# Connected Asset Commissioning, Testing and Information Standard (CACTIS)

Decision paper

31 March 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

# Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to promoting the security and resilience of New Zealand's power system to ensure that it delivers the best possible outcomes for consumers. To help achieve this, we are refining industry rules to accommodate new and emerging technologies and changing system dynamics while maintaining a stable and reliable power system for consumers.

As the sector evolves, it is critical that we, as a regulator, anticipate challenges and enable a smooth transition to a more electrified economy. Through our multi-year Future Security and Resilience (FSR) programme, we are taking a forward-looking approach by enabling new technologies, addressing security and resilience risks, and building a power system that is reliable, flexible, and consumer-focused.

One of the most critical parts of the FSR programme is a review of the common quality requirements[1] in Part 8 of the Electricity Industry Participation Code 2010 (Code). These requirements are foundational to the safe and reliable supply of electricity to consumers.

This paper outlines the Authority's decision to proceed with its proposal to amend Part 8 of the Code to incorporate the Connected Asset Commissioning, Testing and Information Standard (CACTIS) into the Code by reference and make other changes consequential to the introduction of a new system operation document.

## We sought feedback on a Code amendment proposal and draft CACTIS

In July 2025, we sought feedback on a proposal to clarify and update the Part 8 common quality information requirements and to incorporate technical specifications in a new system operation document.

We received 15 submissions on the proposal. The submissions and consultation paper are available on the Authority's website. We thank submitters for taking the time to share their views on the proposals.

In September 2025, the System Operator sought feedback on the draft CACTIS covering technical requirements in relation to asset capability information, asset commissioning (including timing), modelling, testing, and operational communications.

The System Operator received 15 submissions. The consultation paper, submissions and a summary of submissions are available on Transpower's website.

The finalised CACTIS approved by the Authority is attached as Appendix B.

## We are proceeding with the proposed Code amendment

The Authority considered all submissions and has decided to proceed with the proposal, with some changes in response to submitter feedback and input from the independent Common Quality Technical Group.[2]

To address concerns about scope, we have revised the drafting of the Code amendment to clarify the thresholds for compliance with CACTIS requirements.

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1 'Common quality' means those elements of the quality of electricity conveyed across New Zealand's power system that cannot be technically or commercially isolated to an identifiable person or group of persons.

2 The Common Quality Technical Group comprises technical experts from across the industry who provide independent advice to the Authority on common quality requirements related to Part 8 of the Code.

Confidentiality protections will proceed as proposed, with amendments to ensure that intellectual property (IP) in encrypted models is safeguarded. For models provided for study cases, model owners will be able to 'black-box',[3] compile, or otherwise encrypt commercially sensitive components, or any parts where additional IP protection is required.

The Authority has also clarified that asset owners may apply to the System Operator for equivalence arrangements or dispensations where compliance with CACTIS obligations is not feasible.

Legacy clause arrangements will apply to the new CACTIS requirements, except for the operational communications requirements specific to connected asset owners.

## Next steps

The Authority is inviting comments on its proposal to incorporate the approved CACTIS by reference into the Code, as required under Schedule 2 of the Legislation Act. We ask that any comments are provided no later than 14 April 2026. Subject to consideration of any comments received, the Authority intends to amend the Code and incorporate the CACTIS by reference with effect from 1 July 2026.

Under the legacy clause arrangements, the new requirements for modelling, operational communications, and high-speed monitors would not apply to existing assets already electrically connected to a network that cannot meet the requirements without modification.

The new requirements will also not apply to assets that are first electrically connected to a network on or after 1 July 2026 and before 1 July 2027 and cannot meet the requirements without modification. To ensure that this legacy provision only applies to existing projects that are sufficiently advanced and would be materially impacted by needing to comply with the new requirements, owners of these assets must confirm before 1 August 2026 that key development milestones have been met. These milestones include securing financing, obtaining all necessary consents, and obtaining land-use rights. If these milestones are not met, the asset owner will be required to comply with the CACTIS.

The work undertaken to date on the CACTIS has been carried out under stage one of our work on information-related common quality issues. In **Stage two** of this work programme, the Authority will consider the broader framework for the sharing of common quality-related information between the System Operator, Transpower as a transmission network owner, and distributors, and will consult on a Code amendment proposal in the second half of 2026.

[3] A black-box model is a representation of a system whose internal structure is unknown or inaccessible, but whose external behaviour can be observed, measured, and modelled.

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# 1. The Authority has decided to proceed with its proposal

1.1. The Electricity Authority Te Mana Hiko (Authority) has decided to proceed with its proposal to amend the Electricity Industry Participation Code 2010 (Code) to require asset owners to provide to the System Operator common quality-related information that meets the technical specifications set out in a new system operation document – the Connected Asset Commissioning, Testing and Information Standard (CACTIS).

1.2. The amendment will:

(a) improve the accuracy and clarity of asset owners' obligations to provide common quality-related information to the System Operator

(b) enable the System Operator to develop, and update in a timely manner, technical specifications for common quality information requirements

(c) strengthen the protections around commercially sensitive information.

1.3. The CACTIS specifies:

(a) the information that asset owners must provide the System Operator in an asset capability statement

(b) the modelling information that asset owners must provide the System Operator

(c) the information asset owners must provide the System Operator relating to commissioning a new or existing asset or configuration of assets

(d) standards for periodically testing an asset or configuration of assets

(e) minimum requirements for operational communications between asset owners and the System Operator

(f) minimum requirements for high-speed monitoring equipment that asset owners must install

(g) the timeframes in which asset owners must provide the System Operator with the documentation and information required by the CACTIS.

1.4. The approved CACTIS is attached to this paper. The Authority's decisions set out in this decision paper are subject to completion of all steps required to incorporate material by reference under Schedule 2 of the Legislation Act 2019. These steps include:

(a) giving public notice of the proposal to incorporate the CACTIS by reference (published alongside this decision paper)

(b) allowing a reasonable opportunity for persons to comment on the proposal; and

(c) after considering any comments made and having regard to the purpose of the Legislation Act, being satisfied that it is appropriate to incorporate the CACTIS into the Code.

# 2. Background

2.1. On 1 July 2025, the Authority consulted on a proposal to improve the provision of common quality-related information to the System Operator for use in operating New Zealand's power system.[4]

2.2. The Authority received 15 submissions on the consultation paper from the parties listed in Table 1. Submissions are available on our website.[5]

**Table 1: List of submitters**

| Submitter | Category |
|---|---|
| Buller | Distributor |
| Contact | Generator–retailer |
| Electricity Engineers' Association of New Zealand (EEA) | Representative body for electrical engineers |
| Genesis | Generator–retailer |
| Independent Energy Generator Association (IEGA) | Representative body for independent electricity generators |
| Lodestone Energy | Owner/operator of solar photovoltaic generation and battery energy storage systems |
| Manawa | Generator |
| Mercury Energy | Generator–retailer |
| Meridian | Generator–retailer |
| NewPower Energy | Owner/operator of solar photovoltaic generation and battery energy storage systems |
| Orion | Distributor |
| PowerCo | Distributor |
| Transpower | Transmission grid owner and System Operator |
| Vestas | Wind turbine manufacturer |
| WEL Network | Distributor |

4 Electricity Authority, Promoting reliable electricity supply – a Code amendment proposal on common quality-related information, July 2025.

5 Submissions – Promoting reliable electricity supply – a Code amendment proposal on common quality-related information, July 2025

2.3. On 1 September 2025, the System Operator consulted on a draft of the proposed CACTIS.[6]

2.4. Following consultation, the System Operator provided the Authority with an amended draft of the proposed CACTIS for the Authority's approval. The amended draft incorporated the changes and recommendations outlined in the System Operator's *Summary of Submissions and Recommendations* document.[7] The approved CACTIS is attached as **Appendix B**.

2.5. There are security and resilience benefits that will result from updating the technical requirements for common quality information obligations. As inverter-based resources (IBRs) become more widespread, failing to adequately cater for new and emerging technologies can significantly affect the secure operation of the power system. To avoid these security risks, it is necessary to ensure the System Operator is able to obtain the right information for new technologies.

2.6. The new modelling requirements will help ensure the System Operator can maintain system stability, reliability, and efficient planning. Accurate and fit-for-purpose modelling information about IBRs enables the System Operator to assess risks, conduct comprehensive studies to define safe operational boundaries, and maintain power system security.

2.7. The new high-speed data requirements will enable monitoring of equipment performance for compliance purposes and to optimise asset performance. Early detection of problems can prevent widespread power outages and damage to assets, potentially reducing lengthy downtimes and maintenance costs.

2.8. Operational communications data provides the System Operator with visibility of assets and is critical for the operation of the power system. The updated operational communications requirements for IBRs and generation assets connecting to distribution networks will ensure the System Operator can monitor the operational status of each generating station and accurately model the power system.

2.9. There are efficiency benefits in clarifying the existing technical common quality information requirements and moving them from the main body of the Code to a system operation document. This change provides more clarity for asset owners and enables the System Operator to propose updates to the technical requirements more quickly to respond to new and emerging technologies and evolving industry needs.

2.10. This paper sets out the Authority's decision to approve the CACTIS and proceed with its proposal to amend the Code, and gives reasons for that decision.

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6 Transpower, Consultation Document: Connected Asset Commissioning, Testing and Information Standard, September 2025.

7 Transpower, Connected Asset Commissioning, Testing and Information Standard Consultation Summary of Submissions and Recommendations, October 2025.

# 3. The Authority considered the following matters in making this decision

3.1. This section summarises the key issues raised in submissions on the July 2025 Code amendment proposal and outlines the Authority's response to those matters. The summaries provided here highlight the main themes but are not exhaustive. For a full and detailed account of submitters' views, we encourage you to review the individual submissions.

### Submitters supported the intent of the proposal

3.2. Submitters generally supported the intent and objective of the proposal – being to improve the accuracy, consistency, and timeliness of common quality information provided to the System Operator.

3.3. The EEA, Genesis, Meridian, Orion, Powerco, and Transpower said the proposal would enhance system reliability, enable better planning, and allow for more responsive updates to technical requirements.

3.4. Most submitters supported placing in the CACTIS the technical specifications for common quality-related information, noting it would improve the System Operator's ability to respond effectively to technological changes. The EEA and Transpower highlighted the advantages of incorporating technical specifications into the Code by reference. They considered this would enable more flexible and timely updates in line with evolving technologies and system requirements.

3.5. Some submitters supported the proposal in principle but emphasised the importance of ensuring robust governance arrangements, appropriate thresholds, grandfathering arrangements for legacy assets, and the need for a stronger cost-benefit analysis. They also recommended various changes to the technical specifications.

### Submitters raised a number of key issues

3.6. Key issues raised by submitters fell into seven categories:

(a) estimated costs and benefits

(b) confidentiality and intellectual property

(c) thresholds for compliance with the CACTIS requirements

(d) equivalence arrangements and dispensations

(e) 'legacy clause' arrangements for existing assets

(f) governance of system operation documents

(g) cost recovery mechanisms.

3.7. We have also made some further changes to the proposed Code amendment consequential to the introduction of a new system operation document.

3.8. Feedback on the technical specifications in the CACTIS was outside the scope of this consultation. The System Operator has considered and addressed this feedback in its summary of submissions.[8]

3.9. The following sections discuss each of these issues in detail.

## Submitters raised several concerns about the estimated costs and benefits

### Our assessment of costs and benefits in the consultation paper

3.10. Our evaluation of the costs and benefits in the July 2025 consultation paper determined that the proposed Code amendment was expected to deliver a modest but positive net benefit, primarily by improving the security and resilience of the power system.

3.11. More accurate and standardised information was expected to enable the System Operator to better manage system risk, avoid overly conservative operating constraints, and enable it to meet its principal performance obligations (PPOs). The proposal also enables more timely and responsive updates to technical specifications. In aggregate, the amendment was also expected to reduce transaction costs by replacing bespoke information-sharing arrangements with clearer, standardised requirements.

3.12. The costs associated with the amendment fall on industry participants, with System Operator costs assessed as negligible. We expected asset owners would face compliance costs associated with providing and validating additional IBR model types, installing high-speed monitors, and meeting new operational communications requirements. Distributors would also incur costs to provide real-time controllable-load indications.

3.13. While these costs were expected to be material in some cases, they were expected to be proportionate to the benefits. Quantified annual benefits included approximately $16,500 in operational efficiencies, $175,000 in avoided costs from reduced loss of load during emergencies, and $500,000 in avoided investigation costs. Taken together with broader long-term system benefits, the assessment concluded that these outweigh the costs, supporting the Authority's overall assessment that the amendment is a beneficial regulatory change.

### Submitters' views and Authority's response

#### Quantification of costs and benefits

3.14. The IEGA, Meridian, and WEL Networks were concerned that the cost-benefit analysis was qualitative. The IEGA recommended the Authority adopt a risk-based approach to evaluate the System Operator's need for more detailed common quality information.

3.15. Lodestone submitted that the analysis underestimated compliance costs and noted that the quantified costs exceeded the quantified benefits by a factor of three. Meridian suggested that the Authority aggregate known costs at a system level to establish a benchmark for the minimum required benefits.

[8] Transpower, CACTIS Summary of Submissions and Recommendations, October 2025.

3.16. Following consideration of submitters' feedback, we have reviewed the cost-benefit analysis set out in our July 2025 consultation paper. We have reviewed the quantified costs and benefits and updated some of them. The updated cost-benefit analysis is provided in Part 4 of this paper. The updated cost-benefit analysis shows that it is very likely that the amendment will deliver a net benefit.

**Costs for smaller developers**

3.17. Lodestone, Mercury and NewPower raised concerns that the costs associated with the proposal could discourage smaller developers and reduce competition.

3.18. The Authority notes that the proposals relating to modelling, high-speed data, and operational communications requirements are intended to reflect the underlying costs of connecting to and operating on the power system. These costs are not uniform, and different developers may face different compliance burdens depending on technology type, connection configuration, and the size of the generating assets.

**Modelling costs**

3.19. A common theme across submissions was that the cost-benefit analysis in our July 2025 consultation paper understated the costs of compliance associated with the modelling requirements for IBRs. Lodestone, Mercury, and WEL Networks stated that the cost of developing and validating four different models was higher than what the Authority had estimated. Mercury and WEL Networks also questioned whether the use of multiple modelling platforms was justified, and called for clearer evidence that these tools are necessary and represent best practice.

3.20. In the revised CACTIS, the System Operator has reduced the model requirements for IBR generation from four models to three. Following our July 2025 consultation, the Authority engaged with several original equipment manufacturers (OEMs) supplying assets to the New Zealand market. These OEMs confirmed they have internal capability to prepare TSAT models at no additional cost to asset owners. The revised cost-benefit analysis therefore includes an updated estimate of the cost of complying with the modelling requirements, with a range provided to reflect the potential use of third-party translation services.

3.21. In regard to the use of multiple modelling platforms, each simulation tool is used for a specific purpose, and the System Operator requires models tailored to each tool to conduct targeted studies that ensure the power system remains secure and resilient. This reflects the different analytical strengths of each platform and the need to apply the most appropriate tool to each type of assessment. For further information on how the System Operator uses the different modelling platforms, see Appendix A of the System Operator's *Summary of Submissions and Recommendations document*.[9]

3.22. Lodestone also noted that the System Operator would continue to provide model translation services at no cost for models of (machine-based) synchronous generation. Lodestone submitted that this amounted to special treatment for synchronous generation and recommended the System Operator seek to recover its cost of doing this to ensure fairness.

