The future operation of New Zealand's power system

Consultation paper

15 February 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) seeks feedback from interested parties on future challenges and opportunities with the operation of New Zealand's power system.

Power system operation in New Zealand dates from the late 19th century. Over the decades it has evolved to respond to technological changes, changes in electricity demand, and higher expectations of a reliable electricity supply. We now benefit from sophisticated and complex system operation in the delivery of a secure, reliable and efficient electricity supply. But New Zealand's electricity sector is beginning an unprecedented transformation, as the country transitions to a more electrified economy. This will have a significant effect on power system operation.

New Zealand has committed to a target of net zero greenhouse gas emissions by 2050 (excluding biogenic methane). Achieving this will require:

(a) increased electrification of sectors of the economy, such as transport and industrial processes

(b) meeting increased electricity demand with renewable electricity generation.

In addition to more renewable electricity generation, we will see increased use of distributed energy resources, more participants in the electricity industry, including more consumers, as well as new ways to participate. This will create both challenges and opportunities for the operation of the power system.

The future is uncertain, but we do know that coordinating the operation of New Zealand's power system will need to evolve to accommodate and facilitate the changes occurring in the electricity sector. Coordinating the operation of New Zealand's power system will become more complex as more variable and intermittent generation and load resources connect to the power system, and the flow of electricity across the power system becomes increasingly bi-directional.

A critical challenge will be making sure consumers receive a reliable electricity supply at least cost as the power system becomes increasingly complex. Protecting the interests of consumers will remain a key priority for the Authority as the power system evolves. Our aim is to ensure consumers continue to benefit from a secure and resilient power system. We are particularly interested in understanding how we can support domestic and small business consumers to have greater participation across the power system, and what protections might be needed for our most vulnerable communities.

This consultation paper sets out some of the potential challenges and opportunities associated with power system operation in the future. This is the starting point for an ongoing discussion on what may be needed for the future operation of the power system. We want to hear your views on the potential challenges and opportunities that we have identified, and any others you consider important.

During the consultation period the Authority will be available to hold individual and group briefings with interested stakeholders. We will also look to hold webinars for the wider community of stakeholders.

Once the consultation period closes, the Authority will consider the feedback received and what the appropriate next steps should be.

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1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this consultation paper is to seek feedback from interested parties on what they consider to be possible key challenges and opportunities with power system operation in New Zealand over the coming decade and beyond.

1.2. We cannot predict with accuracy how the power system will evolve during this time, but we can 'get ahead of the curve' in terms of preparing for change by understanding what challenges and opportunities may arise.

1.3. Consistent with our statutory objective, the Authority is particularly interested in:

(a) the efficiency and reliability of New Zealand power system operation in the future

(b) how changes to power system operation in the future might affect consumers and industry participants

(c) how best to enable consumers to become 'prosumers' via their ownership of distributed energy resources (DER), in a way that promotes a secure and resilient power system.

1.4. The Authority emphasises this paper is a consultation paper. We have not formed a view as to what the key challenges and opportunities are in relation to future power system operation. We want to hear your views to further build on our understanding of the potential key challenges and opportunities.

1.5. Appended to this paper is a report that provides the findings of a literature review on key challenges and opportunities with power system operation in some overseas jurisdictions, and the planned or actual responses in different jurisdictions. Please see Appendix C.

1.6. The Authority plans to hold briefing sessions and webinars with interested parties on the content of this consultation paper. Given the technical nature of power system operation, we will be engaging with consumer advocacy groups to help ensure consumer interests are kept front and centre of our work.

How to make a submission

1.7. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to FSR@ea.govt.nz with "Consultation Paper—The future operation of New Zealand's power system" in the subject line.

1.8. If you cannot send your submission electronically, please contact the Authority (FSR@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.9. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

(i) explain why you consider we should not publish that part, and

(b) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.10. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

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

When to make a submission

1.12. Please deliver your submission by 5pm on Thursday 11 April 2024

1.13. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority FSR@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Introduction

2.1. Power system operation in New Zealand dates from the late 19th century. Over the decades it has evolved to respond to technological changes, changes in electricity demand, and higher expectations of a reliable electricity supply. We now benefit from sophisticated and complex system operation in the delivery of a secure, reliable and efficient electricity supply. But New Zealand's electricity sector is beginning an unprecedented transformation, as the country transitions to a more electrified economy, and this will have a significant effect on power system operation.

2.2. New Zealand has committed to a target of net zero greenhouse gas emissions by 2050 (excluding biogenic methane). Achieving this will require:

(a) increased electrification of sectors of the economy, such as transport and industrial processes

(b) meeting increased electricity demand with renewable electricity generation.

2.3. In addition to more renewable electricity generation, we will see increased use of DER, more participants in the electricity industry, including more consumers, as well as new ways to participate. This creates both challenges and opportunities for the operation of the power system.

2.4. A critical challenge will be making this transition while delivering a level of reliability of electricity supply that reflects consumers' preferences and minimises total costs,[1] as the power system becomes increasingly complex.

2.5. Enabled by evolving technologies, the transition to a low-emissions power system is expected to include increasingly distributed sources of electricity generation and storage, in many cases located closer to consumers. Most of this generation and storage is likely to be inverter-based.[2] The uptake of DER is expected to contribute to greater demand-side flexibility in the electricity industry.

2.6. Coordinating the operation of New Zealand's power system will need to evolve to accommodate and facilitate the changes occurring in the electricity sector. In particular, coordinating the operation of New Zealand's power system will become more complex as more variable and intermittent generation and load resources connect to the power system, and electricity flows across the power system become increasingly bi-directional. As the Market Development Advisory Group (MDAG) has noted, this is because:

(a) many of New Zealand's new electricity supply sources will not be readily controllable, because they are governed by weather conditions

(b) the New Zealand power system is moving increasingly from being balanced in real time using a relatively small number of large resources to being balanced in

1 Consistent with the Authority's statutory objective – see *Interpretation of the Authority's statutory objective*, 14 February 2011.

2 In simple terms an inverter is an electronic device that converts direct current (DC) electricity to alternating current (AC) electricity. An inverter-based resource is equipment that uses an inverter when functioning. Examples include wind generation, solar photovoltaic generation, and a battery energy storage system.

real time using 'many and small' resources (eg, smaller scale generation including battery energy storage systems, and demand-side flexibility).[3]

2.7. Network planning may also become more complex. For example, if new generation resources are located in regions that have traditionally imported electricity, these regions could become net exporters of electricity. The question then will be what is the export capacity of that region to other importing regions?

This paper is part of the Future Security and Resilience programme

2.8. This paper is part of a multi-year work programme called the Future Security and Resilience (FSR) work programme, which the Authority commenced in 2021. The purpose of the FSR work programme is to ensure New Zealand's power system (at both the transmission and distribution levels) remains secure and resilient as the country transitions towards a more accessible, clean energy and a lower emissions economy.

2.9. The Authority and various agencies are also undertaking other work programmes designed to support New Zealand's transition to a low-emissions energy system. Examples of the Authority's other work in this space include:

(a) updating the regulatory settings for distribution networks[4]

(b) managing peak winter demand[5]

(c) reviewing the common quality requirements[6] in the Electricity Industry Participation Code 2010 (Code)[7]

(d) ensuring an orderly thermal transition[8]

(e) MDAG's advice on price discovery in an increasingly renewables-based electricity system.[9]

The Future Security and Resilience programme has a focus on real-time/near real-time operation

2.10. The FSR programme is focussed on how New Zealand's power system operates in real time, or close to real time,[10] to continuously balance electricity supply and demand and to supply consumers with electricity that is of an appropriate quality.

2.11. Importantly, the FSR programme is not assessing the power system's ability to ensure electricity supply is able to meet electricity demand over periods longer than a

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3 Market Development Advisory Group, 2022, Price Discovery Under 100% Renewable Electricity Supply – Issues Discussion Paper, p. 19.

4 See Updating regulatory settings for distribution networks | Our projects | Electricity Authority (ea.govt.nz).

5 See Managing peak winter electricity demand | Our projects | Electricity Authority (ea.govt.nz).

6 See the Authority's April 2023 issues paper *Future Security and Resilience – Review of common quality requirements in Part 8 of the Code*. The Code defines 'common quality' to mean those elements of quality of electricity conveyed across the transmission network that cannot be technically or commercially isolated to an identifiable person or group of persons.

7 Electricity Industry Participation Code 2010 (Authority website).

8 See Ensuring an orderly thermal transition l Our consultations l Our projects l Electricity Authority (ea.govt.nz).

9 See Pricing in a renewables-based electricity system | Our projects | Electricity Authority (ea.govt.nz).

10 Note that 'real time' for system operation means almost immediate (down to a fraction of a second), whereas real-time pricing is calculated and reported as half-hourly averages.

few days (often referred to as ‘energy adequacy’). Other programmes of work are considering this, such as the MDAG project mentioned above.

The purpose and scope of the Future System Operation workstream

2.12. The purpose of the Future System Operation (FSO) workstream within the FSR work programme is to:

(a) identify any challenges or opportunities with the current arrangements for power system operation in New Zealand that may arise given expected changes to the electricity industry

(b) identify what, if any, regulatory arrangements administered by the Authority would address any challenges with, or enable any opportunities for, power system operation in New Zealand, for the long-term benefit of consumers.

2.13. The Authority has initiated the FSO workstream in response to:

(a) stakeholder feedback on the need for a coordinated approach to the evolution of power system operation over the coming decades

(b) the Authority’s desire to see power system operation in New Zealand incorporating relevant international developments.

2.14. Industry participants are aware of various challenges and opportunities under a transition to net zero emissions. Several industry-led reports have been commissioned to look at decarbonisation pathways and the challenges this will create for New Zealand’s electricity sector.[11] [12] [13] [14]

2.15. The Authority has received feedback from industry stakeholders that it should prioritise investigating challenges and opportunities for power system operation in New Zealand, given the changes to the power system that are happening now, and the changes that are expected to occur in the foreseeable future.

2.16. The Authority’s main statutory objective is to promote a competitive, reliable and efficient electricity industry. The ongoing effective and expert coordination of the power system will be crucial to ensuring a reliable power system is provided at least cost to consumers. The future security and resilience of the power system is one of our key priorities as New Zealand moves to an increasingly electrified economy. Given this, and our independence and pan-industry view, the Authority is well placed to facilitate a review of future power system operation, working closely with and alongside industry stakeholders.

Next steps

2.17. Given the subject of this paper and interest among a wide range of stakeholders, the Authority will be available during the consultation period to hold individual and group briefings with interested stakeholders. We will also look to hold webinars for the wider community of stakeholders.

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11 Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand’s Electricity Sector, available at: the-future-is-electric-full-report-october-2022.pdf.

12 South Island Distribution Group, 2021, Together, A Brighter Tomorrow - Our Clean Energy Future.

13 Electricity Networks Aotearoa, 2022, Powering up for change (ena.org.nz).

14 Wellington Electricity, EV Connect Roadmap (welectricity.co.nz).

2.18. Once the consultation period closes, the Authority will consider the feedback received and what the appropriate next steps should be. This will include considering whether there are challenges or opportunities that may warrant regulatory intervention, for the long-term benefit of consumers.

Structure of this paper

2.19. This paper covers three areas:

(a) Current arrangements for power system operation in New Zealand (section 3).

(b) Key drivers of change to power system operation in New Zealand over the coming decades as New Zealand transitions to net zero emissions (section 4).

(c) Possible key challenges and opportunities in relation to power system operation during New Zealand's transition to net zero emissions (section 5).

