# FUTURE SECURITY AND RESILIENCE

IMPLEMENTING ACTIVITIES FOR
A SECURE AND RESILIENT
LOW-EMISSIONS POWER SYSTEM

18 AUGUST 2022

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# 1 Introduction

1.1 Lowering emissions from New Zealand's energy use will require increasing electrification of sectors of the economy, such as transport, and meeting the increased electricity demand with new renewable generation sources. A critical challenge is to make this transition while keeping the lights on in an increasingly complex system.

1.2 New Zealand's power system is currently a typical centralised power system. The bulk of power supply is from large synchronous generating machines connected to the transmission grid. These large synchronous machines are the main contributors to system strength and inertia, which are critical attributes necessary to maintain stable system operation, good power quality, and predictable recovery following faults and disturbances. Generating stations are naturally located where the 'fuel' resources are on rivers, on geothermal fields, near coal mines and gas pipelines.

1.3 Real time and near-term system operation is also centrally coordinated to ensure supply remains balanced with consumer demand at all times and within a small band of normal frequency.

1.4 The transition to a low-emissions power system is expected to bring increasingly distributed sources of generation, located in many cases closer to end-consumers and including more new renewable generation technologies. Traditional methods for coordinating market and power system operations will need to transition these challenges. Operating distribution networks will require consideration of new approaches.

1.5 Energy resource intermittency will bring new challenges to all levels of the interconnected grid and distribution networks.

1.6 Along with new geothermal capacity, wind and solar photovoltaic (solar) technologies are expected to offer the most economic forms of new renewable generation. While geothermal generation can provide base load synchronous operation, wind and solar generation are intermittent energy sources, as their output at any instant depends on the availability of wind and sunlight. The new wind and solar generation technologies typically connect to the network via inverters, which are electronic devices that convert the generated power to a voltage waveform with variable magnitude and frequency.

1.7 Right now, wind and solar generation units are requesting connection to the power system at locations distributed around New Zealand, and at a wide range of scales, from several kilowatts (kW) for rooftop solar to hundreds of megawatts (MW) for large-scale wind and solar farms. This shows the increasing accessibility of wind and solar technologies, offering consumers opportunities such as the option to supply some of their electricity needs from their own renewable generation resources. The power system must accommodate these requests for connections and integrate the new technologies with the existing technologies, to support the Government's target of 50% of total final energy consumption to come from renewable sources by 2035. Risks, whether technical or related to regulatory settings, must be understood and mitigated through the whole power system.

1.8 Digital technologies, including sensors and data-sharing, can make it possible for greater communication and integration across the power system, so the whole power system can operate more effectively. Meters with digital technology can give consumers better insight into, and control over, their electricity usage. Digital technologies can enable time-of-day variable electricity pricing that may be used to encourage shifting of electricity usage away from times of high-demand or customers can choose to schedule their usage to reduce costs. These possibilities offer potential benefits but may require adaptations through the power system to ensure the power quality that consumers and electricity market participants rely on.

1.9 This is the context for the Electricity Authority's (Authority's) *Future Security and Resilience* (FSR) workstream. The purpose of the FSR workstream is to ensure the power system remains secure and resilient as New Zealand transitions towards a low-emissions energy system for the long-term benefits for consumers.

1.10 The FSR programme is focussed on how the power system operates in real-time or close to real-time, that is, how it is operated to continuously balance supply and demand and ensure the supplied power meets the expectations of consumers and electricity market participants. In other words, it is not assessing the power system's ability to maintain a balance of demand and supply over periods of longer than a few days (often referred to as 'adequacy') which is considered by programmes such as the NZ Battery Project.

1.11 The FSR programme considers security as the ability of the power system under normal conditions to withstand disturbances, ensuring supplied electricity is steady and stable. Resilience is considered as the ability of the power system to quickly recover from disturbances and restore stable operation in response to a variety of expected and unexpected events.

1.12 The FSR programme forms part of the Authority's response to the Government's Electricity Price Review, in particular recommendation G2 to examine the security and resilience of electricity supply. It is one of the Electricity Authority's significant and transformational programmes supporting New Zealand's transition to a low-emissions energy system, as set out in the Authority's *Energy Transition Roadmap*. Key relationships exist between the FSR programme and:

(a) a programme examining wholesale market operation under 100 percent renewable electricity generation, led by the Market Development Advisory Group (MDAG), includes addressing the ability of the power system to meet demand over time (energy adequacy), complementing the real-time focus of the FSR programme

(b) the *Updating the regulatory settings for electricity distribution networks* programme that will ensure the regulatory settings relevant to the electricity distribution sector support the transition to a low-emissions energy system, while promoting competition, reliable supply, and efficient outcomes in the long-term interests of consumers.

# 2 Progress of the FSR programme

2.1 The FSR programme fits between complementary review workstreams on both the market structure[1] and the challenges expected to be encountered by distribution network owners and operators[2], as significantly more new renewable generation capacity is expected to connect to all levels of distribution networks.

2.2 The FSR programme therefore focuses – at least initially – on the core transmission grid starting from the perspective of the grid that currently exists and how it is operated. This starting position considers the type and location of generation resources, grid assets, monitoring and control systems and tools, and the Electricity Industry Participation Code (Code) provisions related to common quality that have been designed to assure a secure and resilient system under current conditions.

2.3 The FSR programme has produced a roadmap to guide and prioritise review activities required for the power system to respond to and support transition to a low-emissions energy system. Starting implementation of the highest priority activities is the first implementation step.

2.4 However, as we progress the FSR programme, we will widen our focus to the whole power system, increasing the scope of possibilities for the benefit of consumers through the transition to a low-emissions energy system.

## A roadmap has been produced to guide FSR activities

2.5 A roadmap is published as Appendix B of this paper. It has been produced from the first two phases of the FSR programme:

(a) **Phase 1** identified potential opportunities and challenges affecting security and resilience of the power system as it transitions towards a low-emissions energy system and with new technologies enabling different contributions to the power system

(b) **Phase 2** identified activities to understand and address the opportunities and challenges identified in Phase 1. Phase 2 prioritised the activities for delivery over a ten-year timeframe and outlined an approach to support or adjust the prioritisation of activities over time, using a set of indicators to monitor trends and industry observations.

2.6 A summary of the roadmap is shown on the next page.

[1] Wholesale market competition review and the MDAG 100 % renewables project

[2] Updating regulatory settings for distribution networks

## Outcomes

2022 · 2025 · 2027

### Changing generation portfolio

**Accommodating future changes within technical requirements**
- Parts 8, 6, 7, 13, 14 of the Code will be updated to incorporate the capability and performance of new technologies and changes in the power system.
- Harmonics standards and other engineering standards, modelling and testing standards will take into account the introduction of new technologies.
- The Policy Statement and any other policies, procedures, guidelines and tools will be updated accordingly.

**Operating with low system strength**
- System strength performance criteria will be defined and established.
- The regulatory framework will be updated to include technical requirements for system strength.
- Develop suitable market products and tools.

**Balancing renewable generation**
- The market system, operational procedures and tools will allow the scheduling and dispatching of renewable generation.
- Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate.
- New or revised ancillary services will effectively manage active power imbalances.

**Managing reducing system inertia**
- A frequency reserve strategy will be created.
- The updated Procurement Plan and testing methodologies will support assessment and procurement of new reserve types.
- Operational procedures and tools will be ready to dispatch new reserve types.

### Rise of Distributed Energy Resources (DER)

**Coordination of increased connections**
- All System Operator and distributor processes will be updated to accommodate increased connections.
- The Grid Owner, Electricity Distribution Businesses and the System Operator will have the resources and capability to commission DER.
- Updated market tools, real-time operational tools and study tools will reflect the behaviour and capability of DER.

**Enabling DER services for efficient power system operations**
- The Code will define the technology agnostic role of DER. The market system will accept offers from DER owners, and operational tools and procedures will assess and dispatch DER.
- Electricity markets, the Grid Owner, Electricity Distribution Businesses and the System Operator will send efficient signals to DER.
- Grid exit point aggregation and participation of third-party flexibility traders will be enabled.

**Visibility and observability of DER**
- The impact of high levels of DER will be understood and managed.
- The regulatory framework will accommodate a high degree of DER uptake.
- Operational requirements will be established between the System Operator and distributors.

### Secure and resilient power system operation: Foundations

- Leveraging new technology to enhance ancillary services
- Maintaining cyber security
- Growing skills and capabilities of the workforce

2.7 The Authority commissioned Transpower in its role as the System Operator to progress the first two phases of the FSR programme. The final Phase 1 report was published in March 2022. The draft report, feedback received on the draft, and final report including discussion on the feedback are available here.

2.8 The final Phase 2 roadmap report in Appendix B includes responses to the seven submissions that were received on the draft roadmap. The draft roadmap and feedback received on the draft are available here.

2.9 Feedback on the draft roadmap was generally supportive of the proposed activities. Within the submissions:

(a) some considered that particular activities should have higher priority than proposed and should be delivered earlier than indicated on the roadmap

(b) some considered the roadmap is too focused on the operation of the transmission grid and does not adequately represent opportunities and challenges of other parties, particularly distributors and consumers

(c) some considered the roadmap is too focused on addressing risks and challenges, rather than having a balance or focus on enabling opportunities.

2.10 The Authority agrees with the prioritisation of activities on the final Phase 2 roadmap. The Authority will review the roadmap periodically as Phase 3 activities progress and may adjust prioritisation or consider new activities. We will monitor the roadmap with a set of indicators (shown on the next page) and ongoing stakeholder feedback from both within and external to the electricity industry.

2.11 The Authority considers the initial focus on the transmission grid has been valuable for teasing out and categorising the complexities inherent in the real-time operation of the power system.

2.12 The Authority's intended activities to progress the FSR programme address the other feedback.

## A set of indicators will help us monitor the roadmap

| Changing generation portfolio | | |
|---|---|---|
| Opportunity/ Challenge | Monitoring outcome | Indicator (in development) |
| Accommodating future changes within technical requirements | Ongoing monitoring of system performance and types of connection requests will enable gaps in technical requirements to be identified | The number and type of DER installations, creates context for action on updating technical requirements |
| Operating with low system strength | Establishing a measure for impact of system strength on system performance will enable the risk to be monitored | Indicator to be developed |
| Balancing renewable generation | Monitoring existing system performance as intermittent generation increases will enable the risk to be monitored | Monitoring of system frequency |
| Managing reducing system inertia | Monitoring existing system performance as the proportion of synchronous generation reduces will enable the risk to be monitored | Capacity of inverter-connected generation relative to total generation capacity |

| Rise of Distributed Energy Resources (DER) | | |
|---|---|---|
| Opportunity/ Challenge | Monitoring outcome | Indicator (in development) |
| Coordination of increased connections | Monitoring connection requests will identify emerging risks | Number/capacity of planned generation installations |
| Enabling DER services for efficient power system operations | Monitoring the amount and type of DER available will assist in identifying opportunities to leverage it for system operations | The number of DER installations |
| Visibility and observability of DER | Establishing a measure for DER impact on system performance will enable the risk to be monitored | Capacity of inverter-connected generation relative to total generation capacity |

| Foundational opportunities and challenges | | |
|---|---|---|
| Opportunity/ Challenge | Monitoring outcome | Indicator (in development) |
| Leveraging new technology to enhance ancillary services | Monitoring the number and type of connections, and amount and type of DER will assist in identifying technologies which could be used to enhance ancillary services | The number and type of DER installations, creates context for action on ancillary services offerings |
| Maintaining cyber security | Monitoring cyber security events will assist in identifying if this risk is increasing or evolving over time | Indicator to be developed |
| Growing skills and capabilities of the workforce | Monitoring the number and type of skilled resource vacancies to assess if this challenge is increasing or evolving over time | Indicator to be developed |

### The focus will widen to the whole power system

2.13 The Authority will progress the FSR programme with a focus on the whole electricity system, widening from the focus on the current system of power transmission that was used to get the programme started.

2.14 The initial focus complemented the Authority's *Updating the regulatory settings for electricity distribution networks* programme, which includes an objective that seeks to address future security and resilience on distribution networks.

2.15 The FSR programme has encountered topic overlaps between the transmission grid, distribution networks, and other industry sectors. The topic overlaps are expected to increase as the FSR programme progresses and as transition to a low-emissions energy system progresses. For example, distributed small-scale generation and demand resources could provide both services to distribution networks, including aggregations of many smaller units; and services to the transmission grid, such as ancillary services including instantaneous reserve or frequency keeping.

2.16 Building on feedback received from industry and from consultation on the draft roadmap, the Authority considers now is the right time to widen the scope of the FSR programme to focus on security and resilience in the near-real and real timeframes, encompassing coordination of the whole power system.

# 3 The Authority seeks views on future arrangement of the power system

3.1 The current arrangement of roles and obligations within the New Zealand power system was established in an era when:

(a) generation was mostly from relatively few large synchronous machines located remote from consumers, and interconnected through the transmission grid

(b) electricity predominantly flowed from grid-located generation stations, through the transmission grid to grid exit points, then entering distribution networks and on at successively lower voltages to supply consumers

(c) the power system was amenable to centralised operation to ensure ongoing real-time supply.

3.2 Under the current arrangements, the System Operator is responsible for the real-time coordination of the power system. The System Operator's responsibilities include the real-time and near-real-time monitoring and management of common power quality, carrying out the dispatch function to maintain supply and demand in balance, and managing risks around contingent events.

3.3 As we transition to a low-emissions energy system, anticipating developments such as greater distribution of energy resources and digitalisation to enable new capabilities and services, it may be that the current arrangement of roles and functions could also transition. The range of future options for system coordination and operation is wide, for example:

(a) An incremental future view might anticipate the need for risk-driven incremental change only, requiring improved tools, modelling capabilities and visibility of new technologies but broadly retaining the current arrangement of roles and obligations. For example, balancing supply and demand will be more complex in a power system that has a higher proportion of intermittent wind and solar generation. Other anticipated changes may create the need for greater operational coordination across both transmission and distribution networks – regardless of who owns the underlying assets – than exists at present.

(b) A different future view might encompass new approaches to coordinating common quality and reliable operation at all levels in the power system, including enhanced market support services enabled by the capabilities of new technologies, both those ready now and others yet to be developed. Energy storage systems are an example of the types of technologies that could provide a wide range of existing and enhanced system support services that ultimately benefit consumers.

(c) Evolution of distribution network operations to cater for significant capacities of distributed energy resources (DER) capable of exporting large amounts of electricity into the network is the focus of some future views. Such DER could affect:

(i) power flow direction swings and the network asset capacity to carry such flows at a scale not experienced before

(ii) local power quality – particularly voltage magnitude and waveform

(iii) grid common quality – particularly system frequency and stability and the ability to ride through and recover from faults.

There is no single definition of the term Distribution System Operator (DSO) but it is generally being used to describe a set of coordinating roles and obligations that could be provided by:

(i) the local distribution network owner in respect of their own assets or

(ii) one or more providers acting independently of the local distribution network owner, possibly coordinating across multiple local networks.

This future view anticipates a range of possibilities, spanning the evolution of centralised coordination models where most market operations remain centralised, but likely with a wider range of service providers, while distributors manage DER on their own networks. Models featuring greater de-centralisation could enable options such as peer-to-peer markets and DER capable of automatic dispatch.

3.4 The future system could include:

(a) system coordinators and operators at grid and distribution network levels

(b) wholesale and retail markets developing at distribution network level

(c) peer-to-peer markets

(d) consumers who choose to store power or supply power at time that suit them, enabled by other providers that aggregate fleets of consumer level DER.

3.5 As we seek the arrangement of power system roles and obligations that promotes the best long-term benefits for consumers, the range of possible future views is wide. The Authority will start engaging with industry to seek views on future arrangement of the power system and report on the feedback later this year.

# 4 The Authority is starting review of the common quality requirements for the power system

## Common quality requirements need to accommodate both synchronous generation and inverter-connected resources

4.1 Common quality requirements for the power system support elements of shared quality of electricity conveyed across the transmission grid. The existing common quality requirements were written when ‘synchronous generation technologies’ dominated New Zealand’s power generation, such as large hydro, geothermal, and thermal machines. The generation portfolio is now changing towards including a greater proportion of inverter-connected resources.