[9] Transpower, CACTIS Summary of Submissions and Recommendations, October 2025.

3.23. The System Operator's practice of providing model translation services is an operational consideration and sits outside the scope of this Code amendment work. However, the Authority will consider whether formalised cost recovery mechanisms are appropriate for services such as these, as part of Stage 2 of our work on common quality information sharing requirements.

### High-speed data requirement costs

3.24. Some submitters also considered the high-speed data requirements costly and potentially disproportionate. Genesis, Lodestone, Manawa, and Mercury submitted that the estimated cost of $20,000–$30,000 per generating station understated the true cost once integration, site-specific engineering, cybersecurity and maintenance were considered. Manawa estimated costs of over $100,000 per generating unit.

3.25. Genesis noted that it had already completed a fleet-wide upgrade to meet previous requirements and that the proposed new resolution standard would require costly re-work. Lodestone and Mercury warned that these costs could delay projects or make smaller developments commercially unviable.

3.26. The high-speed data requirements will apply only to new generating stations with a maximum continuous output of 10 MW or more. As a result, many of the additional costs identified in submissions for existing assets will not be incurred. Following the July 2025 consultation, the CQTG advised that asset owners already install high-speed monitors during commissioning for testing purposes, and where these monitors meet CACTIS requirements, no additional cost will arise. To reflect stakeholder feedback, the revised cost-benefit analysis has an increased upper estimate of the cost of installing high-speed data monitoring equipment to $40,000.

## Our decision

3.27. In response to submitter feedback on the relative costs and benefits and on other points, we have clarified or amended the following aspects of the proposal:

(a) Modelling, operational communications, and high-speed data requirements will apply only to generating stations with a maximum continuous MW output power of 10MW or more.

(b) Excluded generating stations with a generating unit larger than 1MW will be required to notify the System Operator of their intention to connect and provide an asset capability statement to the System Operator. This requirement will not include providing modelling information to the System Operator.

(c) The new requirements for modelling, operational communications,[10] and high-speed monitors will only apply to new and modified assets.

3.28. The Authority considers these clarifications and changes address many of the concerns raised by submitters that the costs of the Code amendment proposal would outweigh the benefits. In particular, the owners of existing assets and smaller generating stations will not face the costs of meeting the new requirements. Part 4 of this paper includes an updated cost-benefit analysis.

[10] Except for the operational communications requirements specific to connected asset owners, which must be met by 1 October 2026 under a transitional provision.

## Confidentiality protections and intellectual property

### What we proposed

3.29. In the draft CACTIS, the System Operator proposed that asset owners would be required to provide the System Operator with models. The intent of the proposal was to move away from the current process of the System Operator signing non-disclosure agreements (NDAs) with original equipment manufacturers (OEMs). The current arrangements result in delays, legal complexity, and administrative burden.

3.30. The Authority proposed to require the System Operator to store unencrypted models securely and to restrict access to authorised personnel. We also proposed to prohibit the System Operator from sharing unencrypted models with any third parties unless the asset owner gave prior written consent or as required by law.

### Submitters' views and Authority response

3.31. Several submitters expressed concerns related to providing models to the System Operator and sharing models between asset owners and third parties. Key issues raised include the protection of intellectual property (IP), legal and contractual limitations, and the operational burden on OEMs.

3.32. Several submitters raised concerns about the CACTIS provision relating to the sharing of models with other asset owners. Mercury and Vestas opposed sharing unencrypted models. They recommended adopting a framework similar to the model adopted by the Australian Energy Market Operator, which allows OEMs to provide modified information that still meets usability requirements and modelling obligations.

3.33. Further engagement with OEMs by the System Operator and the Authority has clarified that some encrypted models also contain IP. This is in the form of source code that is the actual control software installed in the OEM hardware. Most OEMs also confirmed they are comfortable sharing unencrypted models that contain no source code for the purpose of grid owner's study cases.

3.34. Mercury and Meridian emphasised that asset owners often do not own the IP in OEM models. Manawa stated that asset owners' contracts with OEMs may prohibit asset owners from sharing models with other asset owners, and that the proposed framework may expose asset owners to legal risk.

3.35. The Authority acknowledges that contractual arrangements between asset owners and OEMs may restrict the ability of asset owners to share models with other asset owners. For this reason, the CACTIS provision relating to the sharing of models for FRT studies does not mandate disclosure. Instead, asset owners must obtain the necessary consent—either by engaging directly with the relevant OEM or by requesting that the System Operator seek consent on their behalf. This approach is intended to respect commercial and IP constraints while still enabling connection studies.

3.36. The Authority also notes that the concerns raised by Mercury and Vestas regarding the sharing of unencrypted models do not apply to this provision. The CACTIS requirement relates exclusively to the sharing of encrypted models for FRT studies. Unencrypted models are not required to be shared under this framework.

3.37. Contact Energy noted that voltage fault ride through studies often require access to other asset owners' models, and suggested that rather than managing individual consent requests, the System Operator should maintain a centralised power system case containing encrypted models.

3.38. The Authority notes that while the System Operator already holds all relevant encrypted models needed for FRT studies, the commercial sensitivity of these models means that the System Operator must first obtain consent before sharing them with other asset owners. This protects OEM IP and existing contractual arrangements. As part of stage two of this work, the Authority will consider whether the System Operator should be empowered to undertake FRT studies directly in situations where asset owners are unable to obtain the necessary consent to access models themselves.

3.39. Lodestone and Meridian highlighted the commercial and operational challenges faced by OEMs in supporting multiple modelling formats. Lodestone emphasised the commercial sensitivity of inverter models, which often contain source code and require extensive OEM support.

3.40. The Authority notes that the requirement for IBR generation to provide models in multiple software platforms is driven by the complexity of IBR and the nature of the studies required to assess performance. Each simulation tool serves a distinct purpose, and the System Operator requires models tailored to each tool to conduct targeted studies. The Authority also notes that, in response to submitter feedback, the System Operator has removed the requirement for IBR providers to supply WECC models in the revised CACTIS.

3.41. Meridian added that New Zealand-based generators have limited negotiating leverage with international OEMs, which may force asset owners to rely on third-party consultants to meet the modelling requirements. Mercury submitted that the proposal could deter key OEMs from participating in the New Zealand market unless stronger IP protections are introduced.

3.42. The EEA highlighted a risk that insufficient confidentiality protections could lead OEMs to restrict access to detailed models or provide overly simplified versions. It recommended mitigation measures such as standardised NDAs, secure data rooms, encryption options, and clear limits on onward disclosure. The EEA also raised concerns about broader data privacy and cybersecurity risks associated with expanded datasets, recommending minimum security standards and data separation protocols.

3.43. The System Operator intends to develop a contract template for asset owners to use with OEMs that reflects the CACTIS modelling requirements. This template would reduce the need for asset owners to negotiate bespoke terms with OEMs and support greater consistency across the industry. The template would not be mandated in the Code, allowing asset owners and OEMs the flexibility to depart from it where necessary.

3.44. Buller Electricity submitted that the Authority should resolve information sharing challenges before imposing more stringent obligations on asset owners. It noted that OEMs may not accept arrangements that allow the System Operator to share model data with other parties, such as distributors or Transpower as a transmission

grid owner. Buller also highlighted that unresolved information sharing issues could undermine the viability of future distribution system operation (DSO) models.

3.45. The staged approach we are taking is designed to first resolve the immediate issues the System Operator faces in obtaining the information it needs to maintain power system security and resilience. Once this foundation is in place, we will turn to the broader, longer-term questions around information-sharing arrangements across the sector, including how data should be accessed and shared in ways that support emerging operating models.

### Our decision

3.46. The Authority has decided to proceed with the proposed confidentiality protections, with the following changes:

(a) Asset owners must provide the System Operator with a model that the System Operator can use for the network models it prepares for generators to assess their compliance with the Code's fault ride through requirements.[11]

(b) The System Operator must not disclose any modelling information to third parties, except as provided for in the Code.[12]

3.47. These changes will enable generators to use the grid owner study cases for fault ride through studies, while maintaining appropriate protections for IP and commercial sensitivities.

3.48. The Authority has clarified that the confidentiality protections for modelling information apply to both encrypted and unencrypted models.

## The thresholds for compliance with the CACTIS requirements

### What we proposed

3.49. Clause 8.21(2) of the Code currently requires generators to advise the System Operator of their intention to connect to the transmission network or to a local distribution network, a generating unit with a capacity of 1MW or more.

3.50. Generators face no obligation under the clause for any of their generating stations with generating units below the 1MW threshold, regardless of whether the generating station as a whole exceeds the 10MW threshold for being excluded from common quality obligations.

3.51. The Authority proposed to amend clause 8.21(2) so that it also applies to any generating station with a total capacity of 10MW (a.c.) or more.

### Submitters' views and Authority response

3.52. The IEGA and NewPower raised concerns regarding the size threshold for generator compliance with the CACTIS. They emphasised the need to avoid unintended consequences that could undermine the financial viability of small-scale generation and create barriers to entry.

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11 See Transpower's website for more information: Power System Studies and Modelling

12 Clause 3(2) of Technical Code A of Schedule 8.3 of the Code.

3.53. The IEGA and NewPower submitted that the draft proposed CACTIS appeared to require all IBR generators above 1MW to provide the System Operator with four models. They considered this would impose disproportionate compliance costs on smaller generators and could negatively impact their financial viability.

3.54. The IEGA and NewPower expressed similar concerns that the requirements to install and maintain high-speed monitoring equipment appeared to apply to generators above 1MW.

3.55. NewPower raised additional concerns that generators above 1MW would be required to transmit operational data to the System Operator. It queried whether this requirement would mandate Inter-Control Centre Communications Protocol (ICCP) data transmission for all generators above 1MW, or whether generators below the 10MW dispatch threshold could use API-based alternatives.

3.56. The IEGA submitted that the CACTIS requirements should apply to generating stations above 10MW. NewPower recommended that modelling requirements should apply to generators above 30MW, while high-speed monitoring equipment and data transmission obligations should apply to generators above 10MW.

3.57. The Authority acknowledges the concerns raised by the IEGA and NewPower that the requirements for modelling, operational communications, and high-speed data appeared, in the proposed Code amendment, to apply to generators above 1MW.

3.58. We confirm, however, that this was not the intent. Rather, the modelling, operational communications, and high-speed data requirements would apply only to generating stations with a total continuous MW output power of 10MW or more.

### Our decision

3.59. The Authority has clarified the Code amendment to make the intent or the proposal clear that the modelling, operational communications, and high-speed data requirements will apply only to generating stations with a total continuous MW output power of 10MW or more.

## Equivalence arrangements and dispensations

### What we proposed

3.60. Currently, asset owners can apply for equivalence arrangements and dispensations in relation to existing technical code obligations related to asset commissioning, testing, and information provision.[13] The proposal did not include the ability for asset owners to apply for equivalence arrangements and dispensations in relation to obligations in the proposed CACTIS.

### Submitters' views and Authority response

3.61. Transpower and Genesis Energy recommended that the Authority clarify the applicability of equivalence arrangements and dispensations to obligations specified in the CACTIS.

[13] Clause 8.29 of the Code.

3.62. Transpower considered this clarification necessary to ensure consistency and regulatory certainty as obligations migrated from the main body of the Code to the CACTIS.

3.63. Genesis Energy echoed this view and noted that the ability to apply for exemptions and dispensations has been a critical mechanism for managing compliance costs and technical limitations. It also highlighted that recent investments in equipment and system upgrades could result in unintended disadvantage if certain CACTIS provisions were to be applied to existing assets without the asset owner having the ability to seek exemptions or dispensations.

3.64. The Authority agrees with submitters that asset owners should be able to apply for equivalence arrangements and dispensations for obligations specified in the CACTIS. These mechanisms are an important part of the Code's overall regulatory framework, providing flexibility where compliance with a specific requirement is impractical or where an alternative approach delivers an equivalent outcome. Allowing access to these mechanisms for CACTIS obligations will help ensure consistency, proportionality, and regulatory certainty as obligations transition from the main body of the Code into the CACTIS.

#### Our decision

3.65. The Authority has decided to amend the Code to clarify that asset owners may apply for an equivalence arrangement to be approved, or a dispensation to be granted, if an asset owner cannot comply with a CACTIS obligation, as it can do so currently for technical code obligations.

### 'Legacy clause' arrangements for existing assets

#### What we proposed

3.66. The draft proposed CACTIS introduced new technical requirements for modelling, operational communications, and high-speed data, with implementation proposed to take effect from 1 July 2026. However, the consultation paper did not include 'legacy clause' arrangements for existing assets or assets commissioned prior to a specified date.

#### Submitters' views and Authority response

3.67. Several submitters, including Genesis, Meridian, and NewPower, raised concerns that the draft CACTIS was ambiguous about whether the new obligations applied to new assets only, or also to existing assets.

3.68. A wide range of submitters supported grandfathering (or 'legacy clause') arrangements for existing assets, as retrofitting these assets to make them compliant would be disruptive and costly.

3.69. Buller Electricity, IEGA, Manawa Energy, and Lodestone Energy emphasised that imposing new obligations on already-commissioned assets would be inconsistent with good regulatory practice and could result in unnecessary compliance burdens, legal uncertainty, or stranded investments.

3.70. Genesis Energy and Mercury provided similar feedback, noting that many legacy assets commissioned under earlier standards would not be capable of meeting the

new requirements without significant upgrades. Mercury recommended that any retroactive application of requirements be justified through a cost-benefit analysis and accompanied by a reasonable phase-in period.

3.71. Other submitters considered the lack of clarity around how legacy IBRs would be treated under the proposed CACTIS created regulatory uncertainty and increased commercial risk. Lodestone noted that many older IBRs lack manufacturer support, firmware compatibility, or access to detailed control system documentation needed to meet the proposed standards. Requiring full compliance from these assets could result in costly reverse engineering or forced upgrades, which may be disproportionate to the risk they pose to the power system.

3.72. The Authority acknowledges submitters' concerns regarding the practical challenges and costs associated with making existing generating stations compliant with the new modelling, operational communications, and high-speed monitoring requirements. We agree that retrofitting existing assets would be disproportionately costly or technically impractical, and we have reflected this feedback in the Code amendment by introducing legacy clause arrangements for these requirements. These arrangements ensure that existing generating stations that are unable to comply with the new requirements are not required to meet these obligations.

3.73. Some submitters recommended that, if assets were to not be grandfathered, the Authority should adopt a phased implementation approach to ensure that industry participants are given sufficient lead time to comply. The EEA highlighted the risk of connection delays and engineering bottlenecks during the transition period, and proposed mitigation measures such as:

(a) grandfathering for consented projects

(b) clear transitional pathways

(c) a published prioritisation or service-level framework.

3.74. Lodestone suggested that a flexible compliance framework be adopted, which allowed for asset owners to demonstrate functional equivalency through representative testing or simplified modelling. Lodestone considered this would support system reliability goals without undue burden for well-performing assets.

### Our decision

3.75. The Authority has decided to include 'legacy clause' arrangements for the new requirements introduced in the CACTIS, except for the operational communication requirements specific to connected asset owners. We have excluded controllable load indications from the legacy clause arrangements to avoid effectively creating permanent exemptions, which would undermine the intent of the new requirement.

