- **Other events:**
  a) events that are considered to be uncommon and for which the impact, probability of occurrence and estimated cost and benefits do not justify implementing available controls, or for which no feasible controls exist or have been identified, other than unplanned **demand shedding**, **AUFLS** and other emergency procedures or restoration measures or;
  b) events that have no impact or where no pre or post-contingent management is required

12.4 Categorising, at the date of this **policy statement** the following credible events:

- **Contingent events**:

  a) The loss of a **transmission circuit**.

  b) The loss of an **HVDC link** pole.

  c) The loss of a single **generating unit**.

  d) The loss of both **transmission circuits** of a double circuit line, where the **system operator** has determined a high level of likelihood of occurrence based on historical information.

  e) The loss of both **transmission circuits** of a double circuit line, where the **system operator** has been advised of a temporary change to environmental or system conditions that give reason to believe there is a high likelihood of occurrence of the simultaneous loss of both circuits. The **system operator** must make available on its website a range of environmental or system conditions that it considers may create a high likelihood of occurrence of simultaneous loss of both circuits (but this list may not be exhaustive and will not limit the definition of the **contingent event**).

f) The loss of reactive injections, both when provided as an **ancillary service** or when available from transmission assets.

g) The loss of the largest possible load block as a result of paragraphs a) to f) above for each **island**.

- **Extended contingent events:**

a) The sudden loss of the **HVDC link** bipole.

- **Other events:**

a) The loss of a 66kV busbar not connected to the **core grid**.

b) The loss of both **transmission circuits** of a double circuit line.

c) The simultaneous loss of two or more of any of the components in clause 12.1.1.

d) The close consecutive loss of two or more of any of the components in clause 12.1.1.

12.4.1 The following assets are categorised as either a **contingent event**, **extended contingent event** or **other event** according to a methodology and categorisations made available on its website:

a) a 220kV, 110kV or 66kV busbar connected to the core grid
b) a 220kV or 110kV interconnecting transformer

12.4.2 Inviting industry to comment on any proposed changes to the methodology referred to in clause 12.4.1 before those changes come into effect.

12.5 Applying, where possible, the following principles in implementing controls for each of the following category of risk:

- For **contingent events**, the **system operator** must endeavour to schedule and **dispatch** sufficient reserves to provide **asset** redundancy, maintain the levels of quality defined in the Security Policy, and plan to avoid post-event unplanned **demand shedding**, taking into account any other agreed control measures[1] advised to and agreed by the **system operator**.

- For **extended contingent events**, the **system operator** must plan to maintain the levels of quality defined in clause 17.2 of the Security Policy through a combination of **AUFLS**, the provision of reserves, **asset** redundancy, **demand shedding**, and acceptance of greater quality disturbances than for **contingent events**, taking into account any other agreed control measures (for example **special protection schemes** and automatic under voltage load shedding schemes) advised to and agreed by the **system operator**. These control measures do not preclude the **system operator** taking action before an **extended contingent event** occurs, such as **network** reconfiguration, but do preclude the **system operator** changing any **price responsive schedule**, **non-response schedule** and **dispatch schedule** by applying **constraints** that will result in generation being dispatched out of merit order.

- For **other events**, no planned controls have been identified, other than **demand shedding**, **AUFLS** and other emergency or restoration procedures.

- If, in the **system operator's** reasonable opinion, a credible event is likely to lead to a loss of system stability, the **system operator** may rely on **demand shedding** to maintain the power system within identified transient and/or dynamic stability limits in accordance with clause 74.

13. The **system operator** must:

    13.1 In addition to reviews of the **policy statement** in accordance with the **Code**, review the identification, assessment and assignment of potential credible events as classified in clause 12.4 at least once in each five year period.

    13.2 Make available on its website, prior to the commencement of each review of credible events, its intended methodology for identifying and assessing the risks to which the risk management policies are directed.

    13.3 Invite comments from **registered participants** as to its process and the content of the review.

    13.4 Make available on its website an explanation and summary of conclusions for each review of credible events completed under clause 13.1.

14. In determining and applying the methodology in clause 13, the **system operator** must, where appropriate, apply risk management principles consistent with the Australia and New Zealand risk management standard AS/NZS ISO 31000.

---

[1] For example, demand inter-trips, run-back schemes, and Automatic Under Voltage Load Shedding(AUVLS).

Quality Limits and Actions Associated with Events

15. The **system operator**:

    15.1 Is entitled to rely on information regarding **asset** performance advised by **asset owners** in **asset capability statements**.

    15.2 Must use reasonable endeavours (including planned **demand** interruption or **demand shedding**) to **dispatch assets** in a manner so they remain within their stated **asset** capability.

16. Where the **assets** and **ancillary services** made available to the **system operator** are insufficient to achieve the quality levels set out in clauses 17 and 18**,** the **system operator** must follow the **demand shedding** policies in clause 74**.** Where clause 74 provides that **demand shedding** will not occur, the **system operator** may be unable to achieve the quality levels set out in clauses 17 and 18.

17. The quality levels the **system operator** plans to achieve for **contingent events** and **extended contingent events** are set out below. The ability to achieve the quality levels is entirely dependent on sufficient **assets** and **ancillary services** being made available to the **system operator** and the accuracy of the stated capabilities of those **assets** and **ancillary services**.

    17.1 For a **contingent event**, the **system operator** plans to achieve the following quality conditions during and after the occurrence of a **contingent event:**

        17.1.1 No **asset** will exceed its stated load carrying, thermal or voltage capability.

        17.1.2 Subject to clause 40**, grid** voltage will be within the range set out in clause 8.22(1) of the **Code**.

        17.1.3 No **demand** is interrupted other than contracted reserves and/or **interruptible load** contracted or pre-arranged to be interrupted.

        17.1.4 Frequency in either **island** will not drop below 48Hz or rise above 52Hz in the North Island or 55 Hz in the South Island.

        17.1.5 Frequency in either **island** will be restored to within 50 Hz +/- 0.75 Hz within 1 minute.

        17.1.6 **Instantaneous reserves** will be restored within 30 minutes.

        17.1.7 Voltage stability of the power system is maintained.

        17.1.8 Where required by agreements for higher levels of quality, clause 8.6 or clause 17.29 of the **Code**, the quality targets of such agreements will be met.

    17.2 For **extended contingent events**, the **system operator** plans to achieve the following quality conditions during and after the occurrence of an **extended contingent event**:

        17.2.1 No **asset** will exceed its stated load carrying or thermal

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt capability.

17.2.2 Voltage stability of the power system is maintained.

17.2.3 **Target grid voltages** will be as determined under clause 41.

17.2.4 Other grid voltages may be outside the range determined under clause 41. Where this is the case the **system operator** will respond to return these voltages to within the limits determined under clause 41 as soon as practicable.

17.2.5 Disconnected **demand** will be restored as soon as practicable.

17.2.6 Frequency in either **island** will be restored to within the **normal band** as soon as reasonably practicable.

17.3 For **extended contingent events**, the **system operator** may use one or more of the following actions during and after the occurrence of an **extended contingent event**:

17.3.1 The **system operator** may declare a **grid emergency** if it believes the quality levels may not be met after an **extended contingent event**.

17.3.2 **Demand** shedding and **AUFLS** may be used.

18. *[Revoked]*

SECURITY MANAGEMENT

Security Constraints

18A *[Revoked]*

18B *[Revoked]*

19. *[Revoked]*

20. *[Revoked]*

21. *[Revoked]*

22. *[Revoked]*

23. *[Revoked]*

24. *[Revoked]*

25. *[Revoked]*

26. The **system operator** must, from time to time:

26.1 Analyse a range of credible transmission, generation, and power flow scenarios.

26.2 Identify **contingent events, extended contingent events** and **other events** that the **system operator** considers may reasonably impact its ability to meet the **PPOs**.

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

26.3 Identify and input transmission capability limits for **grid assets** in **SPD** to maintain operation within the stated capability (as advised by **grid owners**) after a **contingent event**.

26.4 Identify and input power system stability limits in **SPD** to maintain post-event operation within such stability limits.

27. Using the transmission capability limits and the power system stability limits identified in clause 26 the **system operator** must for each **trading period** develop **security constraints** which it will apply during the relevant **trading period**.

27A The **system operator** may use either automated or non-automated processes to develop the **security constraints** under clause 27. Non-automated processes will be used in situations where the automated processes do not generate appropriate **security constraints**.

28. The **security constraints** which are developed using automated processes under clause 27 are those which arise as a consequence of either or both the transmission capability limits and the power system stability limits being equal to or greater than the applicable **constraint percentage threshold**. **Security constraints** developed using non-automated processes apply regardless of **constraint percentage threshold**.

29. The **system operator** may amend, re-amend, add, remove or exclude the **security constraints** developed under clause 27 before and during **trading periods** when the **system operator** reasonably considers this is required to meet its obligations under the **Code**.

Formatted: Font: Bold

Formatted: Not Expanded by / Condensed by

30. Notwithstanding the provisions of clause 29, the **system operator** must:

30.1 Make available on its website **security constraints** developed using non-automated processes under clause 27A excluding **discretionary security constraints** and **frequency keeping constraints.** The information provided under this clause 30.1 must:

Formatted: English (New Zealand)

- Where practicable, occur four weeks prior to the date on which the **security constraints** are intended to be first used, where the **system operator** identifies an outage or **security constraint** that could be of significant interest to **participants.**
- Otherwise where practicable, occur two weeks prior to the date on which the **security constraints** are intended to be first used.
- Include a brief summary of the **security constraint** design, such summary to be reasonably sufficient for **participants** to assess the effect of the limits or **security constraint**.

30.1A If the system operator makes a change to a **security constraint** of one of the types described in clause 30.1 is made within two weeks before it is intended to be first used,

30.1A.1 if practicable, make available details of the change on the its website in advance; but

30.1A.2 if it is not made available in advance, make available details of the change as soon as practicable.

30.1B Correctly apply **security constraints** regardless of whether or not the information on the **Transpower** website about the power system stability limits or **security constraints** is complete or up to date.

30.2 Notify the **WITS manager** when a **security constraint** other than a **frequency keeping constraint** or general market-node constraint has been applied to **SPD** for use in—

(a) the **price-responsive schedules;**

(b) the **non-response schedules;**

(c) the **dispatch schedule;**

(d) the **week-ahead dispatch schedule**; and

where the calculated value of the constraint exceeds the **constraint publication threshold.**

30.3 *[Revoked]*

30.4 Provide to the **WITS manager**, for making available on **WITS**, in respect of each **security constraint** notified pursuant to clause 30.2**:**

- the form of the **security constraint**;
- the limit of the **security constraint**;
- the **trading periods** to which the **security constraint** has been applied to **SPD**; and
- where applicable, the previous limit of the **security constraint**.

30.4A *[Revoked]*.

30.5 Provide to the **WITS manager**, for making available on **WITS**, information about **grid asset** outages, including start and end times, applied to—

(a) the **price-responsive schedule;** and

(b) the **non-response schedule;** and

(c) the **week-ahead dispatch schedule**.

30B The **system operator** must make available on its website a set of generation scenarios that it will use to develop indicative **security constraints** under clause 30C, and may amend the generation scenarios from time to time. The **system operator** will place any amendments on its website and at the same time notify **participants** of these amendments.

30C Subject to clause 30F, the **system operator** must develop indicative **security constraints** for a **notified planned outage** if it is requested to do so by a **participant** in relation to a specific outage where:

(a) the **system operator** considers it likely that the outage will have a widespread impact on competition or efficiency, taking into account the information provided by the requesting **participant**; and

(b) the request is made more than two weeks prior to the notified start date of the outage.

30D The intent of the indicative **security constraints** developed under clause 30C is to provide an indication of the market system constraints that may be developed for the **notified planned outage** under clause 27.

30E The **system operator** must make available information detailing indicative **security constraints** developed under clause 30C to **participants** on the **Planned Outage Co- ordination Process** website. The information made available must include a summary of the limits or **security constraint** design, such summary to be reasonably sufficient for **participants** to assess the effect of the **security constraint**.

30F The **system operator** may decline to develop indicative **security constraints** under clause 30C if the **system operator** reasonably believes that sufficient relevant historical **security constraint** information has already been made available to **participants** after the **changeover date**. If the **system operator** declines a request pursuant to this clause, it must advise the requesting **participant** where the relevant historical **security constraint** information can be located.

30G The **system operator** must make available on the **Transpower** website a description of the process it will use to develop indicative **security constraints** under clause 30C, The **system operator** may amend the process from time to time.

30H Where the **system operator** declines a request to develop indicative **security constraints** on the grounds that the criteria in clause 30C do not apply, the **participant** may request the **system operator** to agree to develop the indicative **security constraints**. Such agreement may not be unreasonably withheld but may, in the **system operator's** discretion, include the requirement for the requesting **participant** to pay the reasonable costs of the **system operator** in developing the indicative **security constraints**.

Under-Frequency Management

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

31. The **system operator** must aim to schedule sufficient reserves, subject to **asset** and **ancillary service** availability and clause 33A, to meet the specified under-frequency limits and avoid cascade failure for:

31.1 The maximum amount of **MW** injection that could be lost, due to the occurrence of a single **contingent event**; and

31.2 The **extended contingent events**, allowing for **automatic under-frequency load shedding**.

32. In modelling reserve requirements, the **system operator** must:

32.1 Apply the **Reserves Management Tool**

32.2 Use the most recent **asset** capability information provided by **asset owners,** subject to:

- the requirements of the **RMT** specification (including **asset** performance modelling) from time to time agreed between the **system operator** and the **Authority**;

- any **asset** assessments the **system operator** needs to carry out; and
- a reasonable time delay allowing for the system operator to modify the **RMT** to include the latest **asset** capability information.

32.3 Include the impact of **dispensations** and **equivalence arrangements**.

32A Where **asset** capability information has not been provided, the **asset** capability information provided is incomplete, or the **system operator** reasonably considers it cannot rely upon the **asset** capability information provided, the **system operator**:

32A.1 may apply an adjustment factor considered reasonable by the **system operator** based on its current knowledge about the performance of the power system, to account for the fact that the **asset** capability information has not been provided, the **asset** capability information provided is incomplete, or the **asset** capability information provided is reasonably considered unreliable; and

32A.2 must notify the **asset owner** within 3 **business days** following any decision to apply an adjustment factor.

33. To maintain a dispatchable **SPD** solution where there are insufficient **offers** and/or **reserve offers** in the current **trading period**, the **system operator**, using the **SPD software**, must—

33.1 for a pre-event shortage relating to a **contingent event**, **dispatch** all remaining **offered instantaneous reserve,** and, if the quantity of **instantaneous reserve dispatched**, together with **AUFLS**, is insufficient to meet the under-frequency standard in clause 7.2A of the **Code** applicable to an **extended contingent event**, reduce **demand** in accordance with the **demand management** policies; and

33.2 for a pre-event shortage relating to an **extended contingent event** that requires the **dispatch** of **instantaneous reserves** in addition to **automatic under-frequency load shedding**, **dispatch** all remaining **offered instantaneous reserve** and reduce **demand** in accordance with the **demand management** policies.

33A Following the occurrence of an **under-frequency event** in which **interruptible load** has been triggered, the **system operator** may temporarily set the reserve requirements to zero. The **system operator** must then restore the reserve requirements in accordance with the methodology set out in clause 84.

33B For the purposes of the **event charge** calculation pursuant to clause 8.64 of the **Code**, the **system operator** will use the methodology it makes available on its website.

Time Error Management

34. The **system operator** contracts with an **ancillary service agent** to provide **frequency keeping** and manage frequency time error within the limits

Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

required in clause 7.2C of the **Code**. The procurement of this service is described in the **procurement plan**.

Over-Frequency Management

Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

35. For the over-frequency elements of the **PPOs**, the **system operator** procures **over frequency reserves** in accordance with the **procurement plan**.

36. The **system operator** must aim to **dispatch over frequency reserves** when necessary to maintain the frequency below 52 Hz in the North Island and 55 Hz in the South Island for **contingent** and **extended contingent events**. In determining the quantity of **over frequency reserves** to be **dispatched** in the South Island, the **system operator** must take into account the actual amount of **demand**, the **HVDC link** transfer, and the number and capacity of the units able to be **dispatched** for **over frequency reserves** at the time.

Rate of Occurrence of Frequency Fluctuations

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

37. *[Revoked]*

38. The **system operator** may recommend changes to the **procurement plan**, **policy statement** or **Code**, or take other action available to it under the **Code**, with the intent to correct a significant negative trend regarding the rate of **frequency fluctuations**.

Purchaser Step Changes

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

39. *[Revoked]*

39A Clause 8.18 of the **Code** provides that **purchasers** must limit the magnitude of any instantaneous change in the **offtake** of **electricity** and net rates of change in **offtake** to the levels the system **operator** requires.

39B As at the date this **policy statement** comes into effect, the **maximum instantaneous demand change limit** and net rates of change in **offtake** for **electricity** allowable for each **purchaser** within each **island** is 40 **MW** per minute with no more than a 75 **MW** change in any 5 minute period.

39C The **system operator** may specify a **maximum instantaneous demand change limit** and rate of change in **offtake** in relation to a particular **purchaser** that is different from the limit and the rate specified in clause 39B.

39D Clauses 39A and 39B do not apply to step changes and rates of change occurring during independent action or restoration in a **grid emergency**.

Voltage Management

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

40. The **system operator** must plan to manage **grid** voltage as follows:

40.1 Following **a contingent event**, voltage will be maintained within the ranges specified in clause 8.22(1) of the **Code** except where, for a particular **GXP** or region, there is a **wider voltage agreement** in place.

40.2 Where a **wider voltage agreement** applies, the voltage within that **GXP** or region will, following a **contingent event**, be managed so voltage stability is maintained and voltage does not go outside the lesser of the capability of the affected **assets**, as set out in the **asset capability statements** for those **assets**, or the voltage limit agreed in the **wider voltage agreement**.

40.3 Following an **extended contingent event**, voltage will be maintained within the ranges determined under clause 41.1.

41. To manage voltage and control voltage excursions within the quality limits set out in clause 17 of this Security Policy the **system operator** must:

41.1 Determine a set of **target grid voltages** at selected key locations (selected by the **system operator**) to be maintained during normal operations. For the purpose of clause 17 the **system operator** has determined that the **target grid voltages** will be within the range in clause 8.22(1) of the **Code**.

41.2 Recommend to **asset owners** appropriate tap positions for transformers, which have off load tap changers, given the expected range of **dispatch** scenarios.

42. The **system operator** may vary **target grid voltages** for specific **dispatch** scenarios.

43. The **system operator** must monitor voltage trends in real time at key locations determined by the **system operator** and, subject to **asset** availability and **ancillary services**, it must endeavour to **dispatch** sufficient reactive resources to:

43.1 Achieve **target grid voltages**.

43.2 Manage voltage for a **contingent event**.

43.3 Maintain post event operation within stability limits.

44. The **system operator** must **dispatch generating plant** to:

44.1 Maintain a specific voltage during **dispatch.**

44.2 Provide specific **reactive power** outputs (refer also to the **security constraints** section of this Security Policy).

45. The **system operator** must **dispatch** available static reactive devices so that dynamic reactive reserves are available to provide **voltage support** for **contingent events** and **extended contingent events**.

46. In **dispatching** static and dynamic reactive resources, the **system operator** must use the following principles:

46.1 The **system operator** will first **dispatch relevant freely available reactive resources**.

46.2 Where insufficient **relevant freely available reactive resources** are available to maintain **target grid voltages**, the **system operator** will **dispatch** additional reactive resources as procured in accordance with the **procurement plan**.

46.3 Where the **system operator** believes the reactive resources **dispatched** under clause 46.1 and clause 46.2 are insufficient to address voltage management requirements the **system operator** will apply a combination of:

- Procurement and **dispatch** of additional reactive resources as an emergency departure from the **procurement plan** in accordance with clause 8.47 of the **Code**.

- **Security constraints** to provide additional reactive resources through the **dispatch** of generation.

47. If the **dispatch** of reactive resources under clause 46 is not sufficient to provide voltage support for managing a **contingent event** or an **extended contingent event** the **system operator** may commence **demand shedding** in accordance with the Emergency Planning section of this Security Policy.

Management of Quality

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

48. If the **system operator** receives a request to investigate and resolve a security of supply or reliability problem under clause 7.2D of the **Code** and, in the **system operator's** opinion, the problem is not likely to cause cascade failure, the **system operator** must:

    48.1 Act on a written request by a **participant** or the **Authority** to identify the cause of the problem.

    48.2 Investigate the cause of the problem. An investigation may include:

    - Requests for further information from **asset owners**.

    - Testing and measurement.

    - Analysis of those measurements, including system modelling.

    - Application of **constraints** on **dispatch** and reconfiguration of **assets** to identify potential resonance and sources.

    48.3 Where identified, notify the relevant **asset owner** that is causing the problem and invoice any reasonable costs associated with investigating the problem.

    48.4 Keep account of its costs in relation to the studies and invoice in accordance with the **Code** and the **System Operator Service Provider Agreement**.

    48.5 If the problem has not been rectified and continues to persist then, in the absence of a requirement in the **Code** for **asset owners** to meet the relevant standards, the **system operator** must:

    - Notify the **Authority** of the problem.

    - **Advise** the actions that could be taken to rectify the problem.

49. The **system operator** must assess any problem in relation to clause 7.2D of the **Code** to ascertain whether that problem may lead to cascade failure. If the problem could lead to cascade failure the **system operator** must seek to identify the cause of the problem and, if any problem remains unaddressed:

    49.1 Issue a **formal notice** in accordance with clause 5 of **Technical Code** B of Schedule 8.3 of the **Code** requesting a response of the relevant **participants** to correct the problem.

    49.2 Rely on the co-operation of the relevant **participants**, or the co-operation of **asset owners** as required by clause 8.26 of the **Code**.