4.2 ‘Inverter-connected resources’ is used here to describe generation stations and units powered by renewable energy sources such as wind and solar that are connected to the power system through inverters. For this paper, battery energy storage systems connected through inverters and rectifiers, allowing bi-directional power flows for discharging and charging, are also described simply as inverter-connected resources.

4.3 Synchronous generation technologies and inverter-connected resources have essential differences that lead to the technologies potentially having different effects on operation of the power system and suitability of the existing common quality requirements.

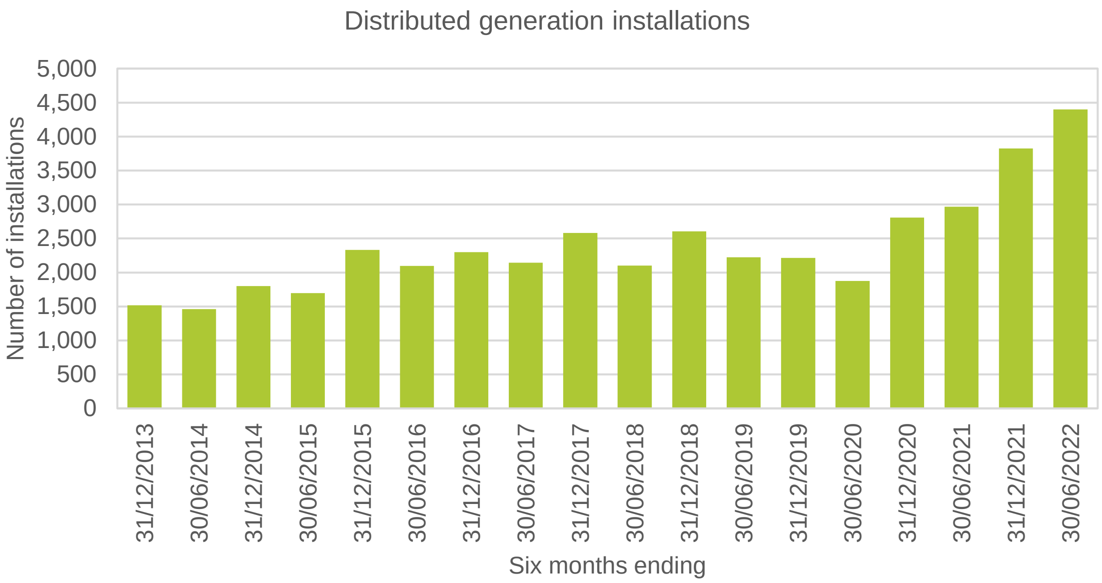
(a) ‘Synchronous generation technologies’ are based on relatively large rotating machines comprised of a turbine physically coupled to a generator. The generator provides alternating current (AC) that is electrically connected to a network through a transformer.

(b) ‘Inverter-connected resources’ are based on usually much smaller generation modules, such as a solar panel or an electrochemical battery, that generate direct current (DC) power. An inverter is the electronic device that changes the DC into AC power with a waveform that can synchronise and connect to a network.

4.4 Appendix A outlines some of the more detailed differences in the operating characteristics of the two generic technologies and their potential effects on the power system. The differences are provided as useful background when considering the common quality requirements in Part 8 of the Code that could be affected as the New Zealand power system gains an increasing proportion of renewable inverter-connected energy resources.

4.5 The common quality requirements in Part 8 of the Code need to be reviewed to ensure they accommodate and facilitate the opportunities offered by inverter-connected resources.

4.6 This is the highest priority activity on the roadmap and the Authority supports this prioritisation. If the Code contains unsuitable common quality requirements, operating the power system could become more complex and require purchase of greater quantities of ancillary services and reserves to continue to ensure steady and stable power quality, leading to greater costs to consumers. This presents an increasing risk to security and resilience as more distributed generation is installed (see the following figure).




Source: www.emi.ea.govt.nz/Retail/Reports/GUEHMT

### Review of the common quality requirements will follow a staged process

4.7 The Authority will commence its review of the common quality topics covered in Part 8 of the Code by engaging with stakeholders for views on issues.

4.8 The Authority intends the review to follow a staged process based on:

(a) an issues paper by early-2023
outlining the issues considered as high-priority to address through review of the common quality requirements, with the opportunity for industry feedback to contribute to the Authority's understanding of the issues and to identify any other issues that should be considered

(b) an options paper by mid-2023
outlining options that the Authority is considering for addressing the high-priority issues relating to the common quality requirements, with the opportunity for industry feedback to contribute to the Authority's assessment of the potential costs and benefits associated with the options

(c) a decisions paper by the end of 2023
sharing the Authority's decisions and rationale for any proposals to amend (or not amend) the common quality requirements that were identified in the issues and options papers. If any amendments are proposed, the Authority would then take these through the process for amending the Code.

# 5 FSR next steps

5.1 The Authority will engage with stakeholders for views on the future arrangement of power system roles and obligations that promote the best long-term benefits for consumers. We intend to report on the engagement by the end of 2022.

5.2 The Authority will engage with industry to progress review of the common quality requirements in Part 8 of the Code. We intend to publish an Issues Paper, including reporting the issues identified through initial stakeholder engagement, by early-2023.

# Appendix A Operating characteristics of synchronous generation technologies and ‘inverter-connected resources’

| | Synchronous generation | Inverter-connected resources[3] | Potential effects on the power system related to differences in the operating characteristics |
|---|---|---|---|
| 1 | Power system configuration and characteristics | | |
| a | Centralised generation | Distributed generation | A large number of smaller generation stations will be connected:<br>• to the transmission grid<br>• to distribution networks<br>• behind-the-meter in consumer premises.<br>These differences can affect how the system operator, for example:<br>• sources voltage support<br>• gathers Supervisory Control and Data Acquisition (SCADA) indications to enable efficient dispatch<br>• procures frequency reserves |
| b | Generally, power flows in *one direction*, away from the transmission grid, across distribution networks to consumers | Power flows in distribution networks will be more frequently *bi-directional* | Electrical power flow is more complex when the power system becomes more distributed in nature. These differences can affect, for example:<br>• daily generation schedules<br>• voltage support requirements<br>• line protection, especially within the distribution networks |
| c | Lower levels of controllable demand | More controllable demand, especially within distribution networks | Distributed Energy Resources (DER) connected within distribution networks can change demand behaviour (i.e., the level and direction of power flow as measured at Grid Exit Points, GXPs). These differences can affect, for example:<br>• demand forecasting, and increasing numbers of non-conforming GXPs<br>• daily generation schedules<br>• voltage support requirements<br>• simulation tools and modelling requirements |
| d | Provides electrical torque | Does not provide electrical torque | Rotating machines intrinsically provide electrical torque; inverter-connected resources do not. These differences can affect, for example:<br>• power system stability<br>• damping of system oscillations<br>• the rate of change of frequency following a contingent event, eg, a large amount of generation tripping unexpectedly |
| 2 | Power station configuration and characteristics | | |
| a | Typically, large station and unit sizes | Typically, smaller station and unit sizes | Smaller generating unit size can affect:<br>• risk management, as contingency risk is smaller<br>• frequency reserve requirements<br>• the (increased) number of units that may need to provide SCADA indications and control signals to system operators |

[3] ‘Inverter-connected resources’ is used here to describe the generation installations powered by renewable energy sources, such as wind and solar, which are connected to the power system through inverters. For this paper, battery energy storage systems connected through inverters and rectifiers, allowing bi-directional power flows for discharging and charging, are also described simply as inverter-connected resources.

| | Synchronous generation | Inverter-connected resources[3] | Potential effects on the power system related to differences in the operating characteristics |
|---|---|---|---|
| b | Each generating unit has discrete components such as a transformer, a speed governor, an automatic voltage regulator (AVR), excitation equipment, and a protection system | Many smaller units have integrated electronic control and protection systems | Protection and control systems are often implemented at unit and station levels making them potentially more complex for inverter-connected generation technologies. These differences can affect, for example:<br>• the number of units that can be commissioned and tested at one time<br>• how asset owner Code compliance and ancillary services contracts are assessed<br>• simulation tools and modelling requirements |
| c | Individual generating units are connected to 1 or more high voltage (HV) busbars | Multiple units or strings connect via a collector system to 1 or more HV busbars | Inverter-based generation can consist of many smaller generating units over a wide area that is aggregated by a collector system for network connection. These differences can affect, for example:<br>• the number of units that must be commissioned and tested<br>• how asset owner compliance with the Code and ancillary services contracts are assessed<br>• simulation tools and modelling requirements |
| 3 | Fuel sources | | |
| a | Large fuel reserves in coal stockpiles, lakes and gas fields are relied upon to provide dependable and dispatchable electricity | Wind and sun provide no fuel reserves, unless excess capacity is installed and the excess energy output is stored | Wind and solar photovoltaic (PV) generation can only generate when the wind blows and the sun shines. Energy production can be intermittent due to wind gusts and clouds. These differences can affect, for example:<br>• daily generation schedules<br>• contributions made towards overall frequency management, especially frequency keeping<br>• security of supply<br>• frequency reserve requirements |
| b | Seasonal variation of hydro inflows | Daily and hourly variation | |
| 4 | Energy conversion method or interface to the grid | | |
| a | Rotating machine with a step-up generation transformer as the interface to the grid | Photoelectric or chemical energy conversion process with an inverter (and a collector network for larger stations) as the interface to the grid | Inverter-connected resources have no rotating mass and do not inherently contribute inertia to the power system. These differences can affect, for example:<br>• frequency reserve requirements<br>• the number of units that must be commissioned and tested<br>• simulation tools and modelling requirements |
| b | High fault current contribution | Low fault current contribution limited by inverter rating | Inverter contribution to fault current is limited to its rating (typically) whereas synchronous generators can provide 4-6 times their rating. These differences can affect, for example:<br>• voltage management due to low power system strength<br>• correct protection operation due to low fault current contribution<br>• equipment fault ride through performance |

| | Synchronous generation | Inverter-connected resources[3] | Potential effects on the power system related to differences in the operating characteristics |
|---|---|---|---|
| c | Few power quality related issues | Power electronics generate harmonics and other power quality issues | Power electronics may introduce more power quality issues such as harmonics, which could affect the quality of supply to consumers and system operation at distribution and transmission levels. |
| 5 | Control systems | | |
| a | Station control | Plant control | The functions of station control for synchronous generation stations and plant control for wind or solar PV farms are different. Plant control functions more as primary voltage and frequency controllers. These changes can affect, for example:<br>• how to assess asset owner compliance with the Code and ancillary services contracts<br>• the number of units that must be commissioned and tested |
| b | Automatic voltage regulator (AVR) + an excitation system | Voltage control + inverter | Wind and solar PV farms utilise a central voltage controller to regulate the voltage at the point of common coupling to the grid or a distribution network. Wind generating units and solar PV inverter strings receive commands from their voltage controller to vary reactive power output to meet a control set-point and can include capacitor banks and other reactive power plant as part of the voltage regulation strategy. These differences can affect, for example:<br>• how asset owner compliance with the Code and ancillary services contracts are assessed<br>• the number of units that must be commissioned and tested<br>• simulation tools and modelling requirements |
| c | Frequency or speed controller (speed governor) | Active power control via frequency-watt curve response | Inverter technology can adjust active power in response to measured frequency whereas synchronous generation regulates speed with a speed governor. Both technologies have the same objective – to contribute to overall frequency management – and have advantages and disadvantages. These differences can affect, for example:<br>• how asset owner compliance with the Code and ancillary services contracts are assessed<br>• the number of units that must be commissioned and tested<br>• simulation tools and modelling requirements<br>• possible new ancillary services |

| | Synchronous generation | Inverter-connected resources[3] | Potential effects on the power system related to differences in the operating characteristics |
|---|---|---|---|
| d | Proven technology | Evolving technology | Inverter-connected technologies and support technologies are evolving rapidly. Vendors commonly consider that aspects of their technologies are their proprietary and confidential intellectual property. The differences can affect, for example:<br>• assessments of asset owner compliance with the Code and ancillary services contracts<br>• information provision<br>• the number of units that must be commissioned and tested<br>• simulation/modelling tools and input information used by the system operator (at distribution network level or transmission grid level) |
| 6 | Plant or unit protection system | | |
| a | Unit level protection | Multiple levels of protection | Synchronous generator protection is well understood whereas wind and solar PV farms are more complex and consist of multiple levels of protection. The differences can affect, for example:<br>• the number of units that must be commissioned and tested<br>• simulation tools and modelling requirements<br>• risk identification due to complexity of controller software, which can be compounded by information being made unavailable by the vendor, eg, voltage dip fault counters in wind turbines. |
| b | More immune to external fault | Can be susceptible to external faults, particularly in a weak system | Inverters can be vulnerable to network frequency and voltage disturbances encountered in system faults. |

# Appendix B Final Phase 2 roadmap prepared by the System Operator

# Roadmap to achieve future security and resilience of the New Zealand power system

Final roadmap

**Version:** 2.0

**Date: August 2022**

| | |
|---|---|
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# 1.0 Context

New Zealand's power system is on the cusp of significant transformation driven by four key factors:

- decarbonisation of the electricity industry – the project of reducing greenhouse gas emissions by increasing renewable generation, and reducing reliance on gas and coal fuelled generation
- decarbonisation of the wider economy – the wider project of reducing the use of fossil fuels by increasing electrification
- changing patterns of distribution – including increasing adoption of distributed energy resource (DER) such as solar photovoltaic (PV), electric vehicles (EVs), batteries and smart appliances
- increased digitisation – including more data and better digital tools

Figure 1 shows the impact of these four factors on the current power system and the changes expected by 2030.

| Key trends | Current | 2030 |
|---|---|---|
| **Decarbonised:** Transition to 100% renewables | • 85% renewable electricity<br>• Mostly synchronous generation<br>• Security of supply managed by market<br>• Thermals to meet peaks and dry years<br>• Small amount of DER | • 100% renewable electricity<br>• More asynchronous and inverter-based generation<br>• Will energy-only market manage security of supply?<br>• New solutions needed for peaks and dry year<br>• Increased reliance on DER |
| **Decarbonised:** More electrified economy | • High reliance on electricity in the economy<br>• Electricity not relied on heavily for transport<br>• Few, traditional demand growth sources – new industry, new housing | • Very high reliance on electricity in the economy<br>• Electricity relied on heavily for transport and in industry<br>• Many different demand growth sources – hydrogen, data centres, EVs, process heat |
| **Distributed:** More distributed electricity system | • Small amount of DER<br>• Limited performance requirements in the Code but small penetration means this is not yet an issue<br>• Limited use of demand-side and battery technology to manage peaks | • Millions of DER able to manage peaks in real-time (EVs, batteries, smart appliances)<br>• Multi-directional power flows<br>• More consumer participation and more market players<br>• Potential issues caused by inverter-based DER |
| **Digitised:** Increasing digitisation and use of digital tech | • Increasing data and data management requirements<br>• Gradual use of automation for control and switching<br>• Increased use of data-driven decision making | • Increased complexity and volume of data<br>• Expectation from operators and customers that controls, and communications will be automated and data-driven<br>• Opportunities to improve consistency and efficiency |

Figure 1 – Key trends in energy transformation and anticipated outcomes in 2030

The transformation of the power system will result in:

- decarbonisation of the electricity industry - the displacement and retirement of synchronous generation, e.g. coal and gas fired generation, together with an increase in inverter-based resource (IBR) generation, being wind and solar PV and battery storage solutions
- decarbonisation of the wider economy - an increase in variable and intermittent energy sources, being wind and solar, to meet increasing demand from transport and process heat electrification
- changing patterns of decentralisation - a move from a largely centralised power system, where large-scale generation of electricity occurs at central power plants connected to the grid, to a more decentralised power system, where more energy sources are located outside the grid, which will challenge the existing industry operating boundaries

- increased digitisation - a switch from passive consumers to active consumers, who can instantly reduce their demand and feed excess generation from DER back into the distribution network to manage their electricity usage.