3.76. Under the legacy clause arrangements, the new requirements for modelling, operational communications, and high-speed monitors will not apply to existing assets already electrically connected to a network that cannot meet the requirements without modification.

3.77. The new requirements for modelling, operational communications, and high-speed monitors will also not apply to assets first electrically connected to a network between 1 July 2026 and 1 July 2027 that cannot meet the requirements without

modification, if the asset owner confirms before 1 August 2026 that the asset owner has met the following milestones:

(i) the asset owner has secured financing that enables the asset owner to develop and commission the asset; and

(ii) the asset owner has obtained all consents necessary to enable the asset owner to develop and commission the asset; and

(iii) the asset owner has obtained rights to use the land on which the asset is to be located.

3.78. If these non-compliant generating stations are subsequently upgraded, compliance with the new requirements for modelling, operational communications, and high-speed monitors would be required.

3.79. On the threshold at which asset modifications require updated modelling, an asset owner will be required to advise the System Operator of any changes to an asset's capability that the asset owner considers material. The System Operator will then determine, acting reasonably, whether those changes necessitate updated modelling. This approach ensures that modelling updates are required only where justified by the scale or impact of the modification, avoiding unnecessary compliance costs.

3.80. To address the risk that routine testing or refurbishment may be unintentionally classified as a modification, the Authority has clarified that, unless the System Operator and the asset owner agree otherwise, an alteration to an asset will be considered a modification for the purpose of the legacy clause arrangements if it results in a change of 5% or greater in the asset's:

(a) MW rating, or

(b) frequency response curve for 100 milliseconds or longer, or

(c) voltage response curve for 100 milliseconds or longer.

3.81. Figure 1 illustrates how alterations to an asset's output—specifically ±5% tolerance bands and example changes of 4% and 10%—affect its time-domain response. Responses that remain within the ±5% tolerance band illustrate changes that would not constitute a modification, while responses exceeding these bounds represent changes that would be treated as modifications for the purpose of the legacy clause arrangements.

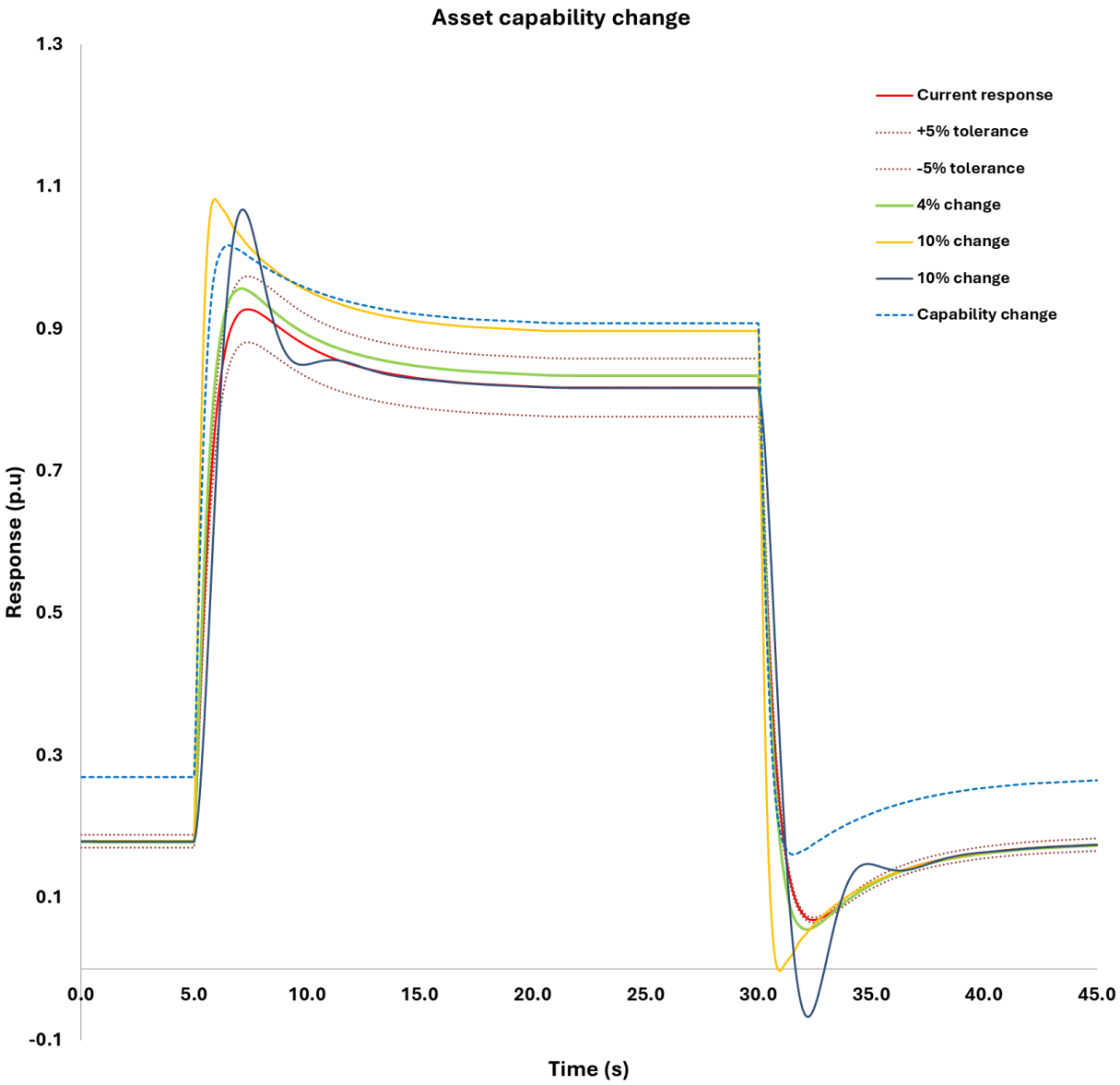


**Figure 1: Comparison of asset dynamic response under current capability, tolerance limits, and potential capability changes.**

3.82. We have adopted this threshold following discussions with the System Operator and the Common Quality Technical Group. Asset owners will be required to demonstrate the extent of performance change through either regression analysis or a simulation study, ensuring transparency and consistency in the application of the Code.

3.83. To address the risk that changes made to assets to meet recently imposed dead band requirements are inadvertently treated as a modification, we have introduced a provision in the Code amendment that excludes these changes from being classified as a modification for the purpose of the legacy clause arrangements.

3.84. As a final point, the Authority notes we are introducing a clause that enables the System Operator to apply to the Authority for us to make a determination to say some or all of the CACTIS requirements apply to legacy assets where we consider this to be in the public benefit. The application of the public benefit test means any

cost to the owner of a legacy asset that loses some or all of its legacy status must be less than the resulting benefit to New Zealand consumers.

3.85. The Authority considers this clause is necessary to preserve the security and resilience of the power system, particularly as New Zealand's electricity generation mix evolves and the significance of accurate asset information to power system operation increases. In rare situations, a legacy asset exempted from CACTIS obligations could create unacceptable risk for the operation of the power system. The determination power provides a proportionate safeguard in this regard, ensuring that the legacy clause provisions do not compromise the System Operator's ability to maintain a secure, reliable and efficiently operated power system.

## Governance of system operation documents

### What we proposed

3.86. The Code amendment proposal required asset owners to provide common quality-related information to the System Operator that met the technical specifications set out in a new system operation document – the CACTIS.

3.87. System operation documents are documents developed by the System Operator, that are incorporated by reference in the Code.

3.88. Part 7 of the Code governs the processes surrounding reviews of system operation documents incorporated by reference, including initiating a review, amendments to the document, consultation, and approval.

### Submitters' views and Authority response

3.89. Submitters raised a range of concerns about the governance arrangements for system operation documents, including:

(a) the review and update processes

(b) the extent of the Authority's oversight

(c) the potential risks of delegating too much discretion to the System Operator.

3.90. Transpower proposed changes to clause 7.14 of the Code to improve clarity around how industry participants' proposals for updates to system operation documents are handled. Transpower also proposed clarifying clause 7.15 of the Code as to what constitutes a completed review of a system operation document.

3.91. The Authority acknowledges the concerns from submitters regarding the governance arrangements for system operation documents. The Authority will consider feedback on amending the process for reviewing system operation documents under Part 7 as part of the next Code review programme.[14]

3.92. Several submitters expressed concern about the potential erosion of the Authority's oversight of the governance of the CACTIS and other system operation documents. Contact Energy acknowledged that the proposed approach may improve efficiency for the System Operator in managing its PPOs but stated that removing the

[14] Electricity Authority, Code review programme, last updated February 2025.

Authority's role in the consultation process could result in stakeholder submissions being inadequately addressed.

3.93. The IEGA and NewPower expressed similar concerns. The IEGA stated that the absence of a defined regulatory process for developing and amending the CACTIS undermined transparency and accountability. The IEGA questioned whether the System Operator would undertake rigorous cost-benefit analysis and consultation comparable to a Code amendment process.

3.94. The IEGA and NewPower raised concerns that externalising common quality information requirements from the Code risks reducing the Authority's expertise and oversight, leading to amendments being approved without proper evaluation or consultation.

3.95. The EEA supported the Authority retaining approval rights over the CACTIS but recommended that the Code amendment include a clear and transparent consultation process, similar to other system operation documents, to ensure industry input was considered.

3.96. We appreciate the importance of maintaining transparency, regulatory oversight, and industry engagement in the development and amendment of these documents.

3.97. In relation to concerns about the process for amending the CACTIS and the Authority's oversight of consultations, we note that Part 7 of the Code contains a robust defined process for amending the CACTIS, including requirements to:

(a) obtain the Authority's consent before consulting on any proposed amendment

(b) consult with affected industry participants

(c) provide key information as part of the consultation, including an evaluation of costs and benefits and an evaluation of alternative options

(d) provide a reasonable consultation period, including complying with any reasonable consultation timeframes prescribed by the Authority

(e) provide the Authority with a report post-consultation that includes:

(i) a summary of submissions and the System Operator's responses to submitters' points

(ii) any further changes made to the system operation document following consultation

(iii) a final draft of the proposed amended system operation document.

3.98. Additionally, the Authority retains the right to approve, decline, or request further consultation on any proposed amendment to a system operation document.

### Our decision

3.99. The Authority has decided to proceed with the proposal but with an additional minor and technical change to clause 7.15.

## Cost recovery mechanisms

### What we proposed

3.100. The Code amendment proposal did not include any mechanism for the System Operator to recover its costs directly from industry participants. This was because the System Operator did not propose in the draft CACTIS to undertake services for industry participants that would make cost recovery mechanisms appropriate.

### Submitters' views and Authority response

3.101. In the draft CACTIS, the System Operator proposed that asset owners would be required to provide benchmarked and validated Transient Security Assessment Tool (TSAT) models to the System Operator.

3.102. Lodestone highlighted the difficulty of assessing model performance across different software platforms. They noted that the presence of confidential information—such as encrypted OEM models—can make it difficult to obtain and validate the necessary data.

3.103. In the draft CACTIS, the System Operator also proposed that asset owners share models with other asset owners for Electromagnetic Transient (EMT) fault ride through studies.

3.104. Submitters raised IP concerns, noting that asset owners do not hold the IP rights to the models and therefore cannot authorise their disclosure.

3.105. The Authority acknowledges that access to models may be a barrier for some asset owners in meeting these requirements. In its *Summary of Submissions and Recommendations* document, the System Operator advised that it has the capability to benchmark and validate TSAT models in-house. It also has the capability to conduct EMT fault ride through studies on behalf of asset owners if asset owners cannot obtain models for neighbouring assets that need to be included in the studies.

3.106. While the System Operator has access to asset models and the technical capability to provide these services, doing so may require a Code amendment to introduce a cost-recovery mechanism, which sits outside the scope of this work.

### Our decision

3.107. The Authority will consider whether cost recovery mechanisms would be appropriate for services such as these as part of Stage 2 of our work on common quality information sharing requirements.

# 4. The amendments are consistent with our main statutory objective

4.1. The Authority's main statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

4.2. After considering all submissions on the Code amendment proposal, the Authority considers the final Code amendments are consistent with our main statutory objective, and with section 32(1) of the Electricity Industry Act 2010 (Act).

4.3. Submitters generally agreed that the proposed amendment aligned with section 32(1) of the Act, as it supported reliable supply and the efficient operation of the power system. However, some submitters expressed concerns about the additional costs to comply with the CACTIS, noting that these costs would likely be passed on to consumers.

4.4. The suite of amendments promotes the three limbs of the Authority's main statutory objective as follows:

(a) **Competition** is supported by promoting competitive neutrality amongst emerging and established technologies.

(b) **Reliable supply** is supported by ensuring that all relevant parties, including owners of evolving technologies such as IBRs, comply with clear and consistent common quality-related information requirements. This will help to maintain the security of the power system as increasing amounts of variable and intermittent generation connect to it.

(c) **Efficient operation** is enhanced through reduced administrative burdens. Clarifying compliance requirements minimises unnecessary costs for asset owners and the System Operator, while providing the System Operator with accurate information for planning and operational decisions.

4.5. In deciding to make this Code amendment the Authority has applied our Code amendment principles, which are set out in our consultation charter.[15] In summary, we consider there is a clear case for regulation, having evaluated the benefits and costs of the Code amendments and compared them against alternative options. The next sub-section summarises this evaluation.

## The benefits of the amendments are greater than the costs

4.6. We have updated the cost-benefit analysis to take account of submitters' feedback.

4.7. Submitters raised several issues with the original assessment — including insufficient quantification of benefits, concerns that compliance costs were understated, and uncertainty about whether the new requirements would apply to owners of existing assets and smaller generating stations.

4.8. The updated evidence, submitter feedback, and refined cost–benefit analysis strengthen our view that the benefits of the amendments are likely to outweigh the costs. The amendments address clear system needs, reduce operational

[15] See Electricity Authority | Consultation Charter 2024.

inefficiencies, and support more accurate, timely, and risk-appropriate management of power system security.

4.9. Although there are compliance costs, these are targeted, proportionate, and, in some cases, lower than initially anticipated due to refinements made in response to submissions. We consider that the cumulative quantified and unquantified benefits, including improved modelling accuracy, reduced transaction and investigation costs, avoided future system-tool investments, and enhanced system resilience, are likely to materially exceed the quantified and unquantified costs. On balance, we consider that the amendments are very likely to represent a net improvement to the efficiency and reliability of the electricity system.

4.10. While it is difficult to quantify all of the costs and benefits, we have quantified them where data is available. Where we have not been able to quantify costs and benefits, we have made a qualitative judgement of them based on the best information available to us.

4.11. We consider that some of the unquantified benefits are material as indicated in the table below. This reflects the evidence that better modelling, improved operational communications, and access to high speed data materially strengthen the System Operator's ability to maintain power system security and avoid high impact events.

4.12. As set out in both the Code amendment proposal and updated cost–benefit analysis, incomplete or inaccurate information forces the System Operator to operate the system more conservatively, increasing market inefficiencies and heightening the risk of unforeseen behaviour during disturbances. Conversely, the new CACTIS requirements are expected to reduce investigation times, support more accurate real-time decision-making, and mitigate the risk of outages. These avoided risks and operational efficiencies are likely to be substantial relative to compliance costs, and international experience shows they can outweigh costs by an order of magnitude.