Regional long term contingency planning

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

50. The **system operator** may from time to time identify, in a region, a material or on-going power system limitation or power system situation where the **system operator** believes there is a reasonable probability it would have to rely on taking emergency action under the Emergency Planning section of the **policy statement** to plan to comply and comply with the **PPOs.**

51. When the **system operator** identifies a power system limitation or power system situation under clause 50, it may establish and facilitate a forum of relevant **asset owner**s and interested **participants** to work jointly with it to assist it plan to comply and to comply with the **PPOs**. The **system operator** must establish a forum when:

51.1 It believes there is a reasonable possibility that:

51.1.1 without suitable contingency planning and information exchange, regionally material **demand shedding** may be required in order for it to comply with the **PPOs**; or

51.1.2 it would have to rely on taking emergency action under the Emergency Planning section of the **policy statement** for credible **dispatch** scenarios over an extended period of time in any region or regions; and

51.2 Co-ordination of multiple **participants** in a region or regions would be required to mitigate the situation identified by it; and

51.3 No single **participant** is able or willing to act unilaterally to resolve the situation identified by it; and

51.4 The **system operator** considers there is sufficient time prior to a situation identified under clause 50 occurring in which to plan to minimise the impact of the situation.

52. In establishing and facilitating a forum described under clause 51, the **system operator** must:

52.1 Invite as contributing parties those **participants** it reasonably believes may be:

52.1.1 affected by the situation; or

52.1.2 able to assist with it planning to comply and to comply with the **PPOs** by reducing the potential need for recourse to the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** (or similar).

52.2 Arrange for **participants** in the forum to undertake such analysis of regional load **demand**, **asset** performance, and such other matters the **system operator** and **participants** in the forum consider relevant, and agree upon the necessary or desirable means to minimise the risk to the **system operator** having to rely on taking emergency actions under the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** with the **assets** and generation **offers** likely to be available.

52.3 Use a planning horizon, for such forums, of no longer than 3 years.

53. Nothing in clauses 50 to 52 (inclusive) shall be construed to restrict or compromise the ability of the **system operator** to rely, when it believes it appropriate, on the Emergency Planning or any other section of the **policy statement** or the **Code.**

Outage Planning

54. To meet its obligations under **Technical Code** D of Schedule 8.3 of the **Code**, the **system operator** must:

54.1 Carry out the assessment of all **notified planned outages** referred to in clause 3 of **Technical Code** D of Schedule 8.3 of the **Code**.

54.2 **Notify** relevant **asset owner**s of **notified planned outages** where it considers such **notified planned outages** may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** close to or in real time in order to comply with the **PPOs**. When making such notifications the **system operator** may request that relevant **asset owner**s notify it of suitable changes to the **notified planned outages**.

54.3 Endeavour, where the relevant **asset owner**s fail to notify it of suitable changes to the **notified planned outages** in clause 54.2, to facilitate arrangements with the relevant **asset owner**s that will result in changes to the **notified planned outages** so that such outages will not result in the **system operator** relying on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs**.

54.4 Re-assess the **notified planned outages** following the notification of any changes by relevant **asset owner**s under clause 54.2 or the facilitation of any arrangements in clause 54.3.

54.5 Advise the relevant **asset owner**s whether or not, following the re-assessment, it believes the relevant **notified planned outages** may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs**.

54.6 Re-assess **notified planned outages** following receipt of any material, new information relating to the said **notified planned outages** or the power system which it believes may impact its ability to plan to comply, and comply with the **PPOs**.

55. Where the **system operator** reasonably identifies **notified planned outages** that may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs** and relevant **asset owners** are unable or unwilling to develop and notify the **system operator** of suitable changes to such outages, it may, where, in its reasonable opinion, there is insufficient time to otherwise plan to avoid **demand shedding** or where the expected period of risk is for a short duration, issue a **formal notice** and rely on emergency action under the Emergency Planning section of the **policy statement** and **Technical Code** B

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Indent: Hanging: 1.25 cm, Right: 1.54 cm, Space Before: 0 pt, Line spacing: Multiple 1 li, Tab stops: 2.68 cm, Left of Schedule 8.3 of the **Code**.

56. Nothing in clauses 54 to 55 (inclusive) shall be construed to restrict or compromise the ability of the **system operator** to rely, when it believes it appropriate, on the Emergency Planning or any other section of the **policy statement** or the **Code**.

EMERGENCY PLANNING

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

General

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

57. The following sections set out the general policies for dealing with emergencies relating to security issues. They do not limit the powers of the **system operator** under the **Code** in respect of emergencies, and the **system operator** always retains the right to exercise its rights and powers under the **Code** in relation to emergencies.

58. To manage events greater than those catered for by the Risk Management Policies, or where the event cannot be satisfactorily managed through the normal application of the Risk Management Policies, the **system operator** may rely on:

    58.1 The load shedding provisions of clauses 8.19(5) and 8.24 of the **Code**.

    58.2 The load shedding systems and independent action defined in **Technical Code** B of Schedule 8.3 of the **Code**.

    58.3 **Asset owner** compliance with the provisions of the **Code**.

    58.4 The use of **standby residual shortfall notices** to advise **participants** when it believes there is or may be a **standby residual shortfall.**

    58.5 Any other means made available by **asset owners** that are assessed by the **system operator** as being capable of mitigating the need for **demand shedding**.

Standby Residual Shortfall

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

59. In the event the **system operator** identifies a **standby residual shortfall**:

    59.1 if the **standby residual shortfall** is greater than the **standby residual shortfall threshold**, it must use reasonable endeavours to send to the **WITS manager**, for making available on **WITS**, a **standby residual shortfall notice**; and

    59.2 it may, for such time as it believes reasonable and prudent, rely on **participant**s making such new **generator offers** and/or **reserve offers** it believes will be sufficient to mean that a **standby residual shortfall** no longer exists.

60. If there is a **standby residual shortfall**, and **participants** do not make sufficient new **generator offers** and/or **reserve offers**, the **system operator** may, in accordance with clause 4 of **Technical Code** D of Schedule 8.3 of the **Code**, request an **asset owner** of **assets** which are the subject of an outage or **notified planned outage** to keep those **assets** in service, with the intention of reducing the likelihood of the **system operator** having recourse to the Emergency Planning section of this **policy statement**.

Formatted: Indent: Hanging: 1.25 cm, Right: 0.11 cm, Line spacing: single, Tab stops: 1.45 cm, Left

61. *[Revoked]*

Formal Notices

62. The **system operator** must issue a **formal notice** in accordance with clause 5 of **Technical Code** B of Schedule 8.3 of the **Code** where a **participant's** response is required to mitigate a risk and where the only other action available to the **system operator** will be to shed **demand**.

62A The **system operator** may issue the following types of **formal notices**:

62A.1 A Grid Emergency Notice which declares a **grid emergency** in accordance with clause 13.97 of the **Code**.

~~62A.2 An Island Shortage Situation Notice which provides notification in accordance with clause 5(1A) of **Technical Code** B of Schedule 8.3 of the **Code** that an **island** wide instruction to disconnect **demand** has been issued, amended, or revoked.~~

62A.2 *[Revoked]*

62A.3 A Warning Notice which advises participants that **grid emergency** conditions are anticipated.

63. Where the **system operator** has identified a situation requiring the use of the controls in this Emergency Planning section of the Security Policy prior to one hour before the start of the relevant **trading period**, the **system operator** must issue a Warning Notice.

64. Where the **system operator** has identified a situation requiring the use of the controls under this Emergency Planning section of the Security Policy within one hour prior to the start of the relevant **trading period** or during the relevant **trading period**, the **system operator** must issue a Grid Emergency Notice.

65. A Grid Emergency Notice must be issued whenever, or as soon as practicable after any of the events set out in clause 74 have occurred or the **system operator** determines they will occur and when the **system operator** considers that it will be unable to mitigate the situation without **participant** independent action, **grid** reconfiguration or **demand shedding**.

66. If the **system operator** decides to declare a **grid emergency**, it must make the declaration by issuing a **formal notice** orally or in writing. **Formal notices** may be issued orally in circumstances where either or both of the following situations exist:

66.1 There is, in its view, insufficient time available to the **system operator** before the emergency arises to issue a written **formal notice**.

66.2 One **participant** is**,** or a restricted number of **participants** are, required to, or able to, take specific action in accordance with **Technical Code** B of Schedule 8.3 of the **Code**, to alleviate a **grid emergency**.

67. **Formal notices** issued in writing must be sent to all **participants** that, in the **system operator's** view, may be able to assist in the mitigation of the **grid emergency** or will have a significant interest in the occurrence and nature of the **grid emergency**. All **formal notices** issued in writing must be shown on the its website as soon as reasonably practicable after being first sent to

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Right: -0.04 cm, Space Before: 0 pt, Line spacing: Exactly 12.6 pt

Formatted: Font: 11 pt

Formatted: Space Before: 0.9 pt, Line spacing: Exactly 11 pt

Formatted: Strikethrough

participants.

68. In addition to the content of a **formal notice** in clause 5 of **Technical Code** B of Schedule 8.3 of the **Code**, the **system operator** must use reasonable endeavours to include in every **formal notice** issued details of **assets**, which are relevant to the cause of the relevant **grid emergency** and the return to service of such **assets**, where such advice would assist it to plan to comply and to comply with the **PPOs**. The ability of the **system operator** to include details of such affected **assets** is subject to the ability and willingness of the owners of affected **assets** to make such details available to other **participants**.

69. The **system operator** must send to **participants** the report it provides to the **Authority** under clause 13.101(1)(a) of the **Code**.

70. Security levels must be re-assessed and **participants** advised as soon as reasonably practicable after the **system operator** is aware of any need to change the status of a **formal notice**. The **system operator** must revise the **formal notice** if:

    70.1 A situation is alleviated prior to the start of the **trading periods** for which the **formal notice** was issued.

    70.2 The start or end time period for which a situation exists, or is expected to exist, changes from the **trading periods** set out in the **formal notice**.

    70.3 The electrical or geographical region affected changes from that set out in the **formal notice**.

71. There may be other notices issued by the **system operator** that, by definition, are not **formal notices** issued in accordance with **Technical Code** B of Schedule 8.3 of the **Code**.

Demand Management

72. *[Revoked]*

Formatted: Font: (Default) +Body (Calibri), 12 pt

73. Where the **system operator** considers that the **dispatch** of available **assets** and **ancillary services** (and the application of the policies set out in other sections of this Security Policy) is not or is likely not to be sufficient or sufficiently timely to mitigate a situation, the **system operator** must declare a **grid emergency** and apply clause 74 in determining whether to initiate **demand shedding**.

74. Demand Shedding

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand shedding policy
A) Steady State, including steady state after an event has occurred.	Any **asset** is exceeding or is forecasted to exceed the advised capability limit stated in the **asset capability statement.**	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
	Voltage instability is or is about to occur.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
	Transient or dynamic instability is or is about to occur.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency.**
	Frequency keeping is unable to be maintained.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency.**
	The **grid**, or part of the **grid**, ~~is or is about to be operated~~will operate outside the ranges specified in clause 8.22(1) of the **Code** for a defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency** (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a risk of significant **asset** damage.		Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
	Public safety is at risk.		Declare a **grid emergency**.	**Demand shedding** may occur if the **system operator** considers it appropriate in the specific circumstances.

Formatted: Justified
Formatted: Justified
Formatted Table
Split Cells
Formatted: Justified
Formatted: Justified
Formatted: Justified
Formatted: Expanded by 0.15 pt
Formatted: Expanded by 0.1 pt
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Expanded by 0.1 pt
Formatted: Expanded by 0.15 pt
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.05 pt
Formatted: Condensed by 0.1 pt
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.05 pt
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.05 pt
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.05 pt
Formatted: Expanded by 0.2 pt
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.2 pt
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.05 pt
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.05 pt
Formatted: Expanded by 0.05 pt
Formatted: Expanded by 0.15 pt
Formatted: Condensed by 0.1 pt
Formatted: Expanded by 0.05 pt
Formatted: Not Expanded by / Condensed by
Formatted: Font: Not Bold
Formatted: Not Expanded by / Condensed by
Formatted: Font: Not Bold
Formatted: Justified
Formatted: Justified

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand shedding policy
	Independent action has been taken in accordance with **Technical Code** B of Schedule 8.3 of the **Code** to restore the **system operator**'s **PPO**s.		Declare a **grid emergency**.	**Demand shedding** may occur depending on the nature of the **grid emergency** and whether the **system operator** considers it appropriate in the specific circumstances.
	Restoration is required after a loss of supply and: ▪ **grid** reconfiguration and/or **demand management** is required; and ▪ more than one instruction to one or more **participants** is required to effect restoration.		Declare a **grid emergency**.	Refer to restoration policy (as contained in clause 84).
	An **unsupplied demand situation** occurs		Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
B) For a defined event.	Any **asset** will exceed the advised capability limit stated in the **asset capability statement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
	A voltage stability limit is being exceeded.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
	A transient or dynamic stability limit is being exceeded.	Issue a Warning Notice	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
	Frequency keeping will not be able to be maintained for a defined event.	Issue a Warning Notice	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.

Formatted: Justified

Formatted: Justified

Formatted: Not Expanded by / Condensed by

Formatted: Not Expanded by / Condensed by

Formatted: Justified

Formatted: Justified

Formatted Table

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand shedding policy
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand shedding** will occur if **participant** responses do not mitigate the **grid emergency** (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a shortage of **instantaneous reserve** for an **extended contingent event**.	Issue a Warning Notice.	Declare a **grid emergency**.	Subject to clause 33.2, **demand shedding** will occur if **participant** responses do not mitigate the **grid emergency**.
	There is a shortage of **instantaneous reserve** for a **contingent event**.	Issue a Warning Notice.	Declare a **grid emergency**.	Subject to clause 33.1, rely on the operation of **AUFLS** where sufficient to ensure compliance with the frequency **PPO**.
C) For a second defined event (after an event has occurred[2]).	Any **asset** will exceed the advised capability limit stated in the **asset capability statement** for a second defined event.		Declare a **grid emergency**.	**Demand shedding** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event or **asset owners** have advised the risks of exceeding capability are unacceptable.
	A voltage stability limit would be exceeded for a second defined event.		Declare a **grid emergency**.	**Demand shedding** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event
	A transient or dynamic stability limit is being exceeded for a second defined event.		Declare a **grid emergency**.	**Demand shedding** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event.

Formatted: Justified

Formatted: Justified

Formatted: Justified

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand shedding policy
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a second defined event unless ~~-~~a ~~-~~**wider** ~~-~~**voltage agreement** ~~-~~applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.		Declare a **grid emergency**.	**Demand shedding** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event. (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a shortage of **instantaneous reserve** for a binding second **contingent event**.		Declare a **grid emergency**.	**Demand shedding** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event and **AUFLS** is insufficient to ensure the frequency **PPO** can be met.

[2]And where there are insufficient means to operate the power system to the requirements of the security policy following the event.

Allocation of Demand Reduction

75. Where a **formal notice** is issued, and the **system operator** instructs any **purchaser(s)** and/or **distributor(s) to** reduce **demand** (as provided for in clauses 6(1)(b) and 6(2)(c) of **Technical Code** B of Schedule 8.3 of the **Code**) the **system operator** may include the following in the (verbal or written) **formal notice**:

    75.1 The **offtake** point or points (**grid exit points**) at which a **demand** reduction is required, which may be selected by the **system operator** at its discretion;

    75.2 ~~The~~Either the quantity of demand reduction required at the relevant **offtake** ~~point(s) (including by reference to~~ points (**grid exit points**), or the maximum **demand** which may be taken at the relevant **offtake** ~~point(s) reducing **demand** so as not to exceed a stated maximum **demand**~~points (**grid exit points**);

    75.3 The time(s) for which the **demand** reduction is required.

75A. Where a **formal notice** is issued instructing the reduction of **demand** in accordance with clause 75, as soon as practicable after the notice is issued the **system operator** must provide the information described in the notice to its systems to comply with schedule 13.3AA of the **Code**.

76. *[Revoked]*

77. Without limiting its rights under **Technical Code** B of Schedule 8.3 of the **Code**, where **demand** from any **offtake** point is not reduced in accordance with the demand allocations specified in the **formal notice**,

Formatted: Justified
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt
Formatted: Indent: Left: 0.38 cm, Hanging: 1.25 cm, Right: 0.67 cm, Line spacing: single
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Font: Not Bold
Formatted: Font: Not Bold, Not Expanded by / Condensed by
Formatted: Font: Not Bold
Formatted: Font: Not Bold, Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Font: Not Bold
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Font: Not Bold, Not Expanded by / Condensed by
Formatted: Not Expanded by / Condensed by
Formatted: Font: (Default) Arial, 11 pt
Formatted: Indent: Left: 0.38 cm, Right: -0.04 cm, Space Before: 0 pt, Line spacing: single, Tab stops: 1.62 cm, Left

the **system operator** may require a relevant **distributor** to reduce **demand** in accordance with the process or processes agreed under clause 7(19) of **Technical Code** B of Schedule 8.3 of the **Code**.

78. In determining any demand allocations to be specified in the **formal notice**, the **system operator** must use reasonable endeavours to avoid a **demand** reduction of greater than 25% at a single **point of connection**, excepting when the total reduction of **demand** required in the affected region exceeds 25%.

79. After any urgent action to require **demand** reduction under **Technical Code** B of Schedule 8.3 of the **Code** the **system operator** must assess whether to proceed to restoration action, or to re-allocate reduced **demand** before restoration.

80. When it is judged by the **system operator** to be appropriate to re-allocate reduced **demand** the **system operator** must, in the absence of any agreement pursuant to clause 81, act to the extent practicable in accordance with the following allocation methodology:

80.1 To manage a peak capacity constraint each affected **offtake** point will be allocated a pro-rata share of the peak **demand** capacity, in the ratio of the annual average peaks of the **offtake** point **demand** and the total **demand** of the affected region. The annual average peak **demands** will be the averages of the five summer or five winter peaks for the previous year, with winter and summer periods defined as for **grid owner** transmission ratings.

80.2 To manage an energy capacity constraint, energy allocated for each affected **offtake** point shall be a pro rata calculation based on a proportion of the energy consumed at the **offtake** point to the total energy consumed in the constrained region. In order to account for seasonal changes and different load characteristics this proportion will vary each month as a weighted average of:

80.2.1 75% of the proportion of energy consumed for the 12 months to the previous 30 June, and

80.2.2 25% of the proportion of energy consumed in the three months of the year up until the previous 30 June, starting one month before and ending one month after the calendar month during which energy allocation is to take place.

81. The **system operator** may use an alternative methodology to that in clause 80, where such alternative methodology has been formally agreed between the **system operator** and directly affected **distributors**.

Restoration

Formatted: Condensed by 0.05 pt
Formatted: Condensed by 0.05 pt
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

82. The **system operator** must procure **black start**. The procurement details for these facilities are included in the **procurement plan**.

83. The **system operator** may rely on the synchronising facilities defined in **Technical Code** A of Schedule 8.3 of the **Code** to allow reconnection of sections of the **grid** and to connect generation to the **grid** during restoration.

84. Where restoration is required, the **system operator** must use the following methodology to re-establish normal operation of the power system by:

84.1 Addressing any aspects involving public safety.

84.2 Addressing any aspects involving avoidance of damage to **assets**.

84.3 Stabilising any remaining sections of the **grid** and connected **assets** and the voltage and frequency of the **grid**, through the combination of manual **dispatch instruction** and allowing automatic action of **ancillary services** and governor and voltage regulation operation by **generating plant**, and including any necessary disconnection of **demand**.

84.4 Actioning the steps set out in clauses 84.5, 84.6, 84.7 and 84.8 below in the order or in parallel as is judged by the **system operator**, at the time, as most effectively allowing reconnection of **demand**. The order that **assets** are **dispatched** will be influenced by availability, technical, geographic and other factors influencing rapid restoration of **demand**.

84.5 Restoring the transmission, generation, and/or **ancillary service assets** that failed when such restoration assists commencement of steps set out in clauses 84.6 and 84.7, where necessary utilising **black start** facilities.

84.6 Restoring any disconnected **demand** (which includes any triggered **interruptible load**) at the rate permitted by the security and capability of the available combined generation and transmission system.

84.7 **Dispatching** additional generation and **ancillary services**, where such additional resources are needed to allow **demand** to be reinstated and necessary quality levels to be maintained.

84.8 Seeking revised **offers** where insufficient **offers** exist to achieve the restoration objectives.

84.9 Restoring normal security and power quality of the **grid** system to the levels set out in the **PPOs** and this Security Policy. If the reserve requirements have been set to zero under clause 33A, the actions taken under this clause must include restoring the reserve requirements to the levels set out in the Under-Frequency Management Policy.

84.10 Restoring energy injection levels to the values contained in an updated **dispatch schedule**.

Chapter 2 - Dispatch Policy

84A. The **system operator** must follow the process described by the Dispatch Process Statement to achieve the **dispatch objective**. Clauses 84B to 84O constitute the Dispatch Process Statement.

Software

84B. The **system operator** must include SPD in the **software** it uses for scheduling and **dispatch**.

84C. The **system operator** must use the reserve management tool (RMT) to assess the likely primary frequency response provided by connected generators and load to determine the minimum quantity of **instantaneous reserve** required to meet the frequency standards defined by clauses 7.2A(5) – (7) of the **Code**.

Week-ahead Dispatch Schedule

84D. The **system operator** must endeavour to prepare a week-ahead dispatch schedule once per day for the period from 14:00 hours the following day to 23:59 hours six days' hence.

84E. The week-ahead dispatch schedule must include as its inputs the inputs for the **non-response schedule** described in Part 13 of the Code, excluding ramp rates.