# 2.0 Purpose of the Future Security and Resilience Programme

As New Zealand's power system is transformed, it is important to understand the implications of the changes to the security and resilience of the system. This will ensure that as an electricity supply industry we can continue to coordinate and operate the power system, as well as continuing to meet consumer expectations.

The Electricity Authority has engaged Transpower, as System Operator, to develop a shared understanding of the future opportunities and challenges for the ongoing security and resilience of New Zealand's power system, and to outline how they can be addressed in an orderly and timely way. That work will be undertaken within what is being called the Future Security and Resilience programme of work.

The Future Security and Resilience programme sits within the system security and resilience workstream outlined in the Electricity Authority's Energy Transition Roadmap, which can be viewed here: Roadmap - Transition to Low Emissions Energy System [v1.0].

The Future Security and Resilience programme is being undertaken in three phases (as shown in Figure 2 below):

- Phase 1: A report which identifies the potential security and resilience opportunities and challenges for the New Zealand power system arising from expected future changes in technologies and use of the system. This is now complete and the report can be viewed here: Appendix-A-Phase-1-final-report.pdf (ea.govt.nz)
- Phase 2: A roadmap that outlines a pathway to understand and address these opportunities and challenges in a timely manner and an approach for monitoring the manifestation of risks. This document is the roadmap.
- Phase 3: Delivery of the programme of work outlined in the roadmap. Ongoing from July 2022.


Figure 2 - Phases of the Future Security and Resilience programme

The Phase 1 report identified 10 specific opportunities and challenges, as follows:

Table 1 – Opportunities and challenges as identified in the Phase 1 report

| Opportunities and challenges | Timeframe | Priority |
|---|---|---|
| Enabling DER services for efficient power system operations | 3-7 years | Medium |
| Visibility and observability of DER | 3-7 years | Medium |
| Coordination of increased connections | 0-3 years | High |
| Balancing renewable generation | 3-7 years | Low |
| Managing reducing system inertia | 7-10 years + | Low |
| Operating with low system strength | 3-7 years | Medium |
| Accommodating future changes within technical requirements | 0-3 years | High |
| Leveraging new technology to enhance ancillary services | Enduring | Medium |
| Maintaining cyber security | Enduring | High |
| Growing skills and capabilities of the workforce | Enduring | High |

Rise of Distributed Energy Resources   Changing generation portfolio   Foundational opportunities and challenges

As part of Phase 1, the Electricity Authority and System Operator engaged with industry in late November and early December 2021, validating these opportunities and challenges, timeframes and associated priorities.

This work is not occurring in a vacuum. There are multiple other future-focused initiatives concurrently underway; for example, those led by the Electricity Authority's Market Development Advisory Group (MDAG), and its Innovation and Participation Advisory Group (IPAG) and the Ministry of Business, Innovation & Employment (MBIE).

As Figure 3 shows, there are many interdependencies between these initiatives. The importance of careful coordination across multiple initiatives is recognised, to ensure duplication of effort is avoided and support industry transparency.

Equally, the importance of co-design is acknowledged. As the Future Security and Resilience programme enters Phase 3 it must include pan-industry engagement, to ensure that the requirements of different parties in the industry are heard and the optimal solution is designed.

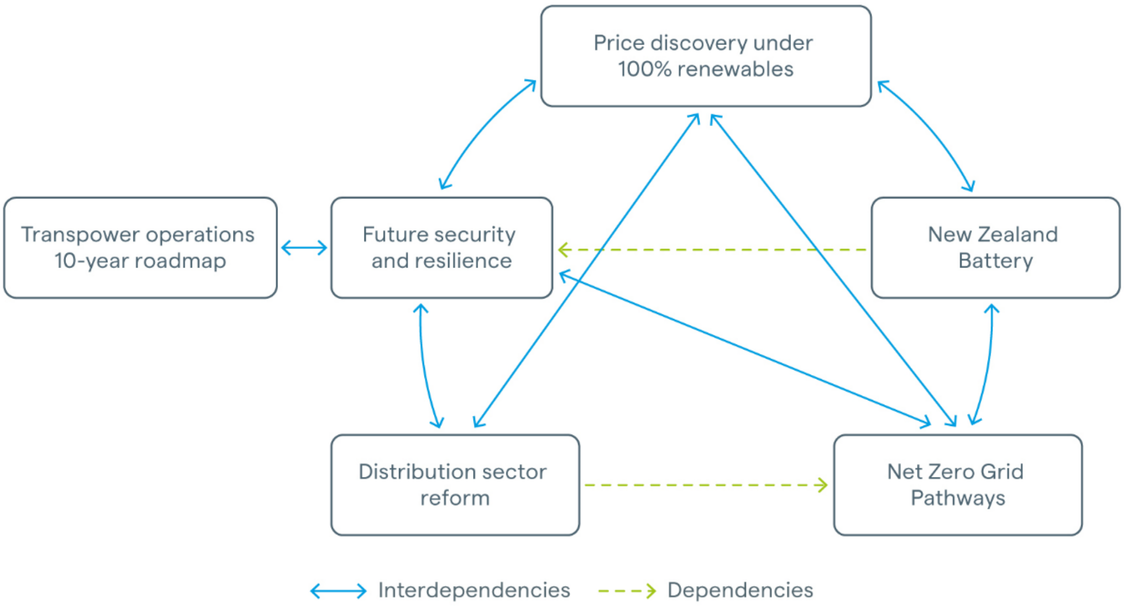


Figure 3 – Known future security and resilience interdependencies and dependencies

**Notes on Figure 3**

The phrase 'distribution sector reform' refers to a range of initiatives, including the Electricity Authority's consultation on updating regulatory settings for Distribution Networks, the IPAG review of Transpower's Demand Response Programme, Wellington Electricity EV connect discussion paper and the Electricity Networks Association Network Transformation Roadmap.

'Price discovery under 100 per cent renewables' refers to an MDAG investigation of how the wholesale electricity market might operate under 100 per cent renewable electricity supply.

The 'New Zealand battery' is a MBIE project investigating solutions to managing dry year security of supply risk.

The 'Net zero grid pathways' is a Transpower project that encompasses the planning and investment required to ensure New Zealand's electricity transmission grid can meet the challenges in enabling electrification of the economy and meeting our decarbonisation targets.

'Transpower operations 10-year roadmap' is a long-term plan outlining the activities required to ensure Transpower meets its operations obligations into the future.

# 3.0 Intent of the roadmap

The intent of this roadmap is to provide:

- a clear understanding of the activities associated with each opportunity and challenge identified in the report
- a succinct desired outcome for each issue identified in the report
- a schedule of when those activities can be carried out
- an indication of the business owner for the activities required.

The roadmap also highlights interdependencies across the multiple activities, allowing for greater efficiency in delivering outcomes and an indication of the resourcing required.

The roadmap will be a living document: as opportunities and challenges emerge faster or slower, or as technology advances change expectations, activities may be reprioritised.

# 4.0 Approach for developing the roadmap

The System Operator developed the roadmap based on a bottom-up approach, which considers an extensive range of possible and credible scenarios, to derive final outcomes ensuring the challenges are met and the opportunities realised. The bottom-up approach commenced with brainstorming the needs of system operation, both real-time operation and electricity market operation, and the changes that are required to maintain or improve the security and resilience of the power system in the long-term interests of consumers.

The opportunities and challenges were assessed to determine the:

- reasons for the change
- linkage to Electricity Authority strategic priorities
- parties who will be affected by the change
- outcome of the change
- benefits of the change
- risks of making and not making the change
- interdependencies between the change and other challenges and opportunities
- ownership: the parties responsible for delivering the change.

All the changes have been consolidated to produce the outcome proposals and associated roadmap.

As part of finalising this roadmap document, industry was asked in early 2022 to provide feedback on initial drafts of the outcome proposals and overall roadmap. Seven parties responded with feedback, which the Electricity Authority and System Operator considered. Details on the feedback and any resulting changes to this document can be found in Appendix B.

# 5.0 Roadmap

The following table sets out the Phase 2 future security and resilience roadmap. It is based on the Outcome Proposal documents (see Appendix A). Note that the order of challenges and opportunities as listed in the Phase 1 report has been changed to assist with visualising the critical path and "Year" denotes the financial year end (30 June), not the calendar year.

| Opportunity or challenge | Activity | | Business owner | Year 1 2023 | Year 2 2024 | Year 3 2025 | Year 4 2026 | Year 5 2027 | Year 6 2028 | Year 7 2029 | Year 8 2030 | Year 9 2031 | Year 10 2032 | Outcome |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accommodating future changes within technical requirements | 7.1 | Review and update Part 8 of the Code | Electricity Authority, System Operator | | | | | | | | | | | Parts 8, 6, 7, 13, 14 of the Code will be updated to incorporate the capability and performance of new technologies and changes in the power system.<br>Harmonics standards and other engineering standards, modelling and testing standards will take into account the introduction of new technologies.<br>The Policy Statement and any other policies, procedures, guidelines and tools will also be updated accordingly. |
| | 7.2 | Review and update Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8 | | | | | | | | | | | | |
| | 7.3 | Identify standards to support technical requirements in the Code | | | | | | | | | | | | |
| | 7.4 | Update the Policy Statement to manage emerging risks | | | | | | | | | | | | |
| | 7.5 | Update the System Operator's policies, procedures, guidelines and tools | | | | | | | | | | | | |
| Coordination of increased connections | 3.1 | Update Grid Owner and System Operator commissioning processes and benchmark agreement | Electricity Authority, System Operator | | | | | | | | | | | All System Operator and distributor processes will be updated to accommodate increased connections.<br>The Grid Owner, EDBs and the System Operator will have the resources and capability to commission DER.<br>Updated market tools, real-time operational tools and study tools will reflect the behaviour and capability of DER. |
| | 3.2 | Review the approach to planning connection studies | | | | | | | | | | | | |
| | 3.3 | Review operational study tools | | | | | | | | | | | | |
| Operating with low system strength | 6.1 | Investigate system strength challenges and opportunities | Electricity Authority | | | | | | | | | | | System strength performance criteria will be defined and established.<br>The regulatory framework will be updated to include technical requirements for system strength.<br>Relevant market products, operational procedures and tools will be in place. |
| | 6.2 | Amend the Code to support performance criteria | | | | | | | | | | | | |
| | 6.3 | Develop suitable market products and tools | | | | | | | | | | | | |
| Enabling DER services for efficient power system operations | 1.1 | Enhance the Code and market system dispatch capability to accommodate DER bids and offers | Electricity Authority, System Operator | | | | | | | | | | | The Code will define the technology agnostic role of DER. The market system will accept offers from DER owners, and operational tools and procedures will assess and dispatch DER.<br>Electricity markets, the Grid Owner, EDBs and the System Operator will send efficient signals to DER.<br>Grid exit point aggregation and participation of third-party flexibility traders will be enabled. |
| | 1.2 | Improve real-time security modelling within operational tools | | | | | | | | | | | | |
| | 1.3 | Investigate new DER services to support efficient operation of the power system | | | | | | | | | | | | |
| Visibility and observability of DER | 2.1 | Establish the impact of DER | Electricity Authority, System Operator | | | | | | | | | | | The impact of high levels of DER will be understood and managed.<br>The regulatory framework will accommodate a high degree of DER uptake.<br>Operational requirements will be established between the System Operator and distributors/DSOs. |
| | 2.2 | Determine the credible event risk of DER | | | | | | | | | | | | |
| | 2.3 | Update the Code to clarify DER obligations and operational requirements | | | | | | | | | | | | |
| | 2.4 | Update procedures and tools to include DER asset information | | | | | | | | | | | | |
| Balancing renewable generation | 4.1 | Improve market system and generation/demand forecast | Electricity Authority | | | | | | | | | | | The market system, operational procedures and tools will allow the scheduling and dispatching of renewable generation.<br>Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate.<br>New or revised ancillary services will effectively manage active power imbalances. |
| | 4.2 | Consider new or revised ancillary services to maintain balancing | | | | | | | | | | | | |
| Managing reducing system inertia | 5.1 | Create a frequency reserve strategy to manage low inertia | Electricity Authority, System Operator | | | | | | | | | | | A frequency reserve strategy will be created.<br>The updated Procurement Plan and testing methodologies will support assessment and procurement of new reserve types.<br>Operational procedures and tools will be ready to dispatch new reserve types. |
| | 5.2 | Ensure the Code defines and market system can accommodate new reserve types | | | | | | | | | | | | |
| | 5.3 | Incorporate new reserve types in the Procurement Plan and testing methodology | | | | | | | | | | | | |
| | 5.4 | Update operational procedures and tools | | | | | | | | | | | | |
| Leveraging new technology to enhance ancillary services | 8.1 | Investigate changes to ancillary services | Electricity Authority, System Operator | | | | | | | | | | | The regulatory framework, engineering standards and procedures will be updated to reflect the capability and performance of new technologies and other changes within the power system.<br>The Code will enable new technologies to offer ancillary services, and the System Operator's processes and tools will allow new technologies to accept offers and dispatch ancillary services.<br>Studies will identify whether and when new ancillary services products are needed. |
| | 8.2 | Ensure tools monitor the performance of the power system | | | | | | | | | | | | |
| | 8.3 | Update the Code, market system and Procurement Plan to enable new technology to provide ancillary services | | | | | | | | | | | | |
| Maintaining cyber security | 9.0 | Continually review and update cyber security measures | New Zealand energy sector | | | | | | | | | | | The energy sector's approach to the management of cyber security will be robust and well coordinated. |
| Growing skills and capabilities of the workforce | 10.0 | Encourage and train the workforce's next generation | New Zealand energy sector, educational institutions, professional associations | | | | | | | | | | | New Zealand will be able to produce its own workforce, with minimum reliance on overseas talent. |

Rise of Distributed Energy Resources   Changing generation portfolio   Foundational opportunities and challenges

# 6.0 Roadmap interdependencies

While broader interdependencies have been outlined in Figure 3 above, it is essential to understand how the roadmap deliverables interact with one another as this will assist in developing a clear critical path for the programme. It may also generate efficiencies where multiple opportunities and challenges can be managed as one.

Most of the opportunities overlap or interact in some way. However, some key interdependencies and dependencies are worth noting.

*Accommodating future changes within technical requirements* has an interdependency with *Coordination of increased connections* and *Enabling DER services for efficient power system operations*. Creating an inclusive Code will enable more and more diverse DER, which also means we must be prepared to cater for increased connections.

Similarly, *Leveraging new technology to enhance ancillary services* is dependent on the work to be done on the Code and other technical standards, and interacts with support for an increased number of connections. It also has interdependencies with a range of topics, including *Managing reducing system inertia*, *Balancing renewable generation* and *Enabling DER services for efficient power system operations*. This is because as more DER becomes available, ancillary services to support system balancing or to provide synthetic inertia can be evaluated.

Being a localised issue, *Operating with low system strength* is dependent upon how connections are managed, but also will clearly influence the extent to which DER can be leveraged. Decisions need to be made in light of these considerations.

Two challenges are interdependent with all opportunities and other challenges: *Maintaining cyber security* and *Growing skills and capabilities of the workforce*. These are foundational challenges; they underpin the entire programme and will be considered within each activity undertaken.

Figure 4 highlights interdependencies and dependencies between the opportunities and challenges. Appendix A provides more details.