3. The current arrangements for power system operation in New Zealand

3.1. This section summarises the current arrangements for power system operation in New Zealand. It presents a baseline and context against which to assess any potential changes to power system operation in the future. Appendix A summarises the key regulatory obligations related to power system operation. It indicates the extensive number of regulatory obligations that would need to be considered if we were to make any regulatory changes in the future.

3.2. The Authority is seeking feedback on whether stakeholders agree with the descriptions in this section, and if not, why not. This feedback will be important to establishing a common understanding of the current arrangements for power system operation, which forms the starting point for a discussion on future system operation in New Zealand.

Overview of power system operation in New Zealand

What is power system operation?

3.3. For the purposes of this paper, the Authority defines ‘power system operation’ to mean the real-time coordination of New Zealand’s power system. By ‘power system’ we mean all components of the New Zealand electricity system that underpin the New Zealand electricity market, including generation, transmission, distribution, and load (demand) assets.

3.4. The real-time coordination of New Zealand’s power system comprises:

(a) scheduling available power system resources so that forecast electricity demand can be met while maintaining the frequency and voltage of electricity within an acceptable range

(b) dispatching available power system resources so that actual electricity demand is met while maintaining the frequency and voltage of electricity within an acceptable range

(c) monitoring the compliance of power system resources with their dispatch instructions

(d) managing risks to the security of the power system in real time, and the quality of electricity supply in real time, including by:

(i) coordinating planned outages of power system resources that are used to help meet electricity demand

(ii) having on standby power system resources that can help the power system recover from electricity blackouts caused by cascade failure of the power system.

(e) managing the security of the power system in real time, and the quality of electricity supply in real time, including by:

(i) scheduling, and dispatching as necessary, standby power system resources to help manage frequency and voltage

(ii) constraining electricity demand and/or supply if this is necessary to avoid electricity blackouts caused by cascade failure of the power system

(iii) electrically disconnecting electricity demand and/or supply if this is necessary to avoid electricity blackouts caused by cascade failure of the power system.

3.5. By ‘power system resources’ we mean resources used in the generation, conversion, transformation, conveyance, storage, and consumption of electricity.

3.6. At present:

(a) the functions of Transpower, in its role of ‘system operator’, include all aspects of what we define to be power system operation, and additional supporting services

(b) the functions of distributors and Transpower, in its role as network owner, include a subset of what we consider to be power system operation – namely helping to manage system security.

Power system operation has a history of evolution

3.7. Power system operation in New Zealand dates from the late 19th century.[15]

3.8. At the outset, ‘electric power schemes’ were privately owned enterprises requiring an energy source (typically water, coal, or diesel oil), a turbine or engine, an electric generator, an electricity distribution system, and a load. These were point-to-point energy transfer enterprises requiring only that supply was sufficient to balance demand at any instance, a job for the generator operators, who were the original system operators. At the end of the working day, the generator was usually shut down, to be restarted when next required.

3.9. The distribution of electricity in municipalities, for public supply to multiple sites and street lighting, developed next. Around 1910, central government began developing plans for larger centralised electricity generation schemes that supplied surrounding regions via evolving transmission networks. System operations became a 24/7 function, initially coordinated at the main power stations. Lake Coleridge supplied Christchurch from 1914; Mangahao supplied Wellington; the Lake Waikaremoana scheme supplied the Hawkes Bay; and Arapuni supplied the Waikato and Auckland regions.

3.10. The late 1920s saw these independent regional grids becoming interconnected, requiring careful coordination of electricity supply to meet expanding consumer demand. System operations evolved to require real-time generation coordination, by scheduling and dispatching individual machines, and network security, by instructing switching operations in conjunction with the operators at main supply substations. Telephony and some remote indications were essential system operator tools. By 1966, the North Island and South Island electricity grids were connected, by a state-of-the-art high voltage direct current (HVDC) power link.

3.11. Each significant increment in the capacity of New Zealand’s power system, coupled with consumer demand for increasing amounts of reliable electricity supply, saw power system operation evolve in sophistication and complexity. In the mid-1990s, another significant evolution of power system operation occurred, with the

15 For an excellent historical account of power system operation in New Zealand, see H. Reilly, 2014, *Keeping the Lights On – the history of power system operations in New Zealand, 1939 – 2013*.

development of New Zealand's wholesale electricity market. The 'system operator' role, as it is referred to today, then comprised three roles – 'scheduler', 'dispatcher', and 'common quality coordinator'.

3.12. This brief snapshot of the history of power system operation in New Zealand highlights how power system operation has evolved in response to changing technology and the demand for, and supply of, electricity. As New Zealand transitions to net zero emissions by 2050, further evolution of power system operation in this country is inevitable.

How is power system operation undertaken at present?

The system operator

3.13. A market operation service provider, called the system operator, is responsible for ensuring the real-time coordination of New Zealand's power system. The system operator is responsible for the scheduling and dispatch of electricity in real time in a manner that avoids fluctuations in the frequency and voltage of electricity supply, or the disruption of electricity supply. The system operator provides support services needed to enable it to perform its core role. The system operator is also responsible for forward looking security of supply assessments and risk management.

3.14. The system operator service provider role was established at the start of 2004. Prior to this, dating from the establishment of New Zealand's wholesale electricity spot market in 1996, the system operator role was split into the roles of 'scheduler', 'dispatcher' and 'common quality coordinator'.[16]

3.15. The system operator has high level, output-focussed principal performance obligations (PPOs) in relation to the real time delivery of common quality and dispatch. PPOs also include a 'plan to meet' obligation. These PPOs may be summarised as operating the power system to maintain frequency and voltage in real time, to avoid a 'cascade failure' of New Zealand's power system.[17]

3.16. The system operator instructs generating stations with a capacity of more than 10MW[18] when to generate electricity and how much electricity to generate (ie, it 'dispatches' generation), so that injections of electricity into the power system match offtake by electricity users at each moment in time.

3.17. Dispatch is largely determined by the outcome of the wholesale electricity spot market, which identifies the least-cost pattern of dispatch given generators' competing supply offers, the level of electricity demand and the available capacity of the transmission network over which electricity can be conveyed.

3.18. In addition to its core role of real time management of the electricity supply/demand balance, the system operator undertakes a significant amount of complex modelling of the transmission network, electricity demand and supply, and power system risk. This is to enable the system operator to operate the power system in a secure manner that maximises the net economic benefit to electricity consumers.

16 The term 'common quality coordinator' was not in use in 1996 but became part of industry lexicon when the New Zealand electricity industry's self-governance arrangement for common quality across the power system was developed between 1997 and 1999. This arrangement was known as the Multilateral Agreement on Common Quality Standards (MACQS).

17 Appendix A contains further information about the PPOs.

18 Clauses 8.25, 13.6, and 13.25 of the Code.

3.19. The system operator coordinates New Zealand's power system from a 'national control centre' that operates 24 hours a day from two physical locations. Energy coordinators are responsible for the real-time dispatch of scheduled power system resources. The largest component of an energy coordinator's role is managing voltage in real time – requiring approximately half of the energy coordinator's effort.

3.20. In addition to its real-time coordination activities, the system operator coordinates planned maintenance outages of assets connected to the transmission network, to ensure the power system continues to operate normally as the maintenance is undertaken. When someone wants to connect a new asset to the transmission network, or a certain type of asset to a distribution network, the system operator works with the asset owner in relation to the testing and commissioning of the asset. The system operator assesses whether the asset meets the requirements of 'asset owner performance obligations' and technical codes contained in the Code.

3.21. The system operator must carry out its obligations under the Code to the standard of a 'reasonable and prudent system operator'. This means the system operator must carry out its Code obligations with skill, diligence, prudence, foresight, good economic management, and in accordance with recognised international good practice, taking into account:

(a) the circumstances in New Zealand

(b) the fact that real-time coordination of the power system involves complex judgments and inter-related events.[19]

3.22. The system operator must also perform its obligations under the Code in a way that assists the Authority to give effect to the Authority's statutory objective[20], except when the system operator is exercising discretion in real time in performing its functions. The system operator must progressively increase the extent to which it assists the Authority to give effect to the Authority's statutory objective.[21] This Code requirement has a strong influence on the system operator's operational decision making.

Ancillary service providers

3.23. Another role the system operator performs is procuring ancillary services to support the delivery of electricity from sellers to buyers at an acceptable level of security and quality. The system operator procures ancillary services as a way of meeting its PPOs. The ancillary services purchased are frequency keeping, instantaneous reserve, over-frequency arming, voltage support, and black start.

3.24. The main purpose of frequency keeping is to manage any generation and demand imbalances, with the objective of maintaining frequency on the transmission network within the range of 49.8–50.2 Hertz (Hz) under normal operating conditions. Factors that contribute to generation and demand imbalances under normal operating conditions include unanticipated changes in demand, differences in the speed with which generating stations change their output, and the inherent inaccuracies between the modelled and actual power system conditions.

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19 Clause 7.1A of the Code.

20 Section 15 of the Act sets out the Authority's main statutory objective: "To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."

21 Clause 3.2A of the Code.

3.25. The purpose of instantaneous reserve is to manage frequency recovery after an under-frequency event. This is where frequency on the transmission network falls below 49.25Hz due to more than 60MW of electricity injection being lost within a minute. The objective is to arrest the frequency fall and then recover the frequency to within the range of 49.8–50.2Hz.

3.26. The purpose of over-frequency reserve is to manage frequency recovery after an event that might otherwise cause frequency to exceed 52Hz in the North Island or 55Hz in the South Island. For such an event, the system operator's objective is to arrest the rise in frequency and return it to within the range of 49.8–50.2Hz.

3.27. The purpose of voltage support is to contribute to managing voltage across the transmission network via the provision of dispatchable reactive power resources. These resources may be static or dynamic in nature, depending on their location on the network and network loading conditions.

3.28. The purpose of black start is to maintain equipment that can initialise the supply of electricity for the progressive re-livening of New Zealand's transmission network following an island or total blackout.

3.29. The process that the system operator follows in procuring ancillary services is set out in a 'procurement plan', which is prepared by the system operator for approval by the Authority. The system operator reviews the procurement plan every two years.

Asset owners

3.30. The Code places certain mandatory performance obligations on 'asset owners' ('asset owner performance obligations' or AOPOs) to enable the system operator to meet its PPOs.

3.31. An asset owner is a participant who owns and/or operates equipment or plant used for the generation or conveyance of electricity and that is connected to, or forms part of the transmission network. This includes equipment or plant that is intended to become connected to the transmission network and in terms of Part 8 of the Code, which regulates common quality, also includes:

(a) an embedded generator

(b) a consumer with a point of connection to the transmission network.

3.32. AOPOs are effectively mandatory ancillary services. They include obligations such as requiring:

(a) synchronised generators and transmission network owners to make the maximum possible injection contribution to maintain frequency in the range of 49.8–50.2Hz[22]

(b) synchronised generators to ensure their assets continuously operate in a manner that supports voltage and voltage stability on the transmission network[23]

(c) generators to ensure their assets 'ride through' specified power system faults[24]

22 Clause 8.17 of the Code.

23 Clause 8.23 of the Code.

24 Clauses 8.25A to 8.25D of the Code.

(d) asset owners to plan for, and respond to, emergency events on the power system.[25]

3.33. Asset owners that cannot comply with their obligations can apply for a dispensation from the obligation or to enter into an 'equivalence arrangement'.[26] The system operator assesses these applications on a case-by-case basis.[27]

Transpower, as a transmission network asset owner

3.34. New Zealand's transmission network is owned almost entirely by Transpower.[28] In its role of network owner, Transpower is responsible for planning, building, maintaining, and making available for use its transmission network.

3.35. The alternating current (AC) part of the transmission network operates at high voltages (220kV, 110kV and 66kV) to provide sufficient levels of transmission capacity over most of New Zealand. The direct current (DC) part of the transmission network (the high voltage direct current (HVDC) transmission link between the South Island and North Island) operates at 350kV.