84F. When the **system operator** has completed a week-ahead dispatch schedule, the **system operator** must make the schedule results available to the **WITS Manager** for publication on **WITS**. The schedule results must include prices for each grid exit point, grid injection point and reference point.

Non-Response Schedule and Security Assessment

84G. In preparing the **non-response schedule** as required under Part 13 of the Code, to plan to comply with the principal performance obligations the system operator must use the **non-response schedule** to conduct regular security assessments for the schedule period. The **system operator** must use the results of the security assessment to make adjustments to inputs to subsequent **non-response schedules** and the **dispatch schedule** to achieve the **dispatch objective**.

84H. The **system operator** may adjust the **demand** input to the **non-response schedule** at a **non-conforming GXP** where it reasonably believes the demand quantity represented by the **nominated non-dispatch bids** for the **non-conforming GXP** is unreliable.

84I. The **system operator** must use the **non-response schedule** to schedule and dispatch **frequency keeping ancillary services**, and use frequency keeping constraints to adjust scheduled frequency keeping units' active power capacities for use in the **dispatch schedule**.

84J. In making its security assessment, in addition to any adjustments required under clause 84G the **system operator** may:

84J.1. request the **grid owner** to make changes to **notified planned outages**;

84J.2. identify potential **contingent events** and **extended contingent events** and make changes to the **instantaneous reserve** requirements;

84J.3. assess power flows to identify and assess possible transmission security restrictions, capacity restrictions, or voltage conditions on the **grid** and make changes to **security constraints**;

84J.4. identify shortfalls in standby capacity reserves and reschedule **frequency keeping** assets.

84K. Where the **system operator** has made adjustments to the inputs to the **non-response schedule** or the **dispatch schedule** described in clauses 84H to 84J, the adjustments must also be applied to the **price-responsive schedule**.

Dispatch Schedule

84L. The **system operator** must prepare the expected profile of **demand** for the **dispatch schedule** and publish its methodology on its **website**. The expected profile of **demand** must consist of:

84L.1. a measurement or estimate of the current system **demand**; and

84L.2. an estimate of the change in system **demand** in the next dispatch interval; and

84L.3. any **demand** information required to comply with schedule 13.3AA of the **Code**.

84M. The **system operator** may depart from the **dispatch schedule**, or adjust the **dispatch schedule** to comply and plan to comply with the **dispatch objective** by applying discretionary constraints, for situations requiring:

84M.1. dispatching a **generating unit** to simulate a change to the **offer** which has not been entered electronically through **WITS**;

84M.2. setting a **dispatchable load purchaser's nominated dispatch bid** to a **nominated non-dispatch bid** to simulate a change to the **nominated bid** which has not been entered electronically through **WITS**;

84M.3. dispatching a **generation unit** to minimum output to avoid loss of reserve capacity within the unit's restart cycle time;

84M.4. dispatching reserve capacity immediately to respond to a **contingent event** or **extended contingent event**;

84M.5. dispatching one or more **generating units** to a minimum **active power** output to provide **reactive power**;

84M.6. dispatching one or more **generating units** prior to the start time of a **notified planned outage** to enable the outage to proceed at the planned time;

84M.7. dispatching one or more **generating units** to allow switching operations to be undertaken in support of a **notified planned outage**;

84M.8. dispatching **generating units** to provide for management of a NZAS **reduction line change operation**;

84M.9. adjusting the power order on the **HVDC Link** prior to a **notified planned outage** to enable the outage to proceed at the planned time;

84M.10. instructing blocking or de-blocking a **pole** of the **HVDC Link** to provide for a feasible power order;

84M.11. adjusting the limits of **HVDC Link** capacity to avoid the need to schedule additional **instantaneous reserve** to cover the **extended contingent event** risk;

84M.12. adjusting the ramp rate of the **HVDC Link** to provide reserve capacity for an imminent system event; or

84M.13. increasing the amount of scheduled **instantaneous reserve** to cover an **extended contingent event** where system conditions have deviated from modelled system conditions for the current **trading period**.

84N. When the **system operator** has adjusted the **dispatch schedule** by applying a discretionary constraint of the type referred to in clause 84M, the system operator must make available to the **WITS Manager** for publication on **WITS** the equation and limit of the discretionary constraint.

84O. The **system operator** must publish on its **website** the post-schedule checks it uses to assess the accuracy of **dispatch prices** and **dispatch reserve prices**.

Dispatch Notification Participation

84P. In assessing an application to become a **dispatch notification purchaser** under clause 13.3E, or a **dispatch notification generator** under clause 13.3F of the **Code**, the **system operator** may decline an application if:

84P.1. for an application from a potential **dispatch notification purchaser**, the total capacity of the **dispatch-capable load station(s)** to be **bid** at a single **point of connection** to the **grid** is 30 MW or more; or

84P.2. the **system operator** requires the applicant to provide real time indications and measurements in accordance with Technical Code C or offers in accordance with 8.25 for the **assets** proposed to be **offered** or **bid**; or

84P.3. the applicant is unable to demonstrate functional systems for submission of **nominated bids** or **offers** to **WITS**, and receipt and acknowledgement of **dispatch notifications**; or

84P.4. the combined total capacity of **assets offered** or **bid** by **dispatch notification purchasers** and **dispatch notification generators** at a single **point of connection** to the **grid** exceeds an amount the **system operator** reasonably considers would threaten the **system operator's** ability to comply or plan to comply with the **PPOs**.

84Q. The **system operator** may suspend or revoke approval for a **dispatch notification purchaser** or **dispatch notification generator** under clauses 13.3E(4) or 13.3F(4) of the **Code** if:

84Q.1. the **participant** submits 3 or more rejection acknowledgements to **dispatch notifications** within a continuous 48-hour period;

84Q.2. the **participant** submits 5 or more rejection acknowledgements to

dispatch notifications within a continuous 30-day period;

84Q.3. the **participant** submits rejection acknowledgements to 3 consecutive **dispatch notifications;**

84Q.4.the **participant** fails to meet any of the criteria described in clause 84P.

85. *[Revoked]*

86. *[Revoked]*

86A. *[Revoked]*

87. *[Revoked]*

88. *[Revoked]*

88A. *[Revoked]*

88B. *[Revoked]*

88C. *[Revoked]*

89. *[Revoked]*

90. *[Revoked]*

91. *[Revoked]*

92. *[Revoked]*

92A. *[Revoked]*

93. *[Revoked]*

93A. *[Revoked]*

93B. *[Revoked]*

93C. *[Revoked]*

~~DISPATCH POLICY & PROCESS STATEMENT~~

~~Software~~

~~85. The policies intended to achieve the **system operator**'s **dispatch objective** are as follows:~~

~~85.1 The **system operator** must use the **software** for scheduling and **dispatch**. The **software** will include **SPD**.~~

~~The Scheduling Process~~

~~Security Assessment~~

~~86. The **system operator** must, in addition to complying with the scheduling requirements of Schedule 13.3 of the **Code**, carry out a security assessment for the **schedule period** to:~~

~~86.1 Take account of the proposed generation, dispatchable **demand** and **assets** made available and any potential contingencies for that period~~

~~and the impact on the achievement of the **PPOs**.~~

~~86.2 Provide changes required to the **non-response schedule** or the **dispatch schedule** (as the case may be) to meet the **dispatch objective**.~~

~~86A. The **system operator** must carry out a security assessment—~~

~~86A.1 At least 4 times a day, with one of those times being 14:00; and~~

~~86A.2 If there is significant change to—~~

~~(a) generation; or~~

~~(b) load profiles.~~

~~87. To carry out the security assessment, the **system operator** must:~~

~~87.1 Use the latest **non-response schedule** for the **schedule length period** for which the **system operator** is carrying out the security assessment.~~

~~87.2 *[Revoked]*~~

~~87.3 *[Revoked]*~~

~~87.4 Update the latest **non-response schedule** for each **trading period** with any changes received from **participants**, latest reserve requirements, and any further adjustments to meet the **dispatch objective** for each **trading period**.~~

~~87.5 Calculate the reserve requirements in the current **trading period** for the following **trading period.** These changes are included as the latest changes in each schedule.~~

~~87.6 *[Revoked]*~~

~~87.7 Assess power flows to identify and assess possible transmission security restrictions, capacity restrictions, or voltage conditions on the **grid**.~~

~~87.8 Identify stability conditions on the **grid**.~~

~~87.9 Identify and apply security constraints.~~

~~87.10 Identify where shortfalls in standby reserves exist by:~~

~~87.10.1 Checking that there are sufficient uncleared energy and **reserve offers** to provide for a second **contingent event**.~~

~~87.10.2 Checking that there are sufficient energy **offers** in each **island** for a frequency keeper to provide the required **frequency keeping** band.~~

~~Price-responsive schedule and non-response schedule~~

~~88. Each **price-responsive schedule** and **non-response schedule** must, in addition to complying with the requirements of clause 13.58A and Schedule 13.3 of the **Code**, include:~~

~~88.1 **Security constraints** derived by the **system operator.**~~

~~88.2 The reserve requirements in the form of the most recent reserve information, for each **trading period**, calculated up until the time that the schedule commenced solving.~~

~~88A. The **system operator** must run the automated process that the **system operator** uses to develop **security constraints** under clause 27 independently for each **price-responsive schedule** and **non-response schedule,** and accordingly the automated **security constraints** for a **non-response schedule** and the concurrent **price-responsive schedule** may be different.~~

~~88B. If the **system operator** amends, re-amends, adds, removes or excludes an automated **security constraint**, under clause 29, in a **non-response schedule**, the **system operator** is not required to do the same for the **price-responsive schedule** which is prepared for the same **schedule length period** as the **non-response schedule.**~~

~~88C. To meet the requirements of clauses 13.72(1)(b) and 13.72(2) of the **Code**, the **system operator**:~~

~~88C.1 Must issue each **dispatch instruction** required under clause 13.72(1)(b) before the start of the relevant **trading period** using scheduled **nominated dispatch bid** quantities.~~

~~88C.2 Must not revise a **dispatch instruction** to a **dispatchable load purchaser** within the **trading period** for which the **dispatch instruction** was issued.~~

~~Dispatch Schedule~~

~~89. The **system operator** must adjust a **dispatch schedule** when required under clause 13 of Schedule 13.3 of the **Code** to include:~~

~~89.1 **Security constraints**.~~

~~89.2 Bona fide changes to generation **offers, nominated bids** and **reserve offers** notified under clause 13.20 or 13.48 of the **Code**.~~

~~89.3 Changes notified by **generators**, **purchasers**, and **ancillary service agents** during a **trading period**.~~

~~89.4 The most recent reserve information received by the **system operator** at the beginning of each **trading period**.~~

~~90. To continually meet the **dispatch objective** during a **trading period**, the **system operator** must adjust the current **dispatch schedule** to:~~

~~90.1 Produce a new **dispatch schedule** during the current **trading period** to incorporate:~~

~~(a) The **frequency keeping** generation relative to the **frequency keeping** capability.~~

~~(b) Any anticipated **demand** change in the near future, except for a **reduction line change operation**.~~

~~(c) **Dynamic load distribution factors** for all **grid exit points**, provided that if the **software** necessary to incorporate **dynamic load distribution factors** into the **dispatch schedule** is unavailable for any reason, the **system operator** may, during the period of unavailability, use the last available **fixed load distribution factor** or factors determined taking into account matters including the following:~~

~~(i) regional weather forecast information; and~~

~~(ii) historical **demand** information based on the time of **day**, the **day** of the week, and the time of the year.~~

~~(d) Observed variation in **generating plant** ramp from the calculated ramp and expected `make-up` of this in the next **trading period(s)**.~~

~~(e) **Security constraints** required to meet the **dispatch objective**.~~

~~91. *[Revoked]*~~

~~92. *[Revoked]*~~

~~Week-ahead Dispatch Schedule~~

~~92A. Once the **system operator** has completed a **week-ahead dispatch schedule**, the **system operator** must provide to the **WITS manager**, for making available on **WITS**, prices for **electricity** determined by the **system operator** from the **week-ahead dispatch schedule** for:~~

~~92A.1 each **grid exit point**;~~

~~92A.2 each **grid injection point**; and~~

~~92A.3 each **reference point**.~~

~~Frequency Keeping~~

~~93. The **system operator** must:~~

~~93.1 Procure **frequency keeping ancillary services** as defined in the **procurement plan**.~~

~~93.2 Use **frequency keeping constraints** to schedule and **dispatch frequency keeping ancillary services** so as to maintain the frequency within the **normal band** for normal operating conditions, excluding events.~~

~~Use of discretion to constrain generation or reserve~~

~~93A. The **system operator** must notify the **WITS manager**, for making available on **WITS**, when it has applied a discretionary constraint to the **dispatch schedule** to directly constrain generation or **instantaneous reserve**. The notification must include:~~

~~(a) the limit of the constraint; and~~

~~(b) the node at which the generation or **instantaneous reserve** has been constrained.~~

~~Adjustment of demand profile~~

~~93B. In addition to complying with the requirements of Schedule 13.3, the **system operator** may include in a **non-response schedule** or **dispatch schedule** any adjustment factors considered reasonable by the **system operator** based on its current knowledge about the quantity of **demand** at each **GXP** to account for the fact that the **system operator** reasonably considers the quantity of **electricity** provided in a **nominated bid** for one or more of those **GXPs** is unreliable.~~

~~93C. Despite clause 93B, the **system operator** must not include in a **non-response schedule** an adjustment factor of the type described in clause 93B in relation to a **nominated dispatch bid**.~~

Chapter 3 – Compliance Policy

Formatted: Heading 1, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt

POLICY AND SCOPE

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

General Policy

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

94. The **system operator** must have systems in place to ensure it is able to efficiently carry out its functions in accordance with the following specific obligations under the **regulations** and **Code**:

94.1 Proactively monitoring and reporting the **system operator's** compliance with its obligations under the **regulations** and **Code**.

94.2 Monitoring and reporting **asset owner** compliance with the following obligations under the **Code**:

- The **asset owner performance obligations**.
- Obligations under the **technical codes**.
- Obligations under **dispensations**.
- Obligations under **equivalence arrangements**.
- Obligations under **alternative ancillary service arrangements**.

94.3 Receiving **asset** capability information and carrying out assessments of **asset** capability.

94.4 Commissioning **assets**.

94.5 Issuing **dispensations** and **equivalence arrangements**.

COMPLIANCE AND PERFORMANCE MONITORING

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

95. The **system operator** must have processes in place to achieve and maintain compliance with its obligations under the **regulations** and **Code** and must monitor its own performance for the purpose of:

95.1 Meeting the **system operator**'s review and reporting obligations under the **regulations** and **Code**.

95.2 Providing a basis for improvement and increased efficiency in the performance of its services over a period of time.

System Operator Compliance with Obligations under the Regulations and **Code**

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

96. The **system operator** must:

96.1 Identify the obligations with which it must comply under the **regulations** and **Code** and document procedures for compliance with such obligations.

96.2 Whenever the **system operator** identifies that it may have breached the **Code**, investigate the incident to determine:

96.2.1 Any contributory causes including any acts or omissions of other persons and secondary events and incidents.

96.2.2 Any mitigating factors.

96.2.3 Any corrective action necessary by the **system operator**, including any process changes, training issues, or areas where a change to the **Code** may be required.

Asset Owner Compliance and Performance Monitoring

97. The **system operator** must proactively monitor and report on **asset owner** compliance with:

97.1 **AOPOs** and the **technical codes**.

97.2 **Dispensations** and **equivalence arrangements**.

97.3 **Alternative ancillary services arrangements**.

Compliance with AOPOs and Technical Codes

98. To monitor **asset owner** compliance with the **AOPOs** and **technical Codes**, the **system operator** must:

98.1 Review the content of **asset capability statements** received from **asset owners** under **Technical Code** A of Schedule 8.3 of the **Code** to assure itself, as far as is reasonably practicable, of an **asset owner's** ability to comply with the **AOPOs** and relevant **technical codes**.

98.2 In accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**, review the information provided in the **asset capability statements**, to establish or confirm the limitations in the operation of the **asset** in question that the **system operator** needs to know for the safe and efficient operation of the **grid**.

98.3 In accordance with **Technical Code** A of Schedule 8.3 of the **Code**, rely on the results of any tests carried out under a **test plan** or a commissioning plan, to establish or confirm **asset** capability in accordance with the **AOPOs** and the **technical code** requirements.

98.4 *[Revoked]*

98.5 In accordance with clause 8.4 of the **Code** and following the receipt of an **asset capability statement**, and subject to any tests carried out under a **test plan** or commissioning plan, rely on the **assets** and information about such **assets** made available to the **system operator** unless the **system operator** considers, acting reasonably and based on the information received by or otherwise known to the **system operator**, that it should not rely upon the accuracy of an **asset owner's asset capability statement**.

98.6 During **dispatch**, log suspected or actual **asset owner** non-compliance with the **AOPOs** and the **technical codes** based upon

Formatted: Heading 3, Left, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri)

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri)

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri)

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri)

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold, Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri)

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold, Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold, Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold, Not Expanded by / Condensed by

Formatted: Heading 3 Char, Font: (Default) +Body (Calibri), Not Bold

Formatted: Font: Italic

information that is available to the **system operator** when fulfilling its **dispatch** obligations under the **Code**.

98.7 Where the **system operator** has non-confidential information on which it has relied in determining, under clause 98.5, not to rely on the accuracy of an **asset owner asset capability statement**, it must notify such information to the relevant **asset owner** as soon as reasonably practicable.

Compliance with Dispensations and Equivalence Arrangements

99. The **system operator** must undertake any specific monitoring required as a condition of a **dispensation** or **equivalence arrangement**.

Compliance with Alternative Ancillary Services Arrangements

100. The **system operator** must, following consultation with the relevant **asset owner**, specify any requirements to facilitate proactive compliance monitoring of the **alternative ancillary services arrangement** as a condition of the **system operator's** approval of such arrangements under Schedule 8.2 of the Code.

Asset Owner Non-Compliance

101. Where the **system operator** suspects that an **asset owner** may have breached or has breached any specific obligation under the **regulations**, **Code** or conditions of any **equivalence arrangement**, **dispensation** or **alternative ancillary services arrangement**, the **system operator** must:

101.1 Consider the circumstances to see if there are reasonable grounds for believing a breach has occurred.

101.2 Seek such further information from a relevant **asset owner** as may be necessary to undertake such consideration.

101.3 Determine in accordance with clause 8.27(2) of the **Code** whether to **dispatch** the **asset** or configuration of **assets** that it does not reasonably believe complies with the **AOPOs**, **technical code**, **dispensation** or **equivalence arrangement** in question.

101.4 Assess any potential impact of the non-compliance on its ability to continue to comply with the **PPOs** and notify such impact to the **Authority**.

101.5 Tell **participants** of its intention to revoke or amend a **dispensation** or **equivalence arrangement** in accordance with clause 8.35 of the **Code**, or its intention to revoke or amend any **alternative ancillary services arrangement** in accordance with clause 8.52 of the **Code**.

Urgent Change Notice

102. The **system operator** must make available on its website an **urgent change notice** form to inform the **system operator** of an urgent or temporary change in **asset** capability where clause 2(6)(b) of **Technical Code** A of Schedule 8.3 of the **Code** does not apply. An urgent or temporary change in **asset** capability is a change where the **asset owner**:

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Space Before: 0.05 pt

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt

102.1 Unexpectedly becomes aware the capability of an **asset** may differ from the capability described in the most recent **asset capability statement** provided to the **system operator** in respect of such **asset** and there is no practicable opportunity to lodge a new **asset capability statement** in accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**, and

102.2 Needs to perform further investigations to determine or confirm the actual capability of the **asset**.

103. An **urgent change notice** will apply for the period specified in the **urgent change notice** and will be the **asset owner's** best assessment (based on the information it has to hand) as to the actual capability of the relevant **asset**. On receipt of an **urgent change notice** by the **system operator**, the most recent **asset capability statement** in respect of the relevant **asset** will be deemed to be amended to reflect the capability set out in the **urgent change notice**.

104. When the **system operator** receives an **urgent change notice** it must as soon as reasonably possible:

104.1 assess the impact the urgent or temporary change in **asset** capability will have on the **system operator's** ability to plan to comply or comply with its **PPOs**.

104.2 endeavour to agree with the **asset owner** any necessary operating conditions or limitations required as a result of the temporary change in **asset** capability.

104.3 advise the **asset owner** of any conditions or constraints that the **system operator** will apply in respect of the **dispatch** of the **asset** (and it must update the **asset owner** if it changes these constraints or conditions at any time).

ASSET CAPABILITY INFORMATION

General Policy

105. In assessing the performance of an asset to assist the **system operator** to plan to comply and comply with the **principal performance obligations** and the **dispatch objective**, the **system operator** will only use information supplied by the **asset owner** through an **asset capability statement**.

106. *[Revoked]*

General Information Required from Asset Owners

107. In accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must **advise** a standard format **asset capability statement** for the following types of **asset owner**:

107.1 **generators** for **generating units** connected to the **grid** and to a **local network**.

107.2 **grid owners**.

107.3 **distributors**.

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Left, Indent: Left: 0 cm, Right: 0 cm

ASSET CAPABILITY ASSESSMENTS

General Asset Capability Assessment

108. The **system operator** has identified a number of areas where **asset** performance can have a significant impact on the **system operator's** ability to comply with the **PPOs**. These include:

108.1 **asset owner** protection systems.

108.2 **generator asset** capability:

- Voltage.
- Frequency.
- Fault ride-through capability.

108.3 **grid owner asset** capability:

- Voltage.
- **HVDC link** frequency capability.
- South Island **AUFLS**.

108.4 **distributor asset** capability:

- North Island **AUFLS**.
- Frequency response capability of unoffered generation on the **distributor**'s network
- Fault ride-through capability of **generating units** on the **distributor**'s network.