4.13. Error! Reference source not found. summarises the expected benefits and costs of the Code amendment.

**Table 2: Summary of Code amendment's expected benefits and costs over 10 years**

| Benefit / Cost | Magnitude of benefit / cost |
|---|---|
| Benefit from improving the security and reliability of the power system | Expected to be material |
| Benefit from better informed development of, and more timely updates to, technical specifications for the Code's common quality-related information requirements | Expected to be material |
| Benefit of avoiding the need for the System Operator to invest in different online tools for its control rooms to replace existing dynamic security assessment tools | Expected to be material |
| Benefit of more timely updates to common quality-related information requirements | Expected to be modest |
| Benefit from reducing transaction costs currently incurred through negotiating information collection | Expected to be modest |

| | |
|---|---|
| Benefit to modelling, voltage management, event investigation and forecasting from operational communications indications and measurements | Expected to be modest |
| Benefit of generating stations being 'constrained on' less due to more accurate modelling information | Expected to be modest |
| Benefit of avoiding testing costs for generating stations exporting 10–30 MW by using event data from high-speed monitors | $0.1m – $0.2m per generating station |
| Benefits to operational efficiency, risk reduction and cost avoidance from controllable load indications | $4.64m |
| Benefit from improved efficiencies for post-event incident analysis | $0.81m – $1.61m |
| Implementation costs faced by the System Operator | Expected to be negligible |
| The ongoing cost for the System Operator to operate under the proposed amendment | Expected to be negligible |
| Cost to connected asset owners to provide controllable load indications | $2.13m |
| Cost to provide additional operational communications indications and measurements for IBRs | $0.05m – $0.1m |
| Cost to provide additional operational communications indications and measurements for synchronous generation | Expected to be negligible |
| Cost of installing high-speed data monitoring equipment for new assets | $0m – $0.87m |
| Cost to provide modelling information for IBRs | $0.71 – $2.74m |
| **Quantified expected net present benefit** | **$0.48m – $3.36m**[16] |

## Estimate of key costs of the Code amendment

### Cost of controllable load indications

4.14. The estimated cost to implement controllable load indications is based on the current status of ICCP connectivity for the 33 direct consumers and distributors connected to the transmission grid. Of these, 18 asset owners do not have an ICCP link and would require new installations, while 9 asset owners already have ICCP links and would only need to update their data sets.

4.15. Our estimate of these costs remains the same as in the consultation paper. The cost of establishing a new ICCP link was estimated at $20,000 for Transpower and $100,000 for an asset owner. The cost of updating an existing ICCP data set was estimated at $5,000 for Transpower and $10,000 for the asset owner. We consider that these estimates remain reasonable. The present value of these costs over ten years is set out in Table 3.

[16] The expected net benefit is only for the elements of the cost benefit analysis that could be quantified.

**Table 3: Costs of requirement to provide controllable load indications.**

| Category | Present value over 10 years |
|---|---|
| **Costs** | |
| **Transpower cost charged to establish a new ICCP** | $0.33m |
| **Connected party costs to establish a new ICCP estimate** | $1.67m |
| **Transpower cost charged to add/update an ICCP data** | $0.04m |
| **Additional connected party costs to add/update an ICCP data set** | $0.08m |

### Cost of implementing operational communications requirements

4.16. The CACTIS introduces new minimum technical requirements for operational communication between asset owners and the System Operator. This is expected to impose additional compliance costs on some asset owners. For synchronous generation, as set out in the consultation paper, we estimate an additional fixed cost of approximately $500 per generating station, along with a variable cost of $2,000 per generating unit. We have reviewed these estimates following submissions on these and consider that they remain reasonable.

4.17. The total cost of implementing operational communications requirements for synchronous generation could not be calculated as the Authority's generation investment pipeline does not include data about the number of generating units for each project. However, we expect the overall cost to be small because the overwhelming majority of new generation that we are aware of is IBR generation.

4.18. Based on data from Transpower's generation connection pipeline (2027-2029) and the Authority's generation investment pipeline (2030–2036), the total cost for IBRs is estimated to be between $50,000 and $101,000 (present value).

4.19. This is based on estimated additional fixed cost ranges from $2,500 to $5,000 per generating station (unchanged from the consultation paper), depending on the type of generation (eg, wind, solar photovoltaic) and the complexity of the generating station. We did not receive submissions on these costs and consider that these estimates remain reasonable. No additional variable costs are expected for IBRs beyond what is already required under current arrangements.

### Cost of implementing high-speed data monitoring equipment

4.20. The estimated costs for compliance with the high-speed data monitoring equipment requirements are based on updated estimates of $0 to $40,000 per station. A common theme across submissions was that the indicative cost estimates in the consultation paper of $20,000 to $30,000 per station underestimated the true cost of compliance. We recognise that, for some parties, the total cost of implementation may be higher than the indicative estimates provided in the consultation paper, particularly when accounting for site-specific engineering and auxiliary equipment.

4.21. However, we note that the requirement to install high-speed data monitoring equipment will not apply to existing generating stations. As such, many of the additional costs identified in submissions, such as power and wiring modifications to

existing assets, information and communications technology upgrades, and outage-related expenses, will not be incurred.

4.22. Additionally, asset owners already install high-speed monitors during commissioning for testing. If these high-speed monitors meet CACTIS requirements, there will be no additional cost. We have therefore increased the upper limit of our estimate for these costs, but not to the same level as some submissions seemed to be suggesting.

4.23. Based on data from Transpower's generation connection pipeline (2027-2029) and the Authority's generation investment pipeline (2030–2036), the total cost of the high-speed data monitoring requirements is estimated to be between $0 and $867,000 (present value).

### Cost to owners of IBRs to comply with the modelling requirements

4.24. Under the proposed modelling requirements, asset owners of IBR generation with connection study obligations must provide three distinct model types to the System Operator. For new assets, most OEMs already supply validated PowerFactory and Power Systems Computer Aided Design (PSCAD) models. As PowerFactory model validation is currently required by the System Operator, this does not represent an incremental cost of the Code amendment.

4.25. Validation of PSCAD models was estimated in the consultation paper to cost between $15,000 and $20,000 per generating station, though costs may vary. These models can typically be converted into the required TSAT format by OEMs or third-party providers. Some submitters were concerned that this under-estimated the costs. We consider that these estimates remain reasonable.

4.26. Following our July 2025 consultation on the Code amendment proposal, the Authority engaged with several OEMs that supply assets to the New Zealand market. These OEMs confirmed they have internal capability to prepare TSAT models at no additional cost to asset owners.

4.27. Where OEMs are unable to provide TSAT models, third-party translation services are available at an estimated cost of $50,000 to $100,000, with an additional $10,000 to $15,000 for validation. As industry standards for Dynamic Link Library (DLL) models continue to evolve, these costs are expected to decline over time, but to be conservative we assume they do not decline for the purposes of the CBA. Again, we consider that our estimates of these costs remain reasonable.

4.28. Based on data from Transpower's generation connection pipeline (2027-2029) and the Authority's generation investment pipeline (2030–2036), the total cost for asset owners to comply with the modelling requirements is estimated to be between $711,000 and $2.74 million (present value).

### Implementation and ongoing costs for the System Operator

4.29. We consider the implementation and ongoing costs for the System Operator to be negligible, as the Code amendment does not require new tools, systems, or material changes to internal processes. The System Operator already uses established tools, modelling practices, and information-handling processes, and asset owners are already required to provide most of the information that will be formally standardised through the CACTIS. The amendment largely clarifies and

streamlines existing obligations, reducing ambiguity rather than introducing new requirements that would necessitate System Operator investment or operational redesign.

## Estimate of key benefits of the Code amendment

### Benefit of controllable load indications

4.30. The quantified benefits below are the same annual values included in the consultation paper, but aggregated over a 10-year period. The estimated benefits of implementing controllable load indications are $4.64 million in avoided costs and operational efficiencies (Table 4). This figure is based on annual savings from improved operational efficiency ($16,500), reduced risk of unnecessary real load shedding during grid emergencies ($175,000), and the avoidance of investigations following major events ($500,000). These estimates were derived using assumptions such as the number of connected parties, the frequency of requests, labour rates, and the value of lost load during shortfall events.

**Table 4: Benefits of requirement to provide controllable load indications.**

| Category | Present value over 10 years |
|---|---|
| **Operational efficiency** | $0.111m |
| **Risk reduction** | $1.74m |
| **Cost avoidance** | $3.36m |

### Benefits of new operational communications requirements

4.31. The new operational communications indications and measurements will deliver benefits to the power system in the form of improved modelling, voltage management, event investigation and forecasting for the System Operator. While these are difficult to quantify, collectively they contribute to a more secure, efficient, and resilient electricity system.

### Benefits of implementing high-speed data monitoring equipment

4.32. This section builds on the qualitative cost–benefit assessment in the consultation paper and addresses the concerns raised in submissions about the justification for introducing high speed data monitoring requirements. Some submitters stated that the original analysis lacked sufficient quantification and did not clearly demonstrate a net benefit. Feedback also questioned whether the benefits were proportionate to the additional operational complexity, and called for a more risk based, evidence driven approach. The updated analysis below sets out a clearer and more detailed account of the expected benefits of implementing high speed data monitoring.

4.33. The benefits of the high-speed data requirements are expected to be in the form of avoided costs associated with testing and post-event incident analysis. The CACTIS introduces the option for generating stations with a maximum continuous MW output power of 10MW or more but less than 30MW to use event data from high-speed monitors in lieu of undertaking tests. We estimate that these asset

owners could avoid $100,000 to $200,000 per generating station, with tests typically occurring every 4 to 10 years.

4.34. Historically, for post-contingent event incident analysis, the System Operator has relied on slow-sampling supervisory control and data acquisition (SCADA) data, which is only suitable for assessing compliance with steady-state AOPOs. This data cannot capture fast-acting events such as voltage controller responses following contingencies on the power system. As generating stations become more responsive, this limitation has made post-contingent event compliance assessments by the System Operator increasingly difficult—often requiring high-sample-rate data from nearby generating stations. This workaround is time-consuming, frequently inconclusive, and can take hours of manual data manipulation.

4.35. Installing high-speed monitors will significantly reduce these inefficiencies. We estimate that avoiding manual data preparation and manipulation could save the System Operator $8,000 per event. With approximately 15 events per year, this represents annual savings of $120,000. If additional data manipulation is required, costs can escalate to $16,000 per event, bringing potential annual savings to $240,000.

4.36. Beyond post-contingent event investigation and compliance efficiencies, high-speed data also supports improved power quality, reduced energy losses, and early detection of oscillation events—helping to avoid partial or total system blackouts. It is difficult to quantify these benefits, but we consider that they would also be material.

### Benefits of requiring TSAT models for IBR assets

4.37. The System Operator uses Powertech Labs Inc's Dynamic Security Assessment (DSA) tools suite for real-time use of TSAT and Voltage Security Assessment Tool (VSAT) capabilities, for continuous power system security monitoring and assessment. Accurate models underpin critical real-time functions such as frequency reserve adequacy, transient stability limits, post-contingent event analysis, and system security forecasting using the DSA suite.

4.38. It is difficult to quantify the benefits of the System Operator having accurate models for these functions because the value lies in:

(a) the ability of the System Operator to operate the power system less conservatively than it would with less detailed and less accurate modelling information, and

(b) avoiding rare but high-impact events rather than producing easily measurable outcomes.

4.39. Operating the power system less conservatively makes relatively more generation available for producing electricity – ie, less generation is held in reserve. This benefits consumers by promoting competition in wholesale electricity production. While the benefit is clear, it is difficult to quantify because the potential increase in output varies by generating station, location within the power system, and technology type.

4.40. While inaccurate models can increase the risk of power system failures due to the power system inadvertently being operated less securely than otherwise, the consequences are probabilistic and event driven. The benefits of accuracy are

reduced risk and improved resilience of the power system, which are challenging to express in monetary terms or operational metrics without extensive scenario analysis.

4.41. The System Operator's reliance on TSAT is expected to grow in the coming years, as its role in system security assessments and real-time operations continues to expand. The requirement for owners of IBRs to provide TSAT models ensures the System Operator can continue to utilise these tools without the need for costly replacement. Avoiding the need to replace the DSA platform represents a significant benefit, as replacement of these tools could exceed more than $2 million, with additional costs for training.

# 5. Attachments

5.1. The following appendices are attached to this paper:

**Appendix A Approved Code amendment**

**Appendix B Approved Connected Asset Commissioning, Testing, and Information Standard (CACTIS)**

# Appendix A Approved Code amendment

A.1. This appendix sets out the Code amendment the Authority has decided to make following our consideration of submitter feedback and in accordance with the decisions set out in the main body of this document.

A.2. Appendix A shows version of the Code that will be in effect on 1 July, including changes made by the Electricity Industry Participation Code (Frequency and voltage related amendments) Amendment 2026.

A.3. Code amendments are displayed as follows:

(a) text or formatting is black underlined if it is to be added to the Code and neither subparagraph (c) or (d) applies

(b) text is shown in ~~black strikethrough~~ if it is to be deleted from the Code and neither subparagraph (c) or (d) applies

(c) text or formatting is red underlined if it is to be added to the Code and it was not shown as such in the consultation paper

(d) deleted text is ~~red strikethrough~~ if it is to be deleted from the Code and it was not shown as such in the consultation paper, and ~~red strikethrough and underlined~~ if it was proposed in the consultation paper and is no longer being progressed.

**1.1 Interpretation**

(1) In this Code, unless the context otherwise requires,—

…

**asset capability statement** means a statement of capability and operational limitations that applies to specific **assets** during the normal and abnormal conditions that may arise on the **grid**, provided to the **system operator** in accordance with clause 2(2~~5~~) of **Technical Code** A of Schedule 8.3

…

**connected asset commissioning, testing and information standard** means the connected asset commissioning, testing and information standard that is incorporated by reference in this Code under clause 8.73

…

**high-speed monitor** means a device capable of capturing and storing high-resolution waveform data of voltage and current signals during power system events or disturbances, with sufficient sampling frequency and accuracy to support detailed analysis of power system behaviour

…

~~**maximum continuous rating** means the maximum electrical performance of an **asset** that can be maintained continuously in normal service~~

…

~~**scaling factor**, for the purpose of Appendix A of Technical Code C of Schedule 8.3, means a factor applied to a measurement at 1 point to calculate a corresponding measurement at another point~~

…

~~S~~**system operation document** means any of the following documents:

(a) the **security of supply forecasting and information policy**:

(b) the **emergency management policy**:

(c) the **policy statement**:

(d) the **procurement plan**:

(e) the **AUFLS technical requirements report**:

(f) the **system operator rolling outage plan**~~.~~:

(g) the **connected asset commissioning, testing and information standard**

…

**7.15 Review of system operation documents ~~policy statement and procurement plan~~**

(1) The **system operator** must review the following **system operation documents ~~policy statement~~** and the **~~procurement plan~~** at least once every 2 years to identify whether the document should be amended:

(a) the **connected asset commissioning, testing and information standard**:

(b) the **policy statement**:

(c) the **procurement plan**.

(1A) The **system operator** may review a **system operation document** not referred to in subclause (1) at any time.