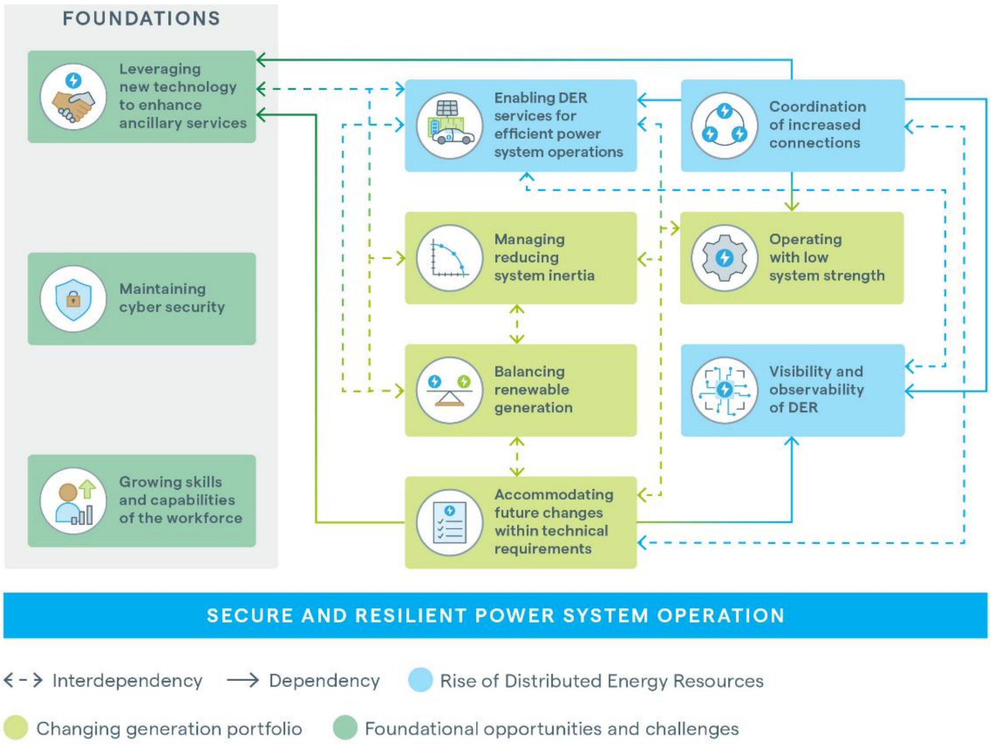


Figure 4 – Interdependencies and dependencies between opportunities and challenges

# 7.0 Monitoring roadmap priorities

Transpower conducts regular monitoring on its blueprint for a decarbonised economy: see [Whakamana i Te Mauri Hiko Monitoring Reports | Transpower]. This type of monitoring will assist in determining whether the forecast for the future is materialising and the rate of change. Table 2 provides examples of specific indicators that could assist in monitoring the prioritisation of each opportunity and challenge. Some challenges, notably *Visibility and observability of DER* and *Operating with low system strength*, require investigations to determine appropriate monitoring measures.

| | Rise of Distributed Energy Resources | | | Changing generation portfolio | | | | Foundational opportunities and challenges | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Enabling DER services for efficient power system operations | Visibility and Observability of DER | Coordination of increased connections | Balancing renewable generation | Managing reducing system inertia | Operating with low system strength | Accommodating future changes within technical requirements | Leveraging new technology to enhance ancillary services | Maintaining cyber security | Growing skills and capabilities of the workforce |
| Why | Monitoring the amount and type of DER available will assist in identifying opportunities to leverage it for system operations | Establishing a measure for DER impact on system performance will enable the risk to be monitored | Monitoring connection requests will identify emerging risks | Monitoring existing system performance as intermittent generation increases will enable the risk to be monitored | Monitoring existing system performance as the proportion of synchronous generation reduces will enable the risk to be monitored | Establishing a measure for impact of system strength on system performance will enable the risk to be monitored | Ongoing monitoring of system performance and types of connection requests will enable gaps in technical requirements to be identified | Monitoring the number and type of connections, and amount and type of DER will assist in identifying technologies which could be used to enhance ancillary services | Monitoring cyber security events will assist in identifying if this risk is increasing or evolving over time | Monitoring the number and type of skilled resource vacancies to assess if this challenge is increasing or evolving over time |
| What (measure) | Number of DER installations | TBC investigation pending | Number, location and type of connection requests | Number of frequency and voltage excursions outside acceptable limits | Number of instances where Rate of change of frequency exceeds 0.8 Hz per second for a CE contingency | TBC investigation pending | System performance<br>Number and type of connection requests | Number and type of connection requests<br>Number and type of DER installations | Number and type of cyber security incidents | Number of vacancies for given technical roles |

Key: Grid Level Industry Wide

Table 2 – Indicators for monitoring opportunities and challenges

# 8.0 Summary and next steps for the programme

The Electricity Authority engaged the System Operator to consider the opportunities and challenges outlined in the Phase 1 report in detail and develop a work plan for each. The roadmap collates these work plans and thereby sets out an overall programme of work and sequencing. However it requires ongoing monitoring of opportunities and challenges and industry engagement to confirm the proposed sequencing over the coming years.

Phase 3 will include a clear change process to expedite necessary changes of scope or priority.

Figure 5 provides a visual summary of the roadmap.

The next steps for the Future Security and Resilience programme are:

- commence the Phase 3 programme
- monitor opportunities and challenges over time and track changes in future trajectory and reprioritise roadmap activities as required.

The Future Security and Resilience programme will integrate with the Electricity Authority's broader future work programme to support New Zealand to meet its energy goals.

# Future Security and Resilience
## Outcomes

### OPPORTUNITIES AND CHALLENGES

#### CHANGING GENERATION PORTFOLIO

**2022**

**Accommodating future changes within technical requirements**
- Parts 8, 6, 7, 13, 14 of the Code will be updated to incorporate the capability and performance of new technologies and changes in the power system.
- Harmonics standards and other engineering standards, modelling and testing standards will take into account the introduction of new technologies.
- The Policy Statement and any other policies, procedures, guidelines and tools will be updated accordingly.

**2025**

**Operating with low system strength**
- System strength performance criteria will be defined and established.
- The regulatory framework will be updated to include technical requirements for system strength.
- Develop suitable market products and tools.

**Balancing renewable generation**
- The market system, operational procedures and tools will allow the scheduling and dispatching of renewable generation.
- Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate.
- New or revised ancillary services will effectively manage active power imbalances.

**2027**

**Managing reducing system inertia**
- A frequency reserve strategy will be created.
- The updated Procurement Plan and testing methodologies will support assessment and procurement of new reserve types.
- Operational procedures and tools will be ready to dispatch new reserve types.

#### RISE OF DISTRIBUTED ENERGY RESOURCES

**Coordination of increased connections**
- All System Operator and distributor processes will be updated to accommodate increased connections.
- The Grid Owner, EDBs and the System Operator will have the resources and capability to commission DER.
- Updated market tools, real-time operational tools and study tools will reflect the behaviour and capability of DER.

**Enabling DER services for efficient power system operations**
- The Code will define the technology agnostic role of DER. The market system will accept offers from DER owners, and operational tools and procedures will assess and dispatch DER.
- Electricity markets, the Grid Owner, EDBs and the System Operator will send efficient signals to DER.
- Grid exit point aggregation and participation of third-party flexibility traders will be enabled.

**Visibility and observability of DER**
- The impact of high levels of DER will be understood and managed.
- The regulatory framework will accommodate a high degree of DER uptake.
- Operational requirements will be established between the System Operator and distributors/DSOs.

### SECURE AND RESILIENT POWER SYSTEM OPERATION

**FOUNDATIONS**
- Leveraging new technology to enhance ancillary services
- Maintaining cyber security
- Growing skills and capabilities of the workforce

Figure 5 – Summary of the Future Security and Resilience roadmap

# Appendix A Outcome proposals

# **Future Security and Resilience 1:** Enabling DER services for efficient power system operations

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | There is limited DER in the power system, and DER is not available for dispatch through the national electricity market. | **Won't be adequate because:** The value of DER will not be realised from either a consumer or a system perspective. The system needs to be able to leverage new technology to provide the services required for operating the grid at the lowest possible cost. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| The Code, the market system and operational processes enable the use of DER capability to both build and operate the future grid and lower costs for consumers. | To enable DER to participate in the electricity market, support system operations, deliver power system operations at lowest cost and assist with 'rightsizing' future electricity networks. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Ancillary service providers (existing and new)<br>Asset Owner (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Electricity market participants<br>Grid Owner<br>System Operator<br>WITS Manager |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The Code will define the technology agnostic role of DER. The market system will accept offers from DER owners who wish to participate in the wholesale electricity market or are required to participate because of their size. Operational tools and procedures will assess and dispatch DER which participates in the wholesale electricity market.<br>Electricity markets, the Grid Owner, Distributors and the System Operator will send efficient signals to DER.<br>Grid exit point aggregation and participation of third-party flexibility traders will be enabled. | **By** 2029 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The market will be more efficient, and technologies providing electricity supply will be more diverse, ultimately improving the security and reliability of the power system.<br>The lowering of network peaks will reduce network costs. | **Risk of action:**<br>Without consideration and broad engagement, ineffectiveness in market system and dispatch design for DER. | **Risk of inaction:**<br>Untapped resources and reduced observability, along with inefficient investment in generation and networks. Difficulty in terms of load forecasting for security and market operation, resulting in the need to carry more capacity reserve/ancillary services, which come at economic cost. | FSRs 2, 7 and 8 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority<br>System Operator | Electricity Authority<br>System Operator | Number of DER installations |

## Outcome Proposal: FSR 1.1 Enabling DER services for efficient power system operations – Enhance the Code and market system dispatch capability to accommodate DER bids and offers

### Problem description

| Timeframe | Current capability | Rationale |
| --- | --- | --- |
| **In** 3–7 years | Small-scale and/or aggregated DER is not able to be dispatched through the national market system. | **Won't be adequate because:** DER dispatch is not optimal, leading to inefficiencies in realising the value of DER. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
| --- | --- | --- | --- |
| Enhance the Code and wholesale market dispatch capability to accommodate willing and required DER participants to supply | To ensure that market dispatch capability can accommodate all participants who wish to be dispatched and those participants who are required to be dispatched. | See overall Outcome Proposal | Asset Owner (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Electricity market participants<br>System Operator<br>WITS Manager |

### Outcome

| Measurable objective | Timeframe |
| --- | --- |
| **The future state needs to look like:** DER will be included in the market design and the Code. | **By** 2027 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The market will be more efficient, and technologies providing electricity supply will be more diverse, ultimately improving the security and reliability of the power system.<br><br>The lowering of network peaks will reduce network costs. | **Risk of action:**<br>Without consideration and broad engagement, ineffectiveness in market system and dispatch design for DER. | **Risk of inaction:**<br>Untapped resources and reduced observability, along with inefficient investment in generation and networks.<br><br>Difficulty in terms of load forecasting for security and market operation, resulting in the need to carry more capacity reserve/ancillary services, which come at economic cost. | N/A |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## Outcome Proposal: FSR 1.2 Enabling DER services for efficient power system operations – Improve real-time security modelling within operational tools

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | No security assessment is carried out to assess the operational risk of DER. | **Won't be adequate because:** As uptake of DER increases, the risk of widespread DER disconnection or unanticipated DER response grows, which may lead to voltage or frequency excursion. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Improve modelling of DER within operational tools and update procedures to consider DER risk. | To ensure DER ability to actively and optimally support the security and reliability of supply is accounted for within operational tools and procedures. | See overall Outcome Proposal | Asset Owner (including DER)<br>DER flexibility traders<br>Distributors<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** DER can be dispatched in line with the dispatch of any other asset in the power system. | **By** 2026 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The impact of DER dispatch on the power system can be modelled and assessed, which in turn will increase the security and reliability of supply. | **Risk of action:** Modelling and procedures developed for DER dispatch assessment in operational tools inadequate and results in insecure or uneconomic system operation. | **Risk of inaction:** Failure to fully account for DER dispatch in operational tools and procedures, leading to insecure system operation. | FSRs 7.1, 7.2, 2.1, 1.3 and 1.1 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

## Outcome Proposal: FSR 1.3 Enabling DER services for efficient power system operations - Investigate new DER services to support efficient operation of the power system

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | The operation of the system does not take DER technology into account. | **Won't be adequate because:** DER can provide valuable services that will improve the security and reliability of the supply and utilisation of existing assets and reduce costs for consumers. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| No change: this is an investigation phase to explore the potential of DER technology. | To ensure the system fully utilises DER capability, to ultimately improve its operation. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset Owners (including DER)<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| The study will be completed. | **By** 2024 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The security and reliability of system operation will improve, system operational costs will reduce and utilisation of existing assets will increase. | **Risk of action:** Without consideration and broad engagement, ineffectiveness in market system and dispatch design for DER. | **Risk of inaction:** Failure to fully utilise DER capability, leading to less secure system operation. | New technologies, network configuration and FSRs 3.1 and 8 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 1** | **Overall outcome** | | | ✓ | ✓ | ✓ | | | | | |
| FSR 1.1 | Enhance the Code and market system dispatch capability to accommodate DER bids and offers | | | | ✓ | | | | | | |
| FSR 1.2 | Improve real-time security modelling within operational tools | | | | | ✓ | | | | | |
| FSR 1.3 | Investigate new DER services to support efficient operation of the power system | | | ✓ | | | | | | | |

# **Future Security and Resilience 2:** Visibility and observability of DER

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | Because DER operation is currently minimal, visibility and observability of DER is not essential: demand is easy to predict and forecast. | **Won't be adequate because:** Likely higher uptake of DER and more controllable demand means that the System Operator will require some visibility of DER to maintain balance within the power system. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Change the Code, operational procedures and tools to improve the visibility and observability of DER. | To ensure that the power system operates in a way that considers the behaviour of DER. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Asset Owners (including DER)<br>DER flexibility traders<br>Distributors<br>Electricity Market Participants<br>Electricity Authority<br>Grid Owner<br>System Operator |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The impact of high levels of DER will be understood and managed. The regulatory framework will accommodate a high degree of DER uptake. Operational requirements will be established between the System Operator and Distributors. | **By** 2027 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Information/data requirements for DER established to ensure parties have sufficient visibility and observability to enable secure system operation. | **Risk of action:**<br>Code or system changes and/or overly onerous costs to enable visibility reduce or impede industry participation, result in inefficient overreach and unnecessary workload for the System Operator and Distributors. | **Risk of inaction:**<br>Insecure system operation<br><br>Extra workload for System Operator and Distributors. | FSRs 1,3 and 7 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority<br>System Operator | Electricity Authority<br>System Operator | TBC - Investigation phase to establish the DER penetration levels which begin to impact system operation. |

## FSR 2.1: Visibility and observability of DER – Establish the impact of DER

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3 years | The impacts of DER on the system are not fully understood. | **Won't be adequate because:** Without fully understanding the impacts of DER at a system level, the System Operator will not be able to formulate appropriate operational measures |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| No change: this is an investigation phase to establish the potential system impacts of DER. | To establish operational measures to maintain the system's security. | See overall Outcome Proposal. | Asset Owners (including DER)<br>Distributors<br>Electricity Authority<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| Studies will be completed, and recommendations proposed. | **By** 2024 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The System Operator will understand how DER will impact the secure management of the power system and be able to prepare accordingly. | **Risk of action:** Wrong analysis resulting in incorrect decision-making. | **Risk of inaction:** Insecure system operation. | FSR 1.3 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

## FSR 2.2: Visibility and observability of DER – Determine the credible event risk of DER

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | DER technology is not registered in the Policy Statement as a credible contingency. | **Won't be adequate because:** The potential risk DER entails is not sufficiently understood; this could lead to insecure system operation. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Complete a credible event review (CER) to determine and classify the risk DER poses to system security. | To mitigate the risk that may result from widespread disconnection or the unstable operation of DER. | See overall Outcome Proposal | Asset Owners (including DER)<br>Electricity Authority<br>Electricity Market Participants<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** A CER will be completed and the Policy Statement updated. | **By** 2024 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Operation of the system will remain secure, and DER capabilities will be fully utilised. | **Risk of action:**<br>Wrong analysis resulting in wrong Credible Contingency risk categorisation and therefore incorrect management and inefficient economic outcomes. | **Risk of inaction:**<br>Failure to consider risk of DER operation, leading to insecure system operation. | FSRs 1.3 and 3. |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

## FSR 2.3: Visibility and observability of DER – Update the Code to clarify DER obligations and operational requirements