Asset Owner Protection Systems

Grid Owners

109. The **system operator** may rely upon **grid owner** compliance with the **technical codes** in the design and configuration of the **grid owner's assets** (including its connections to other persons) and associated protection arrangements, as contained in Subpart 2 of Part 8 of the **Code** and Schedule 8.3 of the **Code**.

110. In accordance with clause 4(5)(b) of **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** and the **grid owner** must agree the locations to check synchronism and **grid owner** confirmation of this synchronism must be requested in the **asset capability statement**.

111. *[Revoked]*

111.1 *[Revoked]*

111.2 *[Revoked]*

111.3 *[Revoked]*

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt, Line spacing: single, Tab stops: Not at 3.95 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Font: Italic

111.4 *[Revoked]*

112. *[Revoked]*

112.1 *[Revoked]*

112.2 *[Revoked]*

113. *[Revoked]*

Generator Asset Capability Assessment

Voltage

114. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant reactive capability** with respect to the **AOPOs** set out in clause 8.23 of the **Code** by;

114.1 assuming:

- the **generating plant** and the **grid** bus are represented as a two-bus system.
- the **generating plant's** outputs are net **active power** and **reactive power** after accounting for local supply or auxiliary load and are measured at the **generating plant** terminal entering the **generating plant** transformer
- the **generating plant** has a terminal voltage control range of +/- 5% unless otherwise stated in the relevant **asset capability statement**.

114.2 Verifying compliance with the reactive power requirements of clause 8.23 of the **Code** by assessing:

- the **generating plant** reactive power range when importing and exporting at full load with respect to the standards.
- the ability of **generating plant**, when importing and exporting **reactive power** at full load, to maintain the voltage within the ranges set out in the tables set out in clause 8.23 of the **Code**.
- the ability for **generating plant** to be connected over the operating ranges set out in clause 8.22 of the **Code** considering:
- **generating plant** reactive power range.
  - **Generating plant** transformer tap range, including the requirement for on-load tap changers.
  - **Generating plant** terminal voltage range.
  - **Generating plant** voltage stability when small voltage perturbations are applied to excitors.

Voltage Fault Ride Through

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Condensed by 0.05 pt

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, First line: 0 cm, Right: 0 cm, Space Before: 0 pt, Line spacing: single

114A For the purpose of carrying out an assessment of fault ride through compliance under clause 8.25A of the **Code**, the **system operator** must make available on its website a summary of the assumptions used in the assessment.

Frequency

115. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant** frequency capability with respect to the **AOPOs** set out in clauses 8.17 to 8.21 of the **Code**, by:

115.1 assessing the **generating plant** trip settings.

115.2 modelling **generating plant** and governor performance to analyse frequency performance.

115.3 assessing **generating plant** performance when islanded.

115.4 modelling **generating plant** governors and excitors to confirm stability when voltage perturbations are applied to excitors and load changes are applied to governors.

Grid Owner Asset Capability Assessment

Voltage

116. To enable the **system operator** to manage the risk of cascade failure, the **system operator** must:

116.1 assess the information **grid owners** provide regarding the details of the operational voltage range capability of their **assets** described in their **asset capability statements**.

116.2 model the performance of dynamic reactive power devices to establish stability and to obtain parameters for the **system operator** to model the system dynamics for planning and system security analysis.

HVDC Frequency Capability

117. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **HVDC Owner** frequency capability with respect to the **AOPOs** set out in clauses 8.17 to 8.21 of the **Code**, by:

117.1 assessing the **HVDC Owner** trip settings.

117.2 modelling the **HVDC link** performance to analyse its frequency performance.

Automatic Under-Frequency Load Shedding (AUFLS)

117A. To manage its risk of cascade failure, the **system operator** must:

117A.1 request that the South Island **grid owner** provide an **AUFLS** load profiling statement on their **asset capability statement** that states the minimum percentage of **AUFLS** load for each block armed to trip.

117A.2 maintain a register of **AUFLS** profiling statements to determine

Formatted: Heading 3, Indent: Left: 0 cm, First line: 0 cm, Right: 0 cm, Space Before: 0 pt, Line spacing: single, Tab stops: Not at 5.19 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

the minimum **AUFLS** percentage available at any time.

117A.3 incorporate **AUFLS** relay testing and confirmation of load profiling in the **test plan**.

Distributor Asset Capability Assessment

Automatic Under-Frequency Load Shedding (AUFLS)

118. To manage its risk of cascade failure, the **system operator** must:

118.1 request that North Island **distributors** provide an **AUFLS** load profiling statement on their **asset capability statement** that states the minimum percentage of **AUFLS** load for each block armed to trip.

118.2 m aintain a register of **AUFLS** profiling statements to determine the minimum **AUFLS** percentage available at any time.

118.3 incorporate **AUFLS** relay testing and confirmation of load profiling in the **test plan**.

COMMISSIONING ASSETS

General Policy

119. The **system operator** must carry out the following actions in relation to commissioning:

119.1 To ascertain whether the commissioning will affect the **system operator's** ability to plan to comply and comply with the **PPO** objectives, evaluate **asset owner** compliance with the **AOPOs** and the **technical codes**, using the information provided by the **asset owner** in accordance with clauses 2 and 3 of **Technical Code** A of Schedule 8.3 of the **Code**, at the following stages:

- Planning.
- Building and prior to commissioning.
- During commissioning.
- On completion of commissioning.

119.2 Make available on its website a \`Connection and Dispatch Guide\` that describes the studies undertaken by the **system operator** at different stages of commissioning and the timeframes for assessment required by the **system operator** at different stages of commissioning. This guide must state the information required from **asset owners** at each of the above stages, including information required by the **asset capability statements** in the form listed on its website for each **asset** that is proposed to be connected, or is connected to, or forms part of the **grid**.

120. The **system operator** must assess **asset capability statements** provided to the **system operator** by **asset owners** for **assets** that are being commissioned or modified at each of the following stages:

120.1 Prior to the completion of planning for the construction of an **asset.**

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

120.2 At completion of construction of an **asset**.

120.3 At completion of commissioning of an **asset**.

120.4 At any time the **asset owner** updates the **asset capability statement** during any stage of commissioning.

121. Upon receipt of an **asset capability statement**, the **system operator** must carry out any assessments necessary and notify the **asset owner**:

121.1 Whether the **system operator** requires any further information to determine whether the **asset** will, in its reasonable opinion, meet the requirements of the **AOPOs** and the **technical codes**.

121.2 Whether, on the basis of the information provided by the **asset owner** and any assumptions made by the **system operator** and notified to the **asset owner**, the **asset** will in the **system operator**'s reasonable opinion meet the requirements of the **AOPOs** and the **technical codes**.

121.3 Whether the **system operator**'s decision is based on any specific conditions and / or assumptions.

121.4 If the **system operator** is not satisfied the **asset** will in its reasonable opinion meet the requirements of the **AOPOs** and the **technical codes**, any appropriate actions required for the **asset owner** to achieve compliance, including application for a **dispensation** or **equivalence arrangement**.

122. If appropriate, the **system operator** may repeat the process described in clause 121 until the **system operator** is reasonably satisfied the **asset** will meet the requirements of the **AOPOs** and the **technical codes.**

Commissioning Plan

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt

123. When the **asset owner** notifies the **system operator** the **asset** is, or will be, ready for commissioning, the **system operator** must require the **asset owner** to provide a commissioning plan to meet the requirements of clause 2(6) of **Technical Code** A of Schedule 8.3 of the **Code**. In order to assess the commissioning plan, the **system operator** may require the commissioning plan to address the following matters (in addition to the specific matters set out at clauses 2(7) and 2(8) of **Technical Code** A of Schedule 8.3 of the **Code**):

123.1 Proposed dates and times for commissioning and testing activities.

123.2 Preliminary stability check.

123.3 Proposed reactive output.

123.4 Configuration.

123.5 Control system tuning.

123.6 Any other matters which the **system operator** reasonably considers relevant to enabling the **system operator** to plan to comply, and to comply, with its **PPOs**.

Dispatch for Commissioning

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

124. *[Revoked]*

Formatted: Font: Italic

125. The **system operator** will only **dispatch** commissioning **assets** solely for commissioning purposes.

During Commissioning

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

126. During commissioning of the **asset**, the **system operator** must review the results of the various tests to:

126.1 Confirm the results of any previous assessments of the **asset** carried out prior to commissioning.

126.2 Re-assess compliance of the **asset** with the **AOPOs** and the **technical codes**.

Final Assessment

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

127. Upon receipt of a final **asset capability statement** from the **asset owner** after commissioning, the **system operator** must:

127.1 Complete a final assessment of the **asset** for compliance with the **AOPOs** and the **technical codes**.

127.2 Finalise the assessment process of any request for **dispensation** or **equivalence arrangement** in accordance with this Compliance Policy.

Test Plan

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

128. The **system operator** must make available on the **Transpower** website:

128.1 a template for a **system test** that can be used by **asset owners** where the circumstances in clause 2(6)(c) of **Technical Code** A of Schedule 8.3 of the **Code** apply. If the **system operator** agrees to **dispatch** the **asset** referred to in a **test plan** submitted to it by an **asset owner** using the template, it must thereafter consider any **asset** capability information in the **test plan** that differs from that contained in the most recent **asset capability statement** provided to the **system operator** in respect of such **asset** to replace the relevant **asset** capability information for the duration agreed in the **test plan**.

128.2 the companion guides for **asset** testing, which assists **asset owners** to implement the requirements for **asset** testing in clauses 2(6) to (8) and 8(2) of **Technical Code** A of Schedule 8.3 of the **Code** and testing after modification and **commissioning**. The companion guides for **asset** testing must:

128.2.1 be reviewed not less than once in each period of five years. When carrying out each review the **system operator** must invite comments from **registered participants** as to the process and the content of the review.

128.2.2 outline the information from **asset** testing undertaken by **asset owners** under clause 8(2) of **Technical Code** A of Schedule 8.3 of the **Code** that will assist the **system operator** understand the nature of the tests carried out and the results thereof.

128.2.3 describe suggested standards or appropriate methodology for the routine testing of **assets** set out in Appendix B of **Technical Code** A of Schedule 8.3 of the **Code**.

128.2.4 describe the tests that **asset owners** can undertake after modification and **commissioning** to ensure the provision of appropriate information to the **system operator** in accordance with clauses 2(2) and 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**.

128.2.5 describe the tests that an **ancillary service agent** may be requested by the **system operator** to undertake to demonstrate an **asset** is capable of meeting the technical requirements and performance standards set out in a relevant **ancillary service** procurement contract.

DISPENSATIONS AND EQUIVALENCE ARRANGEMENTS

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

General Policy

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

129. To facilitate the operation of the processes under the **Code** for the approval of **equivalence arrangements** and grant of **dispensations**, the **system operator** must provide the following information:

129.1 Contact details for communication with the **system operator** on application, information, and revision of information or cancellation of the application or other matters relating to **equivalence arrangements** and **dispensations**.

129.2 A pro forma application form for **dispensations** or **equivalence arrangements**.

129A. The **system operator** must make its assessment of an application for a **dispensation** or an **equivalence arrangement** based on the information it has and the circumstances existing at the time. Information relevant to the **system operator's** assessment includes:

(a) the content of the regulations and **Code**.

(b) the content of the **policy statement** and **procurement** plan.

(c) power system **assets**, availability, and outages.

(d) knowledge regarding **asset** capability.

129B. The **system operator** must consider any request for a **dispensation** or **equivalence arrangement** by the relevant **asset owner** prior to the **asset** in question being commissioned.

Terms and Conditions of Dispensations and Equivalence Arrangements

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

130. The **system operator** may approve such a request subject to reasonable conditions including, without limitation, the following:

130.1 Any approval granted by the **system operator** for a **dispensation** or **equivalence arrangement** prior to the **asset** in question being commissioned will terminate after 2 years from the approval date if the **asset** is not commissioned.

130.2 If required, the **asset owner** may apply to the **system operator** to extend the 2 year term. The **system operator** may not unreasonably withhold such consent.

131. *[Revoked]*

131A. **Dispensations** and **equivalence arrangements** are subject to review at the time the **system operator** produces or reviews the **system security forecast** in accordance with clause 8.15 of the **Code**. The purpose of the review is to ascertain whether there has been any material change in circumstances or to the assumptions on which the **dispensation** was granted or the **equivalence arrangement** approved.

131B. Under Part 8 of the **Code** the **system operator** may revoke or vary a **dispensation**, or revoke an **equivalence arrangement**, in certain circumstances.

132. *[Revoked]*

Dispensation, Equivalence Arrangement and Alternative Ancillary Service Arrangements Register

133. The following must apply to the **publication** of information on the **system operator register:**

133.1 The **system operator register** must contain no information which has been designated a commercially sensitive by the relevant **asset owner**.

133.2 The **system operator** must designate an employee role to be responsible for managing the **system operator register**.

133.3 The **system operator** must maintain an up to date copy of the **system operator register** and make it available to **registered participants** at no cost on the **system operator's** website at all reasonable times.

133A The **system operator** must make available on its website a list of current **dispensations**, **equivalence arrangements** and **alternative ancillary services arrangements**.

Cancellation of Arrangements

134. The **system operator** must consider any request for cancellation of a **dispensation** or **equivalence arrangement** by the relevant **asset owner** provided that the request must:

134.1 Be in writing.

134.2 Be accompanied by a description of how compliance for that **asset**, for which the **dispensation** or **equivalence arrangement** was originally sought, is now achieved.

134.3 Include an updated **asset capability statement**.

134.4 Include any results from **system tests** carried out to confirm compliance with the **AOPOs** and **technical codes**.

Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Font: (Default) +Body (Calibri), Not Expanded by / Condensed by
Formatted: Font: (Default) +Body (Calibri)
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm, Line spacing: single
Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

Chapter 4 – Conflict Of Interest Policy

Formatted: Not Expanded by / Condensed by

Formatted: Not Expanded by / Condensed by

Formatted: Not Expanded by / Condensed by

Formatted: Heading 1, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

General Policy

134A This Conflict of Interest Policy sets out the methods the **system operator** must use to manage possible, actual or perceived conflicts of interest that arise within **Transpower** between its **system operator** functions and any of its other **participant** functions, including the **grid owner** function. A conflict of interest is any situation where one of the following persons has a material interest in the outcome of a **system operator** function:

- **Transpower**, other than in its capacity as the system operator.
- A **Transpower** employee, contractor or director involved in carrying out the function.

134B Some examples of **system operator** functions where conflicts of interest and where questions of independence and impartiality may arise include:

- Procurement of **ancillary services** or **alternative ancillary services**.
- **Causer** recommendations.
- **Dispensation** and **equivalence arrangement** decisions.
- **Outage** co-ordination.
- **Code** compliance monitoring and reporting.

GENERAL APPROACH

Formatted: Heading 2, Indent: Left: 0 cm, First line: 0 cm, Right: 0 cm, Line spacing: single, Tab stops: Not at 1.45 cm

135. The **system operator** must:

135.1 Identify potential conflicts of interest that arise in the performance of the **system operator's** functions, including by providing easily accessible means by which **Transpower** personnel and persons external to **Transpower** can (anonymously if they wish through its website) notify the **system operator** of potential conflicts of interest.

135.2 Investigate and assess the materiality of each conflict of interest that has been identified.

135.3 Apply methods to manage each conflict of interest that are appropriate for the materiality of the conflict of interest.

135.3A Record all potential conflicts of interest in the Conflicts of Interest Register as they arise, including the **system operator's** assessment of materiality for each conflict of interest and the methods used to manage each conflict of interest.

135.4 Report to the **Authority** in the **system operator's** monthly report under clause 3.14 of the **Code**, and on the **Authority's** request, on:

135.4.1 Any new conflict of interest that has arisen since the last report, including the nature of the conflict of interest, the date the conflict of interest was identified and notified to the **Authority** (if prior to the monthly report), the reason it has arisen, assessment of materiality and the methods by which it was or will be managed.

135.4.2 Any breaches of this Conflict of Interest Policy.

135.4A Report to the **Authority** in the **system operator's** annual report under clause 7.11 of the **Code**, on the **system operator's** compliance with its obligations under the **Code**, including:

135.4A.1 the background of any event that warranted the system operator undertaking internal performance review and report findings;

135.4A.2 a description of the event;

135.4A.3 the means by which the conflict of interest was managed; and

135.4A.4 any departures from or proposed changes to policy.

135.5 Treat all **participants** in an even-handed way, including by applying the same processes and standards to its dealings with all **participants**.

135.6 [Revoked]

136. [Revoked]

137. [Revoked]

THE MEANS TO MANAGE CONFLICT OF INTEREST

Formatted: Heading 2, Indent: Left: 0 cm, Right: 0 cm

138. The **system operator** must employ any or all of the following methods to manage conflicts of interest, taking into account the circumstances and materiality of the conflict of interest:

138.1A Appoint an independent person to oversee the management of the conflict of interest.

138.2A Appoint an independent expert to conduct an evaluation or investigation on behalf of, or to advise, the **system operator**.

138.3A Establish independent document and information management systems.

138.4A Establish a communication management system between the relevant parts of Transpower New Zealand Limited, which may include call logs, document logs, meeting minutes and specified points of contact.

138.5A Establish a clear division of management and staff roles. This may include the establishment of separate teams that are physically isolated from each other.

138.6A Advise any relevant non-confidential information considered material in maintaining a transparent and impartial process.

138.7A Any other method the **system operator** identifies and considers appropriate to manage the conflict of interest, which the **system operator** must **advise** as soon as reasonably practicable.

138.1 [Revoked]

138.2 [Revoked]

138.3 [Revoked]

138.4 [Revoked]

138.5 [Revoked]

138.6 [Revoked]

138.7 [Revoked]

138.8 [Revoked]

139. [Revoked]

140. [Revoked]

141. [Revoked]

142. [Revoked]

143. [Revoked]

143.1 [Revoked]

143.2 [Revoked]

143.3 [Revoked]

143.4 [Revoked]

143.5 [Revoked]

143.6 [Revoked]

144. [Revoked]

145. [Revoked]

145.1 [Revoked]

145.2 [Revoked]

146. [Revoked]

146.1 [Revoked]

146.2 [Revoked]

146.3 [Revoked]

146.4 [Revoked]

147. [Revoked]

148. [Revoked]

148.1 [Revoked]

148.2 [Revoked]

149. [Revoked]

149.1 [Revoked]

149.2 [Revoked]

149.3 [Revoked]

149.4 [Revoked]

150. [Revoked]

151. [Revoked]

152. [Revoked]

152.1 [Revoked]

152.2 [Revoked]

152.3 [Revoked]

152.4 [Revoked]

Chapter 5 – Future Formulation and Implementation Policy

Formatted: Heading 1, Indent: Left: 0 cm, Right: 0 cm, Space Before: 0 pt

Policy and Scope

Formatted: Heading 3, Indent: Left: 0 cm, Right: 0 cm

153. The **Code** contains provisions that require the **system operator** to be consulted on the impact of proposed **Code** changes. This ensures that where necessary, the impact of **Code** changes can be reflected in the **policy statement** by making timely changes outside the annual review cycle.

154. The **system operator** maintains operational review processes that capture issues for which possible change to the **policy statement** may be desirable. Such matters are logged for consideration during the next review of the **policy statement**. The matters logged include issues raised with the **system operator** by **participants** and the **Authority**.

155. If an issue is identified requiring urgent attention and change to the **policy statement** outside the annual review cycle the **system operator** must bring the matter to the attention of the **Authority**. The **system operator** must seek the **Authority's** assistance in implementing the required change, such as by **Code** change, change to the **policy statement** or approval of an exemption.

156. [Revoked]

    156.1 [Revoked]

    156.2 [Revoked]

    156.3 [Revoked]

    156.4 [Revoked]

    156.5 [Revoked]

    156.6 [Revoked]

    156.7 [Revoked]

    156.8 [Revoked]

Chapter 6 - Statement of Reasons for Adopting Policies and Means

Formatted: Font: (Default) +Body (Calibri), 11 pt, Not Bold

Formatted: Heading 1, Indent: Left: 0 cm, Right: 0 cm, Line spacing: single

157. The **system operator** has adopted the policies and means set out in the **policy statement** for the following reasons:

157.1 The **system operator** believes they are the policies and means that will best enable it to comply with the **principal performance obligations**.

157.2 They are policies and means that in large measure have been used successfully for many years.

157.3 To the extent the policies and means represent changes from those adopted previously it is because the **system operator** believes no previous policy or means existed or a previous policy or means did not adequately meet the needs of the **system operator**.

157.4 The **system operator** consulted widely when it developed the policies and means set out in the **policy statement** and took into account the views of **participants**.

This statement is made for the purposes of clause 8.11(3)(d) of the **Code**.

Glossary of Terms

158. **Advise** means the **system operator** placing information or other material required to be provided or made available under the **policy statement** on its website. The **system operator** must use its best endeavours to send an e-mail to **participants** telling them the information or other material has been placed on the **system operator's** website.

159. **Asset outage constraints** are a sub-set of **security constraints.** They are **security constraints** previously developed and used by the **system operator** temporarily in response to earlier advised **asset** outages. They are retained by the **system operator** for possible future re-use. They are often applied at short notice.

160. **AUFLS** means **automatic under-frequency load shedding** systems.

161. **Changeover date** means 28 March 2011.

162. *[Revoked]*

162A **Constraint percentage threshold** means the threshold at which constraints developed by automatic processes are applied to schedules in the market system, expressed as a percentage of the limit of the constraint. This threshold is **advised** from time to time by the **system operator**, following consultation with **participants.** Separate constraint percentage thresholds may be **advised** for constraints developed under automated and non-automated processes.