(2) For the purposes of subclause (1), any 2 year period commences on either—

(a) if the previous review does not result in an amendment being made, the date the **system operator** advised the **Authority** of that decision under clause 7.15(3)(b) ~~the date the last review of the document was completed if that review did not result in an amendment being made~~; or

(b) if ~~a~~ the previous review results in an amendment being made, the date the amendment takes legal effect.

…

**8.4 System operator may rely on information provided**

For the purposes of this Code, the **system operator** may—

(a) rely on the **assets** and information about the **assets** made available to the **system operator** by **asset owners**; and

(b) assume that **asset owners** are complying with the **asset owner performance obligations**, ~~and~~ the **technical codes** and the **connected asset commissioning,**

**testing and information standard**, or complying with a valid **dispensation** or **equivalence arrangement**

(c) *[Revoked]*

…

**8.7 System operator must not contract contrary to this arrangement**

Subject to clauses 8.6 and 17.29, the **system operator** must not enter into a contract with another person that is inconsistent with the **system operator's** obligations under this Code, ~~and~~ the **technical codes** and the **connected asset commissioning, testing and information standard**.

…

**8.21 Excluded generating stations**

(1) For the purposes of clauses 8.17, 8.19, 8.25D, and the provisions in **Technical Code** A of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency, an **excluded generating station** means a **generating station** or **embedded generating station** that has a **maximum continuous MW output power** of less than 10 **MW**, unless the **Authority** has issued a direction under clause 8.38 that the **generating station** or **embedded generating station** must comply with clauses 8.17, 8.19, 8.25A, and 8.25B and the relevant provisions in **Technical Code** A of Schedule 8.3.

(2) Whether likely to be an **excluded generating station** or not, a **generator** ~~who is planning to connect to the **grid** or a **local network** a **generating unit** with rated net maximum capacity equal to or greater than 1 MW (alternating current (a.c.) capacity)~~ must provide the **system operator** with written advice of its intention to connect ~~a **generating unit** or **generating station**~~ to the **grid** or directly or indirectly to a **local network** a **generating station** with one or more **generating units** with rated net maximum capacity equal to or greater than 1 **MW** (alternating current (a.c.) capacity), together with other information relating to the ~~that~~ **generating unit** or **generating station** in accordance with clause 8.25(4) ~~where:~~

~~(a) the **generating station** has a **generating unit** has with a rated net maximum capacity equal to or greater than 1 **MW** (alternating current (a.c.)) capacity at the **point of connection** to the **network**.; or~~

~~(b) the **generating station** has a capacity equal to or greater than 10 **MW** at the **point of connection** to the **network**~~.

…

**8.25 Other asset owner performance obligations and technical standards**

…

(3) Each **asset owner** and each **purchaser** must provide communication facilities that comply with the ~~**technical codes**~~ **connected asset commissioning, testing and information standard** ~~or otherwise, as the **system operator** reasonably requires,~~

~~which must assist the **system operator** in planning to comply, and complying, with its **principal performance obligations** and achieving the **dispatch objective**~~.

(4) Each **asset owner** and each **purchaser** must provide information to the **system operator** that complies with the **technical codes** and the **connected asset commissioning, testing and information standard** ~~or otherwise as the **system operator** reasonably requests, to assist the **system operator** in planning to comply, and complying, with its **principal performance obligations** and achieving the **dispatch objective**~~.

(5) If the **system operator** reasonably considers it necessary to assist the **system operator** in planning to comply, and complying, with the **principal performance obligations** and achieving the **dispatch objective**, the **system operator**—

(a) may require that an **embedded generator** provide information regarding the intended output of each **embedded generating station** greater than 10 **MW** in capacity, that must be either—

(i) submitted as an **offer** in accordance with subpart 1 of Part 13; or

(ii) provided in a form and manner specified in the **connected asset commissioning, testing and information standard** ~~agreed between the **system operator** and the **embedded generator**~~; and

(b) must advise the **embedded generator** of its requirement at least 20 **business days** in advance of the requirement coming into effect.

(6) If the **system operator** reasonably considers it necessary to assist it in planning to comply, and complying, with the **principal performance obligations** and achieving the **dispatch objective**, the **system operator** may apply to the **Authority** to require an **embedded generator** to provide information regarding the intended output of a group of **embedded generating stations** that total greater than 10 **MW** in capacity and that are connected to the same **grid exit point**.

(7) If the **Authority** approves the **system operator's** request under subclause (6), the **embedded generator** must provide the information in accordance with the **connected asset commissioning, testing and information standard** ~~must be provided to the **system operator** by the relevant **embedded generator** in a form and manner determined by the **Authority**~~.

…

**8.27 System operator to monitor compliance**

(1) To the extent possible, given the information made available by **asset owners**, the **system operator** must monitor, in the manner set out in the **policy statement**, which for the avoidance of doubt, sets out the **system operator's** only monitoring obligations under this subpart, the ongoing compliance of **asset owners** with the **asset owner performance obligations** ~~and~~, the **technical codes** and the **connected asset commissioning, testing and information standard**.

(2) The **system operator** has a discretion to not **dispatch** an **asset** or configuration of **assets**, if it is not satisfied that the **assets** or configuration of **assets** comply with the relevant **asset owner performance obligations** or provisions of the **technical codes** or provisions of the **connected asset commissioning, testing and information standard**, or that the **asset owner** has and is complying with a valid **equivalence arrangement** or **dispensation** from the relevant **asset owner performance obligations** or provisions of the **technical codes** or provisions of the **connected asset commissioning, testing and information standard**.

(3) The **system operator** must immediately advise an **asset owner** if the **system operator** has reasonable grounds to believe that the **asset owner** is not complying with an **asset owner performance obligation**, **equivalence arrangement** or **dispensation**, and that the **asset owner**—

(a) does not have a valid **equivalence arrangement** or **dispensation** from the relevant **asset owner performance obligations** or provisions of the **technical codes** or provisions of the **connected asset commissioning, testing and information standard**: or

(b) is not complying with a valid **equivalence arrangement** or **dispensation** from the relevant **asset owner performance obligations** or provisions of the **technical codes** or provisions of the **connected asset commissioning, testing and information standard**.

**8.28 Responsibility for compliance**

(1) Each **asset owner** must comply with the **asset owner performance obligations**, ~~and~~ **technical codes**, and the **connected asset commissioning, testing and information standard** at all times and must satisfy the **system operator**, whenever requested by the **system operator** acting reasonably, that each of its **assets** or configuration of **assets** complies with the **asset owner performance obligations**, ~~and~~ **technical codes**, and provisions of the **connected asset commissioning, testing and information standard** that apply to that **asset** or configuration of **assets**.

(2) If the **system operator** advises an **asset owner** under clause 8.27(3), the **asset owner** must co-operate with the **system operator** and use reasonable endeavours to restore compliance as soon as practicable.

(3) During a period of **commissioning** or testing of **assets**, the **asset owner performance obligations**, ~~and~~ **technical codes** and the **connected asset commissioning, testing and information standard** do not apply to the **asset owner** in respect of the **assets**, if—

(a) the obligations that do not apply to the **asset owner** are specified in the agreed **commissioning** plan or testing plan; and

(b) during the period of non-compliance the **asset owner** complies with a **commissioning** plan or testing plan (as appropriate) agreed with the **system operator**; and

(c) the period of non-compliance is no longer than the agreed **commissioning** plan or testing plan; and

(d) subject to subclause (4), if an **asset owner** during a period of non-compliance meets the requirements of paragraphs (a) to (c), neither the **asset owner** nor the **system operator** is liable under this Code in relation to the non-compliance, except that the **asset owner** is not relieved of liability in the case of a negligent act or omission by the **asset owner**.

(4) During any period of non-compliance, the non-compliant **asset owner** must pay the readily identifiable and quantifiable costs associated with its non-compliance, including the costs of the **system operator** purchasing additional **ancillary services** required as a consequence of its non-compliance.

**8.29 Right to apply for approval of equivalence arrangement or grant of dispensation**

(1) Subject to subclause (2), if an **asset owner** cannot comply with an **AOPO**, ~~or~~ a **technical code** obligation, or a **connected asset commissioning, testing and information standard** obligation in respect of a particular **asset** or configuration of **assets**, being an existing, new or proposed **asset**, the **asset owner** may apply for an **equivalence arrangement** to be approved or **dispensation** to be granted in accordance with Schedule 8.1.

(2) The **system operator** may not grant a **dispensation** in relation to an obligation to provide **automatic under-frequency load shedding** under clause 8.19(5) or Schedule 8.3, Technical Code B, clause 7.

**8.30 Approval of equivalence arrangements**

The **system operator** must approve an **equivalence arrangement** if it has received satisfactory evidence that the **asset owner** will put in place on the agreed date technical or commercial arrangements that will, in the reasonable opinion of the **system operator**, achieve compliance with the **AOPO**, ~~or~~ **technical code** obligation, or **connected asset commissioning, testing and information standard** obligation for which the **equivalence arrangement** is sought, even if the **assets** or configuration of **assets** do not strictly comply.

**8.31 Grant of dispensations**

(1) Subject to subclause (1A), the **system operator** must grant a **dispensation** to an **asset owner** who has or will have **assets** or a configuration of **assets** that do not comply with either an **AOPO**, ~~or~~ a **technical code** obligation, or **connected asset commissioning, testing and information standard** obligation if the **system operator** has a reasonable expectation that it can continue to operate the existing system and meet its **principal performance obligations** and if the **system operator** can readily quantify the costs on other persons of that **dispensation**, despite the non-compliance of the **assets**, but—

…

**8.32 Liability of asset owner pending decision**

Pending determination of an **asset owner's** application for a **dispensation** or an **equivalence arrangement**, if the **asset** does not comply with the **AOPOs**, ~~or~~ the **technical codes**, or the **connected asset commissioning, testing and information standard**, the **asset owner** is liable for the non-compliance and is responsible for additional costs incurred by the **system operator** or **asset owners** as a result of the non-compliance, including the costs of the **system operator** purchasing other **ancillary services** as a consequence of the non-compliance.

…

**8.34 Cancellation of equivalence arrangement or dispensation**

(1) An **asset owner** may at any time give written notice to the system operator for an **equivalence arrangement** or a **dispensation** to be cancelled on the grounds that the **asset** or configuration of **assets** subject to the **equivalence arrangement** or **dispensation** complies with **AOPOs**, ~~or~~ **technical codes**, or the **connected asset commissioning, testing and information standard**.

…

**8.37 Other provisions relating to equivalence arrangements and dispensations**

…

(3) The owner or operator of an **asset** or configuration of **assets** must advise the **system operator** if the owner or operator believes that it is in breach of a condition of its **dispensation** or **equivalence arrangement** or that the **asset** or configuration of **assets**, including any **equivalence arrangement**, does not, or is likely not to, comply with the **asset owner performance obligations**, ~~and~~ **technical codes**, or the **connected asset commissioning, testing and information standard**.

**8.38 Authority may require excluded generating stations to comply with certain clauses**

(1) Despite clauses 8.17, 8.19, and 8.25D, the **system operator** may, at any time, apply to the **Authority** for the **Authority** to issue a directive that an **excluded generating station asset** must comply with clauses 8.17, 8.19, 8.25A, and 8.25B, ~~and~~ the provisions of the **technical codes** (or parts thereof), and the **connected asset commissioning, testing and information standard** (or parts thereof).

…

## Subpart 7—Connected asset commissioning, testing and information standard

**8.71 Contents of this subpart**

This subpart contains provisions relating to the **connected asset commissioning, testing and information standard**.

*Connected asset commissioning, testing and information standard*

**8.72 System operator to comply with connected asset commissioning, testing and information standard**

The **system operator** must comply with the **connected asset commissioning, testing and information standard**.

**8.73 Incorporation of connected asset commissioning, testing and information standard by reference**

(1) The **connected asset commissioning, testing and information standard** is incorporated by reference in this Code.

(2) Clauses 7.13 to 7.22 apply to any amendment or replacement of the **connected asset commissioning, testing and information standard**.

**8.74 Content of connected asset commissioning, testing and information standard**

A **connected asset commissioning, testing and information standard** must set out the following requirements on **asset owners** which are to assist the **system operator** in planning to comply, and complying, with the **principal performance obligations** and achieving the **dispatch objective**:

(a) the information that an **asset owner** must provide to the **system operator** relating to **commissioning** a new or existing **asset** or configuration of **assets** or **decommissioning assets**; and

(b) the information, including any modelling information, that an **asset owner** must provide to the **system operator** in an **asset capability statement**; and

(c) requirements for carrying out connection studies for an **asset** or configuration of **assets**; and

(d) requirements for periodically testing an **asset** or configuration of **assets**; and

(e) minimum requirements for operational communications between **asset owners** and the **system operator**; and

(f) requirements for **high-speed monitors**; and

(g) requirements for **asset owners** to provide information to the **system operator** to enable the **system operator** to assess the **grid interface**;

(h) requirements for an **asset owner** to provide information to the **system operator** if an **asset owner** reasonably believes that an **asset** may not comply with an **asset owner performance obligation** or with **Technical Code A** of Schedule 8.3;

(i) requirements on an **asset owner** to undertake remedial action or testing of its **assets** if the situation described in paragraph (h) arises;

(j) time frames that an **asset owner** must meet in relation to any of the matters in paragraphs (a) to (i) or within which information must be provided under this ~~the~~ Code; and

(k) the manner and form in which information must be provided to the **system operator** or requirements that information is provided in a manner and form

that is compatible with the **system operator's** systems, as advised by the **system operator**.

**8.75 Transitional provisions for the connected asset commissioning, testing and information standard**

(1) Subject to subclause (4) and clause 8.76, an **asset** that is first **electrically connected** to the **grid** or to a **local network** before 1 July 2026 meets the requirements of the **connected asset commissioning, testing and information standard** if—

(a) except as specified in any exemption, **dispensation**, **equivalence arrangement**, or in any agreement between the **asset owner** and the **system operator** made before 1 July 2026, the **asset** complied, and continues to comply, with the requirements in Part 8 of this Code as they applied immediately before this clause came into effect; and

(b) the **asset** is not able to comply, without modification, with one or more of the requirements in the **connected asset commissioning, testing and information standard**; and

(c) the **asset owner** updates the **asset capability statement** for the **asset** to record that this subclause applies to the **asset**.

(2) Subject to subclauses (3) and (4), and clause 8.76, an **asset** that is first **electrically connected** to the **grid** or to a **local network** on or after 1 July 2026 and before 1 July 2027 meets the requirements of the **connected asset commissioning, testing and information standard** if—

(a) except as specified in any exemption, **dispensation**, **equivalence arrangement**, or in any agreement between the **asset owner** and **system operator** made before 1 July 2026, the **asset** complies, and continues to comply, with the requirements in Part 8 of this Code as they applied immediately before this clause came into effect; and

(b) the **asset** is not able to comply, without modification, with one or more of the requirements in the **connected asset commissioning, testing and information standard**; and

(c) the **asset owner** updates the **asset capability statement** for the **asset** to record that this subclause applies to the **asset**.

(3) In order for subclause (2) to apply to an **asset**, the **asset owner** must confirm in writing to the **system operator** before 1 August 2026 that the following has occurred in respect of the **asset**—

(a) the **asset owner** has secured financing that enables the **asset owner** to develop and **commission** the **asset**; and

(b) the **asset owner** has obtained all consents necessary to enable the **asset owner** to develop and **commission** the **asset**; and

(c) the **asset owner** has obtained rights to use the land on which the **asset** is to be located.