3.36. Transpower has two national grid operating centres, which manage the operation of Transpower's transmission assets. These centres, which are distinct from the system operator's national control centres:

(a) monitor the status of Transpower's transmission assets 24 hours a day

(b) carry out grid switching operations on transmission assets the system operator has released from service for maintenance and for connecting new assets to the transmission network

(c) analyse system protection operations following events on the transmission network and work closely with the system operator to identify fault causes in order to restore electricity supply as quickly and safely as possible.

The separation of the system operator role from Transpower's other roles

3.37. The Code requires that Transpower's role as system operator under the Code and the Act must be distinct and separate from any other role or capacity that Transpower may have under the Code and the Act, including as a transmission network owner or transmission provider.[29]

3.38. Transpower must report to the Authority on the extent to which Transpower's role as system operator under the Code and the Act has been materially affected by any other role or capacity that Transpower has under the Code or the Act.[30]

3.39. The Code contains a policy on how the system operator will manage any possible, actual, or perceived conflict of interest that arises in the performance of its obligations

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25 Technical Code B of Schedule 8.3 of the Code.

26 Clause 8.29 of the Code.

27 Clause 8.30 of the Code.

28 Transpower is not the only grid owner. Westpower owns some of the West Coast transmission network that forms part of New Zealand's transmission network. Waipa Networks owns the 110kV line between the Te Awamutu and Hangatiki substations, which also forms part of the transmission network.

29 Clause 7.10 of the Code.

30 *Ibid*

under the Code. A conflict of interest is any situation where one of the following persons has a material interest in the outcome of a system operator function:

(a) Transpower, other than in its capacity as the system operator.

(b) A Transpower employee, contractor or director involved in carrying out the system operator function.[31]

3.40. Examples of system operator functions where conflicts of interest and questions of independence and impartiality may arise include:

(a) procuring ancillary services or alternative ancillary services

(b) recommendations as to who caused an under-frequency event

(c) decisions on dispensations and equivalence arrangements

(d) coordinating asset outages

(e) monitoring and reporting on asset owners' compliance with the Code.[32]

3.41. The Code lists several methods the system operator must employ one or more of to manage conflicts of interest. These include:

(a) appointing independent persons to oversee the management of a conflict of interest.

(b) establishing independent document and information management systems

(c) establishing a clear division of management and staff roles, including establishing separate teams that are physically isolated from each other.[33]

3.42. Transpower's governance model seeks to enhance the system operator's independence. A sub-committee of Transpower's board of directors is dedicated to the role of the system operator. The responsibilities of the sub-committee include:

(a) the strategic direction of the system operator function

(b) risk management

(c) the system operator's policy framework

(d) assessing and reporting on the system operator's performance.

3.43. Within the system operator there is a senior management role responsible for the independence and impartiality of the system operator function. Role responsibilities include monitoring and reporting to the Authority on inherent threats to the system operator's independence. Currently, the system operator actively monitors and manages the following threats to its independence:

(a) The system operator's monitoring of the ongoing compliance of generators and transmission network owners with their AOPOs and the Part 8 technical codes.

(b) The system operator's procurement of ancillary services.

(c) Decisions to grant dispensations or approve equivalence arrangements.

(d) The planning and coordination of asset outages.

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31 Clause 134A of the policy statement, which is incorporated by reference in the Code under clause 8.10 of the Code.

32 Clause 134B of the policy statement.

33 Clause 138 of the policy statement.

Distributors

3.44. New Zealand has 29 electricity distributors that connect the transmission network with consumers, smaller electricity networks and generators. These 29 distributors are responsible for owning, planning, building, maintaining, and operating their respective distribution networks.

3.45. Distribution networks operate using alternating current at various voltages including:

(a) sub-transmission at voltages including 110kV, 66kV, 50kV and 33kV

(b) distribution at voltages including 22kV, 11kV and 6.5kV

(c) single wire earth return (SWER) at various distribution voltages

(d) low voltage at 400V (multi-phase) and 230V (single-phase).[34]

3.46. In contrast with New Zealand's electricity transmission arrangements, where the system operator and transmission network owner functions are separately defined in the Code, a distributor's asset ownership and network operations roles are more integrated.

3.47. Table 1 contrasts the relevant operational functions at transmission and distribution levels.

[34] Clause 4 of the Electricity (Safety) Regulations 2010 defines "standard low voltage".

Table 1: Contrasting power system operation functions

	Transpower	Distributors
System operation	Transpower in its role as system operator ensures electricity supply matches electricity demand in real time across the transmission network, 24 hours a day, via the system operator's national control centre. The system operator is also focused on maintaining power system security and responding to emergencies on the transmission network that affect system security.	No directly equivalent role. Distributors manage local network congestion. Traditionally, such congestion has typically been caused by coincident demand (the sum of all consumer electricity demands at a point in time). Most distributors have managed this through the use of their load control systems (often referred to as 'ripple control').
Asset ownership	Transpower's national grid operating centres manage the operation of Transpower's transmission assets 24 hours a day. They have a close working relationship with the system operator and distributors' control rooms.	Distributors' control rooms operate one or more distribution networks in real time. They are focused on power quality and the security of the distribution networks under their control – monitoring voltages, power flows and responding to distribution network overloading and faults.

3.48. The core objective of New Zealand's 29 distributors is to provide sufficient levels of reliable network capacity to consumers located across most of New Zealand:

(a) Distribution network asset owners plan, build and maintain electricity distribution and supply assets in (mostly) non-overlapping geographical regions across New Zealand.

(b) Distribution network operators operate one or more (usually just one)[35] distribution networks by:

(i) staffing a control room with operational monitoring and remote-control systems, such as SCADA[36] and demand management systems

(ii) monitoring the health and security of the distribution network in real time, including voltage and current levels

35 There are a few examples where one distributor manages another, usually adjacent, distributor's network under a facilities agreement. Distributors have come to these arrangements voluntarily, by mutual agreement.

36 SCADA (supervisory control and data acquisition) is a system of software and hardware elements for the control of processes locally or remotely, involving monitoring, gathering and processing real-time data, and direct interaction with devices such as sensors and motors, through human-machine interface software.

(iii) monitoring and, when able and if necessary, controlling generation that injects electricity into the distribution network

(iv) remotely switching circuit breakers to enable planned outages associated with network maintenance, connections, and upgrades

(v) responding to distribution network faults (unplanned outages), by dispatching fault service providers (who may or may not be employed by the distributor) and remotely switching circuit breakers to reconfigure the distribution network

(vi) cooperating and coordinating with Transpower, as the system operator and as a transmission network owner, particularly when responding to emergencies on the transmission network, including by controlling distribution feeder circuit breakers to electrically disconnect load if necessary and then to restore load

(vii) turning off and on load that the distributor has under its control (eg, hot water cylinders) to manage network peak loading periods or for other permitted reasons.

The regulators of power system operation

3.49. The Authority, the Commerce Commission and WorkSafe New Zealand (WorkSafe) have statutory obligations in relation to power system operation in New Zealand.

3.50. The second limb of the Authority's main statutory objective states the Authority is to promote reliable supply by the New Zealand electricity industry for the long-term benefit of consumers. The Authority interprets this to mean the Authority must exercise its functions in section 16 of the Act in ways that, for the long-term benefit of electricity consumers, encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events.[37]

3.51. Part 4 of the Commerce Act 1986 provides for the Commerce Commission to regulate the price and quality of electricity transmission and distribution in a way that promotes the long-term benefit of consumers.[38]

3.52. The Electricity Act 1992 provides for WorkSafe to take all lawful steps that may be necessary to ensure the safe supply and use of electricity.

The regulation of power system operation by the Authority under the Act

The Electricity Act 2010

3.53. The Act provides a framework for the regulation of New Zealand's electricity industry. Although the Act does not define power system operation, the Act defines 'system operator' as the person who ensures the real-time coordination of the electricity system. The Act says the system operator is Transpower New Zealand Limited (Transpower) or any subsidiary of, or successor to, that company.[39]

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37 Electricity Authority, 2011, Interpretation of the Authority's statutory objective, paragraph 2.1.1.

38 Section 52 of the Commerce Act.

39 Section 5 and section 8 of the Electricity Industry Act.

3.54. The Act requires that the Code:

(a) specify the functions of the system operator

(b) specify how the system operator's functions are to be performed

(c) set requirements relating to transparency and performance.[40]

3.55. The Act requires that, as well as acting as system operator for the electricity industry, the system operator must:

(a) provide information, and short- to medium-term forecasting on all aspects of security of supply

(b) manage supply emergencies.[41]

3.56. The Act requires the Authority to appoint a Security and Reliability Council to provide independent advice to the Authority on:

(a) the performance of the electricity system and the system operator

(b) reliability of supply issues.[42]

The Electricity Industry Participation Code 2010

3.57. Several parts of the Code contain provisions regulating power system operation in New Zealand, as shown in Table 2. Parts 7, 8, and 13 of the Code contain the bulk of the provisions.

Table 2: Code provisions regulating system operation

Part	Title
6	Connection of distributed generation
7	System operator
8	Common quality
9	Security of supply
10	Metering
12	Transport
12A	Distributor agreements, arrangements, and other provisions
13	Trading arrangements

40 Section 8 of the Electricity Industry Act.

41 *Ibid*

42 Section 20 of the Electricity Industry Act.

The regulation of power system operation by the Commerce Commission under the Commerce Act 1986

3.58. The Commerce Commission has a role in regulating power system operation under Part 4 of the Commerce Act. Part 4 provides for the Commerce Commission to regulate the price and quality of goods or services in markets where there is little or no competition and little or no likelihood of a substantial increase in competition.[43] Among other things, Part 4 is intended to ensure that regulated businesses have incentives to innovate, invest, and meet consumers' quality demands, but are also limited in their ability to earn excessive profits. The Commerce Commission's aim is to mimic the effects seen in competitive markets so that consumers benefit in the long term.

3.59. The Commerce Commission regulates Transpower and 29 distributors under Part 4 of the Commerce Act. The scope of this regulation includes the power system operation functions listed in paragraph 3.6 that are undertaken by Transpower and these 29 distributors[44] (eg, the 'system operator' role and the network owner role of helping to manage system security and the quality of electricity supply).

3.60. Part 4 of the Commerce Act provides for two types of regulation:

(a) Price-quality path regulation.

(b) Information disclosure regulation.

Price-quality path regulation

3.61. Price-quality path regulation applies to Transpower, in its roles of a transmission network owner and the system operator, and to 16 distributors.[45] It establishes minimum standards of quality of service that Transpower and these distributors must meet and limits the revenues Transpower and the distributors can recover from their customers for those services.[46] Specifically, the Commerce Commission determines, for a regulatory period, price-quality paths that specify:

(a) the maximum price(s) and/or revenues that Transpower and the 16 distributors may charge/recover

(b) the quality standards that Transpower and the 16 distributors must meet.

3.62. These price-quality paths may include incentives for Transpower and the 16 distributors to maintain or improve their quality of supply. [47]

43 Section 52 of the Commerce Act.

44 Referred to by the Commerce Commission as 'electricity distribution businesses'.

45 Alpine Energy, Aurora Energy, EA Networks, Electricity Invercargill, Firstlight Network, Horizon Energy, Nelson Electricity, Network Tasman, Orion, OtagoNet Joint Venture, Powerco, The Lines Company, Top Energy, Unison Networks, Vector, Wellington Electricity.

46 Commerce Commission, 25 May 2023, Default price-quality paths for electricity distribution businesses from 1 April 2025, Proposed process, p. 4.