162B **Constraint publication threshold** means the threshold at which constraints are published on **WITS**, expressed as a percentage of a constraint limit. This threshold is **advised** from time to time by the **system operator,** following consultation with **participants.**

163. **Contingent events** are as defined in clauses 12.3 and 12.4.

164. **Demand shedding** means an unplanned interruption of **demand** initiated by the **system operator**. **Demand management** also has the same meaning.

164A. **Discretionary security constraint** means a **security** constraint applied to **SPD** by the **system operator** that represents a departure from the **dispatch schedule** pursuant to clause 13.70 of the **Code**.

165. **Dynamic load distribution factor** means the proportion of a regional load being drawn at a **GXP** within that region. The **dynamic load distribution factors** are derived from actual load on a regularly updated basis in real time.

166. *[Revoked]*

167. **Extended contingent events** are as defined in clauses 12.3 and 12.4.

168. **Fixed load distribution factor** means the proportion of the regional load forecast assigned to a **GXP** within that region. The **fixed load distribution factors** are set for a specified **trading period** based on the actual load for the same **trading period** in the previous week or in the previous fortnight.

169. **Frequency keeping constraints** means **security constraints** applied by the **system operator** in scheduling and **dispatch** for the purposes of maintaining a frequency keeper within its offered **asset** capability limits.

170. **Maximum instantaneous demand change limit** is the **MW** amount specified from time to time by the **system operator** under clause 39 for **demand** changes that may be made by any **purchaser** within a 1 minute and a 5 minute period.

170A [Revoked]

171. **Other events** are as defined in clause 12.3.

172. [Revoked]

173. **Planned Outage Co-ordination Process** means the process by which the **system operator** receives, assesses and provides feedback on outage notifications in accordance with **Technical Code** D of Schedule 8.3 of the **Code**.

173AA **Reduction line change operation** means the planned or unplanned NZAS reduction line removal and restoration process at Tiwai Aluminum smelter.

173A. **Regulations** means the regulations made pursuant to subpart 1 of Part 5 of the **Act** as may be amended from time to time.

174. **Relevant freely available reactive resources** are reactive resources that exist, the **dispatch** of which will support voltage at the affected location, which are available to the **system operator** at no **procurement plan** cost and without requiring the application of a **security constraint** to provide reactive resources. They include **grid owner assets** capable of providing reactive support and made available, and generation **dispatched**, and required to provide reactive support in accordance with the **voltage support AOPOs**.

175. **Reserves Management Tool** and **RMT** mean the reserves management **software** used by the **system operator** as agreed with the **Authority** pursuant to the **System Operator Service Provider Agreement**.

176. **Scheduling Pricing and Dispatch** and **SPD** mean the scheduling, pricing and dispatch **software** used by the **system operator** as agreed with the **Authority** pursuant to the **System Operator Service Provider Agreement**.

177. *[Revoked]*

178. **Security constraint** is a constraint that is used to maintain the security and stability of the power system.

179. *[Revoked]*

180. A **standby residual shortfall** is a situation when there are either insufficient **generator offers** and **instantaneous reserve** offers following a **contingent event** to schedule sufficient reserves for a second event and/or there are insufficient **generator offers** to restore **interruptible load** following a **contingent event**.

181. A **standby residual shortfall notice** is a notice issued by the **system**

operator to selected **participants** in which it advises that a **standby residual shortfall** has been identified.

181A. **Standby residual shortfall threshold** means the threshold above which a **standby residual shortfall notice** must be issued**,** such threshold being determined from time to time by the **system operator** and notified by the **system operator** to **participants**.

182. **System Operator Service Provider Agreement** means the **market operation service provider agreement** for the provision of **system operator** services.

183. **Target grid voltages** are voltages determined by the **system operator** under clause 41.1 of the Security Policy at selected locations on the **grid** where the voltage is greater than, or equal to 50kV.

184. **Temporary security constraints,** which include **asset outage constraints**, are **security constraints** which are applied in scheduling and **dispatch** to supplement **permanent security constraints** and account for temporary **grid** configuration, transmission capability and system conditions.

185. **Test plan** means:

185.1 a routine test plan agreed pursuant to clause 8(2) of **Technical Code** A of Schedule 8.3 of the **Code**;

185.2 a remedial test plan agreed pursuant to clause 8(3)(a) of **Technical Code** A of Schedule 8.3 of the **Code**; or

185.3 a test plan agreed between the **system operator** and an **asset owner** under clause 2(6) of **Technical Code** A of Schedule 8.3 of the **Code**.

186. **Transmission circuit** means:

186.1 any transmission line owned by a **grid owner**.

186.2 any distribution line owned by a **participant** to which not less than a sum of 60 **MW** of **generation** is connected and which distribution line is connected to the **grid** primarily for the purpose of **injection** into the **grid**.

187. **Urgent change notice** is a notice issued to the **system operator** by a **participant** in accordance with clause 102.

Formatted: Indent: Left: 0.25 cm, Hanging: 1.25 cm, Space Before: 0 pt, Tab stops: 1.5 cm, Left

188. **Week-ahead dispatch schedule** means a schedule produced by the **system operator** for the 260 **trading periods** beginning at 14.00 hours of the next **day** using:

188.1 Generation **offers** or, where no revised **offer** exists, generation **offers** for the previous week.

188.2 Forecast **grid** configuration, including any **notified planned outages.**

188.3 Anticipated **demand** using **fixed load distribution factors**.

188.4 **Nominated bids** or, where no revised **nominated bid** exists, **nominated bids** for the previous week.

189. **Wider voltage agreement** is an arrangement where the **grid owner** has

informed the **system operator**, in writing that:

189.1 The **grid owner** has agreed with other affected **asset owners** at a **GXP** or in a region that the **system operator** may operate outside the ranges set out in clause 8.22(1) of the **Code**.

189.2 Where the **grid owner** has not identified any other affected **asset owners** at a **GXP** or in a region, **the grid owner** agrees with the **system operator** to operate the **grid owner's assets** outside the ranges set out in clause 8.22(1) of the **Code**.

Appendix C The system operator’s assessment of the proposed amendments

TRANSPOWER

Real Time Pricing –
Changes to the Policy Statement

Consultation Information

Date: June 2022

Address:	Transpower New Zealand Ltd Waikoukou PO Box 1021 Wellington New Zealand
Telephone:	+64 4 495 7000
Fax:	+64 4 498 2671
Email:	system.operator@transpower.co.nz
Website:	http://www.transpower.co.nz

Summary

The Electricity Authority is consulting the industry on proposed changes to the Policy Statement that the system operator believes are required for the implementation of the Real Time Pricing market design ("RTP"). This document provides information about the proposed changes and accompanies the draft Policy Statement.

As part of its decision to implement RTP the Authority directed the system operator to include several additions to the Policy Statement in response to feedback from the RTP consultations. In addition, we have also included additional details about our existing policies concerning the scheduling and dispatch processes which would be expected to have an impact on settlement pricing outcomes from time to time.

The proposed changes primarily impact the Security Policy and Dispatch Policy. Substantive changes include:

- further detail on the circumstances in which adjustments are made to the forward schedules and Dispatch Schedule as provided for under clause 12 of Schedule 13.3 of the Code
- reforming the Dispatch Policy to incorporate the production of Dispatch Prices in the dispatch process
- description of the criteria the system operator will use to assess eligibility of market participants as Dispatch Notified participants.

This consultation complements the Authority's final consultation on the revised RTP Code Amendment. The draft Policy Statement has been prepared under clause 8.11A(2) of the Code[1]. As these changes are required as part of the RTP project, the costs and benefits of these changes are deemed to be included in the Authority's assessment of the costs and benefits of the RTP project, and no extra information is provided.

[1] The RTP Decision Paper expresses the need for the system operator to update its Policy Statement, which is considered a request for the system operator to propose a change.

Contents

1.0 We propose to change the Policy Statement for RTP 5
1.1. Consultation process 5
1.2. Interaction with other reviews 5
2.0 Dispatch Policy 6
2.1 The Dispatch Schedule load input will be described in detail through a prescribed guideline 6
2.2 The Post-Schedule Check process will be documented 7
2.3 The system operator may use its discretion to depart from the Dispatch Schedule 7
2.4 The Dispatch Policy has been redrafted for clarity 8
2.5 Constraint scheduling in the PRS will align with the Dispatch Schedule 9
3.0 Security Policy 10
3.1 Security constraints will be applied to manage contingent event risks in the same way as now 10
3.2 AUFLS will continue to be used to some extent to manage shortfalls of instantaneous reserve 11
3.3 Demand may be managed in an Unsupplied Demand Situation 12
4.0 Approval for participation as a Dispatch Notification participant (DNL or DNG) .. 14
4.1 Proposed approval criteria for Dispatch Notification participation 14
Appendix 1 Summary Table of Policy Statement amendments, per clause 16
Appendix 2 Draft Dispatch Schedule Load Input Guideline 18
Appendix 3 Draft Post-Schedule Check Summary 19

1.0 We propose to change the Policy Statement for RTP

As part of the implementation of the Real Time Pricing project (RTP) we have developed changes to the Policy Statement. We believe these changes are necessary to support the implementation of the new market design, which fundamentally changes wholesale market operations to produce trading period Interim Prices based on a time-weighted average of Dispatch Prices produced during the trading period.

1.1. Consultation process

This update to the policy statement is initiated by the Authority, through its RTP Decision Paper[2], deemed as a request to the system operator to propose a change to the policy statement under clause 8.11A(2) of the Code. The costs and benefits of the project have also been deemed to include the costs and benefits of the changes to the policy statement, and no further information is provided in that regard.

The Authority is consulting with industry on these proposed changes in conjunction with its proposed updates to the RTP Code Amendment which was included with its Decision. Some of the information contained in the appendices to this document relates to Code clauses that are proposed by the RTP Code Amendment.

Throughout the discussion provided in this document there are consultation questions which may guide feedback from participants.

1.2. Interaction with other reviews

This Policy Statement review process relates only to the implementation of RTP and is separate to any other Code or Policy Statement reviews, including any arising out of the 9 August 2021 grid emergency.

This draft Policy Statement incorporates all changes in the version approved by the Authority in July 2022.

[2] Decision to implement RTP — Electricity Authority (ea.govt.nz)

2.0 Dispatch Policy

The principal impact of RTP on the system operator's operational policy is to its processes for dispatch. In the current settlement pricing methodology system conditions at the time of dispatch are only relevant to settlement pricing at the trading period start time – the final pricing schedule assumes average and invariant schedule inputs throughout the trading period. However, the system operator continuously models changes to system conditions (for example changes to plant availability, grid configuration, weather etc.) to be able to calculate a secure dispatch solution. The way the final pricing schedule is calculated means any changes to system conditions that are modelled in the market system during a given trading period do not currently impact settlement pricing, unless they comprise the schedule's input conditions at the start of the next trading period.

Under RTP the system operator will produce Dispatch Prices throughout the trading period which will be averaged to produce the trading period settlement prices (Interim Prices). This means any changes that are modelled in the market system in the normal course of system operation will have an immediate impact on price; indeed, this is at the core of the intent of introducing real time pricing.

Three aspects of the system operator's dispatch policy have a significant impact on the Dispatch Price calculation, being:

- the load (demand) input that SPD uses to schedule generation
- the automated post-schedule check process that assures a valid dispatch solution, and
- the use of discretion – manual interventions made by the system co-ordinators in real time to adjust the dispatch schedule for changes in system conditions.

These aspects are discussed in detail below.

2.1 The Dispatch Schedule load input will be described in detail through a prescribed guideline

Current Policy

The Code requires the system operator to prepare a Dispatch Schedule and to implement the Dispatch Schedule by issuing Dispatch Instructions. As part of preparing the Dispatch Schedule the system operator must use, among other things, the expected profile of demand for the relevant dispatch interval. The current Policy Statement does not elaborate on how the expected profile of demand is constructed, except to provide for adjustments to the profile where nominated bids are unreliable.

Proposed Policy

Under RTP the expected profile of demand in the Dispatch Schedule will be the most significant input to the Dispatch Price calculation. Even small variations in the demand profile can considerably impact the price outcomes because dispatchable resources' offers vary highly non-linearly with increasing load. To ensure an efficiently functioning spot market it is important that participants have sufficient information to understand the inputs to the Dispatch Schedule, including the formulation of the expected profile of demand.

The Authority recognised the impact the expected profile of demand can have on settlement prices in its RTP decision paper[3]. The decision specified that the system operator would upgrade its Short-Term Load Forecast tool to incorporate real-time measurements from the grid owner's revenue meters ("ION" meters), and to make use of its SCADA Data Validation (SDV) tool to automatically move through a hierarchy of other data sources where the revenue meter data was unavailable. The Authority further specified that the system operator would document and publish its "STLF Methodology" (generally, the methodology the system operator employs to prepare the expected profile of demand input for the Dispatch Schedule) and refer to that methodology in the Policy Statement. This reference has been included as clause 84L in the draft RTP Policy Statement and the methodology itself is provided as Appendix 4 to this paper.

2.2 The Post-Schedule Check process will be documented

Current Policy

As part of the process by which schedules are calculated and published, the system operator employs an automated post-schedule check (PSC) which validates the schedule results against pre-configured thresholds. The current PSC priorities relate to ensuring the dispatch solution is adequate for maintaining system security; some checks relate to the Dispatch Schedule's pricing outcomes, as those prices offer useful indications where there may be a security issue in the schedule which warrants co-ordinator attention. The schedule checking process is not currently described by the system operator's policies.

Proposed Policy

For the reasons described above, under RTP it will be vital to ensure the Dispatch Schedule is always producing settlement-quality prices. This was highlighted in the Authority's decision paper in its discussion around the changing Pricing Error Claim process. Under RTP pricing errors will only be able to be claimed for errors in the averaging of Dispatch Prices to form Trading period prices. There will be no retroactive correction mechanism available for Dispatch Prices, therefore the onus is on the system operator to ensure Dispatch Prices are free of errors. The Authority further elaborated on this point instructing the system operator to specify how it ensures the accuracy of Dispatch Prices in the Policy Statement and engage with industry to define appropriate validation criteria.

We propose inserting Clause 84O to fulfil this requirement and have provided a draft summary of the checks used for validating Dispatch Prices as Appendix 5.

2.3 The system operator may use its discretion to depart from the Dispatch Schedule

[3] Found at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/decision-to-implement-rtp/

Current Policy

The Code[4] provides for the system operator to use its discretion to depart from the Dispatch Schedule if it is necessary for meeting the Dispatch Objective[5] or the requirements of clause 8.5 (concerning restoration of the power system). The Code and Policy Statement also provide for the system operator to apply adjustments to the Dispatch Schedule to meet the Dispatch Objective[6]. For the purposes of this discussion, we refer to both circumstances as the "use of discretion". The current policy statement expands on these provisions by requiring the system operator to notify the WITS Manager when it has applied a discretionary constraint to generation, for publication of the details of the constraint on WITS[7].

Proposed Policy

The application of discretion (either through departing from the Dispatch Schedule or applying adjustments to the Dispatch Schedule) means the market system solves in real time with different inputs to those that were forecast. This can result naturally from variations in system conditions and asset availability and capability, which change dynamically through each trading period; often the use of discretion is required to adequately model and respond to changing system conditions. As these discretionary actions could impact Dispatch Prices, and hence Trading Period settlement prices, we feel it is important to ensure participants are aware of the circumstances which prompt the need for discretionary intervention.

Our proposed policy is to combine the provisions that allow for co-ordinator intervention generally and define the typical circumstances in which discretionary adjustments are made to the Dispatch Schedule. This has been provided as clause 84M in the draft Policy Statement. The list is not intended to be exhaustive but should be sufficient to give participants an appreciation for the circumstances in which co-ordinator discretion might be expected to be applied (and hence when Dispatch Price outcomes may deviate from forecast).

2.4 The Dispatch Policy has been redrafted for clarity

The Dispatch Policy is required to describe the process by which the system operator adjusts forward schedules and the Dispatch Schedule to meet the Dispatch Objective, including a Dispatch Process Statement. The Dispatch Process Statement must describe the methodologies used by the system operator to meet the Dispatch Objective.

Under RTP the Dispatch Process is not significantly changing, and may generally be described as:

1. the system operator employs various software (referred to in Part 3 of the Code and the System Operator Service Provider Agreement, SOSPA);
2. the system operator prepares the Week-Ahead Dispatch Schedules (WDS);
3. the system operator prepares the Non-Response Schedules (NRS) and makes security assessments;

[4] Refer Code clause 13.70.

[5] Refer Code clause 13.57.

[6] Refer Code Schedule 13.3 clause 13, and Policy Statement clause 89.

[7] Refer Policy Statement clause 93A.

4. The system operator uses the results of the security assessments to determine adjustments required for subsequent NRS schedules and the Dispatch Schedule.

The Dispatch Policy has been rewritten in this draft Policy Statement to describe this process more clearly, updating the existing policy for modern terminology and including at relevant points the substantive changes described in the above sections. Appendix 2 summarises the changes in relation to each clause of the current Dispatch Policy.

2.5 Constraint scheduling in the PRS will align with the Dispatch Schedule

Current Policy

The system operator uses automatic methods for building and applying security constraints ("SFT constraints") to the Non-Response Schedules (NRS) and Price-Responsive Schedules (PRS). The security constraints which are developed for the latest NRS are used by the Dispatch Schedule. System co-ordinators have the ability to adjust these constraints in real time to meet the Dispatch Objective. Generally these adjustments result from deviations in real-time system load from that modelled in the Dispatch Schedule.

Any adjustments made in real time are automatically applied to the next NRS. The adjustments are not generally included in the PRS, as the PRS will have similar but slightly different constraint formulations depending on the load differences modelled in the NRS compared with the PRS. If the system co-ordinators adjustments were to apply to the PRS, the constraint equation used by the PRS would be slightly over- or under-constraining compared to the equivalent automatically-generated PRS constraint. Given the NRS and PRS load scheduling is very similar or the same most of the time[8], the degree of over- or under-constraining in the PRS is likely to be very small.

Proposed Policy

Under RTP the PRS will effectively be used as a "back-up" pricing schedule, in that when the market system is unavailable and Dispatch Prices are not published at the beginning of a trading period, the price in the latest PRS will be used in lieu of prices from the Dispatch Schedule. For this reason it is important the PRS reflects as much as possible any adjustments made in real time which concern future trading periods. As a result, we propose changing our policy for constraint adjustment, such that any constraints that are adjusted in real time must be also applied to the PRS. This allows the PRS to solve equivalently with the Dispatch Schedule and produce prices which are aligned as much as possible to the Dispatch Schedule. This effectively trades-off the potential disbenefit of failing to incorporate the most recent constraint information into the PRS, versus the disbenefit of the constraint formulations being slightly over- or under-constraining, which we have determined to be smaller. This change is reflected in new clause 84K in the draft Dispatch Policy, and the revocation of existing clause 88B.

[8] An analysis considering NRS and PRS cases over the last year (01-Mar-21 to 28-Feb-22) showed that of 238,127 constraints used in the PRS cases, 234,757 (98.6%) were common to the NRS. On average the differences in the constraint limits and constraint factors are approximately zero, but there are outliers. The magnitudes of the differences in constraint limits are dependent on the constraints themselves.

3.0 Security Policy

The Security Policy describes the means that the system operator considers appropriate for complying and planning to comply with its Principal Performance Obligations (PPOs)[9]. RTP does not in principle impact these obligations; regardless of the method by which pricing is determined in the Wholesale Electricity Market, the system operator's obligations related to managing the power system haven't changed. Therefore, any changes to the security policy come as a consequence of ensuring the Dispatch Schedule remains suitable for managing the power system, while also effecting the Authority's RTP market design and providing settlement-quality pricing information from the dispatch process.

The areas of the Security Policy impacted by the RTP market design are:

- creation and application of security constraints (transmission constraints)
- providing for shortfall of instantaneous reserve in the Dispatch Schedule, and the magnitude of the allowable shortfall, and
- the process for instructing and managing the disconnection of demand (particularly related to the unsupplied demand situation trigger).

These impacts are described in detail below.

3.1 Security constraints will be applied to manage contingent event risks in the same way as now

Current Policy

Security constraints are built and applied to protect assets against the sudden unexpected loss of availability of other assets (contingencies). Constraints may be built manually or automatically, the latter being generated by the Simultaneous Feasibility Test (SFT) application as part of producing an NRS or constraint adjustment schedule (CAS). This is described in the current policy statement clauses 26 – 29.

In some circumstances, binding transmission constraints[10] can result in inoperable outcomes – either there is no generation available for redispatch to satisfy the conditions of the constraint, or the constraint results in such a sudden change in the dispatch solution that the system co-ordinators are not confident of their ability to comply with the PPOs under those conditions[11]. In these circumstances, the current policy is to exclude these constraints from the solution, either in planning time (the schedules are configured to not build constraints for parts of the grid that will result in an infeasibility) or in real time (a constraint has been built but the outcome of the dispatch solution would result in an inoperable system state).

[9] Refer Code clause 8.11 and Part 7.

[10] Constraints which are scheduled at 100% of their limit.

[11] SPD and SFT solve iteratively to produce a schedule of generation quantities. SPD is a linear least-cost solver and does not account for other system needs such as maintaining voltage levels. To determine whether a schedule of generation is feasible from that viewpoint, advanced energy management system applications are used to study the result. This is typically done in advance of real time as part of the security assessment process.

Proposed Policy

We propose no change to the current policy for creating and modifying security constraints up to and within real time. This raises some implications when the policy is applied within a RTP market environment. Firstly, deciding to exclude transmission constraints in particular regions where they would create inoperable dispatch solutions effectively exposes regions which can permit transmission constraints to high prices or scarcity prices when the constraints bind, where other regions are not exposed to this risk. The alternative, to enable automatic security constraints universally across the grid, is not practical for the reasons described above (and would potentially impose a market cost without due benefit of increased security). Secondly, on rare occasions a potential contingency on the transmission network could result in the system operator instructing load shedding to avoid exceeding asset capability, but this load shedding would not result in a scarcity price (the contingency having not been modelled in the market system). We see this as acceptable within the market settings as the situation leading to this outcome would be suitably rare and likely only during outages of other equipment, whereas the Authority's intent behind the market design is for scarcity prices to reflect a (generation or transmission) capacity shortfall on the intact grid.