(4) Subclauses (1) and (2) do not apply in respect of the following:

(a) the time frame requirements in Chapter 1 of the **connected asset commissioning, testing and information standard**:

(b) the requirement in the **connected asset commissioning, testing and information standard** for **connected asset owners** to provide the **system operator** with indications and measurements in Chapter 8 of the **connected asset commissioning, testing and information standard**:

(c) subject to subclause (5), an **asset** from the date a modification is made to the **asset** that results in a 5% or greater change to the **asset's**—

(i) **MW** rating; or

(ii) frequency response curve for 100 milliseconds or longer; or

(iii) voltage response curve for 100 milliseconds or longer.

(5) Subclause (4)(c) does not apply if—

(a) the **asset owner** and the **system operator**, acting reasonably, agree that subclause (1) or (2) should continue to apply to an **asset** notwithstanding the modification; or

(b) the modification is made so that one or more **generating units** comply with the maximum dead band requirement in clause 5(1)(c) of **Technical Code** A.

(6) An **asset owner** must, as soon as practicable, update the **asset capability statement** for an **asset** to record when subclause (1) or (2) ceases to apply to the **asset**.

## 8.76 Determination that there is a public benefit in the connected asset commissioning, testing and information standard applying to an asset

(1) If there is a **benefit to the public** in the **connected asset commissioning, testing and information standard** (or any part thereof) applying to an **asset** that would otherwise not have to comply with the **connected asset commissioning, testing and information standard** due to clause 8.75, the **system operator** may apply to the **Authority** for a determination under this clause.

(2) The **Authority** must issue a determination under this clause if satisfied that there is a **benefit to the public** in the **connected asset commissioning, testing and information standard** (or any part thereof) applying to the **asset** that is subject to the application.

(3) If a determination is issued under this clause, the owner of the **asset** must comply with the **connected asset commissioning, testing and information standard** (or any part thereof) to the extent provided for, and with effect from the date specified, in the determination.

…

# Schedule 8.1

# Approval of equivalence arrangement or grant of dispensation

…

**2 Application and supporting information**

Each application for an **equivalence arrangement** or a **dispensation** must—

(a) be in writing; and

(b) specify the **AOPO** or **technical code** obligation or **connected asset commissioning, testing and information standard** obligation from which approval for an **equivalence arrangement** or the grant of **dispensation** is sought; and

…

# Schedule 8.3

# Technical Codes

*Technical Code A – Assets*

…

**2 General requirements**

(1) Each **asset owner** must ensure that—

(a) its **assets** at **grid exit points** and at **grid injection points**, and, in the case of **connected asset owners**, the **assets** of any **embedded generator** connected to it, are identified and referred to by a **system number**; and

(b) its **assets**, both in the manner in which they are designed and operated, are capable of being operated, and operate, within the limits stated in the **asset capability statement** provided by the **asset owner** for that **asset**; and

(c) it meets any ~~other reasonable~~ requirements of the **system operator**~~,~~ identified in the **connected asset commissioning, testing and information standard** ~~during planning studies, which are required for the **system operator** to plan to comply, or to comply, with its **principal performance obligations**~~.

~~(2) Each **asset owner** must provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, to allow the **system operator** to assess compliance of its **asset** or any configuration of **assets** with the requirements of the **asset owner performance obligations** and **technical codes** at each of the following times :~~

~~(a) before the completion of planning for the construction of that **asset** or configuration of **assets**:~~

~~(b) at, or before, the completion of construction but before the **commissioning** of that **asset** or configuration of **assets**, except that the **asset owner** must put in place a **commissioning** plan in accordance with subclauses (6) to (8) to minimise the impact of **commissioning** tests on the **system operator's** ability to comply with its **principal performance obligations**, and adhere to this plan during **commissioning**, unless otherwise agreed to by the **system operator**.~~

~~(2A) For **asset owners** that are **generators**, the obligation to provide the **system operator** with an **asset capability statement**, and any other information reasonably required by the **system operator**, applies only to **generators** with a **generating unit** with rated net maximum capacity equal to or greater than the threshold specified in clause 8.21(2).~~

(3) On, or before, completion of **commissioning** of an **asset** or configuration of **assets**, the **asset owner** must obtain a final assessment of the **asset** or configuration of **assets** in writing from the **system operator** in accordance with the requirements set out in the **connected asset commissioning, testing and information standard** ~~that the **asset** or configuration of **assets** meets the requirements of the **asset owner performance obligations** and **technical codes**. This final assessment must be based on the information supplied by the **asset owner** and, if necessary, the result of **system tests** at **commissioning**~~.

(4) ~~The **system operator** must give the assessment referred to in subclause (2)(b) within a reasonable time frame and supply the **asset owner** with all information that supports its assessment.~~ Any permission granted by the **system operator** to an **asset owner** to conduct **commissioning** of any **asset** or configuration of **assets** must permit connection of the **asset** (or configuration of **assets**) solely for the purposes of **commissioning**.

(5) Each **asset owner** must provide the **system operator** with an **asset capability statement** in accordance with the **connected asset commissioning, testing and information standard** ~~in the form from time to time published by the **system operator** for each **asset** that —~~

(a) for each **asset** that is—

(i) proposed to be connected, or is connected to, or forms part of the **grid**; or

(ii) proposed to be connected, or is connected directly or indirectly to a **local network**; and

(b) for each **asset**, where the **asset owner** is a **generator**, ~~for each **asset**~~ that—

(i) forms part or all of a **generating station** with a capacity equal to or greater than the threshold specified in clause 8.21(1) ~~8.21(2)(b)~~ at the **point of connection** to the **network**; or~~.~~

(ii) forms part or all of a **generating unit** with a ~~rated net maximum~~ capacity equal to or greater than the threshold specified in clause 8.21(2)~~(a)~~ at the **point of connection** to the **network**~~.; or~~

~~(5A) The **asset capability statement** must—~~

~~(a) include all information reasonably requested by the **system operator** so as to allow the **system operator** to determine the limitations in the operation of the **asset** that the **system operator** needs to know for the safe and efficient operation of the **grid**; and~~

~~(b) include any modelling data for the planning studies, as reasonably requested by the **system operator**; and~~

~~(c) be updated and reissued to the **system operator** as information and design development progresses through the study, design, manufacture, testing and **commissioning** phases; and~~

~~(d) be complete and up to date before the **commissioning** of the **asset**; and~~

~~(e) be complete and up to date at all times while the **asset** is—~~

~~(i) connected to, or forms part of, the **grid.**; or~~

~~(ii) connected directly or indirectly to a **local network**.~~

(6) Each **asset owner** must provide a **commissioning** plan or test plan ~~in accordance with~~ to the **system operator** in compliance with the **connected asset commissioning, testing and information standard**. ~~subclauses (7) or (8) (as the case may be) in the following situations:~~

~~(a) when changes are made to **assets** that alter any of the following at the **grid interface**:~~

~~(i) the **single line diagram**:~~

~~(ii) a protection system, other than a change to a protection system setting:~~

~~(iii) a **control system**, including a change to a **control system** setting:~~

~~(iv) any rating of **assets**:~~

~~(b) when **assets** are to be connected to, or are to form part of, the **grid**:~~

~~(c) if it is necessary for an **asset owner** to perform a **system test** or other test to ascertain or confirm **asset** capabilities, and if the **commissioning** or testing or connection of those **assets** may affect the **system operator's** ability to plan to comply, or to comply with, its **principal performance obligations**. If an **asset owner** is unsure whether the **commissioning** or connection of an **asset** may impact on the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations** it must contact the **system operator** for advice.~~

~~(7) The **commissioning** plan prepared by an asset owner and agreed by the **system operator** must—~~

~~(a) include a timetable containing the sequence of events necessary to connect the **assets** to the **grid** and conduct any proposed **system test**; and~~

~~(b) contain the protection and control settings to be applied before the assets are made live (where live has the meaning given to it in the Electricity (Safety) Regulations 2010); and~~

~~(c) contain the procedures for **commissioning** the plant with minimum risk to personnel and plant and to the ability of the **system operator** to plan to comply and to comply with its **principal performance obligations**.~~

~~(8) If a test plan is required under subclause (6), it must be prepared by the **asset owner** in consultation with the **system operator**. The test plan must contain sufficient information to enable the **system operator** to plan to comply, and to comply, with the **principal performance obligations**.~~

(9) Once assessed by the **system operator**, acting reasonably, the **asset owner** must follow the **commissioning** plan or test plan at all times, unless otherwise agreed with the **system operator** (such agreement must not be unreasonably withheld if compliance with the **commissioning** plan or testing plan is not practicable and non-compliance does not impact on the **system operator's** ability to comply with its **principal performance obligations** or on other **asset owners**).

(10) Each **asset owner** must—

(a) carry out connection studies for each **asset**~~,~~ in accordance with the **connected asset commissioning, testing and information standard**; and

(b) provide connection study reports~~, including modelling information,~~ to the **system operator** in compliance with the **connected asset commissioning, testing and information standard**~~.~~; and

(c) ensure that modelling information is provided to the **system operator** in compliance with the **connected asset commissioning, testing and information standard**; and

(d) provide a model to the **system operator** in compliance with the **connected asset commissioning, testing and information standard** that can be used for the network models in clause 8.25A(3)(a).

**3 Requirements for asset information**

~~(1) In accordance with clause 8.25(4), the following information is required by the **system operator** to assist it to plan to comply, and to comply, with its **principal performance obligations**:~~

~~(a) sufficient information must be exchanged between the **system operator** and the **asset owner** to ensure that both fully understand the implications of any changes to the **asset capability statement** or of any proposed connection of the relevant **assets** to the **grid** or to the **local network**. This information must be exchanged in accordance with a timetable agreed to by the **system operator** and the **asset owner**:~~

~~(b) if reasonably requested by the **system operator**, the **asset owner** must provide sufficient information to the **system operator** to demonstrate the compliance~~

~~of the **asset owner's assets** with the **asset owner performance obligations** and the **technical codes.**~~

(2) Information about an **asset**, **supply** or **demand** of other **asset owners** must only be disclosed by the **system operator**—

(a) as expressly provided for in this Code; or

(b) as reasonably required in a **grid emergency** or to ensure the security of the **grid**; or

(c) as required by law; or

(d) otherwise as may be agreed with the relevant **asset owners**.

(2A) The **system operator** must—

(a) store ~~unencrypted models~~ the information provided under clause 2(10)(c) in a secure server that is accessible only to **system operator** employees, contractors or advisers that require access to the ~~unencrypted models~~ information to perform their roles; and

(b) ~~not disclose unencrypted models to third parties~~ treat the information provided under clause 2(10)(c) as confidential to the party that provided that information~~,~~ except as ~~provided in subclause (a), including a **grid owner** or **distributor**, without the prior written consent of the **asset owner** that provided the model or as~~ required by law.

~~(3) Each **asset owner** must provide the **system operator** with—~~

~~(a) all information reasonably requested by the **system operator** so as to ensure compliance with clause 8.25(4) and to enable the **system operator** to assess the **grid interface**; and~~

~~(b) details of protection systems, including settings, to ensure that the requirements of clause 8.25(4) are met.~~

(4) Each **asset owner** must ensure that all supporting information for the operational control of **assets** is kept up to date.

…

**7 Modifications and changes to assets**

(1) Subject to subclause (1B), **assets** ~~**Assets**~~ that are modified, or are proposed to be modified, are—

(a) to be treated as ~~deemed to be~~ new **assets** for the purposes of this ~~the~~ Code~~,~~ and ~~this **Technical Code**~~ the **connected asset commissioning, testing and information standard**; and

(b) are subject to the requirements for connection to the **grid** and the requirements for **commissioning assets** in this ~~the~~ Code and the **connected asset commissioning, testing and information standard**.

(1A) For the purposes of this Schedule, the following are considered to be modifications to **assets**, if the new connection or alteration may affect the capacity of the **assets** or may affect **asset owner performance obligations**, ~~or~~ **technical code** requirements or requirements in the **connected asset commissioning, testing and information standard**:

(a) a new connection of **assets** to the **grid** or a **local network**:

(b) a new connection of **assets** to form part of the **grid**:

(c) a new connection of an **embedded generator** to a **local network** other than an **excluded generator** as defined in clause 8.21(1):

(d) an alteration to **assets** already connected to the **grid** or, in the case of an **embedded generator**, already connected to a **local network**.

(1B) Subclause (1) does not apply in respect of the requirements in Chapter 4 of the **connected asset commissioning, testing and information standard**.

(1C) If an **asset owner** reasonably considers that a modification to an **asset** materially affects the **asset's** capability, the **asset owner** must advise the **system operator** as soon as reasonably practicable.

(1D) If, in respect of an **asset** notified under subclause (1C), the **system operator** reasonably considers it necessary, the **system operator—**

(a) may require that an **asset owner** provide updated modelling information for that **asset** in accordance with the **connected asset commissioning, testing and information standard**; and

(b) must advise the **asset owner** in writing of this requirement as soon as it is made.

(2) If an **asset owner** proposes or intends to decommission an~~y~~ **asset~~s~~**, ~~The~~ the **asset owner** must provide the **system operator** with a **decommissioning** plan for that **asset** and give written notice to the **system operator** ~~in a timely manner of any **assets** that have been **decommissioned**~~ in accordance with the **connected asset commissioning, testing and information standard** ~~if the assets affect or could affect the system operator's ability to comply with its principal performance obligations~~.

**8 Records, tests and inspections**

(1) Each **asset owner** must arrange for, and retain, records for each of its **assets** to demonstrate that the **assets** comply with the **asset owner performance obligations**, ~~and~~ this **technical code** and the **connected asset commissioning, testing and information standard**.

(2) In addition to the requirements for **commissioning** or testing in clause 2(6), ~~to~~ 2(8), and 2(10) each **asset owner** must ~~carry out periodic testing~~—

(a) carry out periodic testing of its **assets**, including **automatic under-frequency load shedding** systems, in accordance with ~~Appendix B~~ the **connected asset commissioning, testing and information standard**; and

(b) *[Revoked]*

(c) provide **high-speed monitors** that comply with the requirements specified in the **connected asset commissioning, testing and information standard**.

(2A) Each **asset owner** with one or more **generating units** commissioned before 1 January 2016 for which wind is the primary power source must complete the first of each test required under subclause (2)(a) for those **generating units** no later than 31 December 2028.