47 Section 53M of the Commerce Act.

Information disclosure regulation

3.63. Information disclosure regulation applies to Transpower, in its roles of a transmission network owner and the system operator, and to 29 distributors.[48] It requires the public disclosure of information on each distributor's performance and network plans.

3.64. The purpose of requiring Transpower and distributors to disclose information is to ensure sufficient information is readily available to interested persons to assess whether the purpose of Part 4 of the Commerce Act is being met.[49]

3.65. The Commerce Commission summarises and analyses the information disclosed by Transpower and distributors and publicly reports on their performance. The purpose of this is to help to positively influence the behaviour of Transpower and the distributors.[50] The summary and analysis produced by the Commerce Commission helps people to understand better the information publicly disclosed by Transpower and distributors. This, in turn, helps people to assess whether the purpose of Part 4 of the Commerce Act is being met.[51]

The regulation of power system operation by WorkSafe under the Electricity Act 1992 and the Electricity (Safety) Regulations 2010

WorkSafe's regulation of power system operation relates to electrical safety

3.66. WorkSafe is a crown agency established by section 5 of the WorkSafe New Zealand Act 2013. WorkSafe has the following functions under the Electricity Act 1992:

(a) To carry out inquiries, tests, audits, or investigations that may be necessary to determine whether a person is complying with the Electricity Act.

(b) To take all lawful steps that may be necessary to ensure the safe supply and use of electricity.

(c) To perform other functions provided for under the Electricity Act.[52]

3.67. WorkSafe is responsible for administering the Electricity (Safety) Regulations 2010 (Safety Regulations), which regulate electrical safety and related matters.[53] Some of these relate to power system operation.

Obligations under the Electricity (Safety) Regulations 2010

3.68. The Safety Regulations are the primary means of regulating safety across the electricity industry in New Zealand. They are enacted under the Electricity Act 1992.

3.69. These regulations have a relatively small influence on power system operation. However, these regulations do cite various standards (such as AS/NZS3000 and

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48 Alpine Energy, Aurora Energy, Buller Electricity, Centralines, Counties Energy, EA Networks, Electra, Electricity Invercargill, Firstlight Network, Horizon Energy, Mainpower New Zealand, Marlborough Lines, Nelson Electricity, Network Tasman, Network Waitaki, Northpower, Orion, OtagoNet Joint Venture, Powerco, Scanpower, The Lines Company, The Power Company, Top Energy, Unison Networks, Vector, Waipa Networks, Wellington Electricity, WEL Networks, Westpower.

49 Section 53A of the Commerce Act.

50 Commerce Commission, 25 May 2023, Default price-quality paths for electricity distribution businesses from 1 April 2025, Proposed process, p. 4.

51 Commerce Commission, 17 August 2023, Part 4 Targeted Information Disclosure Review Framework paper, p. 13.

52 Section 5 of the Electricity Act.

53 Section 169, section 169A, section 169B, and section 169C of the Electricity Act.

AS/NZS4777.1), which have an effect on power system operation. The parts of the Safety Regulations that are most relevant to power system operation are:

(a) Part 3 – Systems of supply

(b) Part 4 – Safety of works.

Power system operation in New Zealand will continue to evolve

3.70. As noted at the start of this section, power system operation in New Zealand has evolved over more than a century in response to changes in technology and in the supply and demand for electricity. Looking forward, the current arrangements for power system operation in New Zealand will continue to evolve for these, and possibly other, reasons.

3.71. Power system operation in the future may:

(a) require more coordination of variable power flows across the points of connection between the transmission network and distribution networks, in order to maintain adequate power quality

(b) require increasingly complex tools and processes to deal with increasingly complex operating scenarios across the power system and greater visibility of distribution networks (particularly the low voltage sections) and assets connected to distribution networks (ie, DER)

(c) require more sophisticated outage planning 'deeper' into distribution networks (eg, to increasingly lower voltages)

(d) need to accommodate more dynamic pricing on distribution networks

(e) require a transmission system operator and one or more distribution system operators (or none, if the roles of transmission and distribution system operation are integrated)

(f) evolve organically (through market innovation) and not require any of the above.

3.72. In the following section, we look at some factors that might affect power system operation in the future, leading to changes such as those listed above.

Q1. Do you consider section 3 to be an accurate summary of the existing arrangements for power system operation in New Zealand? Please give reasons if you do not agree.

4. Drivers of change to power system operation in New Zealand over the coming decades

Six key drivers of change to power system operation

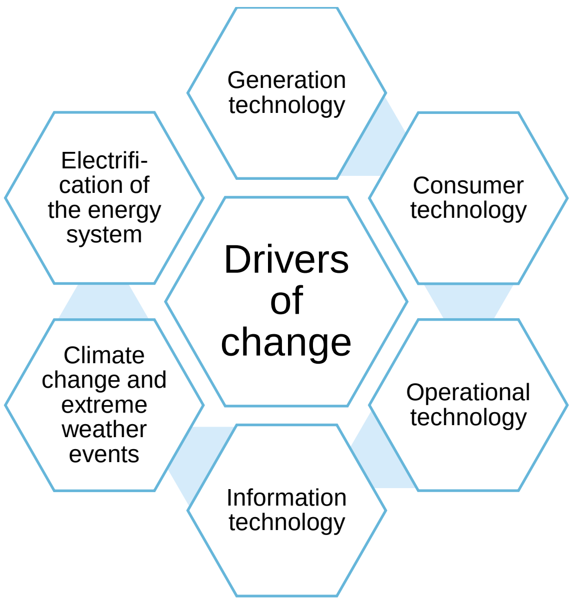
4.1. This section describes six key (non-regulatory) drivers of change to power system operation in New Zealand as the country transitions to an increasingly electrified economy. The section discusses:

(a) how these changes may impact the incentives to meet the obligations described in Section 3

(b) how these changes may impact the ability to meet the obligations described in Section 3.

4.2. The six key drivers of change to power system operation in New Zealand are captured in Figure 1 below.

Figure 1: Drivers of change to power system operation



Key driver 1: Changes in generation technology

4.3. The flow of electricity in New Zealand's power system is largely uni-directional at present. Typically, electricity flows from large power plants, located near fuel sources, to consumers via transmission and distribution networks. Reflecting this system topology, the system operator is tasked with operating the transmission network to transport electricity from transmission (grid) injection points (GIPs) to transmission (grid) exit points (GXPs). Distributors then reticulate electricity from GXPs to consumers.[54]

4.4. Transmission-connected power plants predominantly comprise conventional synchronous machines powered by hydro, thermal (coal and natural gas), and

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[54] A few very large consumers are connected directly to the transmission network rather than to a distribution network.

geothermal fuel resources. In 2022, synchronous generation accounted for approximately 93.5% of total electricity generated in New Zealand.

4.5. However, technology, and the need to reduce greenhouse gas emissions, are driving a move towards the use of inverter-based resources (IBRs) for generating electricity. An IBR is equipment that uses an inverter when functioning. Examples include:

(a) wind generation

(b) solar photovoltaic generation – ranging from small residential rooftop installations to large (utility) scale solar farms

(c) a battery energy storage system – ranging from a small residential wall-mounted battery and an electric vehicle battery to a large (utility) scale battery.

4.6. Boston Consulting Group (BCG) estimates 4.8GW of new large-scale renewable generation will be needed to achieve 98% renewable generation by 2030.[55] Much of this new generation will be IBR generation. There is also significant growth expected in small-scale residential IBR generation, especially rooftop photovoltaic solar generation and electric vehicles with batteries that can inject electricity into the local electricity network.

4.7. The deployment of IBRs poses a number of technical challenges for power system operation due to several factors, which we now briefly describe.

Non-synchronous nature and inertial characteristics

4.8. System frequency is an indicator of the instantaneous power balance between electricity production and consumption. The level of inertia in the power system determines how quickly frequency will change when there is an imbalance between generation and demand. Inertia is the resistance of the power system to changes in frequency, which results from the masses of large synchronously rotating generators and motors taking time to slow down or speed up.

4.9. IBR generators have no synchronously rotating mechanical parts like turbines or rotors to provide inertia to the power system, or to help arrest and stabilise the system frequency following a disturbance on the power system.

4.10. As the amount of IBR generation increases relative to the total size of the power system, system inertia is expected to decrease (in the absence of IBRs providing synthetic inertia). A reduction in system inertia means system frequency will change more rapidly in response to supply/demand imbalances. This in turn will require, for a given level of demand, more frequency management resources (eg, frequency keeping and instantaneous reserve).

Variability and intermittency

4.11. Traditionally, electricity supply and demand has been relatively predictable. Challenging this, IBR generation has variable and/or intermittent generation profiles, depending upon meteorological conditions. Variability in weather patterns plays out over the full range of timescales, from intra-day to seasonal and annual.

4.12. Solar photovoltaic IBR generation exhibits diurnal and intra-day variability based on solar irradiation levels. This generation exhibits intra-day intermittency based on

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55 Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 15, available at: the-future-is-electric-full-report-october-2022.pdf.

passing overhead clouds. Wind turbine output varies with wind speed. As already experienced in New Zealand, there have long been cases of significant variability in wind generation overseas. For example, on Christmas Eve 2004, the German energy utility E.ON faced a drop in wind generation in E.ON's control area of over 4,000MW in only 10 hours.[56]

4.13. From an operational standpoint, such variability and intermittency is anticipated to have implications for the system operator's generation scheduling role and for security-constrained economic dispatch of generation.

4.14. The amount of variable/intermittent generation entering the New Zealand electricity market is expected to increase considerably over the next decade.[57] The share of electricity generated from wind and solar is estimated to increase from around 6% of total generation today to 47% by 2050.[58]

4.15. As the percentage of IBR generation connected to New Zealand's power system increases, more flexible generation and demand resources will be required to counterbalance the variability/intermittency of IBR generation.

4.16. Fast fluctuations in output from wind or solar energy do not only disrupt the hourly load-following phase of power system planning, but also the second-to-second balance between total electric supply and demand. The system operator may need to ensure sufficient resource adequacy and fast ramping on a near real-time basis.

Dynamic response during transient events

4.17. Transient events are experienced when the electrical power supplied to a circuit changes momentarily. Transient events affect voltage and current, on both AC and DC circuits. Transient events on a power system indicate an unstable system. Power system reliability is increased by controlling transient events in order to return the system to a steady state.

4.18. IBRs, which generate DC electricity, connect to AC transmission and distribution networks through inverters, which decouple IBRs from electricity network dynamics.

4.19. The controller of an IBR generating unit and the control architecture of an inverter are based on power electronics. They have unique algorithms that dictate how the IBR responds to transient events on the power system. This is markedly different to the electro-mechanical control system of a traditional generating unit. As a result, the dynamic response of IBR generating units to power system disturbances is quite different to that of conventional, synchronous machines (ie, generating units and motors). The interaction of distributed IBRs may exacerbate transient events on the power system and could affect overall power system stability.

4.20. The following attributes of IBRs (whether connected to the transmission network or the distribution network) will have an impact on the whole of the power system:

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56 E.ON Netz, 2005, Wind Report 2005, p. 8.

57 See, for example:

- Market Development Advisory Group, February 2022, Price Discovery Under 100% Renewable Electricity Supply – Issues Discussion Paper, available at MDAG Issues discussion paper.
- Concept Consulting, 2022, Generation investment survey 2022 – Prepared for Electricity Authority, available at 2022 Generation investment survey.

58 Market Development Advisory Group, February 2022, Price Discovery Under 100% Renewable Electricity Supply – Issues Discussion Paper, p. 16.