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | The obligations and operation requirements that apply to current grid-connected assets do not currently apply to DER. | **Won't be adequate because:** DER behaviour may increasingly influence the security of the grid and the operation of the system. The System Operator must consider DER behaviour during operation. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Change the Code to clarify the obligations and operational requirements relevant to DER. | To ensure that uptake of DER occurs according to an appropriate regulatory framework. | See overall Outcome Proposal | Asset Owners (including DER)<br>DER flexibility traders<br>Distributors<br>Electricity Market Participants<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The regulatory framework will be updated to establish operational requirements between the System Operator and Distributors. | **By** 2025 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Improved clarity in terms of operational requirements will allow relevant parties to work together to ensure the secure operation of the system. | **Risk of action:**<br>Code changes overly onerous, increase costs which reduce or impede industry participation, resulting in extra workload for the System Operator and Distributors. | **Risk of inaction:**<br>Insecure system operation | FSRs 3.1, 3.2 and 7 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 2.4: Visibility and observability of DER – Update procedures and tools to include DER asset information

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | Security analysis, in real-time dispatch and offline studies, does not consider the influence of DER. | **Won't be adequate because**: DER behaviour may increasingly influence the security of the grid and the operation of the system. The System Operator must address this. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Ensure that DER asset information is available to support overall system operability, and updated operational procedures and tools. | To increase the visibility and observability of DER, to enable improved demand forecasting, outage assessments, security of supply modelling, system security forecasts and annual security assessment, among other procedures and tools, and thereby ultimately enhance the secure operation of the system. | See overall Outcome Proposal | Asset Owners (including DER)<br>DER flexibility traders<br>Distributors<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** An operational framework and information and modelling requirements will be established. | **By** 2026 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Improved visibility of DER will enable the system to operate securely with a high uptake of DER. | **Risk of action:**<br>Increasing visibility will increase DER asset information potentially increasing pressure on resources to effectively incorporate DER into system operation. | **Risk of inaction:**<br>Insecure system operation. | FSRs 3.1, 3.2 and 7 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 2** | **Overall outcome** | | | ✓ | ✓ | ✓ | | | | | |
| FSR 2.1 | Establish the impact of DER | | | ✓ | | | | | | | |
| FSR 2.2 | Determine the credible event risk of DER | | | ✓ | | | | | | | |
| FSR 2.3 | Update the Code to clarify DER obligations and operational requirements | | | | ✓ | | | | | | |
| FSR 2.4 | Update procedures and tools to include DER asset information | | | | | ✓ | | | | | |

# **Future Security and Resilience 3:** Coordination of increased connections

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 0–3 years | New Zealand has a centralised power system characterised by fewer and bigger generating stations, requiring less effort to manage the connection/commissioning process and operation. | **Won't be adequate because:** An exponential increase in connections is likely, due to increasing uptake of DER and smaller generating units. The System Operator will need to put more effort in to commissioning generating stations and maintaining the safe and reliable operation of the system. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Update the Grid Owner's and the System Operator's processes to accommodate a likely increase in connections.<br><br>Update benchmark agreement. | To ensure optimal assessments of the impact of connecting DERs and optimal connection processes, thereby ultimately ensuring that the power system operates securely, and market outcomes are efficient. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Asset owners (including DER)<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** All System Operator and Distributor processes will be updated to accommodate increased connections. The Grid Owner, Distributors and the System Operator will have the resources and capability to commission DER. Updated market tools, real-time operational tools and study tools will reflect the behaviour and capability of DER. | **By** 2025 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Efficient and secure DER connection. | **Risk of action:**<br>Inappropriate new connection risk assessments, eroding system security and/or adding unnecessary time and costs. | **Risk of inaction:**<br>Lack of effective integration of DER into system operation, resulting in lost opportunities, insecure operation and delays to the energy transition.<br><br>Significant levels of DER connecting to distribution networks may be set up with operational response parameters that adversely affect grid security and reliability. | FSRs 1, 2 and 7 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority<br>System Operator | Electricity Authority<br>Grid Owner<br>System Operator | Number, location and type of connections requests |

## FSR 3.1: Coordination of increased connections – Update the Grid Owner and System Operator commissioning processes and benchmark agreement

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 0–2 years | The Grid Owner and System Operator commissioning processes and benchmark agreement as well as Distributor processes and guidelines are based on the current power system, and have evolved around the requirements of the Code, focusing on generating stations that have obligations to support grid operation. | **Won't be adequate because:** Processes and guidelines need to reflect the inverter technology that DER entails and ensure robust commissioning and testing processes. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Update Grid Owner and System Operator processes and the benchmark agreement. | To ensure the timely and efficient integration of DER into the system. | See overall Outcome Proposal | Asset owners (including DER)<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The Grid Owner, Distributors and the System Operator will have adequate commissioning processes and an updated benchmark agreement which incorporates the capability to commission DER. | **By** 2023–2024 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The effort required of the System Operator and Distributors to commission DER and facilitate the efficient connection of DER to the network will reduce. | **Risk of action:**<br>Inappropriate new connection risk assessments, eroding system security and/or adding unnecessary time and costs. | **Risk of inaction:**<br>Delays in commissioning.<br><br>Lack of clear technical requirements resulting in undesirable DER performance.<br><br>An inability to effectively manage multiple station commissioning risks. | FSRs 1, 2 and 7 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority<br>System Operator | Electricity Authority<br>Grid Owner<br>System Operator | See overall Outcome Proposal |

## FSR 3.2: Coordination of increased connections – Review the approach to planning and connection studies

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 1–3 years | The System Operator carries out planning and connection studies for individual generating stations as needed. | **Won't be adequate because:** As the number of individual generating stations increases, the current process for planning and connection studies will become less feasible. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Develop a new approach to planning and running connection studies that is fit for purpose within the new environment. | To reduce the effort required to carry out planning and connection studies and thereby ensure adequate assessment of the impacts of new connections. | See overall Outcome Proposal | Asset owners (including DER)<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The System Operator will implement revised planning processes and connection studies to assess new connections. | **By** 2024–2025 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The effort and cost required of asset owners to complete connection studies will reduce.<br><br>New assets will operate securely and stably. | **Risk of action:**<br>Inappropriate new connection risk assessments, eroding system security and/or adding unnecessary time and costs. | **Risk of inaction:**<br>Inefficient connection processes and insecure system operation, unnecessary delays in connecting new assets. | FSRs 7, 8.1 and 8.2 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

## FSR 3.3: Coordination of increased connections – Review operational study tools

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 1–3 years | The System Operator tools only model grid-connected stations in detail. They currently model embedded resources and DER as equivalent. | **Won't be adequate because:** There is uncertainty about how to model DER. Equivalent models are good enough for MW dispatch, but inadequate for detailed study related to voltage and system stability. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Review operational study tools used for connection assessment and modelling purposes. | To enable power system operations to benefit from the capability of DER. | See overall Outcome Proposal | System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Updated market tools, real-time operational tools and study tools used for modelling purposes to reflect the behaviour and capability of DER. | **By** 2023–2024 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The effort required of the System Operator to commission DER and facilitate the efficient connection of DER to the system will reduce. | **Risk of action:** Inappropriate new connection risk assessments, eroding system security and/or adding unnecessary time and costs. | **Risk of inaction:** Inefficient connection processes and insecure system operation. | FSRs 7 and 8.1 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 3** | **Overall outcome** | ✓ | ✓ | | | | | | | | |
| FSR 3.1 | Update the Grid Owner and System Operator commissioning processes and benchmark agreement | ✓ | ✓ | | | | | | | | |
| FSR 3.2 | Review the approach to planning connection studies | | ✓ | | | | | | | | |
| FSR 3.3 | Review operational study tools | | ✓ | ✓ | | | | | | | |

# **Future Security and Resilience 4:** Balancing renewable generation

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | A low proportion of variable generation. Conventional generation is highly dispatchable and controllable, ensuring relative certainty in terms of the ability of available generation to meet demand. | **Won't be adequate because:** An increasing proportion of variable generation making forecasting and maintaining security more challenging. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Make changes to the Code and the System Operator's operational procedures and tools to accommodate an increasing proportion of variable renewable generation. | To ensure that dispatch efficiently accommodates the intermittency and variability of renewable generation and ensure enough generation can be dispatched to meet demand. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Ancillary service providers (existing and new)<br>Asset Owners (including DER)<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The market system, operational procedures and tools will enable the scheduling and dispatch of renewable generation.<br>Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate.<br>New or revised ancillary services will effectively manage active power imbalances. | **By** 2027 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Better balancing of supply and demand improving system security. | **Risk of action:**<br>The development of Code and operational procedures and tools that are not fit for purpose and/or uneconomic to implement | **Risk of inaction:**<br>Inability to balance the variability of renewable generation in real time, resulting in load shedding or inefficient operation and scheduling of the generation fleet | FSR 1 and 2 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | Number of frequency and voltage excursions outside acceptable limits |

## FSR 4.1: Balancing renewable generation – Improve market system and generation/demand forecast

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3 years | Generation is offered to the market for at least 36 hours ahead of real time. Intermittent generators must offer for the next two hours, based on their current output.<br><br>The System Operator forecasts confirming demand. | **Won't be adequate because:** As the proportion of intermittent generation offers increases, the likelihood of inaccuracy in the forward supply curve will also increase. Basing offers for the next two hours on current output does not take account of variance in generation output that is known (sunrise/sunset) or expected (changes in wind or cloud cover).<br><br>As the variability in the supply curve increases, the accuracy of the demand forecast becomes increasingly important. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Ensure the obligations the Code places on the formulation of intermittent generation offers are designed to produce the best quality offers, from initial submission through to use in real time.<br><br>Ensure the System Operator's demand forecast is sufficiently accurate. | To reduce the proportion of inaccurate offers, inaccurate demand forecasts and any combined inaccuracies, and thereby ultimately ensure the security and reliability of the system. | See overall Outcome Proposal | Asset Owners (including DER)<br>Electricity Authority<br>Electricity market participants<br>System Operator |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate. | **By** 2026 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Accurate intermittent generation offers, and demand forecasts will enable the market and the System Operator to balance the variance in renewable generation outputs and operate a secure and reliable power system. | **Risk of action:**<br>Increased costs of offering intermittent generation potentially discouraging participation. | **Risk of inaction:**<br>Inability to balance the variability of renewable generation in real time, resulting in load shedding or inefficient operation and scheduling of the generation fleet | FSR 3 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority) | System Operator | See overall Outcome Proposal |

## FSR 4.2: Balancing renewable generation – Consider new or revised ancillary services to maintain balancing

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3 years | Frequency keeping ancillary services maintain small active power imbalances. | **Won't be adequate because:** The highly intermittent nature of some renewable generation will decrease the effectiveness of the current process. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Ensure that the System Operator's Procurement Plan, testing and operational procedures are appropriate for an increasing proportion of variable renewable generation. | To ensure system frequency is maintained within the normal band. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset Owners (including DER)<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** New or revised ancillary services will effectively manage active power imbalances. | **By** 2027 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Improving balancing capability will reduce the impacts of renewable intermittency and allow the System Operator to maintain system frequency within the normal band. | **Risk of action:**<br>Incorrect changes to existing or new ancillary services identified which are insufficient to maintain balancing and/or are uneconomic to implement | **Risk of inaction:**<br>Inability to balance the variability of renewable generation in real time, resulting in load shedding or inefficient operation and scheduling of the generation fleet. | FSRs 1.3 and 2.1 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 4** | **Overall outcome** | | | ✓ | ✓ | ✓ | | | | | |
| FSR 4.1 | Improve market system and generation/demand forecast | | | ✓ | ✓ | | | | | | |
| FSR 4.2 | Consider new or revised ancillary services to maintain balancing | | | | | ✓ | | | | | |

# **Future Security and Resilience 5:** Managing reducing system inertia

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 7–10 years | Following a contingency, the System Operator schedules frequency reserves to manage frequency within the operational limits. | **Won't be adequate because:** IBR generation will increasingly displace synchronous generation, reducing system inertia and making present frequency reserve ineffective in managing fast rate of change frequency events. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Create a new frequency management strategy to manage low inertia | To improve the System Operator's ability to manage frequency following a contingency. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Ancillary service providers (existing and new)<br>Asset Owner (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Electricity Authority<br>Electricity Market Participant<br>System Operator<br>WITS Manager |

## Outcome

| Measurable objective | Timeframe |
| --- | --- |
| **The future state needs to look like:** A new frequency reserve strategy will be created. The updated Procurement Plan and testing methodologies will support assessment and procurement of new reserve types. Operational procedures and tools will be ready to dispatch new reserve types. | **By** 2029 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
| --- | --- | --- | --- |
| The efficiency of the operation of the market will improve, along with the security of the system. | **Risk of action:**<br>Sub optimal and/or uneconomic frequency reserve strategy and ancillary services developed. | **Risk of inaction:**<br>Avoidable costs are incurred managing a low inertia system using existing ancillary services. | FSRs 1, 2 and 4 |

## Governance

| Business owner | Delivered by | Priority indicator |
| --- | --- | --- |
| Electricity Authority<br>System Operator | Clearing Manager<br>Electricity Authority<br>System Operator<br>WITS Manager | Number of instances where rate of change of frequency exceeds 0.8 Hz per second for a contingency |

## FSR 5.1: Managing reducing system inertia – Create a frequency reserve strategy to manage low inertia

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 7–10 years | Following an under-frequency contingency, the System Operator dispatches fast and sustained instantaneous reserves to manage frequency. | **Won't be adequate because:** The system will increasingly be characterised by low inertia. A new reserve type will need to be developed to respond to this. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| No change: this is an investigation phase to determine the right reserve type for a low-inertia system and to inform Code changes. | To ensure the effective operation of the system. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset Owner (including DER)<br>DER flexibility traders<br>Electricity Authority<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| The study will be completed and inform the development and implementation of a new reserve strategy. | **By** 2029 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| An efficient frequency reserve strategy is developed which considers the changing generation mix.<br><br>Right reserve type identified for more effective management of fast rate of change frequency events. | **Risk of action:**<br>Investigation results in suboptimal and/or uneconomic frequency reserve strategy. | **Risk of inaction:**<br>Avoidable costs are incurred managing a low inertia system using existing ancillary services. | FSRs 1.3, 2.1 and 4.2 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 5.2: Managing reducing system inertia – Ensure the Code defines and market system can accommodate new reserve types

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 7–10 years | The functionality of the market system aligns with the current reserve products. | **Won't be adequate because:** The market system needs to accommodate the dispatch, scheduling and optimisation of new reserve products. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Ensure that the market system can accept offers, schedule and dispatch new reserve products, and that the market system's invoicing and payments processes accommodate these new products.<br><br>Ensure that these changes are reflected in the Code and associated documents. | To ensure system frequency is maintained within the normal band. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset Owners (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Electricity Authority<br>Electricity Market Participants<br>System Operator<br>WITS Manager |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** To be determined following the development of the strategy outlined in 5.1. | **By** 2030 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The Code and market system will support the implementation of the frequency reserve strategy. | **Risk of action:**<br>Change in the market system for the wrong reserve types or misalignment with needs/operating procedures results in suboptimal and/or uneconomic frequency management. | **Risk of inaction:**<br>Avoidable costs are incurred managing a low inertia system using existing ancillary services. | FSRs 5, 5.1, 5.3 and 5.4 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Clearing Manager<br>Electricity Authority<br>System Operator<br>WITS Manager | See overall Outcome Proposal |

## FSR 5.3: Managing reducing system inertia – Incorporate new reserve types in the Procurement Plan and testing methodology

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 7–10 years | The Procurement Plan specifies technical requirements of current reserve types, and the testing methodology assesses asset capabilities. | **Won't be adequate because:** New reserve types will require new technical requirements and different testing methodologies. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Ensure the System Operator's Procurement Plan and testing methodologies take new reserve types into account. | To ensure system frequency is maintained within the normal band. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>DER flexibility traders<br>Electricity Authority<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The updated Procurement Plan and testing methodologies will support the assessment and procurement of new reserve types. | **By** 2030 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Frequency management capability will improve, thereby improving market efficiency and supply security. | **Risk of action:** Procurement and test processes updates are not flexible enough to respond to changing reserve strategy over time and/or uneconomic to implement. | **Risk of inaction:** Avoidable costs are incurred managing a low inertia system using existing ancillary services. | FSR 5.1 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 5.4: Managing reducing system inertia – Update operational procedures and tools