3.2 AUFLS will continue to be used to some extent to manage shortfalls of instantaneous reserve

Current Policy

The system operator's emergency management policy describes the actions it takes in a Grid Emergency, particularly when there is insufficient offered dispatchable resource capacity to meet demand and instantaneous reserve requirements. In this situation, the system operator may schedule an instantaneous reserve shortfall (aka deficit) in real time. Clause 33 of the Policy Statement describes that the system operator may schedule a reserve shortfall and continue to dispatch without demand management, relying on Automatic Under Frequency Load Shedding (AUFLS) to manage frequency and avoid cascade failure should a contingent event occur.

This scheduling outcome happens automatically as a result of the configuration of constraint violation penalty (CVP) values in SPD. Because deficit instantaneous reserve is valued at $100,000/MW and deficit energy is valued at $500,000/MWh, the relative cost benefit of deficit instantaneous reserve allows generation capacity to be scheduled to provide energy in preference to instantaneous reserve. Because these values are an order of magnitude larger than energy or instantaneous reserve offers, SPD schedules as much instantaneous reserve deficit as is necessary or capacity is available[12] to minimise the quantity of energy deficit.

An instantaneous reserve shortfall in real time does not necessarily lead to reserve prices reflective of the shortfall in final pricing. Because final pricing solves using the average trading period system conditions as inputs, on average an instantaneous reserve deficit may not have occurred (it may only have been apparent in real time for a spike in load in the middle of the trading period, for instance). Where final pricing does solve with an instantaneous reserve deficit, this is initially solved using the $100,000/MW constraint violation penalty. Because that value does not reflect the true economic value

[12] This applies to generation capacity which is offered as both energy and instantaneous reserve. Interruptible Load cannot provide energy capacity and so is always scheduled as instantaneous reserve where economic to do so.

of an instantaneous reserve shortfall[13], a manual post-processing mechanism is applied[14] which adds virtual reserve capacity valued at the higher of three times the largest scheduled energy offer, or the largest scheduled instantaneous reserve offer. SPD then resolves without an instantaneous reserve shortfall, and a marginal price reflective of the virtual reserve provider's synthetic offer.

Proposed Policy

Under RTP Dispatch Prices must be settlement-quality all the time, even during shortfalls of instantaneous reserve capacity. Consequently, the evaluation of the value of an instantaneous reserve shortfall must be automated through applying appropriate constraints in SPD, using the values for instantaneous reserve shortfall supplied by the Authority. This allows SPD to trade-off the value of an instantaneous reserve shortfall against an energy shortfall in the same way as it does now with CVP values, but with economically justifiable values instead.

Depending on the Authority's settings of the instantaneous reserve shortfall price-quantity tranches, SPD may schedule some or all available spinning reserve capacity as energy, in the same way it does today. No change to the Policy Statement is proposed, as clause 33 continues to provide for AUFLS to manage the contingent event risk for any amount of reserve shortfall.

3.3 Demand may be managed in an Unsupplied Demand Situation

Current Policy

In a Grid Emergency the system operator may rely on the provisions of Technical Code B of Part 8 of the Code. Under these provisions, the system operator may request or instruct the disconnection of demand in order to comply or plan to comply with its PPOs.

In real time the current configuration of SPD will schedule all offers that do not exceed the energy deficit CVP value of $500,000/MWh – practically, all available generation will be dispatched to meet demand. The system operator would only instruct demand management after all available resources have been dispatched.

Proposed Policy

Under RTP the inclusion of the value of lost load into SPD's optimisation algorithm means generation which is offered at values which exceed the value of lost load would not be scheduled or dispatched in real time[15]. In this circumstance the system operator would be compelled to request or instruct the disconnection of demand to keep the system in balance. In the RTP Code Amendment this is enabled

---

[13] The value of energy or instantaneous reserve shortfall should be approximately the value of lost load, estimated by the Authority as on the order of $10,000 - $20,000/MWh. Refer to section 4 of the Remaining Elements of RTP consultation paper for details: [Consultations — Electricity Authority (ea.govt.nz)].

[14] The Virtual Reserve Provider, refer to Code clause 13.166A.

[15] Or for which the 'delivered' cost of the energy exceeds the VoLL value. E.g. the price effect of transmission losses or the cost of instantaneous reserve to cover energy being supplied by a contingent event (CE) risk.

through what is termed an “unsupplied demand situation”. We propose to update the Emergency Planning section of the Security Policy to align with this Code provision.

4.0 Approval for participation as a Dispatch Notification participant (DNL or DNG)

Dispatch Notification is a new mode of participation in the Wholesale Electricity Market, whereby Dispatch Notification Purchasers ("DN Loads", "DNL") and Dispatch Notification Generators ("DNG") may operate in much the same way as conventional participants, but with greater flexibility and less compliance costs. In its Decision Paper[16] the Authority tasked the system operator with developing approval criteria for participation as Dispatch Notification participants.

The system operator is naturally incentivised to approve application for asset owners and operators to become Dispatch Notification participants, as it improves the visibility of price-responsive load and generation on the grid. However, in incorporating those intentions into the scheduling and security checking processes the system operator needs confidence that these potential participants will, for the most part, honour the intentions described by their bid and offer information and comply with dispatch notifications. If this does not occur, the system operator could find itself in planning time relying on capacity to balance the system that is not available in real time, which could lead to emergency measures being taken.

The proposed approval criteria are detailed at clauses 84P and 84Q of the draft policy statement and are included below. We would appreciate feedback from parties interested in the Dispatch Notification scheme.

4.1 Proposed approval criteria for Dispatch Notification participation

Dispatch Notification Participation

84P. In assessing an application to become a **dispatch notification purchaser** under clause 13.3E, or a **dispatch notification generator** under clause 13.3F of the **Code**, the **system operator** may decline an application if:

84P.1. for an application from a potential **dispatch notification purchaser**, the total capacity of the **dispatch-capable load station(s)** to be **bid** at a single **point of connection** to the **grid** is 30 MW or more; or

84P.2. the **system operator** requires the applicant to provide real time indications and measurements in accordance with Technical Code C or offers in accordance with 8.25 for the **assets** proposed to be **offered** or **bid;** or

84P.3. the applicant is unable to demonstrate functional systems for submission of **nominated bids** or **offers** to **WITS**, and receipt and acknowledgement of **dispatch notifications**; or

84P.4. the combined total capacity of **assets offered** or **bid** by **dispatch notification purchasers** and **dispatch notification generators** at a single

[16] Refer section 5.6.

point of connection to the **grid** exceeds an amount the **system operator** reasonably considers would threaten the **system operator's** ability to comply or plan to comply with the **PPOs**.

84Q. The **system operator** may suspend or revoke approval for a **dispatch notification purchaser** or **dispatch notification generator** under clauses 13.3E(4) or 13.3F(4) of the **Code** if:

84Q.1. the **participant** submits 3 or more rejection acknowledgements to **dispatch notifications** within a continuous 48-hour period;

84Q.2. the **participant** submits 5 or more rejection acknowledgements to **dispatch notifications** within a continuous 30-day period;

84Q.3. the **participant** submits rejection acknowledgements to 3 consecutive **dispatch notifications;**

84Q.4. the **participant** fails to meet any of the criteria described in clause 84P.

Appendix 1 Summary Table of Policy Statement amendments, per clause

Question 10: In reviewing the other changes to the Policy Statement drafting as detailed in the following table, are there any changes with which you disagree? If so, please provide discussion and alternative wording.

Current Clause	Proposed Clause	Summary	Description of Change	Rationale
Preamble				
	9A	Introduces **dispatch prices**	Includes dispatch prices into Dispatch Policy	Completeness
Security Policy				
11.7		Introduces **unsupplied demand situations**	Includes **unsupplied demand situations** into Security Policy	Completeness
62A.2		Island Shortage Situation Notice policy	Revoked	Island Shortage Situations no longer exist under RTP
74		An unsupplied demand situation may trigger demand management	Inserting an unsupplied demand situation as a triggering event for demand shedding	Completeness with the other triggers for demand management
75		Content of formal notices instructing demand reduction	Clarifying the details of the instruction to be included in the formal notice	Clarity
	75A	Applying formal notice information to scheduling process	Requires the system operator to apply the content of the formal notice in the process which produces Dispatch Prices	Enables the demand limit information to be used by SPD to calculate Dispatch Prices correctly using the scarcity pricing mechanism described in the Code
Dispatch Policy				
	84A	Introduces Dispatch Process Statement	new	Clarity
85.1	84B	Invoke SPD		
	84C	Invoke RMT	new	Completeness

Current Clause	Proposed Clause	Summary	Description of Change	Rationale
	84D	Introduce WDS	new	Completeness
	84E	WDS Inputs	new	Completeness, alignment with Code for NRS, PRS etc
86	84G	SO to make security assessments	minor wording change	Clarity
86A	84G		incorporated into above clause	
87	84J	manual inputs to scheduling process		
88			Revoked	Redundant
88A			Revoked	No longer applicable
88B			Revoked	No longer appropriate under RTP
	84K	NRS – PRS alignment	Policy change	Required for preserving consistence between PRS and RTD schedule inputs
90	84L	Expected Profile of Demand	Policy change, invokes new controlled Guideline	RTD load input now critical determinant of settlement price. Methodology to be published per RTP Decision Paper 4.141
	84M	Discretionary Scenarios	Policy change, explicitly states list of expected scenarios requiring co-ordinator discretion	Transparency
92A	84F	Week-ahead Dispatch Schedule publication	minor wording change	Clarity
93	84I	Adjusting schedules for Frequency Keeping dispatch	minor wording change	Clarity
93A	84N	Publishing Discretionary Constraints	no change	
93B	84H	Right to adjust bids	no change	
	84O	SO to publish Post Schedule Check details	new	RTP Decision Paper 4.184
	84P	DNL and DNG Approval Criteria	new	RTP Decision Paper 5.6
	84Q	DNL and DNG Suspension and Revocation Criteria	new	RTP Decision Paper 5.6

Appendix 2 Draft Dispatch Schedule Load Input Guideline

Appendix 3 **Draft Post-Schedule Check Summary**

TRANSPOWER

TRANSPOWER.CO.NZ

Appendix D GL-OC-984 Dispatch schedule load input guideline

TRANSPOWER

GL-OC-984 Dispatch Schedule Load Input guideline

Expected Profile of Demand Formulation

TP Ref:	GL-OC-984	Status:	Being Reviewed	Approval Date	[Published Date]

Version	Date	Change
V0.1		Initial draft for internal development
V0.9		Draft for EA internal review

	Position	Date
Prepared By:	Transpower as system operator	June 2022
Reviewed By:		

Related Documents
Electricity Industry Participation Code, Parts 8 and 13
Policy Statement

IMPORTANT

Disclaimer

This guideline is developed within the current regulatory framework and is accurate as at the published date. Subsequent changes to the Code or other regulations and policies may result in inaccuracies. Please contact Transpower to discuss current requirements.

This guideline does not relieve asset owners from identifying and meeting their obligations set out in the Code. Where there is conflict between this guideline and the Code, the Code takes precedence. Asset owners are strongly advised to seek expert advice to understand their full obligations under the Code.

Copyright

Contact Details

Address: Transpower New Zealand Ltd
22 Boulcott St
PO Box 1021
Wellington
New Zealand

Telephone: +64 4 495 7000

Email: system.operator@transpower.co.nz

Website: www.transpower.co.nz

Table of Contents

1 Introduction 2
1.1 Document Purpose and Scope 2
1.2 Relevant Regulations and Policies 2
1.3 Notes on terminology 3
2 Overview 4
2.1 Dispatch Schedule 4
2.2 Expected Profiile of Demand calculation 4
3 Current GXP Load Source Measurement, Validation and Selection 8
3.1 Current GXP Load Sources 8
3.2 Conversion to Gross Load 9
3.3 Provision to the Market System 9
3.4 Load Measurement Validation 11
3.5 Current GXP Load Source Selection 11
3.6 Co-ordinator Override 12
4 Required Load Calculation 13
4.1 5-minute Average Load Calculation 13
4.2 Application of GXP Load Scaling 13
4.3 Pre-Solve Deviation 13
4.4 Island Load Error 14
5 Shortfall Quantity Adjustment 15
5.1 Circumstances Requiring Load Adjustment 15
5.2 Determining Required Adjustments 15
6 System Maintenance and Abnormal Conditions 18
6.1 Changes to network / market model 18
6.2 Site-specific communications outages 18
6.3 Market system outage and Stand-Alone Dispatch 18
6.4 Full SCADA system outage 18
Appendix A – Definitions of Key Terms 19

1 Introduction

1.1 Document Purpose and Scope

This document describes the methodology for preparing the Expected Profile of Demand as used in the **dispatch schedule**. The Expected Profile of Demand is the demand at each **Grid Exit Point (GXP)** that is expected to be required to be met by Dispatchable Resources (generation and Dispatchable Demand) at the end of the five-minute interval for which the **dispatch schedule** is solving. This profile forms one of the key inputs to the **dispatch schedule** which ultimately determines **dispatch instructions** and **dispatch prices**. Under the real time pricing market design **dispatch prices** are averaged on a time-weighted basis to form **trading period** prices.

1.2 Relevant Regulations and Policies

1.2.1 Policy Statement

This document is presented under the requirement of clause 84L of the **policy statement**.

The **policy statement** is a document incorporated into the **Code** by reference[1]. It describes (among other things):

- the **system operator's** use of the Scheduling, Pricing and Dispatch ('SPD') software for the formation of **dispatch instructions**;
- the inputs to the **dispatch schedule** and how the **system operator** makes adjustments to the schedule;
- the additional requirements the **system operator** observes in order to meet its obligations under the Scheduling and Dispatch subpart of Part 13 of the **Code**; and
- how the **system operator** uses its Discretion in dispatch.

1.2.2 Electricity Industry Participation Code ('the Code')

The requirements for the formation and quality of the **dispatch schedule**, and the provision of associated information are described in the **Code** at Part 13, Clauses 13.69A – 13.69D.

Under Schedule 8.3 of the **Code**, Technical Code C also requires **asset owners** (including **grid owners**) to provide the **system operator** with the relevant indications and measurements described in Appendix A of that Technical Code.

The details in this document do not supersede, alter or remove any obligations as outlined under the **Code** or the **policy statement**.

1.2.3 Other documentation published by the system operator

Readers may wish to read this document in conjunction with the following other published guidelines and procedures:

- GL-OC-209 SPD Schedule Inputs
- GL-DP-983 Post Schedule Checks

[1] Refer clause 8.10 of the **Code**.

1.3 Notes on terminology

1.3.1 Similar terms

The concepts described in this guideline exist simultaneously in multiple 'domains', such as engineering, economics, power system operation and legislation. Different domains develop independently and thus naturally assign different names for similar concepts; for instance, the consumption of electricity measured as a flow of energy out of the **grid** is known interchangeably as 'Load' and '**demand**'. As applied to the process of preparing the inputs to the **dispatch schedule**, this concept of load is allocated various labels depending on its state in the overall process and the context in which it is described. Where possible, the terminology is defined at first use and summarized in the Glossary provided at Appendix A, together with equivalent terms from different domains.

1.3.2 Correspondence with the Code

Where terms have been defined in the **Code**, these are presented in bold text. These include terms which are defined in the **policy statement**.

1.3.3 "Net" vs "Gross"

In its Schedules, the market system attempts to balance Required Load (the "target" for the amount of energy to schedule) with Dispatchable Resources. This means Required Load must be *gross* of any generation located behind the **GXP** that is offered into the market (offered Embedded Generation).

The **grid owner** is required to provide the system operator with a demand measurement that is the *net* volume of electricity flowing out of the grid at each **GXP**. Therefore the **system operator** must adjust this value to be the *gross* load by adding any Embedded Generation at each **GXP**. The instantaneous measurement of offered Embedded Generation is provided separately by the **generators**.

Conversely, Dispatchable Demand (DD) provides a Dispatchable Resource that reduces the load target. Dispatchable Demand will be dispatched according to the bid information supplied by the Purchaser – if there is an adequate volume of appropriately priced generation available, then Dispatchable Demand will be dispatched. Because Dispatchable Demand is optimisable in this way, it is not treated as Required Load, and is subtracted from the gross load input.

2 Overview

2.1 Dispatch Schedule

In order to schedule generation and other Dispatchable Resources in real time the **system operator** produces a **dispatch schedule**. The **dispatch schedule** forms the basis of **dispatch instructions** that are issued to Dispatchable Resources. A key determinant of the dispatch solution is the Expected Profile of Demand for the schedule timeframe. An overview of this process, with the associated obligations in the **Code** and **policy statement**, is presented as Figure 1.

2.2 Expected Profiile of Demand calculation

2.2.1 Application timing

The Expected Profile of Demand is the (non-DD) load used in the **dispatch schedule**. The Expected Profile of Demand is the **system operator's** estimate of what the non-DD load will be at each **GXP**, at the end of the Market Interval for which the schedule is produced. As an input to SPD it is known as Required Load.

Dispatch schedules are typically completed approximately 30 seconds before the Market Interval to which it applies, but system co-ordinators may also solve a manual **dispatch schedule** and redispatch the power system more regularly. As an example, for the 10:30-10:35 Market Interval, an automated Dispatch Schedule will commence at 10:29:00 and complete around 30s later, and there may be manual schedules solving for this market interval anytime until 10:34.

2.2.2 Calculation – high level

The **dispatch schedule** Required Load is calculated on the basis of a measurement of the load at the time the schedule is initiated ("Current GXP Load"), which is Scaled by a quantity consisting of the expected change in load within the Market Interval ("Pre-Solve Deviation, PSD"), and the estimated error between measured electricity generation and load.

$$\textit{Required Load (RTD)} = \textit{Current GXP Load} + \textit{PSD(GXP)} + \textit{Load Error} \qquad (1)$$

Figure 2 shows the sequence of processes used to generate the Expected Profile of Demand.

Where practicable, the Current GXP Load is sourced from the Grid Owner's revenue meters, sometimes known as "ION" meters. Several back-up data sources for Current GXP Load may be used where revenue meter data is not available. This source validation and selection is described in detail in Section 3.

The PSD is the quantity of expected change in load over the Market Interval, at the Island level. To allocate the Island-level quantity across the island's GXPs, a Load Participation Factor is used, derived from the recent historical measured load at each **GXP** (or from back-up sources where necessary). The application of the Scaling quantity is contingent on a number of conditions at each **GXP**. This is further detailed in Section **Error! Reference source not found.**.

Once the estimated Required Load has been determined and SPD has solved, any Energy Shortfalls are identified and correlated with outages of grid equipment. Where there is a correlation, or where the application of the PSD has caused an Energy Shortfall, the Required Load is adjusted to remove the Shortfall. This is described further in Section 5.

This calculation must be robust to changes in system modelling (both network and market models), and planned and unplanned outages affecting site-specific communications and system failures. Details of how the load input subsystem responds to these system events is provided in Section 6.

2.2.3 Non-conforming GXPs

The Required Load at **non-conforming GXPs** is the Current GXP Load; no Scaling is applied. If a **non-conforming GXP** is subject to a grid outage, any Shortfall is adjusted as per the treatment described in Section 5.

2.2.4 RTD Pricing Optimisation (“RTDP”) during Demand Management

When the **system operator** instructs demand management (“load shedding”) under clause 6 of Technical Code B of Schedule 8.3 of the **Code**, to maintain a wholesale price reflective of the load that was shed, a separate optimisation is run within the **dispatch schedule** from which **dispatch prices** and Shortfall quantities are published. This optimisation runs with a load input which is adjusted for the Load Shed Quantity instructed at each GXP.

$$\textit{Required Load (RTD-}\boldsymbol{P}\textit{) = Current GXP Load + Load Shed Quantity (GXP)} \qquad (2)$$

The Load Shed Quantity does not incorporate Scaling as described above. Further detail on the RTD-P optimisation and the derivation of the Load Shed Quantity is provided in Schedule 13.3AA of the **Code**.