(a) response to faults such as fault ride through, frequency ride through, and reactive power/voltage support

(b) overall protection coordination

(c) coordination of system restoration

(d) non-dispatchable ramping and variability of certain IBRs

(e) nuisance tripping[59] and sympathetic tripping.[60]

4.21. A recent blackout incident in Texas, USA, involved nuisance tripping of around 800MW of large-scale IBRs connected to the distribution network. None of the affected IBRs were tripped by the fault itself. Rather, they were due to distribution network feeder-level trippings or control system behaviour within the IBR.[61]

Key driver 2: Changes in consumer technology

4.22. Electricity consumers have traditionally been passive customers but are now becoming more actively involved with the power system, as so-called 'prosumers'. The term 'prosumers' broadly refers to electricity consumers who can also generate electricity within their premises, 'behind' the electricity meter. Prosumers use their generation capacity for their own consumption and/or to export electricity to the electricity network.

4.23. In addition to generating electricity, consumers are increasingly participating in demand-side flexibility/management by varying when they use electricity and how much electricity they use.

4.24. The rise of prosumers is occurring with the uptake of DER, such as rooftop solar photovoltaics, battery energy storage systems, and electric vehicle charging and discharging at residential and commercial level (including public electric vehicle charging facilities).

4.25. Between 2010 and 2020, the price of a residential solar photovoltaic system declined by 65%. A further decline of 60% is predicted to occur during the 2020s, according to the (US-based) National Renewable Energy Laboratory, as cited by BCG.[62] The National Renewable Energy Laboratory also predicted residential batteries will keep getting cheaper, by up to 50% this decade.[63]

59 Nuisance tripping is when a circuit breaker identifies a hazard/fault on a network and cuts the supply of electricity in that network, when in fact there is no hazard/fault. This type of tripping causes the unnecessary loss of electricity supply to consumers connected to the network.

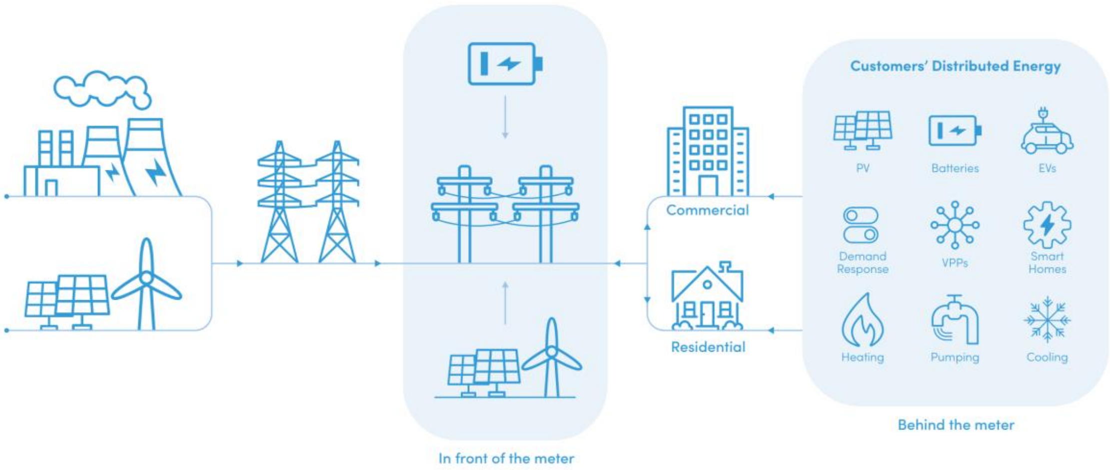
60 Sympathetic tripping refers to the operation of a circuit breaker in the 'healthy' section of a network due to a hazard / fault on another section of the network. This type of tripping causes the unnecessary loss of electricity supply to consumers connected to the healthy section of the network.

61 North American Electric Reliability Corporation and Texas Reliability Entity, 2021, Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, available at: nerc.com/Documents/Odessa_Disturbance_Report.pdf.

62 Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 52, available at: the-future-is-electric-full-report-october-2022.pdf.

63 *Ibid*

Figure 2: 'Behind the meter' consumer DER[64]



4.26. 'Flexibility' is the ability to shift the location and timing of both the demand for, and the generation of, electricity. Typically, this is in response to a signal (eg, price). Demand side flexibility in particular will be a cost effective way of achieving the transition to net zero emissions.

4.27. Consumers can now, through dispatch notification, leverage their DER, including rooftop solar photovoltaics and battery energy storage systems, smart electric vehicle chargers, heat pumps, storage heating, and other smart home appliances and equipment in response to price signals. Currently, these price signals must be initiated by retailers or aggregators. An example is Contact's '3 hours of power' plan, giving free electricity to its customers from 9pm to midnight. The system operator should in due course be able to manage system constraints by requesting ramp up or ramp down of prosumer generation and demand through aggregators, or even aggregation technologies yet to be developed.

4.28. Reportedly, some 20% of energy consumed in Copenhagen city buildings is flexible,[65] meaning it can be ramped up or down to help balance the power system. This makes extensive use of energy management systems and Internet of Things (IoT) platforms.

4.29. Trials conducted by National Grid ESO in the United Kingdom showed that by deploying time-of-use strategies, peak evening load could be reduced by 17%. Households that owned smart electric vehicle chargers had greater flexibility and were able to reduce their evening peaks by up to 23%. Extrapolating out to 2030, it was estimated that domestic flexibility provided by households could reduce peak electricity demand by 6.8GW.[66]

4.30. Modelling by Concept Consulting[67] forecasts there could be one million electric vehicles in New Zealand by 2030, rising to 2.4 million by 2040, and 4.3 million by 2050. Plugged in electric vehicles could become the largest source of demand-side flexibility in New Zealand, overtaking hot water cylinders (currently enabled through distributor-controlled ripple control technology). Unlike hot water cylinders, plugged in

64 Energy Transformation Taskforce of the State Government of Western Australia, 2019, Distributed Energy Resources Roadmap, available at wa.gov.au/system/files/2020-04/DER_Roadmap.pdf.

65 IBM blog https://www.ibm.com/blog/flexible-energy-platform-renewable-power/.

66 National Grid ESO, 2021, CrowdFlex – Phase 1 Report, pp. 3–4.

67 Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 52, available at: the-future-is-electric-full-report-october-2022.pdf.

electric vehicles can (subject to their level of charge) inject electricity into the power system.

4.31. The Sapere cost-benefit analysis,[68] cited in the Authority's issues paper on updating the regulatory settings for distribution networks,[69] stated the main benefit of flexibility from DER would be in terms of resource adequacy, reducing or deferring the need for new lines and generation ($5.9 billion or 86% of the total potential benefits of $6.9 billion in 2021-50). Other estimated benefits of DER were considered to exist in terms of resource adequacy to offset thermal peaking, hydro firming, instantaneous reserve, and voltage management.

Key driver 3: Changes in operational technology

4.32. The power system is evolving into a 'system of systems', with distribution networks providing a platform to utilise new operational technologies. These include:

(a) **Peer-to-peer trading:** transactional energy mechanisms and trading platforms such as those enabling multiple trading relationships (eg, the Ara Ake and Kainga Ora trial) can enable bilateral trading of electricity, without the need for a centralised market clearing mechanism.

A national rollout of multiple trading relationships or another framework (eg, a financial equivalent) could facilitate transactions for large electricity consumers operating across different regions.

(b) **Vehicle-to-electric-grid technology:** this technology enables energy to flow bi-directionally between a distribution network and an electric vehicle battery. Several trials in overseas jurisdictions have used automated frameworks for charging and discharging electric vehicles based on real-time market signals.

The United Kingdom energy regulator, Ofgem, says research shows that vehicle-to-grid technology has the potential to save GBP3.5 billion annually in areas such as electricity network strengthening, storage, and generation. By 2030, vehicle-to-grid technology could provide around 16GW of daily flexible capacity to the United Kingdom power system.[70] Similar trials are being undertaken in New Zealand, with a partnership between the Energy Efficiency and Conservation Authority (EECA) and Northpower.[71]

(c) **Microgrid community grids:** these are autonomous networks of DER located close to or within a community. They can operate independently (referred to as operating on an 'islanded' basis) or be connected automatically to the local distribution network when required.

Microgrids can potentially assist with improving the power system's resilience to extreme events such as floods and earthquakes, by being able to operate at times when the main network is damaged. A microgrid could be as small as a single household, as provided by solarZero households during the February

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68 D. Reeve, C. Comendant and T. Stevenson, 2020, Distributed Energy Resources – Understanding the potential, A Sapere report for Transpower, available at: Distributed energy resources: Understanding the potential (transpower.co.nz).

69 Electricity Authority, 2022, Issues paper: Updating the Regulatory Settings for Distribution Networks, p. 10, available at: Updating the Regulatory Settings for Distribution Networks.

70 Ofgem case study: https://www.ofgem.gov.uk/publications/case-study-uk-electric-vehicle-grid-v2g-charging.

71 https://northpower.com/v2g.

2023 Cyclone Gabrielle.[72] Operating and controlling microgrids as electrical islands might require a different regulatory framework to be developed in the future.

(d) **Aggregators and virtual power plants**: a virtual power plant is an aggregated group of generators (generally small-scale) at a particular GXP. Being part of a virtual power plant enables a group of generators to participate in the wholesale electricity market more effectively as a single entity.

Unlike a microgrid, a virtual power plant is not driven by physical assets (inverters) closely connected. Instead, a virtual power plant is largely software driven. Being connected to the distribution network, it can potentially provide resources and services to the system operator when required. A solarZero trial in winter 2023 proved this could work in New Zealand, using dispatch notification.[73]

(e) **Increased uptake of non-network solutions:** these are solutions that can delay or replace the need for network investment and contribute to system reliability. Non-network solutions are technology-based operational solutions that do not need additional transmission or distribution assets such as transformers or additional cables or overhead lines.

At the distribution level, several non-network solutions are being trialled in New Zealand, including those that provide demand response/price incentives for peak load shaving.[74]

4.33. These new operational technologies, particularly those of a relatively large capacity (whether individually or aggregated) will need to be integrated into system operations at both the transmission and distribution network level. Such high-level infrastructure architecture has yet to be established.

4.34. Most of the present operational controls are not automated, nor can they be communicated in real time. To realise the potential of DER and other new operational technologies connected to the power system, advanced operational tools like artificial intelligence and machine learning will likely need to be employed across the power system.

Key driver 4: Changes in information technology (digitisation and digitalisation)

4.35. Digitisation refers to the creation, or conversion, of information/data in, or into, a digital format that is easily analysed by machines for computational purposes.

4.36. Digitalisation is the transformation of a system through the use of digital technologies to improve the system's processes. Figure 3 illustrates the far-reaching and comprehensive potential for digitalisation of the power system.