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 7–10 years | Operational procedures and reserve management tools assess reserve requirements for scheduling and dispatching. | **Won't be adequate because:** New reserve types will require new operational procedures and reserve management tools. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Ensure the System Operator's operational procedures and tools take new reserve types into account. | To ensure system frequency is maintained within the normal band. | See overall Outcome Proposal | System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Operational procedures and tools will be ready to dispatch new reserve types. | **By** 2030 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The System Operator's ability to manage frequency following an under-frequency event in a lower-inertia system will improve, which will benefit the market and improve the security of supply. | **Risk of action:**<br>Suboptimal implementation resulting in uneconomic frequency management. | **Risk of inaction:**<br>Unable to efficiently operate new reserve type results in uneconomic outcomes. | FSRs 5.1 and 5.2 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 5** | **Overall outcome** | | | | | | | ✓ | | | |
| FSR 5.1 | Create a frequency reserve strategy to manage low inertia | | | | | | | ✓ | | | |
| FSR 5.2 | Ensure the Code defines and market system can accommodate new reserve types | | | | | | | | ✓ | | |
| FSR 5.3 | Incorporate new reserve types in the Procurement Plan and testing methodology | | | | | | | | ✓ | | |
| FSR 5.4 | Update operational procedures and tools | | | | | | | | ✓ | | |

# Future Security and Resilience 6:
System strength

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | The system is characterised by a high proportion of synchronous generation and a low proportion of IBR generation. Synchronous generation is a positive contributor to the strength of the system. | **Won't be adequate because:** The increasing proportion of IBR generation will lower system strength, potentially causing abnormal performance, instability and generation loss. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Investigate the challenge of low system strength, then define an acceptable performance assessment criterion and update the Code accordingly, to define a baseline for system performance and associated market products.<br><br>Implement supporting operational procedures and tools. | To ensure assets remain connected and operate securely and stably during and following voltage disturbances caused by a fault. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator<br>WITS Manager |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** System strength performance criteria will be defined and established. The regulatory framework will be updated to include technical requirements for system strength. Relevant market products, operational procedures and tools will be in place. | **By** 2029 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Ensuring that IBR can ride through system fault will ultimately improve the security and reliability of the system. | **Risk of action:** Unintended consequences such as additional costs incurred to meet system strength performance criteria. | **Risk of inaction:** Suboptimal performance of assets, or IBR being disconnected or operating unstably following a system fault, which may lead to an under-frequency event or system-wide disturbances.<br><br>Inefficient incentives on those causing increased costs to manage them. | FSRs 1 and 8 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | TBC - Investigation phase to develop a monitoring mechanism for system strength |

## FSR 6.1: Operating with low system strength – Investigate system strength challenges and opportunities

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–4 years | Clause 8.25A and 8.25B of Part 8 of the Code sets out assessment criteria related to fault ride-through capability and reactive current and active power output. No other technical requirements specify IBR performance requirements under low system strength conditions. | **Won't be adequate because:** Clause 8.25A and 8.25B do not specify the levels of system strength that must be maintained, so new resources may not be able to connect to the system or generate, and any cost of maintaining system strength will not be efficiently allocated. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Undertake an initial assessment to define a baseline for system strength in New Zealand and performance criteria to complement Clause 8.25A and 8.25B of Part 8 of the Code | To ensure performance levels for IBR are appropriate and ultimately maintain the secure and stable operation of the system | See overall Outcome Proposal | Asset owners (including DER)<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| Studies will be completed, and performance criteria will be defined. | **By** 2026 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Clarity of requirements will guide asset owners when they are procuring IBR, and the effort required for the System Operator to check compliance will reduce. | **Risk of action:** Wrong analysis resulting in incorrect localised system strength thresholds. | **Risk of inaction:** Suboptimal performance of assets connected to the power system, leading to degradation of system conditions as a whole and a potential negative impact on other connected assets.<br><br>Inefficient incentives on those causing increased costs to manage them. | FSRs 1.3 and 8 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | System Operator | See overall Outcome Proposal |

## FSR 6.2: Operating with low system strength – Amend the Code to support performance criteria

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In 4** years | The Code does not specify technical requirements for the operation of IBR in low-system-strength conditions. | **Won't be adequate because:** As the uptake of IBR increases, clearly defined technical requirements will facilitate the secure and stable operation of all generation technologies. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Amend the Code with additional clauses relevant to support system strength. | To ensure performance levels for IBR are appropriate and ultimately maintain the secure and stable operation of the system. | See overall Outcome Proposal | Asset owners (including DER)<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Part 8 of the Code will be updated to include requirements for system strength. | **By** 2026 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Clear criteria will guide asset owners when they are procuring assets, and the effort required for the System Operator to check compliance will reduce. | **Risk of action:**<br>Code changes developed are too conservative, leading to a slowed uptake of technology and/or uneconomic implementation costs.<br><br>Code changes are not effective leading to ongoing security risks, inefficiencies and costs. | **Risk of inaction:**<br>Suboptimal performance of assets connected to the power system, leading to degradation of system conditions as a whole and a potential negative impact on other connected assets.<br><br>Inefficient incentives on those causing increased costs to manage them. | FSRs 1.3, 6.1 and 6.2 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 6.3: Operating with low system strength – Develop suitable market products and tools

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 3–7 years | There are no products in the market or operational tools able to dispatch resources to provide adequate system strength to allow the system to operate securely and stably. | **Won't be adequate because:** As uptake of IBRs increases, system strength may drop below an acceptable level. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Develop suitable market products to dispatch system strength to meet any shortfall. | To ensure system strength does not drop below the level that can cause IBR to operate below the defined performance level. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator<br>WITS Manager |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Products and operational tools to dispatch resources to provide additional system strength will be on the market. | **By** 2024–2028 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The operation of assets will become more cost-effective and secure. | **Risk of action:**<br>Wrong implementation, leading to suboptimal operation | **Risk of inaction:**<br>Suboptimal performance of assets connected to the power system, leading to degradation of system conditions as a whole and a potential negative impact on other connected assets.<br><br>Inefficient incentives on those causing increased costs to manage them. | FSRs 1.3, 6.1 and 6.2 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 6** | **Overall outcome** | | | ✓ | ✓ | ✓ | ✓ | ✓ | | | |
| FSR 6.1 | Investigate system strength challenges and opportunities | | | ✓ | ✓ | | | | | | |
| FSR 6.2 | Amend the Code to support performance criteria | | | | ✓ | ✓ | | | | | |
| FSR 6.3 | Develop suitable market products and tools | | | ✓ | ✓ | ✓ | ✓ | ✓ | | | |

# **Future Security and Resilience 7:** Accommodating future changes within technical requirements

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 0–3 years | The Code, technical standards and operational procedures are based on a centralised generation model and a high proportion of synchronous generation. | **Won't be adequate because:** Increasing uptake of DER and IBR is expected to change the direction of power flow and the behaviour of the system, rendering the Code, standards and procedures not fit-for-purpose. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Review and update the Code and ensure alignment of all other standards, operating procedures, processes and practices. | To ensure assets are dispatched and the power system is operating in a secure and efficient manner. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Academic institutions<br>Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Distributors<br>EEA<br>Electricity Authority<br>Electricity Market Participants<br>Grid Owner<br>Ministry of Business, Innovation & Employment<br>Standards New Zealand<br>System Operator<br>WorkSafe |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Parts 8, 6, 7, 13 and 14 of the Code will be updated to incorporate the capability and performance of new technologies and changes in the power system. Harmonics standards and other engineering standards, modelling and testing standards will take into account the introduction of new technologies. The Policy Statement and any other policies, procedures, guidelines and tools will be updated accordingly. | **By** 2025 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Use of new-generation technologies will be optimal and efficient, ensuring the system remains secure and maintaining the quality of the supply. | **Risk of action:**<br>Code and technical standard updates that are not inclusive and flexible enough to support evolving technology; a resulting need for ongoing amendments and/or are uneconomic to implement. | **Risk of inaction:**<br>Insecure system operation and inefficient market operation, affecting the security, quality and cost of electricity supply.<br><br>Operation being constrained by outdated regulation.<br><br>Investors uncertain of asset performance obligations. | FSRs 1, 3 and 8 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority<br>System Operator | Electricity Authority<br>System Operator | System performance<br>Number and type of connection requests |

## FSR 7.1: Accommodating future changes within technical requirements – Review and update Part 8 of the Code

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 0–2 years | The technical requirements and asset owner performance obligations set out in Part 8 of the Code have been designed to support the operation of the current system, which features high levels of synchronous generation technology. | **Won't be adequate because:** Increasing uptake of new IBR generation technology will require new technical requirements and asset owner performance obligations. |

### Opportunity statement

| What is the change required? | Why is it required? | Which EA strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Review and update Part 8 of the Code. | To ensure the technical requirements in Part 8 are aligned to new generation technologies. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Electricity Market Participants<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Part 8 of the Code will be updated. | **By** 2024 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The power system will continue to be operated securely, reliably and cost-effectively.<br><br>Clear requirements are established for IBR. | **Risk of action:**<br>Incorrect Code change, leading to suboptimal operation and/or are uneconomic to implement | **Risk of inaction:**<br>Inability of the System Operator to plan for and to meet its principal performance obligations (PPOs) which negatively impacts consumers.<br><br>Investors uncertain of asset performance obligations. | New technology and system requirements |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 7.2: Accommodating future changes within technical requirements – Review and update Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 1–3 years | The Code has been designed for a power system characterised by a high degree of centralised generation and highly distributed passive loads. | **Won't be adequate because:** Increasing uptake of DER will change the generation profile of the system. The Code needs to reflect this, to allow maximum use of DER (for example, through participation in the system operation and provision of ancillary services). |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Review Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8. | To ensure the technical performance of DER is aligned to Part 8 of the Code and enable DER to offer ancillary services, thereby ensuring the effective operation of the power system and market system. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Distributors<br>Electricity Authority<br>Electricity Market Participants<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Parts 6, 7, 13 and 14 of the Code will be updated. | **By** 2024–2025 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The power system will continue to be operated securely, reliably, and cost-effectively.<br><br>Requirements are aligned with Part 8 for IBR. | **Risk of action:**<br>Incorrect Code change, leading to suboptimal operation and/or uneconomic to implement. | **Risk of inaction:**<br>Limitation of potential benefits from DER, reducing investment return, potentially constraining the system and reducing the security of supply.<br><br>Investors uncertain of asset performance obligations. | New technology and system requirements |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 7.3: Accommodating future changes within technical requirements – Identify standards to support technical requirements in the Code

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 1–3 years | New Zealand engineering standards (such as AS/NZS 4777.2 Grid connection of energy systems via inverters, Part 2: Inverter requirements) reflect conditions in other power systems, and may not be sufficiently fit for purpose for use with the New Zealand power system. | **Won't be adequate because:** New Zealand standards should be aligned to this country's specific operational requirements, to ensure the security of the system. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Identify standards to support the technical requirements in the Code, and work with the EEA and other relevant institutions to adopt new or adapt or replace the current standards. | To ensure appropriate standards are in place that ultimately maintain and ideally improve the security of the system | See overall Outcome Proposal | Academic institutions<br>Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>Distributors<br>EEA<br>Electricity Authority<br>Grid Owner<br>Ministry of Business, Innovation & Employment<br>Standards New Zealand<br>System Operator<br>WorkSafe |

## Outcome

| Measurable objective | Timeframe |
| --- | --- |
| **The future state needs to look like:** Relevant engineering standards (for example, standards about inverter performance), modelling and testing standards will be updated. | **By** 2023–2032 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
| --- | --- | --- | --- |
| Appropriate standards will guide asset performance, ultimately improving the security and quality of the supply.<br>Standards that apply across the entire New Zealand system will be coherent across transmission and distribution networks, enabling of new technologies, and fit for purpose in a synchronous power system. | **Risk of action:**<br>Incorrect standards selected or changed, leading to suboptimal operation and/or are uneconomic to implement. | **Risk of inaction:**<br>Reduced supply security or quality leading to higher operational costs. | New technology and equipment capabilities |

## Governance

| Business owner | Delivered by | Priority indicator |
| --- | --- | --- |
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 7.4: Accommodating future changes within technical requirements – Update the Policy Statement to manage emerging risks

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 0–3 years | The Policy Statement defines the risks and detailed procedures to support the System Operator to achieve various PPOs and other deliverables. The Policy Statement is based on the current power system and has compulsory review periods more relevant to a steady state operating environment. | **Won't be adequate because:** The Policy Statement needs to reflect and accommodate a power system characterised by a greater proportion of DER and a more complex power flow. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Undertake risk analysis to identify and quantify new risks and derive procedures to manage them. | To ensure the System Operator can manage new risks and thereby maintain the security and reliability of the system. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>Distributors<br>Electricity Authority<br>Grid Owner<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The Policy Statement will be reviewed and updated. | **By** 2023 and otherwise within the maximum periods between reviews set out in the Code |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Cascade failure and the unnecessary constraint of assets will be avoided. | **Risk of action:**<br>Analysis resulting in wrong credible event risk categorisation and therefore management and economic outcomes. | **Risk of inaction:**<br>Impact of unknown risks on the operation of the power system, potentially leading to cascade failure and poor supply quality. | FSRs 3.2, 7.1, 7.2 and 7.3 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 7.5: Accommodating future changes within technical requirements – Update the System Operator's policies, procedures, guidelines and tools

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** 0–3 years | The System Operator's policies, procedures, guidelines and tools are designed to achieve its PPOs and other deliverables according to the Code, based on the current power system. | **Won't be adequate because:** The System Operator's policies, procedures, guidelines and tools need to reflect and accommodate a power system characterised by an increasing proportion of DER and the consequently increasingly more complex operating conditions anticipated. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Update the System Operator's policies, procedures, guidelines and tools for the power system and the electricity market. | To ensure the secure and efficient operation of the power system and the electricity market. | See overall Outcome Proposal | System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** Policies, procedures, guidelines and tools will be updated to consider the introduction of new technologies. | **By** 2024–2026 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Asset capability will improve, along with the security and efficient operation of the system and the electricity market as a whole. | **Risk of action:** Incorrect implementation resulting in insecure and inefficient operation. | **Risk of inaction:** Reduced supply security or quality leading to higher operational costs. | FSRs 7.1, 7.2, 7.3 and 7.4 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 7** | **Overall outcome** | ✓ | ✓ | ✓ | | | | | | | |
| FSR 7.1 | Review and update Part 8 of the Code | ✓ | ✓ | | | | | | | | |
| FSR 7.2 | Review and update Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8 | | ✓ | ✓ | | | | | | | |
| FSR 7.3 | Identify standards to support technical requirements in the Code | ✓ | ✓ | ✓ | | | | | | | |
| FSR 7.4 | Update the Policy Statement to manage emerging risks | ✓ | | | | | | | | | |
| FSR 7.5 | Update the System Operator's policies, procedures, guidelines and tools | | ✓ | ✓ | | | | | | | |

# **Future Security and Resilience 8:** Leveraging new technology to enhance ancillary services

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| Enduring | Ancillary services were designed to manage the power system to meet Code requirements – both in terms of products needed and the technologies that can deliver those products. | **Won't be adequate because:** New technologies are capable of providing some of the existing ancillary services. They are also capable of providing new ancillary services, if needed, to maintain the same level of supply security and reliability.<br>Enabling new technologies to provide ancillary services allows asset owners access to additional revenue streams, enabling value stacking, which may increase the uptake of new technologies and reduce unnecessary entry barriers in relevant markets. |