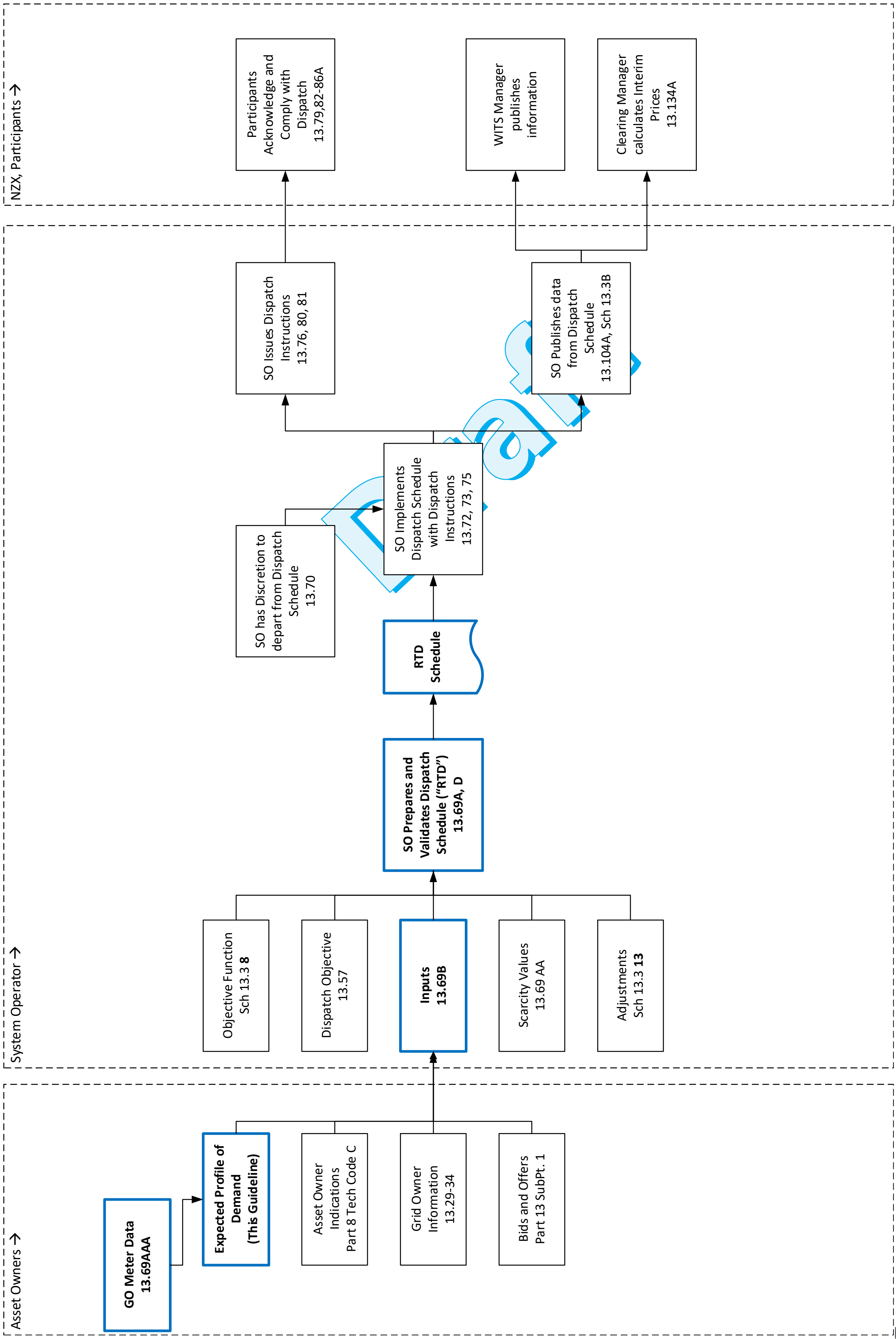

Figure 1 – Dispatch process overview, highlighting the scope of this Guideline (blue outlined artifacts).

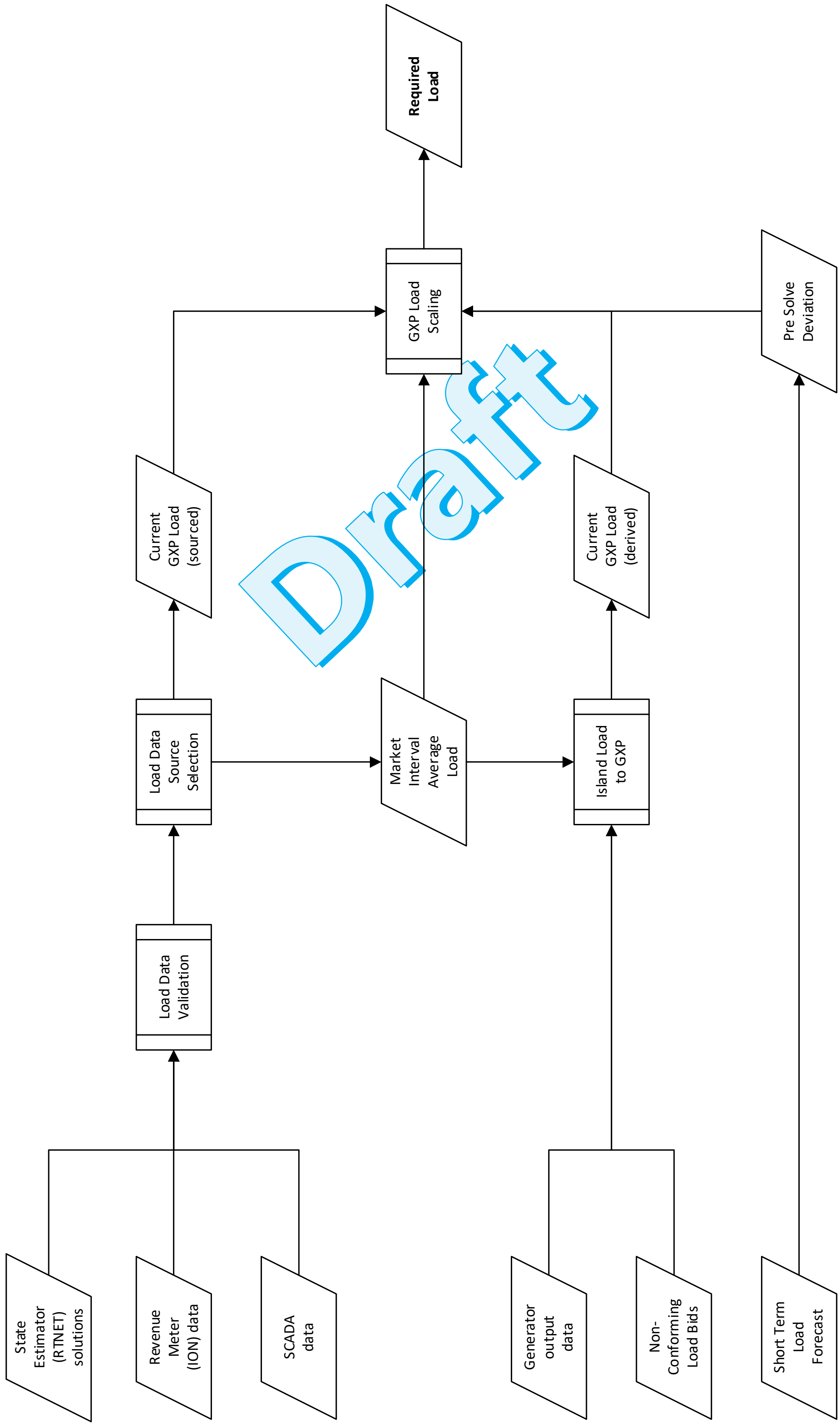

Figure 2 – Simplified process schematic for formulating Required Load in the dispatch schedule.

3 Current GXP Load Source Measurement, Validation and Selection

3.1 Current GXP Load Sources

The basis for the calculation of Expected Profile of Demand at each **GXP** is the instantaneous measurement of Current GXP Load. There are two semi-independent primary measurement sources employed by the **system operator**, both supplied by **Transpower** as the **grid owner** – "ION[2]" revenue meters and field measurements processed with the national SCADA system ("SCADA"). In addition, there are two derived measurements of instantaneous GXP load, the State Estimator ("SE") and Island Load Disaggregation.

3.1.1 Revenue Meter Measurements

Under clause 13.69AAA of the **Code**, the **grid owner** is required to supply real time net **demand** values for each of its **GXPs** to the **system operator**, from its grid revenue meters (where practicable). The **grid owner** maintains revenue metering to fulfil their obligations to supply **GXP volume information** to the **reconciliation manager**[3]. In addition to providing half-hourly volumes, the revenue meters are capable of making instantaneous measurements which are the basis of the **GXP** Load measurement. The required accuracy of the revenue meters is +/- 0.75%[4].

Revenue meters are typically located on each feeder at a station. The summation of each of the meters' measurements constitute the (net) flow at the **GXP** and is calculated with the same regularity as the individual meter measurements.

The revenue meters have an intrinsic quality indication which is based on whether communications to each of the meters constituting the GXP Load summation are good. If communications to an individual meter fails, the reported quality is bad. This impacts whether the market system selects the revenue meter as the chosen data source for a given **GXP** at that point in time.

The revenue meter GXP Load summation and quality is sampled by the SCADA system on a 4-second frequency, with a 0.001 MW dead band; if the load measurement has not changed by +/- 0.001 MW between measurements, no new data is provided to the SCADA system.

3.1.2 SCADA Field Measurements

The **grid owner** is also required to provide indications and measurements to the **system operator**, including **grid interface** MW, to an accuracy of +/- 2%[5].

Grid interface MW values are calculated as the multiplication of measured currents of each feeder circuit and measured bus voltages. If communication to either of the measurement devices is lost, the SCADA system derives a bad quality indication. Measurements are sampled on a 4-second basis with associated dead bands for current and voltage.

3.1.3 State Estimator

Monitoring and controlling the power system requires continuous measurement of thousands of different variables around the network such as bus voltage, branch flows, transformer taps and circuit breaker status. Where direct measurements of individual values are unavailable or compromised due to equipment outages or

[2] "ION" refers to the brand name of the revenue meter employed by **Transpower** as the **grid owner**.

[3] Refer clause 15.9 of the **Code**.

[4] Refer Schedule 10.1 of Part 10 of the **Code**

[5] Refer clause 6 and Appendix A of Technical Code C of Schedule 8.3 of Part 8 of the **Code**.

failures, or where there is disagreement among a subset of the measured values the **system operator** relies on its Energy Management System's (EMS/SCADA) State Estimator application – known as RTNET.

RTNET runs an optimisation algorithm to find the best representative state of the **grid** given the available measurements and consistent with known parameters of the grid such as branch impedance and equipment connectivity. The result is a powerflow-like solution which is used as the basis of further security assessments (e.g. Contingency Analysis) to ensure the **grid** remains secure.

RTNET can be used to back-fill missing measured data in **system operator** systems – for example generator injections or load values – although these values may not always correspond exactly in some locations due to network boundary modelling. Where there is a systemic discrepancy between actual measured loads and RTNET estimated values, the State Estimator is not selected for use as a valid load measurement source.

3.1.4 Island Load Disaggregation

In the absence of reliable real time load measurements, the **GXP** loads can be estimated based on current generation output measurements. This is the method that was used to calculate **GXP** level load for the dispatch schedule prior to RTP.

Generators are required to provide real time indications of their output to the **system operator**[6]. Since at any point the system generation and load should be approximately equal, we can infer that the sum of generator output is equal to the load (plus losses) on the system. Therefore, having made an estimate of system losses, we know at an Island level the total Island Load. This Island Load can be apportioned to each **GXP** with Load Participation Factors, which are calculated as the average measured or estimated load from the last 5 minutes.

3.2 Conversion to Gross Load

As described in section 1.3.3 the Market System aims to schedule offered generation to balance the Required Load. Where real time indications are received as net load values (revenue meter and SCADA instantaneous measurements) these must be adjusted for offered embedded generation and Dispatchable Demand[7] consumption behind the **GXP**. This calculation is performed in the SCADA system. The quality of the gross load is derived as the least quality of the constituent parts of the calculation, so if any of the net load value, the offered embedded generation value, or the Dispatchable Demand value are bad quality, the quality of the gross load calculation is an inherited bad quality.

$$\begin{aligned} &\textit{Gross Load (GXP)} = \textit{Net Load (GXP)} + \sum \textit{Offered Embedded Generation} - \\ &\qquad \sum \textit{Dispatchable Demand} \end{aligned} \tag{3}$$

3.3 Provision to the Market System

Each of the primary data sources and State Estimator results are provided to the market system through the EMS/SCADA system. EMS/SCADA is used to collect all real time load measurements on the power system and is maintained as a critical component of the operation of the national grid. It is a dual-redundant network of communications devices and software platforms for which unplanned outages are rare and planned maintenance outages are typically brief. Figure 3 shows a schematic of the components of the EMS/SCADA communications network to the Market System.

[6] Refer clause 6 and Appendix A of Technical Code C of Schedule 8.3 of Part 8 of the **Code**.

[7] For more information, refer to the Transpower website: https://www.transpower.co.nz/system-operator/electricity-market/dispatch-capable-load-station-setup

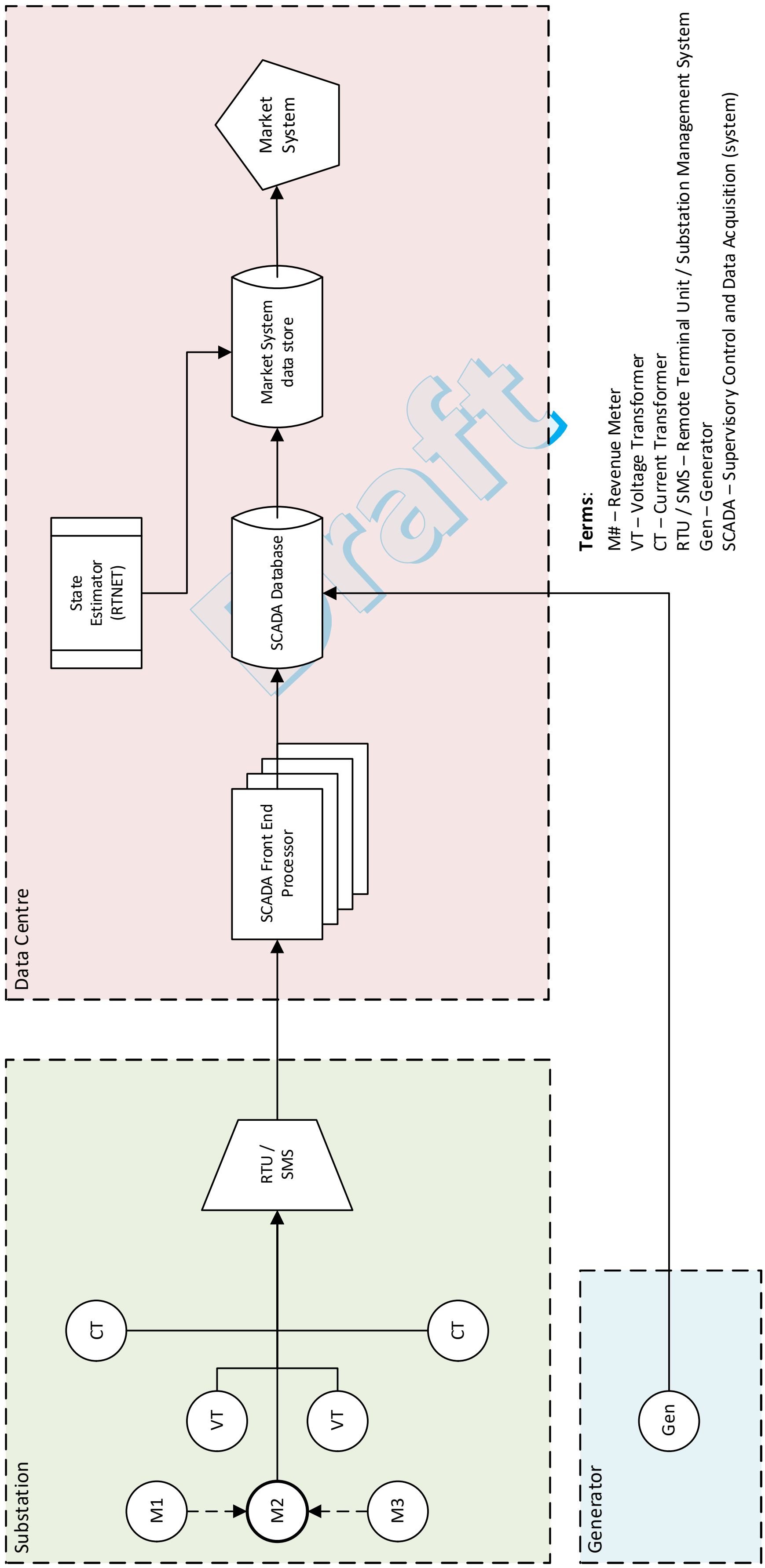

Figure 3 – Field measurement data flows into SCADA and the Market System.

3.4 Load Measurement Validation

The revenue meter system, the EMS/SCADA system and the Market System all employ logical validation checks to prevent bad quality data being used in downstream processing. The validation checks are described in Table 1. The relevant validation checks are applied when each measurement is sampled in the EMS/SCADA domain, and when the Market System runs its validation and selection procedure on receipt of the raw data supplied by EMS/SCADA.

Table 1 – Summary of **GXP** Load measurement validation in each technical domain

Domain	Check	Criteria	Result
Revenue Metering	Live communications to each meter at GXP	Communications lost to one or more meters for more than 30s	**Aggregate Quality Bad**
EMS/SCADA	Revenue meter aggregate quality	Quality is Bad	**Quality Suspect**
	Live communications to each field measurement device (including revenue meters)	Communications lost within 4s sample time	**Quality Suspect**
	Limit check – SCADA	Measurement exceeds reasonable physical range	**Quality Suspect**
	Limit check – revenue meter	Measurement exceeds configured operational limit	**Quality Suspect**
Market System	Dead-band	Measurement has changed by at least a minimum quantity, or its quality has changed, or sufficient time has elapsed since last measurement received	Measurement available to market system for processing
	Not from the past	The measurement is current in time	Measurement available to market system for processing
	Received quality	Measurement quality Good or Replaced	Measurement acceptable for further checks
		Measurement quality Suspect or Garbage	Measurement rejected
	Minimum number of acceptable measurements	A sufficient (configurable) number of acceptable measurements have been received	Latest measurement acceptable for further checks
	Trip check	Measurement drops to zero (+/- allowance for noise)	If Tripped then Age and Limit check disabled for that GXP, measurement available for selection
	Age check	Measurement does not change within a configurable 'Time to Live (TTL)'	If last change exceeds TTL then measurement not available for selection
	Limit check	**Measurement exceeds configured operational limit**	Measurement not available for selection

3.5 Current GXP Load Source Selection

Having received the instantaneous measurements and State Estimator solution, and applied the acceptance rules for each, the Market System then determines which figure to use as the Current GXP Load (or whether to estimate the load using Island Load Disaggregation). For each **GXP** a hierarchy of source preference is specified, with the typical selection being:

1. Revenue Meter
2. SCADA
3. State Estimator.

The Market System reviews whether an acceptable measurement exists for each source in turn, and uses the first good source in the hierarchy. If none of the configured sources are acceptable, the value for Current GXP Load is calculated by Island load Disaggregation.

3.6 Co-ordinator Override

When the system co-ordinators expect that none of the automated processing described above will result in a correct value for the Current GXP Load, the co-ordinators may apply an override value that will substitute any automatically calculated value. There are two cases where this may occur:

- overrides may be used to manage a Tiwai Point Reduction Line offload in order to maintain an accurate dispatch solution
- for post-event restoration activities or system failures where measurement data quality is compromised, and estimation methods are not providing adequate solutions.

4 Required Load Calculation

4.1 5-minute Average Load Calculation

The distribution of island-level load quantities to **GXP** is governed by the 5-minute average load for each **GXP**, also known as Current Bus Load Participation Factor or Current BLPF. In normal operation, where **GXP** load measurements are available, the 5-minute average load is the time-weighted average of selected **GXP** load measurements across the 5-minute Market Interval. Where no acceptable load measurements are available within a given Market Interval, the previous 5-minute average load quantity is assumed to persist for a configurable duration, usually 30 minutes.

Beyond this point, an adjusted Trading Period BLPF is used. The Period BLPF is the 30-minute average load quantity for each **GXP** from the same trading period the previous week. This quantity is scaled according to the sum of **GXP** current measured loads across the load forecast region to which the **GXP** belongs, compared to the load for the same **GXPs** within forecast region from the previous week.

$$\textit{Adjusted Period BLPF (GXP)} = \textit{Last Week Period BLPF (GXP)} \times (\textit{Current Area Load} \,/\, \textit{Last Week Area Load}) \qquad (4)$$

4.2 Application of GXP Load Scaling

Having sourced or calculated the Current GXP Load, the Required Load for each **GXP** can be calculated according to equation (1) by adding a Scaling value. The Scaling value is derived from disaggregating the PSD, an estimate of how much Island load is expected to increase or decrease in 5 minutes' time, plus the Island Load Error, to each **GXP** according to a set of disaggregation rules. Scaling will not be applied to a GXP where either:

- the **GXP** is a **non-conforming GXP** (see section **Error! Reference source not found.**);
- the Current GXP Load has been overridden (see section 3.6);
- the 5-minute average load for the **GXP** is negative (unoffered embedded generation has exceeded the load at the **GXP**); or
- the GXP is subject to an Applied Load Limit[8].

Where the Scaling value is applied, it is calculated according to the following equation:

$$\textit{Scaling value (GXP)} = \textit{Current BLPF} \times (\textit{Pre-Solve Deviation} + \textit{Island Load Error}) \qquad (5)$$

4.3 Pre-Solve Deviation

The Pre-Solve Deviation (PSD) is the expected change to the current (Island) load for the next 5-minute interval. Every six to ten seconds the market system automatically calculates the expected change based on the change in the short term load forecast from the current interval to the next.

System co-ordinators can override automatically calculated PSD with manual values. This may be necessary where system conditions are not able to be modelled accurately in the market system, for example during generator warm-up prior to ramping.

[8] Refer to the Energy Scarcity Pricing Mechanism for more detail.

4.4 Island Load Error

Electricity **supply** and **demand** must always be in balance (as close as practical to maintain system frequency at 50 Hz). Therefore, at any instant the aggregated generation output across a given island is almost equal to the island load, plus **losses** across the transmission network. Given a reasonable **loss** estimate[9], and assuming greater accuracy in generator measurements than load measurements[10] we can therefore compare the aggregate island load measurements with the aggregate generator output and derive a difference between the two quantities. This is termed the Island Load Error:

$$\textit{Island Load Error} = \sum \textit{generator output} - \left(\sum \textit{GXP load} + \textit{Losses} \right) \quad (6)$$

The Island Load Error for each **dispatch schedule** is calculated and allocated to each eligible **GXP**, as described in section **Error! Reference source not found.**, according to equation (5).

[9] The Dispatch Schedule uses the losses calculated from the previous SPD solve for its initial loss estimate, which is then refined within each case.