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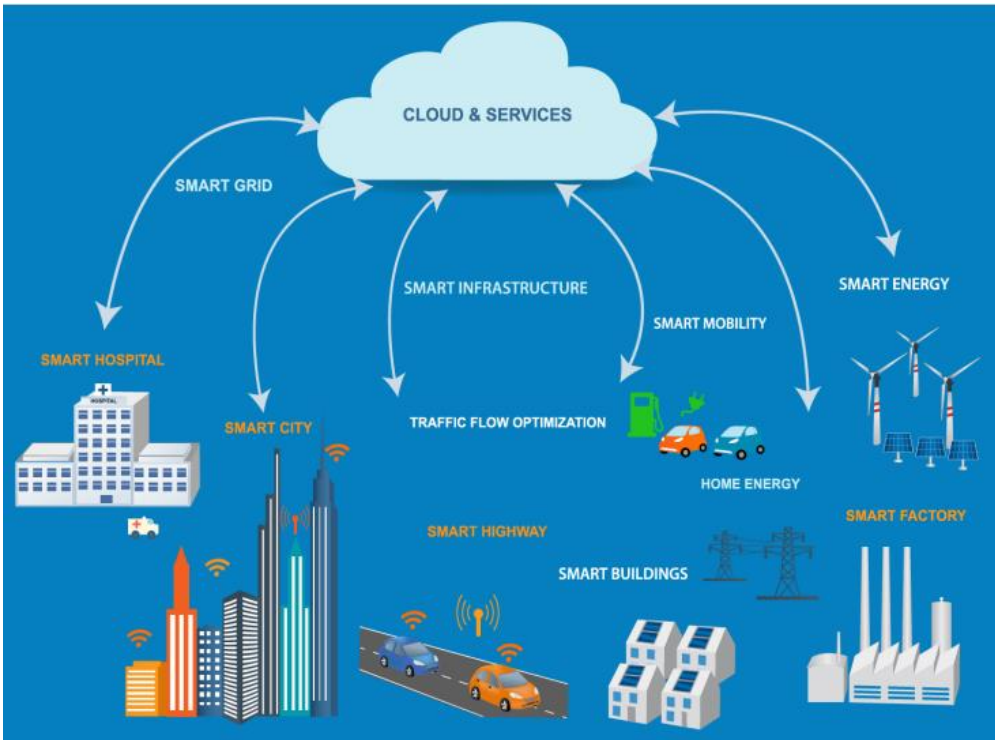
72 https://www.energyawards.co.nz/article/awards-finalist-solarzero-community-energy-resilience.

73 https://www.ea.govt.nz/news/eye-on-electricity/security-of-supply-while-two-thermal-generators-are-on-outage.

74 See for example, the Authority's programme of work here: https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/consultation/regulatory-settings-to-support-non-network-solutions-and-flexibility-services/.

Figure 3: Future digitalisation scenario – European association for the cooperation of transmission system operators for electricity (ENTSO-e, 2018)



4.37. The International Energy Agency estimates that digitally enabled demand response could reduce the variability of IBRs by more than 25% by 2030 globally, thereby increasing power system efficiency and reducing costs for consumers.[75]

4.38. Most DER will be monitored and controlled through IoT devices. The rapid growth of DER requires increased network connectivity for data acquisition and sharing, which creates critical cybersecurity risks that must be addressed.

4.39. A high penetration of DER with IoT functionality connected to the distribution network will eventually allow distribution network operators to rely on data-driven, automated and artificial intelligence control architecture for network reliability and optimised system operation. But exploiting that potential functionality requires more granular and real-time data, more common communications protocols, and more coordinated data exchange between system operators at the transmission and distribution levels of the power system.

4.40. The long-term prospect is for digitisation of system operation at the distribution level to provide an information layer that transforms data into useful insights, providing system operators with the capability for real-time computation and predictive analytics.

4.41. Advanced data capturing and processing tools, such as phasor measurement units and advanced data management systems, are being deployed by system operators in overseas jurisdictions. With the increased uptake of DER and other new IoT devices, the capture, handling, processing, and analysing of data will challenge system operators until they have better visibility of these devices. This will be

75 International Energy Agency, 2023, Unlocking Smart Grid Opportunities in Emerging Markets and Developing Economies, p. 11, available at: https://www.iea.org/reports/unlocking-smart-grid-opportunities-in-emerging-markets-and-developing-economies.

particularly the case for those devices located at lower voltage levels within distribution networks.

4.42. With the very high uptake of large-scale IBR and DER connected at the residential level, the number of IoT devices exchanging data across the power system will be enormous. Robust cybersecurity and data privacy practices will be crucial to the stability of the power system, and to give consumers the confidence to deploy new and evolving technologies that enable consumers to engage with the power system.

4.43. There will be opportunities to use digital tools to improve the performance and utilisation of energy resources. For example, the operators of energy resources will use more timely and granular data to make better decisions and use new tools to automate the control of energy resources.

4.44. The system operator, in a recent discussion note on distributed flexibility, identified the importance of information and data sharing for system security and efficiency, stating:

> *'Information and data sharing between flexibility service providers, distribution networks, and the system operator will be critical in ensuring overall system security and increasing efficiency for consumers.'*[76]

Key driver 5: Climate change and extreme weather events

4.45. Consensus exists that climate change is real and that rising concentrations of greenhouse gases have started to impact not only global temperatures, but also levels of water vapour and patterns of precipitation. In addition, more extreme weather patterns are being seen than before, and more often – for example, cyclones, floods and droughts.

4.46. The Ministry for the Environment recently summarised the latest research into the impacts of climate change on severe weather in New Zealand.[77] Results included:

(a) **More flooding:** the Intergovernmental Panel on Climate Change (IPCC) released its 'Sixth Assessment Report' in 2021.[78] In it, a global panel of climate scientists projected that floods across the world will continue to become more frequent between now and 2050.

(b) **More extreme storms:** it is also projected that severe convective storms (thunderstorms) will carry more rain in a warming world.

(c) **Larger rain showers:** the National Institute of Water and Atmospheric Research (NIWA) produces regional climate projections for New Zealand based on the IPCC's data. NIWA has estimated that in New Zealand, one degree of warming translates to a median 13.5% increase in rainfall per hour in a one-in-50-year event of one hour duration. [79]

(d) **More cyclones:** NIWA also projects more intense regional cyclonic storms in the southern hemisphere by 2100, and an increase in the frequency and extent of

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76 Transpower, 2022, Enabling distributed flexibility to support whole system reliability and efficiency: a system operator view, p. 4, available at: Enabling whole system reliability and efficiency with distributed flexibility - a system operator view.

77 See https://environment.govt.nz/news/the-science-linking-extreme-weather-and-climate-change.

78 See https://www.ipcc.ch/report/ar6/wg1/.

79 See environment.govt.nz/climate-change-projections-for-New-Zealand.

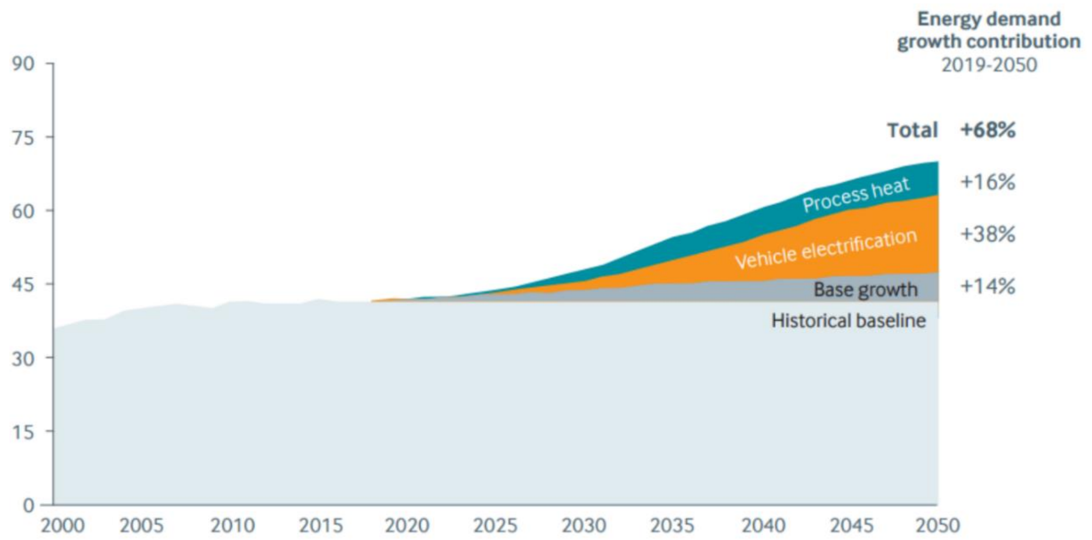
'atmospheric rivers', which could bring more rain. Atmospheric rivers are plumes of moisture in the air that move from the tropics to the mid-latitudes and are closely related to extratropical cyclones. They are projected to become more frequent with increased atmospheric warming.[80]

(e) **More drought:** the National Climate Change Risk Assessment report for New Zealand[81] estimated that by 2090, annual rainfall is expected to be 50mm less for much of the North Island. The strongest changes are expected over the northern and eastern regions, and in the northeastern and central South Island east of the main divide, indicating long-term drying of these regions

Key driver 6: Electrification of the energy system

4.47. New Zealand's electricity demand could be 68% higher in 2050 than 2019 (see Figure 4), driven by the expected electrification of transport and process heat.

Figure 4: Electricity Demand 2000 to 2050, TWh: Accelerated Electrification



Source: Whakamana i Te Mauri Hiko - Empowering our Energy Future[82]

4.48. While there is uncertainty around the projections for gross electricity demand (eg, the impact of data centres, hydrogen,[83] and electric vehicles), broadly there is consensus that base and peak electricity demand will increase significantly.

4.49. Large transmission and distribution network investments will likely be required to enable and accommodate increasing electrification. For example, BCG estimates there will be $47 billion of distribution investment and $18 billion of transmission investment required in the 2020s and 2030s.[84] These numbers include investment for other changes, such as enabling renewable generation and supporting DER uptake,

80 *Ibid*

81 Ministry for the Environment, 2020, National Climate Change Risk Assessment for New Zealand – Arotakenga Tūraru mō te Huringa Āhuarangi o Āotearoa: Technical report – Pūrongo whaihanga, available at: https://environment.govt.nz/assets/Publications/Files/national-climate-change-risk-assessment-technical-report.pdf.

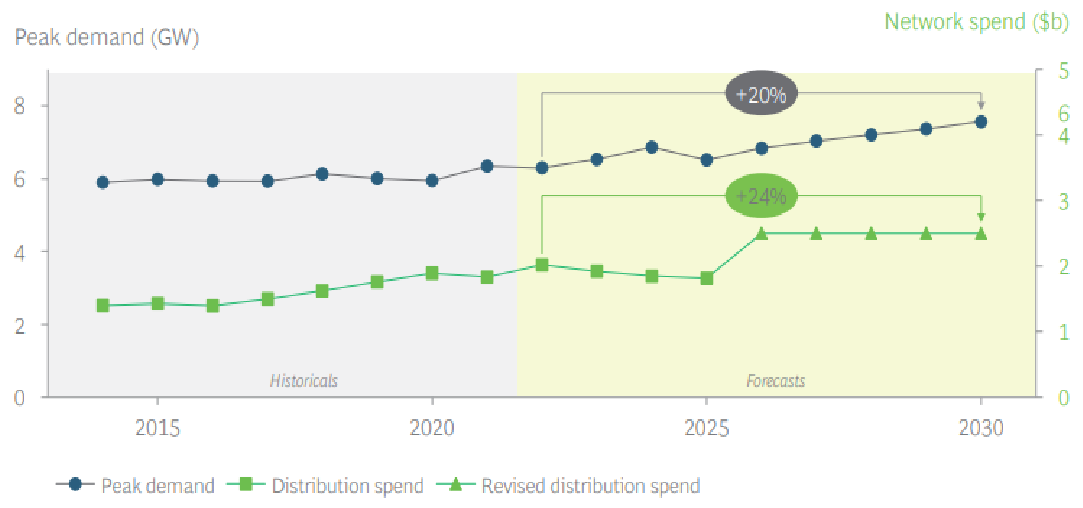
82 Transpower, 2020, Whakamana i Te Mauri Hiko, Empowering our Energy Future, p. 23, available at: www.transpower.co.nz/whakamana-i-te-mauri-hiko-empowering-our-energy-future.

83 Transpower, 2023, Whakamana i Te Mauri Hiko Monitoring Report, p. 4, available at: WiTMH March 23.

84 Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 14, available at: the-future-is-electric-full-report-october-2022.pdf.

but most of the extra investment is to accommodate increasing electrification. Figure 5 shows both the recent and projected correlation between peak electricity demand and distribution investment in New Zealand.