## Opportunity statement

| What is the change required? | Why is it required? | Which EA strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Enable new technologies to offer ancillary services.<br>Redefine the ancillary services required to meet grid reliability standards to accommodate increasing levels of DER and IBR. | To make the best use of the capabilities of new technologies and, potentially, to maintain the secure operation of the power system at lower overall cost to consumers. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Ancillary service providers (existing and new)<br>Asset Owners (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Electricity Authority<br>System Operator<br>WITS Manager |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The regulatory framework, engineering standards and procedures will be updated to reflect the capability and performance of new technologies and other changes within the power system. The Code will enable new technologies to offer ancillary services, and the System Operator's processes and tools will allow new technologies to participate on a level playing field with existing providers. | **By** 2025 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Market operation will be more efficient, and system operation more secure. | **Risk of action:**<br>Without proper analysis or industry engagement, enhancements to ancillary services introduce inefficiencies and/or are uneconomic to implement. | **Risk of inaction:**<br>Failure to make full use of the capabilities of new technologies to manage credible risks and increase competition and efficiency. | FSRs 1, 7 and 8 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Clearing Manager<br>Electricity Authority<br>System Operator<br>WITS Manager | Number and type of connection requests<br><br>Number and type of DER installations |

## FSR 8.1: Leveraging new technology to enhance ancillary services – Investigate changes to ancillary services

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In:** 3–7 years | Ancillary services are procured under annual contracts. Frequency regulation and contingency reserve are scheduled in real time through market optimisation. | **Won't be adequate because:** The System Operator may need to procure different forms of frequency reserve and voltage regulation reserve and may need to consider different scheduling requirements due to changes in power system behaviour caused by uptake of new technologies. Providers of new technology-enabled products will push for market access. |

### Opportunity statement

| What is the change required? | Why is it required? | Which EA strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| No change: this is an investigation phase to determine changes to existing ancillary services to allow greater participation from new technology. | To ensure the System Operator procures the right type of services to manage the power system at the lowest cost to consumers. | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>DER flexibility traders<br>Electricity Authority<br>System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| Studies will be completed, and recommendations proposed. | **By** 2024 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The System Operator will better understand how to adapt ancillary services to accommodate new technology for managing the power system securely. | **Risk of action:** Incorrect analysis or poor industry engagement, identifies enhancements to ancillary services which introduce inefficiencies and/or are uneconomic to implement. | **Risk of inaction:** Ineffective and inefficient system operation. | FSR 1.3 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority | Electricity Authority<br>System Operator | See overall Outcome Proposal |

## FSR 8.2: Leveraging new technology to enhance ancillary services – Ensure tools monitor the performance of the power system

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In:** 3–7 years | The current real-time power system tools can model the performance of the existing ancillary services and their current means of provision. | **Won't be adequate because:** Current real-time power system tools may not be able to accurately model new means of provision of ancillary services (such as batteries), or they may not be able to accurately model new ancillary services. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Ensure the right tools are in place to monitor the performance of the power system, particularly in a post-event state | To ensure the power system continues to operate in a safe and secure manner | See overall Outcome Proposal | System Operator |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The System Operator will be ready to accurately model new technologies for provision of ancillary services and new ancillary services to support the operation of the system. (The timeframe for the ability to model new ancillary services cannot be established until these services are designed: see FSR 2.1.) | **By** 2025 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The power system will continue to operate securely, including when ancillary services are being provided from new technology. | **Risk of action:**<br>Tool update costs exceeding the benefits of enabling new technology including DER to provide ancillary services. | **Risk of inaction:**<br>Insecure system operation | FSRs 2.1 and 2.3 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| System Operator | System Operator | See overall Outcome Proposal |

## FSR 8.3: Leveraging new technology to enhance ancillary services – Update Code, market system and Procurement Plan to enable new technology to provide ancillary services

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In:** 3–7 years | Market system tools are designed around the current provision of the existing set of ancillary services. | **Won't be adequate because:** As DER uptake increases, the ability for DER to provide ancillary services increases too. Maintaining the status quo locks DER out of a potential revenue stream, limits competition in the ancillary services market and eliminates the opportunity to leverage the technical capability of DER to provide ancillary services. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Update the Code, market system and Procurement Plan to enable provision of existing ancillary services from new technology. | To enhance and increase competition in the ancillary services market and maintain the security of the power system | See overall Outcome Proposal | Ancillary service providers (existing and new)<br>Asset owners (including DER)<br>Clearing Manager<br>DER flexibility traders<br>Electricity Authority<br>System Operator<br>WITS Manager |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The System Operator will be ready to make full use of the capabilities of new technologies to support the operation of the system. | **By** 2026 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Market operation will be more efficient, and system operation more secure.<br><br>New technology, including DER, will be able to compete equitably in ancillary service markets. | **Risk of action:**<br>The cost of updates to the market system exceeding the benefits delivered. | **Risk of inaction:**<br>Suboptimal use of new technologies and their capabilities.<br><br>Increased ancillary service costs. | FSRs 2.1 and 2.3 |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Electricity Authority<br>System Operator | Clearing Manager<br>Electricity Authority<br>System Operator<br>WITS Manager | See overall Outcome Proposal |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 8** | **Overall outcome** | | | ✓ | ✓ | | | | | | |
| FSR 8.1 | Investigate changes to ancillary services | | | ✓ | | | | | | | |
| FSR 8.2 | Ensure tools monitor the performance of the power system | | | | ✓ | | | | | | |
| FSR 8.3 | Update Code, market system and Procurement Plan to enable new technology to provide ancillary services | | | | ✓ | | | | | | |

# Future Security and Resilience 9:
## Maintaining cyber security

### Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** Enduring | Adequate security measures are in place to protect against potential cyber attacks. | **Won't be adequate because:** As inter-connections within the power system increase, alongside use of smart technologies, the risk of cyber-attack also increases. The adequacy of the current measures will decrease accordingly. |

### Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Continually review and update cyber security measures | To improve the effectiveness of cyber security measures and ensure they are up to date | Trust and confidence<br>Low-emissions energy<br>Thriving competition | New Zealand energy sector |

### Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** The energy sector's approach to the management of cyber security will be robust and well coordinated. | **By** 2032 |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| The resilience of the power system will improve, and system-wide disturbances and power outages will be avoidable. | **Risk of action:** No risk of action – the action is to mitigate a risk. | **Risk of inaction:** Vulnerability to external cyber threats. | N/A |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| New Zealand energy sector | New Zealand energy sector | Number and type of cyber security incidents |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 9** | **Overall outcome** | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |

# **Future Security and Resilience 10:** Growing skills and capabilities of the workforce

## Problem description

| Timeframe | Current capability | Rationale |
|---|---|---|
| **In** Enduring | There is a shortage of power system engineers and other roles within the energy sector. | **Won't be adequate because:** As energy sectors around the world transition to accommodate an increasing proportion of renewable resources, the shortage will become more acute. |

## Opportunity statement

| What is the change required? | Why is it required? | Which Electricity Authority strategic priority does this outcome enable? | Who will be impacted and should be involved? |
|---|---|---|---|
| Encourage and train the workforce's next generation | To mitigate workforce shortages and ensure that the expected transition within the energy sector takes place in a safe and timely manner. | Trust and confidence<br>Low-emissions energy<br>Thriving competition | Educational institutions<br>New Zealand energy sector<br>Professional associations |

## Outcome

| Measurable objective | Timeframe |
|---|---|
| **The future state needs to look like:** New Zealand will be able to produce its own workforce, with minimum reliance on overseas talent. | **By** As soon as possible |

## Benefits

| What will this improve and what benefits will be introduced? | Risks? | | Interdependencies |
|---|---|---|---|
| Workforce shortages will decrease, and the energy sector's ability to transition to 100% renewable generation in a successful and timely manner will increase. | **Risk of action:** No risk of action – the action is to mitigate a risk | **Risk of inaction:** Shortage of workforce with the right skillsets to transition to and operate the future power system | All the opportunities and challenges in the roadmap |

## Governance

| Business owner | Delivered by | Priority indicator |
|---|---|---|
| Educational institutions<br>New Zealand energy sector<br>Professional associations | Educational institutions<br>New Zealand energy sector<br>Professional associations | Number of vacancies for given technical roles |

| Activity | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **FSR 10** | **Overall outcome** | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |

# Appendix B Phase 2 Industry Feedback

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Simply Energy | Agree with the action items relating to FSR 5 – Managing reducing system inertia but submission related to 2 key themes:<br><br>1. flexibility to bring forward the timing of a broader review ahead of 2029/2030<br><br>Experience overseas shows that high levels of renewables results in less system inertia. 2029/2030 appears to be too far away to evaluate whether FIR/SIR are still fit for purpose. Timing should be brought forward especially if certain market conditions are triggered | Noted. The New Zealand power system has its own context/characteristics, meaning direct comparisons to overseas jurisdictions may not be appropriate.<br><br>The timing in the FSR roadmap is based on when System Operator sees low levels of inertia impacting on our ability to maintain system security and resilience. This is dictated by the WiTMH demand and generation scenario considered, along with previous work investigating inertia on the New Zealand power system.<br><br>As outlined in the roadmap and noted in the submission, monitoring of key indicators will be undertaken to ensure if activities are correctly prioritised. Accordingly, the roadmap may change over time. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Simply Energy | 2. There are short term measures which can increase market efficiency and security prior to a comprehensive review of reserves<br><br>A. Interruptible load (IL) provides a faster response than generation-based reserve, however both are paid the same rate for participating in the FIR market. Updating NZ's FIR market to pay based on actual response time would be a more efficient approach and provide fair incentive for development of fast-acting IL, and greater competition in the reserves market.<br><br>Could potentially split the current FIR market into two markets by introducing a very fast 1s market, in addition to the existing fast 6s market. Believe the introduction of a very fast 1s market would reduce costs and increase power system security and resilience for consumers and should be evaluated as a near-term priority. | FSR Phase 1 and 2 focused on opportunity and challenge definition and developing a roadmap of activities to be able to investigate and develop solutions.<br><br>Suggestions are noted and the Authority has indicated such issues will be considered in Phase 3. | None |
| Simply Energy | B. Inequity in the IL metering point for flexibility traders vs distributors. Flexibility traders are required to have a measure participating IL at each point of connection while distributors are only required to have one high speed meter per grid exit point. This legacy distributor agreement distorts the FIR and SIR markets, suppresses SIR prices and disincentivises maintenance and development of reserve. Believe a level playing field should be investigated as a priority. | Feedback is noted and the Authority has indicated such issues will be considered in Phase 3.<br><br>Going forward the intent is to ensure all ancillary services are consistent with promotion of competition. As the system becomes more complex, it is anticipated that technology specific measurements will become a standardised expectation. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Mercury | Agrees in general with the draft FSR roadmap however it does not clearly identify how it fits into the broader scheme of the Authority's Energy Transition Roadmap. Concerned that there is a risk that activities generated in this roadmap misalign with other workstreams resulting in duplication of effort, contradictory conclusions, unintended outcomes, or omission of key activities. | Noted. The Roadmap has been updated to include clearer linkages to the Energy Transition Roadmap. | Added a link to Energy Transition Roadmap in section 2 (purpose) |
| Mercury | Proposes that roadmap should be mapped top-down against other workstreams set out in the Energy Transition Roadmap<br>e.g. FSR 5 Managing reducing system inertia has a timeline of 2029/2030. Concerned this timeline does not consider broader workstreams particularly investment incentives through appropriately designed frequency products. | The FSR Roadmap will evolve over time. As other workstreams become more detailed the Authority has indicated it intends to coordinate activities to ensure the best delivery across workstreams. This detail will be shared on an ongoing basis to provide as much clarity as possible. | None |
| PowerCo | Concerned at the SO-centric nature of the FSR report and roadmap as some of the initiatives will impact the security and resilience at a distribution level too and may require significant change for distributors. A co-design process across transmission and distribution is vital to ensure correct functionality is developed. | Noted. The FSR report and roadmap has not attempted to speak about the impacts to Distributors however distribution level impacts have been acknowledged.<br>The roadmap has been updated to further acknowledge the Authority's intention for industry involvement and a co-design process in Phase 3. | Reviewed/updated wording in Roadmap to ensure need for industry inclusion in Phase 3 is emphasised. |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| PowerCo | The roadmap will benefit from more clarity about the roles and responsibilities of the SO and market participants to enable DER services. Functionality and operability of DER services on distribution networks varies significantly between generation location and sizes. Delivering initiatives in this space will require a cohesive approach across a range of parties and dimensions so that data and network systems support a successful implementation. | Noted. Roles and responsibilities of the SO and electricity market participants will be defined as part of Phase 3 under activities 1.1 and 2.1.<br>There are different models that could be implemented, and some models may not achieve the interests of all stakeholders, hence development of future market roles and responsibilities requires input from a range of stakeholders to be acceptable and successful. | Reviewed/updated wording in outcome proposals to ensure intent is objective and clearly understood |
| PowerCo | The roadmap illustrates that centralised dispatch of DER is the most efficient outcome for the New Zealand electricity system. Wholesale market outcomes are indeed one source of value for DER owners, but there are other sources of value such as DER providing services to distribution networks. | We disagree with this feedback. The roadmap defines coordination and management of DER as an outcome that needs to be achieved and does not promote any dispatch model.<br>The most efficient outcome for New Zealand will be co-designed (with industry input) in Phase 3. | Reviewed/updated wording in outcome proposals to ensure intent is objective and clearly understood |
| PowerCo | To enable real-time DER dispatch when it's connected to a distribution network, the provider, system operator, and distribution network operators to account for network constraints. The system operator does not have visibility of these and there may be alternative means for coordinating supply and demand in the market and system. For example; distributors could have an operator role to dispatch DER accounting to maintain the security, stability, and resilience at the distribution system level. | Feedback is noted and such issues are intended to be considered in Phase 3. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| PowerCo | We encourage the team to provide more information, even if qualitative, about the factors affecting the timing and cost/benefit of the different initiatives. | Noted. | None |
| Meridian | Many of the proposed actions involve consideration of new or revised ancillary services (see actions 4.2, 5.1, 5.2, 6.3 and 8.1). It appears that the soonest the Authority and system operator will consider new or revised ancillary services in 2025. Meridian queries whether this should be brought forward given the potential consumer benefits of reserve products in the minutes to hours range to support system security and resilience to mitigate the risk of events like those of 9 August 2021, as well as meet future needs with an increasingly renewable and intermittent generation mix. This potential need was also identified through the MDAG consultation on price discovery in a 100% renewable electricity market. | Noted. Resource adequacy was not included in the scope of the FSR roadmap. As mentioned, it has been within the scope of MDAG's price discovery in a 100% renewable electricity market.<br><br>The timing in the FSR roadmap is based on when we expect to require new or revised ancillary services to support system security and resilience which is dictated by the WiTMH demand and generation scenario considered.<br><br>The FSR roadmap is expected to evolve over time. As other workstreams become more detailed the Authority has indicated it intends to coordinate activities to ensure the best delivery across workstreams. This detail will be shared on an ongoing basis to provide as much clarity as possible. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Meridian | Setting the rules and product specifications early for any new or revised ancillary services would enable developers to build technologies such as battery storage, vehicle to grid and demand response aggregation in a manner that meets the security and resilience needs of the future. Delaying consideration of new or revised ancillary services could lead to investments being made in the interim that do not comply with the specifications, i.e. a missed opportunity. | Noted. The structure of the roadmap is such that it attempts to address the most urgent concerns for the system, one of which involves updating the Code to be technology neutral.<br><br>It is more efficient to focus on updates to the Code to make it technology neutral and enable participation. ahead of considering new or revised ancillary services.<br><br>It is important to remember the FSR roadmap timing is indicative and may change according to the system conditions. | None |
| Nova Energy | Given that the SO has no accountability for the costs or delays that generators and DER aggregators experience in joining the market, there is a real risk that connection requirements designed and coordinated by technical experts from within the SO alone will ultimately lead to a more expensive electricity market. Nova therefore believes that the Electricity Authority (Authority) needs to be far more actively engaged in determining the technical Code requirements of the market than is apparent in the work to date; this includes the development and implementation of the Roadmap. | This statement is inaccurate. The System Operator is accountable (under its principal performance obligations) for effectively operating the power system at the lowest possible cost. This includes connection requirements.<br><br>Noted. The Authority is leading FSR Phase 3 activities and has indicated it intends to determine the technical Code requirements of the market with System Operator and broader technical input as required. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Nova Energy | Challenges, such as a need to make up for a relative drop in system inertia (FSR 5) is not an immediate priority given the existing generation mix, but it is important for parties to understand the financial implications of their preferred technologies when planning new generation projects. For instance, it may eventually be appropriate for inverter based resources (IBR) to contribute financially to support spinning resources, such as geothermal generation, synchronous wind turbines, or alternative solutions such as synchronous condensers. Such potential costs need to be signalled early if the best mix of generation sources is to be achieved in the long term. | The desire for early signals of costs relating to challenges is noted. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Nova Energy | SO's perspective is important but so is that of other participants. For example; sections 2.1 – 2.4 of the Roadmap, which refer to establishing and managing the potential impacts of DER. Nova has no issue with this being addressed but has concerns that the Roadmap has this piece of work being viewed almost entirely from the SOs perspective. Similarly, in paragraph 2 on page 7 of the Roadmap in reference to the various initiatives underway: 'Transpower will consider these, including the potential for 'win-win' outcomes in phase 3...' While the Authority retains control of any changes to the Code, under the existing terms of the Roadmap the Authority appears to be devolving excessive influence to the SO in determining the potential future make-up of New Zealand's electricity market. The same focus is also illustrated under FSR 3: 'To ensure optimal assessments of the impact of connecting DERS and optimal connection processes thereby ultimately ensuring that the power system operates securely, and market outcomes are efficient'. It is acknowledged in FSR 3 that Asset Owners will be impacted by connection processes, yet there is no mention of Asset Owners having a role in their development. | Noted. In making changes the Authority has indicated it intends to consider all participants and potential participants.<br><br>Additionally, the Authority has indicated the FSR process intends consultation on all proposed changes which ensures all parties have the opportunity to contribute to the outcome.<br><br>The roadmap has been updated to further acknowledge the Authority has indicated it intends industry involvement and a co-design process in Phase 3. | Reviewed/updated wording in Roadmap to ensure need for industry inclusion in Phase 3 is emphasised. |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Nova Energy | Proposals under FSR 4: Balancing renewable generation, to add 'new or revised ancillary services to maintain balancing' will have important market implications for generators, retailers, major consumers and providers of DER and demand response. As such, any proposed initiatives will need wide market acceptance and more input than just the technical aspects that are the focus of the SO. It may also be found that retaining existing thermal peaking capacity for an extended period may be more cost effective (inclusive of carbon costs) than giving priority to creating new market mechanisms. The approach outlined in the Roadmap seems to preclude such possibilities. | Noted. The roadmap has been updated to further acknowledge the Authority has indicated it intends industry involvement and a co-design process in Phase 3. | Reviewed/updated wording in Roadmap to ensure need for industry inclusion in Phase 3 is emphasised. |
| Nova Energy | Given the wider market dynamics are effectively out of scope for the SO, the Authority must be more actively involved in setting connection standards and parameters determining the operation of the Grid. This means being more directly involved in the implementation of the Roadmap than is apparent in the draft. To do this, the Authority may need to build on its technical expertise and engage directly with the SOs technical advisory service, rather than relying on the SO to determine its own priorities. | Noted. The Authority is leading FSR Phase 3 activities. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| solarZero | Noted code changes have meant that batteries can participate in the reserves market, but that the Code and the software operating the system are not quite suitable.<br>From an investor's perspective it is important that there is a clear programme of regulatory change and associated electricity system software development that gives investors the confidence to invest in the development of DER.<br>Work on updating the Code needs to start now.<br>Noted that the FSR roadmap expects that distributed batteries will be providing existing ancillary services in year 4. Recent Code changes mean batteries could provide ancillary services (reserves)this year, not in four years' time, i.e. we are four years ahead of the timing outlined in the FSR report. | The recent changes to allow batteries to participate in the reserves market are recognised as a short-term fix and a permanent solution will be forthcoming. Some of the intended Code change activities may address the concerns raised.<br>The timing in the FSR roadmap is based on when we, as System Operator, expect to require new or revised ancillary services to support system security and resilience which is dictated by the WiTMH demand and generation scenario considered.<br>It is important to remember the FSR roadmap timing is indicative and may change according to the system conditions. | None |
| solarZero | A theme in the roadmap is that DER is a problem/risk that needs to be carefully managed. We suggest DER is an opportunity that enables a more efficient and resilient power system. The wording in a number of sections needs to be reviewed to reflect the opportunities that DER provide for improved power system management. | The roadmap has been reviewed and edited (where necessary) to better reflect opportunities vs risks.<br>Note DER has presented as a risk in international jurisdictions, compounding system events due to inability to ride through faults. This risk needs to be understood and managed in New Zealand. | Reviewed/updated wording in roadmap to better reflect opportunity vs risks |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| solarZero | FSR1: Enabling DER for efficient power system operations. Work needs to start on a Code refresh right now together with the associated market software changes, because Code changes and associated software development seems to take so long in New Zealand compared to some overseas jurisdictions. | The timing in the FSR roadmap is based on many factors, including the WiTMH demand and generation scenario considered. | None |
| solarZero | FSR2: Visibility and observability of DER. The tone of this section is that DER could be a significant risk to the power system. That thinking needs to be turned on its head. DER has the potential to provide significant benefits and provide opportunities for much better power system management. These benefits/opportunities were outlined in Transpower's Whakamana i Te Mauri Hiko and it is surprising that those benefits are not more clearly outlined in this FSR roadmap. | Opportunities are presented in FSR1 *Enabling DER for efficient power system operations* and FSR8 *Leveraging new technology to enhance ancillary services*. We believe these two items accurately reflect the opportunities and capture WiTMH sentiment.<br><br>FSR2 *Visibility and observability of DER* is presented as a challenge because this is appropriately focused on risk management concerns as DER penetration increases.<br><br>This difference in perspective highlights the importance of industry involvement and a co-design process in Phase 3, and the Authority has indicated this is intended. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| solarZero | FSR3: Coordination of increased connection. As with FSR 2, DER are presented as a potential problem. In fact, DER presents a significant opportunity. The language in both FSR 2&3 needs to be changed to reflect the benefits that DER can provide to the power system and ways to unlock those benefits. For example, FSR 3.3 identifies the opportunity "To enable power system operations to benefit from the capability of DER" but the risk is identified as "Inappropriate new connection risk assessments, eroding system security". The risk here should be something along the lines of "Power systems operations may not gain the full potential benefits DER can provide". | FSR3 *Coordination of increased connections* is presented as a challenge because the focus is on risk management. This does not imply a dislike of the technology; it is simply taking a whole-system view of the impacts of change.<br><br>This difference in perspective highlights the importance of industry involvement and a co-design process in Phase 3, and the Authority has indicated this is intended. | None |
| solarZero | FSR4: Balancing renewable generation. We support the move towards new/additional ancillary services to support more variable renewable generation. | Noted. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| solarZero | FSR5: Managing reducing system inertia. We support developing a new frequency management strategy. However, we consider 7 years to be too long. Work needs to start now on this strategy, at least in terms of developing the general direction so that DER providers can plan for new frequency services as companies such as ours develop and roll out technology, which we are doing now. | The timing in the FSR roadmap is based on when we, as System Operator, see low levels of inertia impacting on our ability to maintain system security and resilience. This is dictated by the WiTMH demand and generation scenario considered, along with previous work investigating inertia on the New Zealand power system.<br>As outlined in the roadmap and noted in the submission, monitoring of key indicators can be undertaken to ensure if activities are correctly prioritised, and the Authority has indicated this is intended. Accordingly, the roadmap may change over time. | None |
| solarZero | FSR6: System Strength. The tone of this section is one of command and control. The tone needs to change to enabling and using markets to drive outcomes. For example, FSR 6.2 states "Amend Code to require DER to support performance criteria". Instead 6.2 should be along the lines of "Amend Code to enable DER to support system strength" and should closely link to 6.3 which is about market products and tools. | This was not intentional. The roadmap has been reviewed and edited (where necessary) to change the tone. | Reviewed/updated wording in roadmap |
| solarZero | FSR7: Accommodating future changes within technical requirements. We strongly support this section and its focus on updating the Code and the relevant power management tools within the next three years. | Noted. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| solarZero | FSR8: Leveraging new technology to enhance ancillary services. We support the intent of this section, but we question the timeline. As outlined above we will be using DER to provide reserves some four years ahead of the roadmap timelines. FSR 8.3 states "Update market system to enable DER to provide existing ancillary services" and proposes a four-year time frame. Within four years we would like to see clear actions that enable DER to provide new and improved ancillary services, not just existing ancillary services. | The timing in the FSR roadmap is based on when we, as System Operator, expect to require new or revised ancillary services to support system security and resilience which is dictated by the WiTMH demand and generation scenario considered.<br>As outlined in the roadmap and noted in the submission, monitoring of key indicators will be undertaken to ensure if activities are correctly prioritised, and the Authority has indicated this is intended. Accordingly, the roadmap may change over time. | None |
| solarZero | FSR9: Cyber security. Agree with the sentiment of this section. | Noted. | None |
| solarZero | FSR10: Growing skills and capabilities of the workforce. This is very important. We suggest, for example, a stronger focus in universities on DER so that graduates enter the workforce with an understanding of DER. Further, we support a research programme, like the previous Green Grid programme, that enables researchers to explore DER, work with industry and via knowledge sharing train the workforce of the future, assist with enhancing technical standards, support the development of industry practice and the like. | These suggestions are noted. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Amazon Web Services | Because of the increasing reliance on data management, automation and direct consumer engagement, the changing 'national grid' needs to be optimised for security and resilience.<br><br>Through the lens of scalability – the ability to draw up and down to meet demand – traditional utility systems may not be equipped to provide the required scale and flexibility to respond with their IT needs in the event of a cybersecurity event. Scaling from hundreds to millions of assets that must be monitored and coordinated requires advanced data ingestion and compute capabilities, and these needs will vary by orders of magnitude between blue-sky days and emergency peaks. Attempting this with on-premise systems would result in expensive overprovisioning that would still be insufficiently agile to be meeting fast-changing needs. With data centres in multiple geographic regions, AWS offers a much higher level of resilience and system recovery than a single on-premise data centre. | Noted. This will be considered during Phase 3. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Amazon Web Services | The Roadmap's Phase 1 and 2 publications ranks cybersecurity as 'high' and 'enduring' amongst the opportunities and challenges following feedback from the industry after the Phase 1 discussion process. We agree with the re-classification to 'high' and believe that the government's cyber security action plan will need to be both focused and long-term. Phase 2 mentions cybersecurity as not having interdependencies with other initiatives outlined in the roadmap, however we contend strongly that cybersecurity is an independent factor to be addressed explicitly in the roadmap. In order to address cybersecurity concerns, reviews of cloud and network security to underpin the various electricity related technologies should not be undertaken in isolation from other initiatives in the Roadmap. | Noted. FSR9 *Maintaining cybersecurity* has been defined as a foundational challenge and therefore is interdependent with every opportunity and challenge in the roadmap (similar to FSR10 *Growing skills and capabilities of the workforce*). The interdependency section (6) of the roadmap has been updated to note cybersecurity as a fundamental requirement for consideration in Phase 3. | Updated roadmap section 6 (interdependencies) to reflect feedback |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Amazon Web Services | The Phase 1 and Phase 2 reports recognise the importance of new energy technologies like Battery Energy Storage Systems (BESS) in addition to the need for standards around such technologies. BESS and other energy-related technologies are interconnected through a web of technology. BESS for example operate in conjunction with 5G and cloud technology in order to connect distributed BESS, cloud integration of energy storage system (ESS) and data edge computing. We encourage policy makers to assess this wider scope of inter-related technologies in developing any standards and to do so in conjunction with the technology industry and in line with international standards. | Noted. This will be considered during Phase 3. | None |
| Amazon Web Services | Promoting cloud-first policies and cloud migration has immediate decarbonisation benefits. Furthermore, energy-efficient backend systems should be recognised for the increased role they can play in enabling Distributed Energy Resources (DER) services for efficient power systems. | Noted. This will be considered during Phase 3. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Amazon Web Services | As New Zealand continues to pursue energy transition and decarbonisation, adaptations to regulatory approaches for emerging technologies can foster the needed innovation in support of those objectives. Through our support to cloud-enabled transformation across utilities globally, we have seen the benefits to consumers, industry and regulators alike. The emergence of digital platforms in the electricity industry can provide opportunities to deliver broad benefits for consumers, support greater reliability of electricity supply and enable the efficient and healthy functioning of the industry. | Noted. This will be considered during Phase 3. | None |
| Amazon Web Services | The emergence of digital platforms in the electricity industry can provide opportunities to deliver broad benefits for consumers, support greater reliability of electricity supply and enable the efficient and healthy functioning of the industry. Other benefits identified include load forecasting, improved operational efficiency, predictive maintenance and asset optimisation. | Noted. This will be considered during Phase 3. | None |

| From industry | | From System Operator | |
|---|---|---|---|
| Submission | Feedback | Response | Change to Roadmap |
| Amazon Web Services | Digital platforms that can deliver data across the grid's operations can provide invaluable insights, including in real time, that are simply not available in the silos of many utility industries today.<br><br>The emergence of platforms that can provide end-to-end data and insights present opportunities to radically improve the efficiency of the industry in responding to consumer demand and in managing resilient and responsive grid operations. Better data and analytics across the grid will improve the position of regulators through access to rich sources of information and insights that support industry oversight. The availability of more data about operations across the grid also provides opportunity to improve competition through opportunities for new market entrants with offerings responding to increasing consumer expectations for a responsive industry.<br><br>AWS has other use cases which we would be happy to share with the Electricity Authority to discuss further applications cloud technology can have in the future security and resilience of New Zealand's power system. | Noted. This will be considered during Phase 3. | None |

# Appendix C Glossary

| Term/abbreviation | Definition |
|---|---|
| Ancillary service provider | A contracted provider of ancillary services (the System Operator currently procures five: frequency keeping, instantaneous reserve, over-frequency reserve, voltage support and black start) |
| Asset owner | A participant who owns an asset used for the generation or conveyance of electricity and a person who operates such asset and, in the case of Part 8, includes a consumer with a point of connection to the grid |
| The Code | The Electricity Industry Participation Code: a set of rules that govern New Zealand's electricity industry |
| CER | Credible event review is a process carried out by the System Operator to review credible contingency events and the classifications of the contingencies |
| Contingency | The uncertainty of an event occurring, and the planning to cover for it; for example, in relation to transmission, the unplanned tripping of a single item of equipment, or, in relation to a fall in frequency, the loss of the largest single block of generation in service, or loss of one HVDC pole |
| Credible Contingency | Credible contingency events are events that may plausibly occur, and if they do occur, have the potential of a significant impact on supply security and reliability |
| DER | Distributed energy resources are controllable energy resource located in the distribution network and not connected directly to the grid. Examples include solar PV, battery energy storage systems and EVs |
| Electricity Authority | Electricity industry regulator in New Zealand |
| EEA | Electricity Engineers' Association |
| FSR | Future Security and Resilience |
| Grid Owner | Referring to Transpower New Zealand as the Grid Owner |
| IBR | Inverter-based resources are assets connected to the grid which interface using inverter technology |
| IPAG | Innovation Participation Advisory Group advises the Electricity Authority on issues relating to new technologies and business models, and consumer participation |
| MBIE | Ministry of Business, Innovation and Employment |
| MDAG | Market Design Advisory Group advises the Electricity Authority on the issues relating to the evolution of the electricity market |
| NZX | New Zealand's national stock exchange |
| Policy Statement | A statement within the Code that sets out how Transpower will meet its obligations as System Operator |
| PPO | The System Operator's principal performance obligations (as set out in the Code) |
| Procurement Plan | A document that sets out the mechanisms the System Operator uses for procuring ancillary services |
| System Operator | Referring to Transpower New Zealand Limited as the System Operator |
| WITS | NZX's wholesale information and trading system |
| WiTMH | Whakamana I Te Mauri Hiko – A paper produced by Transpower which outlines New Zealand's opportunity to build a low carbon economy through our energy choices |

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