[10] This has been assumed historically, and given there are fewer measurement points for generation, there is less opportunity for measurement error.

5 Shortfall Quantity Adjustment

5.1 Circumstances Requiring Load Adjustment

The Required Load is inherently an estimate; the magnitude of the load at each **GXP** is derived considering the expected change in load at an island level, which is then allocated according to the proportion of load consumed at each **GXP** in the previous Market Interval. The Required Load calculated in this way could therefore exceed the available **supply** capacity[11] for each **GXP**. We would not normally expect load at a **GXP** to exceed the grid's ability to supply it, therefore it would be unreasonable to model this in the **dispatch schedule**.

Similarly, the **system operator** continuously forecasts the **supply** capacity at each **GXP** as part of the scheduling process. To do this, the system operator models outage information supplied to it by the **grid owner**. The **grid owner** provides:

- the **grid** equipment that is affected by a physical outage;
- the planned start and end times of the physical outage, to the half-hour;
- the actual start and end times of the physical outage corresponding to the commencement of the initial switching sequence, and the termination of the final switching sequence;
- whether the outage is continuous or daily over several days; and
- the state of the equipment during the physical outage, specifically, whether it is removed from service (RS), or open-ended (OPE).

Notably, SPD uses a half-hourly offered grid in the process which determines the network topology for its optimisation. The **dispatch schedule** uses Current GXP Load inputs to calculate a powerflow for generation scheduling. One possible consequence of the interaction between a half-hourly offered **grid** model and real-time load measurements is SPD can be left with an Infeasibility – it may be scheduling a quantity of Required Load at a location at a time when the modelled **supply** capacity is insufficient to meet it, despite the **grid** being physically able to supply the current Load (i.e. the physical outage hasn't started at the modelled start time).

Both these circumstances would lead to spurious Energy Shortfalls and scarcity prices, if not adjusted prior to real time **dispatch**.

5.2 Determining Required Adjustments

5.2.1 Discovering Energy Shortfall

To determine whether **supply** capacity has been exceeded in a Schedule, we need to compare the Required Load with the modelled capacity. In practice, given **supply** capacity can be dynamic, this comparison is performed within SPD itself. If SPD solves with an Energy Shortfall, and the Shortfall is a result of the circumstances described in section 5.1, the load input must be adjusted and the Schedule re-solved.

5.2.2 Assessing adjustment quantity

An Energy Shortfall may exist for four reasons:

1. There is a genuine Shortfall at a **GXP**;
2. A Current GXP Load is derived using the Island Load Disaggregation methodology and the result is in excess of GXP **supply** capacity;

[11] The combination of generation and transmission resources needed to delivery the Required Load.

3. The Scaling quantity added to the Current GXP load exceeds the **supply** capacity at the **GXP**;

4. The **GXP** is affected by a modelled **grid** outage which constrains its **supply** capacity.

In order to determine the quantity of load (if any) to reallocate to mitigate a Shortfall, SPD first identifies whether any grid outages are modelled which affect **GXP supply** capacity. This is achieved by passing SPD a model of related Connection Assets for each **GXP**. If an outage exists which models any of the connection assets as unavailable[12], then SPD nominates the entire Shortfall quantity at that **GXP** for adjustment.

If the Current GXP Load has been derived using the Island Load Disaggregation methodology (ie no direct measurement of Current GXP Load is available), the entire Shortfall quantity is nominated for adjustment, on the basis that the estimated load is too uncertain to constitute a genuine Shortfall and the associated pricing implications.

If a **GXP** is not affected by an outage of a relevant connection asset, SPD considers the Shortfall quantity compared to the Scaling component of the GXP Required Load. SPD then nominates the lesser of the two for adjustment. If the GXP Required Load is in excess of its supply capacity even with the entire Scaling components removed, then a genuine Shortfall exists.

On occasion the Current GXP Load may temporarily exceed the modelled **supply** capacity. Provided the modelling is correct, it is reasonable to proceed with the resultant scarcity price, as this price is reflective of the inability to supply the Load within the offered **asset** capability. In this situation the **system operator** may initiate emergency procedures to prevent damage to **assets**[13]. If **demand** management is instructed at a **GXP**, then uncleared Load will be scheduled at the **GXP** and this will be used to derive **dispatch prices**.

5.2.3 Adjusting nominated adjustment quantities

Having discovered and assessed the Energy Shortfall at each **GXP**, SPD will make adjustments to the Load input to reallocate the nominated Shortfall quantities. Where possible, the total island load quantity must be preserved in order to maintain the quality of the overall **dispatch** solution (conversely, simply removing the scheduled energy shortfall would leave generation under-dispatched to meet the actual load on the system).

The nominated Shortfall quantities are reassigned to other nodes on the grid according to a modelled map. The other nodes are known as Load Transfer PNodes. Each **GXP** has one and only one Load Transfer PNode, and each Load Transfer PNode has a Load Transfer PNode of its own. The mapping is constructed according to the principles of nominating the electrically nearest live node, accounting for locational congestion where possible. For each **GXP**, applying these principles forms a 'chain' or potential nodes where the nominated load may be allocated, which are in sequence:

1. The high-voltage side of a supply transformer;

2. Another node within the same station;

3. A 'regional reference node', or node which represents a notional supply locus for the region;

4. A series of core-grid nodes that predominately supply the regional reference nodes; and

5. The island reference node.

[12] Either removed from service or open-ended.

[13] Refer to Policy Statement clauses 57-84.

SPD identifies the best acceptable node in this sequence, being a live node that is not itself supply constrained. SPD then transfers the nominated Shortfall quantity at a **GXP** to the selected node, plus a small margin of error, to the identified nodes. SPD then solves again, and the Schedule workflow finalises the results in the usual way.

5.2.4 Proxy pricing

When a GXP is Disconnected or Dead with load, SPD is unable to calculate the value of electricity at that location (there is no connected offered generation in its model). Instead a price must be assigned. When a GXP is disconnected the price of electricity at the GXP is determined from the electrically nearest live node. This makes use of Load Transfer PNode methodology described in section 5.2.3. When a Proxy Price is required, the price will be derived from the Load Transfer PNode determined under this methodology.

5.2.5 Error handling

If a suitable Load Transfer PNode cannot be found, SPD must "fail gracefully" to allow co-ordinators to diagnose and correct the problem with the input information. In extreme cases, a Dispatch Schedule may be dispatched without an appropriate shortfall adjustment. Where SPD has discovered a spurious Shortfall that it cannot adjust, it will remove the Shortfall quantity and if the PNode is Dead or Disconnected, assign a price of $0.00.

6 System Maintenance and Abnormal Conditions

6.1 Changes to network / market model

From time-to-time **GXPs** are added and removed from the grid, and network configurations can change, resulting in changes to the measurement equipment and calculation. These changes are typically modelled in the system during business hours, tested and exported with an effective date and time. These changes do not typically have significant impact on load measurement.

6.2 Site-specific communications outages

The Current GXP Load measurement system is designed to be robust to planned and unplanned outages of measurement devices, communications links and front-end data management systems. The market system employs logical data validation rules designed to exclude (to the extent possible) measurement errors. Communications outages can happen at any point along the Load data handling sequence and each system maintains methods for detecting communications network dropouts. Where either of these conditions are met, the market system validation detects the data as Suspect, and automatically attempts to use the next best data source.

6.3 Market system outage and Stand-Alone Dispatch

System operations must continue in the event of a market system outage. Our backup electronic dispatch mechanism is Stand-Alone Dispatch (SAD). SAD is a simple platform for calculating a generation schedule for electronic dispatch; apart from electronic dispatch, there is deliberately no other interface to other systems. Current GXP Load measurement is not used in SAD; instead, an approximate Island Load Disaggregation is used as the basis for calculating generation dispatch. While on SAD, the system operator will not publish dispatch prices.

6.4 Full SCADA system outage

Full SCADA outages are very rare and can cause significant impacts to system operation over and above calculating a dispatch solution. During a SCADA outage we expect to not have access to any Load measurement data and State Estimator data could be significantly degraded. The system operator maintains the capability to continue to generate Dispatch Schedules using Island Load Disaggregation and estimating full Island load based on previously dispatched generation quantities and recent historical load measurements.

Appendix A – Definitions of Key Terms

Term	Definition
Applied Load Limit	Where an instruction to disconnect demand has been issued, the Applied Load Limit is the limit of load to be taken at a GXP which is derived from the nature, quantity and location of the instruction.
Connection Asset	In the context of dispatch, an asset forming part of the grid, an outage of which is nominated to affect supply capacity at a GXP
Current GXP Load	The (measured or derived) load at a given GXP at the present time, particularly at the time a dispatch schedule is initiated.
Dead (with Load)	A GXP which is modelled as disconnected from any offered generation, but which has Load.
Disconnected	In this context, a GXP is Disconnected when it has no Load or modelled connected offered generation.
Discretion	Related to dispatching the power system, Discretion is the right of the system operator to dispatch a resource out of economic merit as determined by the solution to the objective function, for the purposes of meeting the dispatch objective.
Dispatchable Demand (DD)	Demand that is made available for reduction on instruction from the system operator as part of the dispatch process.
Dispatchable Resource	In the context of this document, an offered quantity of energy (either from generation or Dispatchable Demand) or instantaneous reserve (either from partly loaded spinning reserve, tail water depressed reserve or interruptible load).
Embedded Generation	A quantity of energy supplied by an embedded generating station, which may be offered into the market for optimisation.
Energy Management System (EMS/SCADA)	The suite of applications used by the system operator to monitor and control the grid.
Energy Shortfall	The result of the Required Load exceeding the available supply capacity at a GXP.
Expected Profile of Demand	The demand quantities at each GXP input to the dispatch schedule.
Infeasibility	The outcome of SPD being unable to solve normally without breaking one of its mathematical constraints, for which a constraint violation penalty value is assigned.
Island Load Disaggregation	The calculation used natively by SPD to estimate Current GXP Load, where real time GXP Load measurements are unavailable. It uses a methodology of estimating Island Load from the sum of current generation measurements, subtracting losses, and disaggregating the result to each GXP passed on recent past real time measurements.
Island Load Error	The difference between the Island Load calculated from the sum of measured generation less losses, and the sum of measured GXP loads (including estimates).
Load	The flow of electrical energy out of the grid, measured in (mega)Watts [MW]. In the context of this document, synonymous with demand. See also Required Load
(Bus) Load Participation Factor (BLPF)	The fraction of load at a GXP compared with the total load for a particular Load Area or Island. In the Required Load context, this is derived principally from Current GXP load measurements for the previous Market Interval.
(Instructed) Load Shed Quantity	The quantity of load that is estimated to have been shed at a GXP following issuance of an instruction to disconnect demand under Technical Code B of Schedule 8.3 of the Code.
Load Transfer PNode	The modelled location on the network to which any Energy Shortfall will be transferred, in the event that the Shortfall is caused by a modelled transmission outage.

Term	Definition
Market Interval	Periods of 5 minutes duration beginning at hh:m0 and hh:m5, for which the dispatch schedule solves.
Market System	The collection of software applications which together produce schedules of prices and quantities, and provide for issuing dispatch instructions
Objective Function	The function which is solved in order to meet the dispatch objective. Described mathematically at clause 8 of Schedule 13.3 of the Code.
Optimisation	The act of a solver (usually SPD) working to solve the Objective Function.
Participant	In this document the term participant means electricity industry participants who receive dispatch instructions. The Code, clause 13.72, stipulates that dispatch instructions are to be issued to generators, ancillary service agents and dispatch capable load purchasers.
Pre-Solve Deviation (PSD)	The expected change to the current (Island) load for the next Market Interval
Required Load	The Load value at each GXP for which a schedule completes its Optimisation.
(Instantaneous) Reserve Shortfall	The result of the required Fast or Sustained Instantaneous Reserve (as the case may be) exceeding the available reserve capacity in an Island.
Scaling	The adjustment added to each Current GXP Load reflecting the expected change in load in the Market Interval.
Schedule	An instance of an Optimisation solution (“study”, ”solve”) for one or more market intervals or trading periods, consisting of schedule inputs and schedule contents (results).
Scheduling, Pricing and Dispatch [software] (“SPD”)	The software the system operator uses to solve the Objective Function.
Stand-Alone Dispatch (SAD)	A software application employing a stand-alone version of SPD which allows the system operator to calculate economic dispatch when the Market System is unavailable.
State Estimator	A calculation engine which uses available power system measurements to estimate data points which are unavailable. The State Estimator used by the system operator is the RTNET application, part of the EMS/SCADA suite.
Supervisory Control and Data Acquisition (SCADA)	The system by which physical measurement of the power system are recorded and processed, and remote controls are issued.

Appendix E GL-DP-983 Post schedule check summary

This table details the Post-Schedule Checks used in preparing Schedules which produce Dispatch Prices (the RTD and PRS Schedules). The Checks provide a facility for automatic verification and validation of Schedule Results and allow system co-ordinators to assess and take action where necessary to ensure the reliability of the Schedules prior to dispatch and publication.

Some Checks result in automatic actions to prevent adverse outcomes such as:

- block publication of Schedules which have non-physical or infeasible results
- interrupt automatic Schedule publication to allow for further manual validation before approval
- switch dispatch operation to manual send, prompting system co-ordinators to validate schedule results before dispatching (and publishing Dispatch Prices)
- alert co-ordinators to unusual schedule inputs or results which may indicate an input error.

Checks may be duplicated where they applied to different Schedule types which prompt different automatic actions (generally the Event name has the Check prepended with "RTD…").

The list is accurate at the time of publication, but subject to change at any time.

#	Event	Description: Alerts when-
1	ManualRTDSolutionAvailable	a manually initiated Dispatch Schedule is available to be dispatched
2	FirstManualRTDSolutionAvailable	a manually initiated Dispatch Schedule is available to be dispatched
3	ProcessFailed	a Schedule fails to complete; co-ordinator intervention is required to reinitialise the schedule
4	SFTDCConstraintsCreated	SFT solved as DC Powerflow
5	SFTUnsolvedContingencies	SFT failed to create a Security Constraint; co-ordinators may apply a manual constraint if required
6	RealTimeDispatchPublishExp	a Dispatch Schedule fails to Publish as expected
7	FKOfferChangeForManualPeriod	an electronic change to offer impacts a manually scheduled Frequency Keeping plant
8	BonaFideOfferReceived	an electronic change to offer is received within the gate closure period
9	LoadForecastDiscrepancy	a Load Forecast update is received which exceeds the set threshold for a Region/Trading Period
10	SCADANotUpdating	SCADA data has not been received for the threshold period
11	MinResidualWarning	the (generator) residual MW quantity has dropped to the threshold prompting further co-ordinator situational assessment
12	SRCShortfall	the Standby Residual Check calculation has calculated a Shortfall
13	DetectedNonPhysicalLosses	a Schedule has solved with Non-Physical Losses
14	MIPFailRemovalNonPhysicalLosses	SPD has failed to remove Non-Physical Losses through application of the Special Ordered Sets – schedules will not be published in this condition

#	Event	Description: Alerts when-
15	RtdHvdcSchedFailed	the HVDC Scheduling calculation has not completed successfully in a Dispatch Schedule; co-ordinator intervention is required to manually update the modelled HVDC configuration for Dispatch
16	RtdZeroClearedEnergyOffers	the Dispatch Schedule has solved with no scheduled energy
17	ZeroClearedEnergyOffers	a Schedule has solved with no scheduled energy
18	RtdZeroClearedRes6s	the Dispatch Schedule has solved with no scheduled Fast Instantaneous Reserve
19	ZeroClearedRes6s	a Schedule has solved with no scheduled Fast Instantaneous Reserve
20	RtdZeroClearedRes60s	the Dispatch Schedule has solved with no scheduled Sustained Instantaneous Reserve
21	ZeroClearedRes60s	a Schedule has solved with no scheduled Sustained Instantaneous Reserve
22	RtdExcessiveChange	the change in Island Power System generation total exceeds the threshold
23	RtdRes6sChange	the change in Island scheduled Fast Instantaneous Reserve exceeds the threshold
24	RtdRes60sChange	the change in Island scheduled Sustained Instantaneous Reserve exceeds the threshold
25	RtdBindingRampRates	the Dispatch Schedule has solved with a number of binding ramp rates exceeding the threshold
26	RtdExcessivePriceChange	the Dispatch Schedule has solved with a change in energy prices exceeding the threshold
27	RtdZeroPriceGen	the Dispatch Schedule has solved with the proportion of zero-priced generation exceeding the threshold
28	ZeroPriceGen	a Schedule has solved with the proportion of zero-priced generation exceeding the threshold
29	RtdDeficitGen	the Dispatch Schedule has solved with a Deficit Generation infeasibility
30	DeficitGen	a Schedule has solved with a Deficit Generation infeasibility
31	BindingConstraints	a Schedule has solved with a number of near-binding constraints which exceed the threshold
32	RtdBindingConstraints	the Dispatch Schedule has solved with a number of near-binding constraints which exceed the threshold
33	SftConstNeedAdjustment	the SFT Check application shows an SFT constraint limit (right-hand side) is incorrect in a Schedule
34	RtdSftConstNeedAdjustment	the SFT Check application shows an SFT constraint limit (right-hand side) is incorrect in a Dispatch Schedule
35	MissingSftConst	the SFT Check application shows an SFT constraint is missing in a Schedule
36	RtdMissingSftConst	the SFT Check application shows an SFT constraint is missing in a Dispatch Schedule
37	HighNodalPrices	a Schedule has solved with an Energy price which exceeds the threshold
38	RtdHighGenPricesOFN	the Dispatch Schedule has scheduled generation with offer prices exceeding the threshold (persistent)
39	HighGenPrices	a Schedule has scheduled generation with offer prices exceeding the threshold

#	Event	Description: Alerts when-
40	RtdHvdcMinBinding	the Dispatch Schedule has scheduled HVDC transfer at its minimum transfer limit for the market interval
41	RtdHvdcMaxBinding	the Dispatch Schedule has scheduled HVDC transfer at its maximum transfer limit for the market interval
42	BranchBinding	a Schedule has solved with a number of binding branch flows which exceeds the count threshold
43	RtdBranchBinding	the Dispatch Schedule has solved with a number of near-binding branch flows which exceeds the count threshold
44	PscFailed	the Post-Schedule Check application has failed
45	RtdBrokenRampRates	the Dispatch Schedule has solved with a number of broken ramp rates exceeding the count threshold
46	RtdBadScadaGenData	the number of stations with bad SCADA indications has exceeded the threshold
47	DeficitReserve	a Schedule has solved with a Deficit (CE or ECE) Reserve infeasibility
48	RtdDeficitReserve	the Dispatch Schedule has solved with a Deficit (CE or ECE) Reserve infeasibility
49	RunbackNotDefined	the HVDC Scheduling calculation has failed to find an appropriate HVDC Runback logic
50	DetermineRunbackLimitFailed	the HVDC Scheduling calculation has failed to calculate an HVDC Runback Limit
51	FirstRTDDispatchNotSent	the first Dispatch Schedule of a trading period has not been dispatched within the threshold time
52	NegPriceCheck	the Dispatch Schedule has solved with a number of negative Pnode energy prices which exceeds the count threshold
53	HvdcRPModeManualRMTReq	the Dispatch Schedule has solved with an HVDC transfer that is infeasible for the current HVDC configuration
54	HvdcRiskSubBindingACOutage	a Schedule has solved with the HVDC Risk Subtractor binding due to an AC Equipment outage
55	HvdcTransferBelowFKCMin	the Dispatch Schedule has solved with an HVDC Transfer that is too low for Frequency Keeping Control (FKC) to operate
56	RtdHvdcConfigSwitchPointNth	the Dispatch Schedule has solved with an HVDC Transfer which would trigger an HVDC Configuration change
57	RtdHvdcConfigSwitchPointSth	the Dispatch Schedule has solved with an HVDC Transfer which would trigger an HVDC Configuration change
58	RtdHvdcRiskSubBindingACOutage	the Dispatch Schedule has solved with the HVDC Risk Subtractor binding due to a AC Equipment outage
59	CheckACRiskGroupOverlap	more than one Optional AC Risk has been specified which each contain the same Risk Plant
60	HVDCFKCStatusMatchRes60s	an NRSS Schedule has solved with scheduled SIR Sharing that would make FKC inoperable for one or more trading periods
61	HVDCFKCStatusMatchRes60sRT	the Dispatch Schedule has solved with scheduled SIR Sharing that would make FKC inoperable
62	HVDCReservesSharingValueChange	the amount of Reserve Sharing has changed from the previous Trading Period
63	NFRDifferenceRTD	there is a difference between the configuration settings used for the latest RTD solve and those settings used to calculate the RMT NFR's.
64	RTReserveLimitBinding	the Dispatch Schedule calculated Reserve Sharing Limit for FIR/SIR is Binding.

#	Event	Description: Alerts when-
65	RealTimeRPStatusDifference	there is a discrepancy between the round power mode on the HVDC "Current" tool tray and the round power status on the HVDC "Abnormal" tool tray.
66	IGOffConstrainedDispatch	an intermittent generator was previously dispatch constrained but now appears unable to meet the previous dispatch level
67	MSLoadControl	the market system has recorded Instructed Load Shed quantities on returning from SAD
68	SADLoadControl	SAD MOL upload includes Instructed Load Shed quantities
69	SPDOutageLoadCorrection	SPD has adjusted its GXP load distribution to account for an outage timing mismatch
70	NewSecurityConstraintAlarm	a Schedule has run which has generated a new Security Constraint for the current trading period
71	RTD Infeasibility type other	the Dispatch Schedule has solved with an infeasibility (not otherwise alarmed)
72	PRS Infeasibility type other	a PRS Schedule has solved with an infeasibility

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code 2010
CE	Contingent event
ECE	Extended contingent event