Figure 5: Historical and forecast peak demand from distribution expenditure



4.50. Wellington Electricity estimates that electricity consumption on its network will increase by around 80% by 2050. It estimates that if it uses traditional methods to add the required network capacity, the costs would be around $1 billion, increasing the network line charges to consumers by around 80%.[85]

4.51. Transpower, through its Net Zero Grid Pathways work programme, is considering the amount of transmission network investment that will be needed as New Zealand transitions to net zero emissions.[86] Net Zero Grid Pathways is a move away from a 'just-in-time' approach to transmission investment, towards building, or having development plans in place, ahead of consumer-driven change.

4.52. Of course, investment levels forecast for transmission and distribution network upgrades could be overestimated, particularly if non-network solutions are used effectively to reduce the level of network investment required. For example, Sapere has estimated the main benefit of flexibility[87] from controllable DER is the deferral of network build and generation capital expenditure. Sapere has estimated this could realise a potential net economic surplus of $5.9 billion from 2021 to 2050, which equates to 86% of the $6.9 billion in total potential benefits from DER realising its potential.[88]

4.53. However, while there is uncertainty around the exact level of network investment that is needed over the coming decades as New Zealand transitions to net zero, most reports on the topic agree that the level of investment will be in the billions of dollars and a lot larger than the upgrades seen in recent decades.

85 See www.welectricity.co.nz/projects/ev-connect.

86 See www.transpower.co.nz/net zero pathways.

87 As noted in paragraph 4.26, 'flexibility' is the ability to shift the location and timing of both the demand for, and the generation of, electricity, typically in response to a signal such as price.

88 D. Reeve, T. Stevenson & C. Comendant, 2021, Cost-benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority, available at: www.ea.govt.nz/documents/1742/Sapere CBA.pdf.

Q2. Do you agree that we have captured the key drivers of change in New Zealand's power system operation in section 4? Please give reasons if you do not agree.

Q3. Do you have any feedback on our description of each key driver in section 4?

5. Possible challenges and opportunities in power system operation during New Zealand's transition to net zero emissions.

Overview

5.1. Section 4 discussed the drivers of change in the power system. Various challenges and opportunities will arise because of these changes. Section 5 sets out possible challenges and opportunities that we may need to respond to as a result of the key drivers of change in power system operation.

5.2. Feedback on this section will help the Authority assess the challenges and opportunities with system operation that may emerge over the coming decades.

Is there sufficient coordination of system operation?

5.3. Operation of the transmission and distribution networks is expected to become more complex over the coming years, both in 'real time' (up to 24–36 hours before dispatch) and over a longer window of time.

5.4. The increasing complexity of coordination is expected to result from the factors mentioned in section 4, such as the increasing demand for electricity, more variable and intermittent generation, DER, and more bi-directional power flows.

5.5. Consumers and aggregators will account for a vast increase in the number of power system participants. The power system must accommodate and benefit these new players, particularly consumers. Consumers of the future will be more independent and have more control over their energy use. Consumers that are integrated into the power system will likely decide how best to use their resources by relying on information available to them, rather than responding to instructions from a system operator.

5.6. Improvements in technology are driving down the prices of electric vehicles, batteries and solar panels. Communication and the exchange of data are improving continually. Limited DER visibility and connectivity are however slowing the uptake of DER and electric vehicles.

5.7. The impediments to greater visibility must be addressed – such as the need for common standards and/or protocols, to facilitate interoperability. The Authority's work programme on updating the regulatory settings for distribution networks is tackling these issues.

5.8. The connection of DER and electric vehicles to electricity networks according to common standards and protocols is essential for realising the potential of these resources. For example, a common communication protocol would help enable dynamic operating envelopes (DOEs), which can facilitate a relatively more efficient allocation of network capacity to DER controlled by consumers and third-party aggregators – particularly for distribution networks that are close to capacity.

5.9. There has been much discussion in New Zealand, and internationally, about whether, and if so to what extent, there is a need for distribution system operators. This discussion has included consideration of the roles and capabilities required, and who is best placed to undertake such a function (eg, whether distribution system operators should be independent of distribution network owners). Some distributors have recently used the term ‘distribution system operator’ while discussing the role of implementing DOEs on their networks.

5.10. In the future, the management of day-to-day power system operations, including the control of frequency, voltage and network loading, will likely be increasingly automated. Visualisation of the power system will be data driven and will rely on artificial intelligence-based and other advanced tools such as state estimation of the systems.

5.11. However, at first several preliminary steps are likely to be needed, such as greater communication between the system operator, distributors, and parties operating on networks (eg, aggregators/flexibility traders). As stated in an Energy Systems Integration Group report:[89]

> *“Closer coordination implies that distribution and transmission systems will increasingly need to be planned and operated as an interactive, integrated whole, with power flows to and from distribution systems that shift as DERs respond to changing conditions in wholesale markets, and wholesale markets and operations respond to changes in loads and DERs in distribution systems.”*

5.12. The Authority’s recent move to introduce electricity spot market settlement on real-time pricing (RTP) has the potential to facilitate greater participation of aggregated demand response and DER in the power system.[90] A further move towards five minute blocks of time over which prices are calculated (rather than being smoothed over 30 minutes) could incentivise fast-start flexible response, especially from large utility-scale batteries, which are typically required for a few minutes or less. However, these initiatives may cause rapid and/or unexpected changes in load on distribution networks, in response to changes in wholesale market prices. In turn, this may cause issues for distributors, such as congestion on part(s) of their networks.

5.13. In light of the potential for large amounts of uncoordinated DER to cause significant issues on distribution networks, distributors have approached the Authority for assistance in achieving greater visibility of distribution network users. This has included compelling flexibility traders/DER aggregators to negotiate with distributors, via the default distributor agreement, over the use of distribution networks. Some distributors have also said there is a need for explicit powers to control flexibility resources in network emergencies.[91] The Authority intends to consult on these matters this year.

5.14. One question is whether there are difficulties in negotiating agreements between distributors, retailers and flexibility traders which are preventing distributors from operating their networks efficiently. If so, do these difficulties hamper the increased participation of consumers and new players in the operation of the power system?

5.15. Currently, it is mainly larger distributors in New Zealand proposing the implementation of DOEs, whereas there are other distributors not yet facing congestion constraints but nevertheless seeking ways of using flexibility to aid system operations and delay

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89 Energy Systems Integration Group, 2022. DER Integration into Wholesale Markets and Operations: A Report of the Energy Systems Integration Group’s Distributed Energy Resources Task Force, p. 1, available at: www.esig.energy/reports-briefs.

90 See Spot market settlement on real-time pricing | Our projects | Electricity Authority (ea.govt.nz).

91 As noted in paragraph 4.26, ‘flexibility’ is the ability to shift the location and timing of both the demand for, and the generation of, electricity, typically in response to a signal such as price.

network investment. For example, the Flextalk[92] initiative of the Electricity Engineers Association is exploring how to use an open-access communication protocol to manage electric vehicle charging.

5.16. We would like to hear from new players in the markets for flexibility and ancillary services about barriers to greater participation in these markets within the power system. Your feedback, in the form of information and evidence, will help us better understand the issues described in the preceding paragraphs, and what appropriate next steps are in terms of any potential regulatory intervention.

Q4. What do you consider will be most helpful to increase coordination in system operation? Please provide reasons for your answer.

Q5. Looking at overseas jurisdictions, what developments in future system operation are relevant and useful for New Zealand? Please provide reasons for your answer.

Are existing system operation requirements compatible with distributed energy resources?

5.17. Increasing levels of DER will likely drive increasingly frequent bi-directional power flows across GXPs. The increasing prevalence of IBRs (as thermal generation is retired) will create challenges for several aspects of power quality, such as frequency, voltage, flicker and harmonics.

5.18. A key issue for future system operation is the lack of visibility and control of DER, which impacts power system operation at both the distribution and transmission levels and requires coordination to maximise efficient network utilisation.

5.19. The Authority wants to ensure consistency between electricity market settings and the technical requirements of power system operation. We also want to ensure that consumers are provided with solutions that enable choice, affordability, and reliability of electricity supply. We believe a whole-of-power-system approach to the planning and operation of New Zealand's power system is needed to unlock the full potential of consumer-side technology development.

5.20. Some technical concerns are being addressed in the Authority's review of Part 8 of the Code, which deals with common quality (a key workstream in the FSR work programme).[93] However, other parts of the Code likely require amending.

5.21. In Part 7 of the Code there is potentially scope for more guidance to be given to the system operator on how it should deal with increasing complexity both in the power system itself and in power system coordination. This includes considering whether the system operator's PPOs might be expected to remain fit for purpose over the coming years.

5.22. More generally, the Authority is interested in stakeholders' views as to whether they see the Authority's role in relation to future system operation as being to facilitate change primarily through Code amendments, or through other pro-competitive measures or policies, or both.

92 See www.eea.co.nz/FlexTalk/about-project.aspx.

93 See Part 8 common quality requirements | Our consultations | Electricity Authority (ea.govt.nz).

5.23. The observability and controllability of DER are not well defined. Depending on the uptake of DER, the system operator will, in the future, need to:

(a) identify system services (active power management, frequency and voltage control, emergency management, system restoration, network (de)congestion)

(b) coordinate more actively with distributors and service providers connected to distribution networks.

5.24. The power system will be more vulnerable to cyber-attacks as interconnections within the power system increase, alongside the use of smart technologies.[94] The adequacy of current measures will decrease accordingly. Maintaining cyber security has been identified as a foundational challenge in the FSR work programme.

5.25. The Authority expects controls and communications for energy resources will increasingly be automated and data driven. Consumers will expect their controllable energy resources (eg, electric vehicle chargers) to respond automatically to an external trigger (eg, an adverse or beneficial price change). We note EECA's work in this area – seeking to ensure increased use of electric vehicle smart chargers.

5.26. There are increasing expectations that industry participants and consumers can seamlessly access and share their data.[95] This will mean that participants will need to have systems and processes in place to facilitate this.

5.27. The Authority is prioritising three projects to improve access to data and information, as part of its work programme to deliver key distribution sector reform.[96]

5.28. The Ministry of Business, Innovation and Employment is working to establish a consumer data right, which is expected to be rolled out to the energy sector in due course.[97] This will require participants to have systems that facilitate the sharing of consumer information with third parties, which will likely need to be supported by standards for data sharing.[98] The ability to access this data will help third parties unlock new products and services, which will in turn facilitate competition and provide benefits to consumers.

5.29. In summary, the Authority expects that enhanced observability and controllability of DER, efficient data exchange and the right level of transparency of data, and the existence of connected data hubs with non-discriminatory access for network operators, will be important in the future. These things will be able to support various aspects of power system operation, including supporting real-time coordination and

94 Transpower, 2021, Opportunities and challenges to the future of security and resilience of the New Zealand power system, pp. 49–50, available at: Future security and resilience - Phase 1 draft report - discussion paper | Our consultations | Electricity Authority (ea.govt.nz).

95 One of the five categories in the FlexForum's Flexibility Plan 1.0 is "*Data and information steps to ensure electricity sector participants and consumers are enabled to access and share appropriate data and information*". See FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf (araake.co.nz).

96 Electricity Authority, 2023, Delivering key distribution sector reform, pp. 13–14, available at: Updating regulatory settings for distribution networks - Work programme | Our projects | Electricity Authority (ea.govt.nz).