(3) If the **system operator** advises an **asset owner** that it reasonably believes that an **asset** may not comply with an **asset owner performance obligation** or this **technical code**, the **asset owner** must advise the **system operator** and undertake remedial action or testing of its **assets** in accordance with the **connected asset commissioning, testing and information standard**.—

~~(a) as soon as practicable, but no later than 30 days after receiving a written request, advise the **system operator** of its remedial or test plan for the **assets**; and~~

~~(b) as soon as reasonably practicable undertake any remedial action or testing of its **assets** in accordance with its plan advised to the **system operator** in paragraph (a). The **system operator** may require such testing or remedial action to be undertaken in the presence of a **system operator** representative.~~

…

~~*Appendix B: Routine testing of assets and automatic under-frequency load shedding systems*~~

~~**1 Periodic tests to be carried out**~~

~~(1) This Appendix sets out periodic tests required for the purposes of clause 8(2) of **Technical Code** A.~~

~~(2) Each **asset owner** may be legally required, other than under this Code, to carry out additional tests to ensure that their **assets**, including **automatic under-frequency load shedding** systems, are safe and reliable.~~

~~(3) *[Revoked]*~~

~~(4) Each **asset owner** with one or more **generating units** commissioned before 1 January 2016 for which wind is the primary power source must complete the first of each test required in this Appendix for those **generating units** no later than 31 December 2028.~~

~~**2 Generating unit frequency response**~~

~~Each **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38, must—~~

~~(a) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** analogue over-frequency relays and analogue under-frequency relays at least once every 4 years; and~~

(b) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** non-self monitoring digital over-frequency relays and non-self monitoring digital under-frequency relays at least once every 4 years; and

(ba) for **generating units** with an inverter, test the trip frequencies and trip time delays of non-self monitoring digital over-frequency protection settings and non-self monitoring digital under-frequency protection settings for the **generating units** at least once every 4 years; and

(c) for **generating units** with no inverter, test the trip frequencies and trip time delays of each of its **generating units'** self monitoring digital over-frequency relays and self monitoring digital under-frequency relays at least once every 10 years; and

(ca) for **generating units** with an inverter, test the trip frequencies and trip time delays of self monitoring digital over-frequency protection settings and self monitoring digital under-frequency protection settings for the **generating units** at least once every 10 years; and

(d) based on the tests carried out in accordance with paragraphs (a), (b), (ba), (c) or (ca), provide a verified set of under-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and

(e) based on the tests carried out in accordance with paragraphs (a), (b), (ba), (c) or (ca), provide a verified set of over-frequency trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

**3 Generating unit governor and speed control**

Each **generator**, other than **generators** who are owners of **excluded generating stations** that are not subject to a directive issued by the **Authority** under clause 8.38 must—

(a) for each of its **generating units** with no inverter, test the governor response of the **generating unit's** mechanical or analogue speed governor and/or mechanical or analogue frequency **control system** at least once every 5 years; and

(b) for each of its **generating units** with no inverter, test the response of the **generating units'** digital or electro-hydraulic frequency **control system** at least once every 10 years; and

(ba) for its **generating units** with an inverter, test the response of each frequency **control system** used for those **generating units** at least once every 10 years; and

(bb) unless agreed otherwise with the **system operator**, for its **generating units** with an inverter test the response of each frequency **control system** used for those **generating units** within 3 months of a change to the control settings

and/or firmware of the frequency **control system** (where the change to the firmware has the potential to materially affect the performance of the frequency response of the **generating units** or **generating station** that the **generating units** are part of); and

(c) based on the tests carried out in accordance with paragraphs (a), (b), (ba) or (bb), provide a verified set of modelling parameters and governor or frequency **control system** response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the frequency **control system**; and

(ii) for **generating units** with a turbine, a block diagram showing the mathematical representation of the turbine dynamics including non-linearity and the applicable fuel source; and

(iia) for **generating units** with a power converter, a block diagram showing the mathematical representation of the power converter and its electrical control; and

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and

(iv) for **generating units** with an inverter, a verified set of control settings and relevant firmware version identifiers for the frequency **control system** used for each **generating unit**.

**4 Generating unit transformer voltage control**

Each **generator** with a **point of connection** to the **grid** must—

(a) test the operation of each of its **generating unit** transformers' on-load tap changer analogue **control systems** at least once every 4 years; and

(b) test the operation of each of its **generating unit** transformers' on-load tap changer digital **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of control parameters including voltage set points, operating dead bands and response times to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

**5 Generating unit voltage response and control**

Each **generator** with a **point of connection** to the **grid** must—

(a) test for each of its **generating units** with no inverter, test the modelling parameters and voltage response of the **generating unit's** analogue voltage **control system** at least once every 5 years; and

(b) for each of its **generating units** with no inverter, test the modelling parameters and voltage response of the **generating unit's** digital voltage **control system** at least once every 10 years; and

(ba) for its **generating units** with an inverter, test the response of each voltage **control system** used for those **generating units** at least once every 10 years; and

(bb) unless agreed otherwise with the **system operator**, for its **generating units** with an inverter test the response of each voltage **control system** used for those **generating units** within 3 months of a change to the control settings and/or firmware of the voltage **control system** (where the change to the firmware has the potential to materially affect the performance of the voltage response of the **generating units** or **generating station** that the **generating units** are part of); and

(c) based on the tests carried out in accordance with paragraphs (a), (b), (ba) or (bb), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the voltage **control system**; and

(ii) *[Revoked]*

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams; and

(iv) for **generating units** with an inverter, a verified set of control settings and relevant firmware version identifiers for the voltage **control system** used for each **generating unit**.

**6 North Island connected asset owner automatic under-frequency load shedding systems profiles and trip settings**

Each North Island **connected asset owner** must—

(a) provide the profile information described in clause 7(9) of **Technical Code** B of Schedule 8.3 to the **system operator** in an updated **asset capability statement** at least once every year; and

(b) test the operation of its analogue **automatic under-frequency load shedding** systems at least once every 4 years; and

(c) test the operation of its non-self monitoring digital **automatic under-frequency load shedding** systems at least once every 4 years; and

(d) test the operation of its self monitoring digital **automatic under-frequency load shedding** systems at least once every 10 years; and

(e) based on the relevant test carried out in accordance with paragraphs (b), (c) or (d), provide a verified set of trip settings and time delays to **the system**

**operator** in an updated **asset capability statement** within 3 months of the completion date of the relevant test.

**7 South Island grid owner automatic under-frequency load shedding systems profiles and trip settings**

Each South Island **grid owner** must —

(a) provide the profile information described in clause 7(9) of **Technical Code** B of Schedule 8.3 to the **system operator** in an updated **asset capability statement** at least once every year; and

(b) test the operation of its analogue **automatic under-frequency load shedding** systems at least once every 4 years; and

(c) test the operation of its non-self monitoring digital **automatic under-frequency load shedding** systems at least once every 4 years; and

(d) test the operation of its self monitoring digital **automatic under-frequency load shedding** systems at least once every 10 years; and

(e) based on the relevant test carried out in accordance with paragraphs (b), (c) or (d), provide a verified set of trip settings and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of the relevant test.

**8 Grid owner transformer voltage range**

Each **grid owner** must —

(a) test the operation of each of its transformers' on-load tap changer analogue **control systems** at least once every 4 years; and

(b) test the operation of each of its transformers' on-load tap changer digital **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of control parameters to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test, including voltage set points, operating dead bands and response times.

**9 Asset owner dynamic reactive power compensation device transient response and control**

Each **asset owner** with a **dynamic reactive power compensation device** directly connected to the **grid** must —

(a) test the transient response, steady state response and a.c. disturbance response of each of its **dynamic reactive power compensation devices** at least once every 10 years; and

(b) test the operation of each of its **dynamic reactive power compensation devices'** analogue **control systems** at least once every 4 years; and

(c) test the operation of each of its **dynamic reactive power compensation devices'** digital **control systems** at least once every 10 years; and

(d) based on the test carried out in accordance with paragraph (a), provide a verified set of modelling parameters, transient response parameters, steady state response parameters, and a.c. disturbance response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including—

(i) a block diagram showing the mathematical representation of the **dynamic reactive power compensation device**; and

(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams; and

(iii) a detailed functional description of all of the components of the **dynamic reactive power compensation device** and how they interact in each mode of control; and

(iv) step response test results; and

(v) a.c. fault recovery disturbance test results; and

(e) based on tests carried out in accordance with paragraphs (b) or (c), provide a set of **control system** test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

**10 Grid owner capacitors and reactive power control systems**

Each **grid owner** must—

(a) test the capacitance of each of its capacitors at least once every 8 years; and

(b) test the operation of each of its reactive power control assets' analogue **control systems** at least once every 4 years; and

(c) test the operation of each of its reactive power control assets' digital **control systems** at least once every 10 years; and

(d) based on the test carried out in accordance with paragraph (a), provide a set of test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and

(e) based on tests carried out in accordance with paragraphs (b) or (c), provide a verified set of **control system** test results including voltage set points, operating dead bands and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

**11 Grid owner synchronous compensators**

Each **grid owner** must—

(a) test each of its synchronous compensators' analogue and electromechanical voltage **control systems** at least once every 5 years; and

(b) test each of its synchronous compensators' digital voltage **control systems** at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including—

(i) a block diagram showing the mathematical representation of the voltage **control system**; and

(ii) *[Revoked]*

(iii) a detailed functional description of the voltage **control system** in all modes of control; and

(iv) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams.

**12 HVDC link frequency control and protection**

The **HVDC owner** must—

(a) test the operation of each of its **HVDC link's** analogue **control systems** at least once every 4 years; and

(b) test the operation of each of its **HVDC link's** digital **control systems** at least once every 10 years; and

(c) test the operation of each of its **HVDC link's** analogue protection systems at least once every 4 years; and

(d) test the operation of each of its **HVDC link's** digital protection systems at least once every 10 years; and

(e) test the modulation functions on its **HVDC link** at least once every 10 years; and

(f) based on the tests carried out in accordance with paragraphs (a) or (b), provide a set of **control system** test results and verified modelling parameters to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and

(g) based on the tests carried out in accordance with paragraphs (c) or (d), provide a set of protection system test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and

(h) based on the tests carried out in accordance with paragraph (e), provide a set of modulation function test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including—

(i) a block diagram showing the mathematical representation of the **HVDC link**; and

(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagram; and

(iii) a detailed functional description of all of the components of the **HVDC link** and how they interact in each mode of control.

**13 Asset owner a.c. protection systems**

Each asset owner must—

(a) test the operation of the analogue protection systems on its a.c. **assets** at least once every 4 years; and

(b) test the operation of the non-self monitoring digital protection systems on its a.c **assets** at least once every 4 years; and

(c) test the operation of the self monitoring digital protection systems on its a.c. **assets** at least once every 10 years; and

(d) test the operation of the protection system measuring circuits on its a.c. **assets** by secondary injection at least once every 4 years; and

(e) test the operation of the protection system trip circuits, including circuit breaker trips, on its a.c. **assets** at least once every 4 years; and

(f) confirm at least once every 4 years that its protection settings are identified, co-ordinated, applied correctly and meet the requirements of the **AOPOs** and the **technical codes**; and

(g) based on tests carried out in accordance with paragraphs (a) to (e), provide a verification to the **system operator** in an updated **asset capability statement** that the protection systems meet the requirements of the **AOPOs** and **technical codes** within 3 months of the completion date of each such test; and

(h) based on the confirmation carried out in accordance with paragraph (f), provide an updated **asset capability statement** to the **system operator** within 3 months of the completion date of each such confirmation.

**14 Representative testing**

(1) Subject to clause 8(3) of **Technical Code** A, each **asset owner** may provide the information required under clauses 3(c), 5(c), and 11(c) to the **system operator**, based on representative modelling parameters and response data instead of based on the tests required under clauses 3(a) and (b), 5(a) and (b), and 11(a) and (b), for any group of identical **assets**, if each of those **assets**—

(a) was manufactured to the same specification; and

(b) is installed at the same location; and

(c) is controlled in the same way; and

(d) has a similar maintenance history.

(2) Each **asset owner** providing representative modelling parameters and response data to the **system operator** in accordance with subclause (1) for a group of identical **assets** must—

(a) complete a full set of tests in accordance with clauses 3(a) or (b), 5(a) or (b), and 11(a) or (b), as applicable, on an **asset** that is representative of that group to derive a verified set of modelling parameters and response data; and

(b) complete sufficient testing on the remaining **assets** in that group of identical **assets** in accordance with clauses 3(a) or (b), 5(a) or (b), and 11(a) or (b), as applicable, to verify that the performance of the remaining **assets** in that group is fully consistent with the modelling parameters and response data derived from the tests carried out on the representative **asset**; and

(c) certify to the **system operator**, that to the best of the **asset owner's** information, knowledge and belief, the performance of that group of **assets** is fully consistent with the representative modelling parameters and response data provided to the **system operator** for that group of **assets**.

**15 Transitional provisions**

(1) Unless a test interval of less than 60 months is specified in this Appendix, each **asset owner** must complete the first of each test required in this Appendix no later than 5 June 2013.

(2) A test that is required to be carried out in accordance with this Appendix, but that an **asset owner** carried out before 5 June 2008, is deemed to be the first test of that type required in this Appendix, if—

(a) the **asset owner** has submitted the relevant written test results to the **system operator**; and

(b) the **system operator** has advised the **asset owner** that the specification of the test is acceptable; and

(c) the interval between the actual date of the test and the date on which this Code came into force is less than the maximum test interval specified for the corresponding test in this Appendix.

(3) If a test has been deemed to be the first test in accordance with subclause (2), the date by which the next such test must be carried out must be calculated using the actual date upon which the first test was carried out, not the date upon which it was deemed to have been carried out.

…

*Technical Code B – Emergencies*

…

**7 Load shedding systems**

…

(9) In addition to their obligations to provide information under Chapter 7 of the **connected asset commissioning, testing and information standard** clauses 6 and 7 of Appendix B of **Technical Code** A, each North Island **connected asset owner** and each South Island **grid owner** must provide **automatic under-frequency load**

**shedding** block **demand** profile information to the **system operator** if reasonably requested by the **system operator**. For each North Island **connected asset owner** that information must be in the form, and supplied by the date, specified by the **system operator** in the **AUFLS technical requirements report**. For each South Island **grid owner** that information must be in the form specified by the **system operator** in the relevant **asset capability statement**.

(9A) If requested by the **Authority**, the **system operator** must provide information it obtains under Chapter 7 of the **connected asset commissioning, testing and information standard** ~~clauses 6 and 7 of Appendix B of **Technical Code** A~~ and subclause (9) of this clause to the **Authority**, supplemented by the **system operator's** assessment, based on its analysis of that information, as to whether the **automatic under-frequency load shedding** scheme is secure.

…

~~*Technical Code C – Operational communications*~~

~~**1 Purpose**~~

~~The purpose of this technical code is to state the minimum requirements for the communications required under this Code between asset owners, except owners of excluded generating stations, and the system operator, in order to assist the system operator to plan to comply, and to comply, with the principal performance obligations. Additional requirements may be set out in other clauses. This technical code does not deal with the content of communications, which is dealt with in each technical code and in Part 13 where relevant.~~

~~**2 Application**~~

~~This technical code applies to the system operator and to all asset owners except owners of excluded generating stations. If the system operator reasonably considers it necessary to assist the system operator in planning to comply, and complying, with the principal performance obligations, the system operator may require that an excluded generating station comply with some or all of the requirements of this technical code.~~

~~**3 General requirements for operational communications**~~

~~(1) Each voice or electronic communication between the **system operator** and an **asset owner** must be logged by the **system operator** and the **asset owner**. Unless otherwise agreed between the **system operator** and the **asset owner**, every voice instruction must be repeated back by the person receiving the instruction and confirmed by the person giving the instruction before the instruction is actioned.~~

~~(2) The **system operator** and each **asset owner** must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the **system operator** and the **asset owner**. Each **asset owner** must also nominate and advise the **system operator** of the person to receive instructions and **formal notices** as set out in **Technical Code** B. The preferred points of contact must include those to be used when the **system operator** instructs the **asset owner**, when the **system**~~

**operator** sends **formal notices** to the **asset owner** and when the **asset owner** contacts the **system operator**. The alternative points of contact must be used only if the preferred points of contact are not available.

(3) The **grid owner** and each other **asset owner** must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the **grid owner** and the other **asset owner** for the purpose of communications regarding the availability of the **grid owner's** data transmission communications. The alternative points of contact must only be used if the preferred points of contact are not available.

**4 Specific requirements for voice communication**

(1) Each **asset owner** must have in place a primary means of communicating by voice between the **control room** of the **asset owner** and the **system operator**. The primary means of voice communication must use either—

(a) the **grid owner's** speech network; or

(b) a widely available public switched telephone network that operates in real time and in full duplex mode.

(2) Each **asset owner** must have in place a backup means of communicating by voice between the **control room** of the **asset owner** and the **system operator**. The backup means of voice communication—

(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and

(b) may include, but is not limited to, satellite phone or cellular phone; and

(c) may be used only if the primary means of voice communication described in subclause (1) is unavailable or otherwise with the agreement of the **system operator**.

(3) An **asset owner** who has a **control room** with, at any time, operational control of more than 299 **MW** of **injection**, **offtake**, or power flow must have 2 or more back up means of voice communication between the **control room** of the **asset owner** and the **system operator**, each of which must meet the requirements of subclause (2).

**5 Specific requirements for transmitting information**

(1) Each **asset owner** must transmit information between its **control room** and the **system operator** in writing.

(2) Despite subclause (1), an **asset owner** may request the **system operator** to approve an alternative means of transmitting information (such approval not to be unreasonably withheld).

(3) Each **asset owner** must have in place a backup means of transmitting information. The backup means of transmitting information—

(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and

(b) may include, but is not limited to, voice communication or email; and

(c) may only be used if the primary means of transmitting information described in subclause (1) or (2) is unavailable or otherwise with the agreement of the **system operator**.

**6 Specific requirements for data transmission communication**

(1) Each **asset owner** (other than a **grid owner**) must have in place—

(a) a primary means of transmitting data between the **assets** of the **asset owner** and a **SCADA** remote terminal unit of a **grid owner**; or

(b) if approved by the **system operator** (such approval not to be unreasonably withheld), a primary means of transmitting data between the **assets** of the **asset owner** and the **system operator**.

(2) A **grid owner** must have in place a primary means of transmitting data between the **assets** of the **grid owner** and the **system operator**.

(3) Each **asset owner** must have in place a backup means of transmitting data for each type of indication and measurement specified in Appendix A of this **technical code**. The backup means of data transmission communication—

(a) must be approved by the **system operator** (such approval not to be unreasonably withheld); and

(b) may include, but is not limited to, use of voice communication or document transmission communication; and

(c) may only be used if the primary means of data transmission communication described in subclause (1) or (2) is unavailable or otherwise with the agreement of the **system operator**.

**7 Availability of primary means of communication**

(1) Each **asset owner** must use reasonable endeavours to ensure that the primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2) is available continuously.

(2) If the primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2) is unavailable, an **asset owner** must use reasonable endeavours to restore availability of the primary means of communication as soon as practicable.

**8 Notice of planned outages of primary means of communication**

Each **asset owner** must give written notice to the **system operator** of any planned outage of a primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2).

**9 Performance requirements for indications and measurements**

(1) Each **asset owner** must provide the relevant indications and measurements shown in Appendix A to the **system operator**, in accordance with clause 6. The **system operator** may require the **asset owner** to provide additional information if, in the reasonable opinion of the **system operator**, such information is required for the

**system operator** to plan to comply, and to comply, with its **principal performance obligations**.

(2) The **asset owner** must use reasonable endeavours to ensure that the accuracy of the measurements it provides to the **system operator** in accordance with subclause (1) complies with Appendix A.

(3) Each indication and measurement provided in accordance with subclause (1) must be updated at the **grid owner's SCADA** remote terminal or the **system operator's** interface unit at least once every 8 seconds when provided by the primary means of data transmission communications.

*Appendix A: Indications and Measurements*

*(Clause 9(1)-(3) of Technical Code C)*

**Table A1: Requirements of generators**

Each **generator** must provide the indications and measurements in Table A1. If net (or gross) measurements are required in Table A1, the use of **scaling factors** together with the provision of the relevant gross (or net) values is acceptable with the **system operator's** approval. Each **generator** must provide **scaling factors** to the **grid owner** so that the **grid owner** can apply the adjustment at the **SCADA** server.

| **Indication or measurement** | **Values required** | **Accuracy**[3] |
|---|---|---|
| **Station net MW** | Import and export | ±2% |
| **Generating unit gross MW**[1] | Import and export, for each **generating unit** | ±2% |
| **Station net Mvar** | Import and export | ±2% |
| **Generating unit gross Mvar**[1] | Import and export, for each **generating unit** | ±2% |
| **Generating unit circuit breaker status**[1] | Open /closed /in transition/ indication error[2] | N/A |
| **Grid interface circuit breaker status** | Open /closed /in transition/ indication error[2] | N/A |
| **Grid interface disconnector status** | Open /closed /in transition/ indication error | N/A |
| **Special protection scheme status** | Enabled/disabled/summer/winter | N/A |
| **Maximum output capacity of generating station (for intermittent generators only)** | Number of connected **generating units** × **MW** capability of each **generating unit** | N/A |

**Table A2: Requirements of grid owners:**

Each **grid owner** must provide the indications and measurements shown in Table A2 in respect of assets connected to, or forming part of, the **grid**.

| **Indication or measurement** | **Values required** | **Accuracy**[3] |
|---|---|---|

| | | |
|---|---|---|
| **Grid interface circuit breaker status** | Open /closed /in transition/ indication error[2] | N/A |
| **Grid interface disconnector status** | Open/ closed/ in transition/ closed to earth/ indication error | N/A |
| **Grid interface auto reclose status** | Enabled/disabled/ operated/locked out | N/A |
| **Grid interface MW** | **Import and export** | ±2% |
| **Grid interface Mvar** | Import and export | ±2% |
| **Circuit Amps** | Current at each termination point of a circuit | N/A |
| **Circuit MW** | **MW** at each termination point of a circuit | N/A |
| **Circuit Mvar** | Mvar at each termination point of a circuit | N/A |
| **Tap positions for interconnecting transformers and supply transformers with on-load tap changers** | Tap position for all windings including tapped tertiaries | N/A |
| **Tap positions for interconnecting transformers and supply transformers with off-load tap changers**[4] | Tap position for all windings including tapped tertiaries | N/A |
| **Reactive plant (eg RPC equipment, capacitor, reactor, condenser) Mvar** | Import and export | ±2% |
| **Bus voltage** | kV | ±2% |
| **Special protection scheme status** | Enabled/disabled/summer/winter | N/A |
| **HVDC modulation status** | Frequency stabiliser/ spinning reserve sharing/ Haywards frequency control/ AC transient voltage support | N/A |

**Table A3: Requirements of connected asset owners**

Each **connected asset owner** must provide the indications and measurements shown in Table A3 in respect of **assets** connected to, or forming part of, the **grid**

| Indication or measurement | Values required | Accuracy |
|---|---|---|
| **Grid interface circuit breaker status** | Open/ closed/ in transition/ indication error[2] | N/A |
| **Grid interface disconnector status** | Open/ closed/ in transition/ indication error | N/A |
| **Grid interface auto reclose status** | Enabled/disabled/operated/locked out | N/A |
| **Special protection scheme status** | Enabled/disabled/summer/winter | N/A |

| | | |
|---|---|---|
| ~~**Reactive plant 5 (eg RPC equipment, capacitor, reactor, condenser) Mvar**~~ | ~~Import and export~~ | ~~±2%~~ |

~~1 Required only if a **generating unit** has a maximum continuous rating of greater than 5 **MW**.~~

~~2 No intentional time delays should be included for **circuit breaker** indications as these are time tagged by the **system operator** to less than 10 ms.~~

~~3 If accuracy is measured at the input terminal of the RTU of the **grid owner**, under normal operating conditions at full scale.~~

~~4 Indication required within 5 minutes of status change.~~

~~5 Required only if reactive plant has a maximum continuous rating of greater than 5 Mvar.~~

…

# Part 12
# Transport

…

## 12.10 Default transmission agreements

…

(3) The service levels set out in Schedule 5 of a **default transmission agreement** must be determined on the following basis:

(a) the capacity service levels for each **branch** must be consistent with—

(i) the capacities of the **branch** or component **assets** in the most recent **asset capability statement** provided by **Transpower** under clause 2(~~2~~5) of **Technical Code** A of Schedule 8.3; or

…

## 12.107 Transpower to identify interconnection branches, and propose service measures and levels

…

(5) The information provided under subclause (4) must,—

(a) in the case of information provided under subclause (4)(a), (c) and (d), be consistent with the information disclosed by **Transpower** in the most recent **asset capability statement** provided by **Transpower** under clause 2(~~2~~5) of **Technical Code** A of Schedule 8.3; and

(b) in the case of information provided under subclause (4)(b), be consistent with the **manufacturer's specification** for the component **assets** and the information disclosed by **Transpower** in the most recent **asset capability**

**statement** provided under clause 2(~~2~~5) of **Technical Code** A of Schedule 8.3, if this differs from the **manufacturer's specifications**;

…

**12.112 Exceptions to clause 12.111**

(1) **Transpower** is not required to comply with clause 12.111(1)(a) or (2) if—

…

(ea) in relation to the **HVDC link**—

(i) the **HVDC owner** is operating the **HVDC link** in accordance with—

(A) a **commissioning** plan provided to and agreed with the **system operator** in accordance with ~~under~~ clause 2(6) ~~to~~ and (9) of **Technical Code** A of Schedule 8.3; or

(B) a test plan provided to and agreed with the **system operator** in accordance with ~~under~~ clause 2(6) ~~to~~ and (9) of **Technical Code** A of Schedule 8.3; and

…

**12.116 Information on capacities of individual interconnection assets**

…

(2) The information required under subclause (1)—

(a) must be consistent with the **manufacturer's specification** for the **asset** or with the most recent **asset capability statement** provided by **Transpower** under clause 2(~~2~~5) of **Technical Code** A of Schedule 8.3, if this differs from the **manufacturer's specification**; and

…

# Schedule 12.4
# Transmission Pricing Methodology

…

**10 Calculations and Estimations**

…

(4) Except as otherwise stated in this Code, **Transpower** may use the following information to calculate **allocation data** and is not required to (but may) use any other information:

…

(e) indications and measurements required to be provided by a **participant** to the **system operator** under this Code, including under the **connected asset commissioning, testing and information standard** ~~Technical Code C of~~

~~Schedule 8.3 of this Code~~, that are published or made available to **Transpower**.

…

# Schedule 12.6

# Default transmission agreement template

…

### 37.3 Information on capacities of individual Connection Assets

…

(b) The information required under paragraph (a) above:

(1) must be consistent with the **manufacturer's specification** of the Connection Asset or with the most recent Asset Capability Statement provided by Transpower under clause 2(5~~4~~) of Technical Code A of Schedule 8.3 of the Code, if this differs from the **manufacturer's specification**;

…

# Part 13

# Trading arrangements

…

### 13.29 Standing data on grid capability to be provided to system operator

In addition to the **asset owner** obligations to provide the **system operator** with **asset capability statement** information under ~~clauses 2(5) and (6) and 3(1) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset commissioning, testing and information standard**, each **grid owner** must provide standing data on the capability of the transmission system to the **system operator** that is consistent with the configuration of the transmission system in the algorithms described in Schedule 13.3. The transmission data must include—

(a) AC system configuration, including the transmission **lines**; and

(b) AC system capacity including the limits of each transmission line of the transmission system; and

(c) AC system loss characteristics including transmission loss functions for each transmission line of the transmission system.

…

### 13.30 Standing data on HVDC capability to be provided to system operator

(1) In addition to the **asset owner** obligations to provide the **system operator** with **asset capability statement** information under ~~clauses 2(5) and (6), and 3(1) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset commissioning, testing and**

**information standard**, the **HVDC owner** must provide standing data on the capability of the **HVDC link** to the **system operator** consistent with the **HVDC link configuration**.

…

(3) Subclause (2)(d) applies only if—

(a) the **HVDC owner** is operating the **HVDC link** in accordance with—

(i) a **commissioning** plan agreed with the **system operator** under clause 2(6) ~~to~~and (9) of **Technical Code** A of Schedule 8.3; or

(ii) a test plan provided to the **system operator** under clause 2(6) ~~to~~and (9) of **Technical Code** A of Schedule 8.3; and

…

**13.31 Standing data on transformer capability to be provided to system operator**

In addition to the **asset owner** obligations to provide the **system operator** with **asset capability statement** information under ~~clauses 2(5) and (6), and 3(1) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset commissioning, testing and information standard**, each **grid owner** must provide standing data on the capability of transformers to the **system operator** consistent with the configuration of those transformers. The data must include—

(a) the transformer capacity of each transformer; and

(b) the transformer loss characteristics, including transformer loss functions, for each transformer.

…

**13.32 Transmission grid capability information to be updated**

In addition to the **asset owner** obligations to provide the **system operator** with **asset capability statement** information under ~~clauses 2(5) and (6) of~~ **Technical Code** A of Schedule 8.3 and the **connected asset commissioning, testing and information standard**, and subject to that standard, ~~any timetable agreed with the **system operator** under clause 3(1) of **Technical Code** A of Schedule 8.3,~~ each **grid owner** must submit to the **system operator** for each **trading period** of a **schedule period**, or for such longer period of time as agreed between the **system operator** and each **grid owner**, any updates to the information described in clauses 13.29 to 13.31 and 13.33(d).

…

**13.33 Grid owners must submit revised information to system operator**

Up to one hour before the beginning of the relevant **trading period**, but subject to any timetable requirements in the **connected asset commissioning, testing and information standard** ~~any timetable agreed with the **system operator** under clause 3(1) of **Technical Code** A of Schedule 8.3~~, each **grid owner** must immediately

submit revised information to the **system operator** if there has been or is likely to be—

(a) a change to the information described in clauses 13.29 or 13.30; or

(b) a change of 5% or more in the capacity limit of any transmission line of the transmission system, of the **HVDC link**, or of any transformer, represented in the algorithms described in Schedule 13.3; or

(c) a change to loss characteristics, including loss functions, for any transmission line of the transmission system or of the **HVDC link**, or for any transformer, represented in the algorithms described in Schedule 13.3 that causes any **losses** or marginal **losses** to change by 5% or more; or

(d) a change in the availability of **assets** forming part of the **grid**.

…

…

# Part 17
# Transitional provisions

…

**17.47 Specific requirements for document transmission communication**

(1) *[Revoked]*

~~(2) An approval of primary or backup means of document transmission communication under clauses 4.1 or 4.2 of technical code C of schedule C3 of part C of the **rules** that was in force immediately before this Code came into force, is deemed to be an approval under clause 5(2) or (3), as the case may be, of **Technical Code** C of Schedule 8.3.~~

…

# Appendix B Approved Connected Asset Commissioning, Testing, and Information Standard (CACTIS)

B.1. This appendix sets out the approved Connected Asset Commissioning, Testing, and Information Standard.