97 Consumer data right | Ministry of Business, Innovation & Employment (mbie.govt.nz).

98 BCG has identified 'data requirements and access' as a barrier to flexibility on the power system. BCG has proposed that an initiative to address this would be to "Set standards for, and support facilitation if needed, for data sharing across flexibility market actors (e.g., network providers, retailers, flexibility traders and metering equipment providers) aligned with MBIE's consumer data right." See Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 186, available at: the-future-is-electric-full-report-october-2022.pdf.

balancing, the efficient use of flexibility, and addressing congestion. These will also help facilitate a whole-of-system approach to network planning, which we now turn to.

Q6. Do you consider existing power system operation obligations are compatible with the uptake of DER and IBR generation? Please provide reasons for your answer.

Is there sufficient coordination of network planning?

5.30. Significant transmission and distribution network investment is expected to be required over the coming decades to support the transition to net zero emissions. BCG estimates that in the 2020s and 2030s there will be a total requirement for $47 billion of distribution investment and $18 billion of transmission investment.[99]

5.31. Ensuring the most efficient level of network investment can have significant benefits for consumers, as it results in line charges that are no higher than necessary. It is important to consider whether, going forward, existing levels of network planning coordination will be sufficient to ensure the most efficient level of network investment occurs in New Zealand.

5.32. Consideration needs to be given to whether network planning is sufficiently coordinated between the transmission and distribution levels (vertically), and across regions/distribution networks (horizontally). Consideration should also be given to whether network planning is being sufficiently informed by relevant wider energy planning activities across sectors (such as, gas, heat, hydrogen, and transport).

5.33. A more coordinated approach to network planning would require distributors and Transpower, as a grid owner and as the system operator, to share information in more depth and more regularly. An efficient data governance framework would be required for data handling and storage procedures. At the same time the framework should consider confidentiality, privacy and competition law because of the range of participants (including prosumers) accessing the data.

5.34. In New Zealand, distributors plan network upgrades broadly based on capacity, security, resilience and existing and forecast demand. The Commerce Commission requires distributors to disclose in their annual asset management plans, among other things, each planned asset replacement and renewal project and programme, a description of and the rationale for the projects and programmes, an overview of any network investments and non-network solutions considered, and the basis for selecting preferred solutions.

5.35. Transpower, as a transmission network owner, plans its network upgrades in a similar way. As with distributors, the Commerce Commission requires Transpower to publish information each year detailing its performance.

5.36. In its *Whakamana i Te Mauri Hiko* publication, Transpower discussed the importance of having a whole-of-system plan for how the power system can evolve to help decarbonise the energy sector and broader economy.[100] Transpower noted that integrated system plans are common internationally. They help guide investment

99 Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, available at: the-future-is-electric-full-report-october-2022.pdf.

100 Transpower, 2020, Whakamana i Te Mauri Hiko, Empowering our Energy Future, pp. 53–54, available at: www.transpower.co.nz/whakamana-i-te-mauri-hiko-empowering-our-energy-future.

decision making and enable all of the electricity sector to have an appropriate level of clarity and insight into the operation and evolution of the broader power system.

5.37. Transpower's 'Net Zero Grid Pathways' is designed to be an integrated system plan that provides an indicative 15-year roadmap for the transmission network and power system that is consistent with a net zero emissions future.[101] Transpower consulted with distributors and other key stakeholders in preparing the Net Zero Grid Pathways.

5.38. In 2021 there was an electrical disturbance in Texas, USA, which caused active power reduction of more than 800MW from solar photovoltaic generation connected both at transmission and distribution network levels. One of the key findings from the North American Electric Reliability Corporation (NERC) report[102] on the disturbance was the lack of rigorous modelling processes at the planning/interconnection stage.

5.39. The NERC report found that inverter-level and feeder-level tripping of the solar generation could have been identified at the planning stage through detailed wide area network modelling. This modelling process requires accurate and robust IBR generating station models and feeder-level network models. NERC is currently updating its modelling and planning policies and processes due to high levels of IBR connected to distribution networks in the USA, impacting the transmission network during system transient events.

5.40. An International Renewable Energy Agency report notes increased cooperation between the operators of distribution networks and transmission networks can better align distribution and transmission network expansion plans. This in turn can identify synergies that could result in significant cost savings on large infrastructure investment projects.[103]

5.41. In its *The Future is Electric* report, BCG said a 'concerted, aligned effort from the electricity sector, consumers and government' is required to implement the pathway BCG identified as the lowest cost pathway for producing 'optimal outcomes for the grid and consumers overall'.[104]

5.42. The Authority notes that increased system operator-distributor cooperation enables effective utilisation of DER in congestion management, thereby enabling some of the benefits of DER referred to section 4 (ie, deferring or partly avoiding investment in transmission and distribution network infrastructure).

5.43. Coordination between the electricity sector and other sectors, such as gas, may also need to be improved going forward. For instance, Wellington Electricity is forecasting that converting all of Wellington's natural gas use to electricity will add 260MW to the peak demand on Wellington Electricity's network if the increased demand is not managed.[105] Hundreds of millions of dollars of associated network upgrades would be required.[106]

101 Net Zero Grid Pathways | Transpower.

102 Odessa Disturbance: Joint NERC and Texas RE Staff report. 2021. https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf.

103 International Renewable Energy Agency, 2020, Co-operation between transmission and distribution operators, Innovation landscape brief, p. 14, available at www.irena.org/Publication/2020/IRENA TSO-DSO co-operation.

104 Boston Consulting Group, 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 117, available at: the-future-is-electric-full-report-october-2022.pdf.

105 Wellington Electricity, 2023, Pricing strategy & roadmap, p. 10.

106 See:

5.44. The NZ Gas Infrastructure Report highlighted the importance of coordination across a broad range of stakeholders, such as electricity networks, to achieve the government's climate change commitments.[107]

5.45. Overseas jurisdictions have introduced changes to help ensure optimal levels of coordination when it comes to electricity network planning. For example:

(a) In **Ireland**, there is a Joint System Operator Programme to reflect how the transmission system operator and the distribution system operator are jointly addressing electricity system and customer needs through whole-of-system solutions, in a collaborative and effective manner.[108] Part of this multi-year work programme is the development of a future distribution system operator – transmission system operator operating model which is designed, in part, to improve coordination in network planning.

(b) In **Australia**, Integrated System Plans were introduced in 2018. These are whole-of-system plans that provide an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years and beyond. The Australian Energy Market Operator (AEMO) produces an integrated system plan every two years.[109]

(c) In the **UK**, Ofgem is proposing to introduce 'Regional System Planners' as part of the new Future System Operator to help improve, among other things, the coordination of network planning across the energy system.[110]

5.46. The Authority does not have a view on whether more coordination is needed when it comes to network planning to ensure the most efficient level of network investment is achieved for consumers. The Authority is seeking information and evidence to help assess whether there is a coordination issue.

5.47. If there is evidence of a coordination problem, the next step would be crafting an accurate problem definition and identifying possible options to address the problem. This might involve identifying new or enhanced roles or functions to improve coordination in pursuit of a whole-of-system approach to network investment planning. A possible option would also be no intervention if analysis shows that coordination will increase as and when needed.

5.48. Climate change is making electricity network planning much more challenging. It is becoming more difficult to anticipate and forecast electricity demand and supply in real time. For example, wind and solar generation critically depend on minute-by-minute weather and climatic conditions.

5.49. Climate change may result in more frequent dry years and more years characterised by severe floods, coupled with potentially longer periods of cold weather. This will

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- Wellington Electricity's submission on the New Zealand Climate Change Commission's '2021 Draft Advice for Consultation', p. 6, available at: climatecommission.govt.nz/consultation/publishablefiles/Wellington Electricity.
- Wellington Electricity's submission on the Electricity Authority's 2021 consultation paper 'Updating the Regulatory Settings for Distribution Networks, Improving competition and supporting a low emissions economy – Discussion paper, p. 4 and p.38, available at: Updating regulatory settings for distribution networks | Consultation | Electricity Authority (ea.govt.nz).

107 NZ Gas Infrastructure Future (gasischanging.co.nz).

108 DSO/TSO Multi-Year Plan 2023–2027 – EirGrid.

109 AEMO | Integrated System Plan (ISP).

110 Consultation: Future of local energy institutions and governance | Ofgem.

make it more challenging for power system operation to keep the lights on, for example during storms (security), and getting the lights back on quickly (resilience).

Q7. Do you consider we need an increased level of coordination of network planning, investment and operations across the New Zealand power system? Please provide reasons for your answer.

Are there significant conflicts of interest associated with network ownership, network operation and network planning?

5.50. The Authority is interested in understanding whether conflicts of interest in respect of power system operation, electricity network ownership, and electricity network planning may exist, or emerge, during the transition to net zero emissions.

5.51. This could apply to potential or perceived conflicts of interest for Transpower, in its roles as a transmission network owner, transmission network planner, and as the system operator. It could also apply to potential or perceived conflicts of interest for distributors, in their roles as distribution network owners, distribution network planners and distribution network operators, and for some distributors, via their ownership and/or control of DER.

5.52. Conflicts of interest could be due to issues including:

(a) A misalignment of incentives between the different roles of network ownership, network operation and network planning, where these roles are all performed by the same (or related) entities.

(i) For example, a network owner might prefer more investment in network assets, resulting in a larger regulatory asset base, and consequentially higher regulated revenue, whereas in its role as network operator and/or network planner it might prefer a smaller asset base, used more efficiently.

Ofgem explained this risk in the UK context as follows:[111] *"the common ownership of the SO and TO [transmission owner] may result in overstating the need for network assets due to an informational or financial potential conflicts of interest towards transmission network asset solutions to energy system problems"*.

(ii) The potential for this conflict of interest to apply is greater where the business in question is privately owned, as is the case in the UK, with National Grid plc. Arguably, privately-owned businesses have stronger profit motives than state-owned enterprises, which are directed to earn targeted rates of return.

(b) Some behavioural 'status quo' bias towards increasing the size of the network rather than relying on unproven non-network solutions.

(i) An example of a potential conflict of interest caused by this issue would be where the network owner is also the network planner and operator. In its role as network owner, the entity might prefer proven network solutions over

[111] Ofgem, 2021, Future of the System Operator: Impact Assessment, p. 15, available at: gov.uk/fso-impact-assessment.pdf.

more experimental non-network solutions, whereas in its role as network planner, or network operator, it might see things differently.

(ii) A potential conflict of interest for distributors that procure non-network solutions in-house and seek more control over their networks. For example, a distributor setting a DOE might preferentially allocate capacity to themselves rather than their competitors in the non-network solutions market. While there are several ways of achieving non-discriminatory allocation or curtailment of capacity (pro rata, price-based, tradable physical rights, or priorities based on interconnection),[112] these might not be accepted as long as an interested party (eg, a distributor that procures non-network solutions in-house) is making those decisions.

(iii) Asymmetry of information between the regulated business (eg, Transpower or a distributor) and a regulator tasked with making decisions for the long-term benefit of consumers. As power system operation becomes more complex, so do the information requirements, which exacerbates the information deficit of the regulator relative to the regulated business. It becomes increasingly difficult for a regulator such as the Commerce Commission or the Authority to evaluate whether the decisions made by regulated businesses are efficient, and therefore for the long-term benefit of consumers.

5.53. If there are conflicts of interest, this could lead to outcomes such as:

(a) over-investment in transmission and/or distribution network assets

(b) preferring investment in transmission and/or distribution network assets, or network solutions over non-network solutions, even when non-network solutions are in the best interests of consumers

(c) limiting network competition for third parties to provide network solutions or non-network solutions (for example, the criteria set for third parties to provide non-network solutions may be unduly onerous, or they might not be given their fair share of DOE capacity)

(d) advice provided to regulators or the government by one or more of the parties with a conflict of interest may not align with the best interests of consumers (eg, the advice may be biased in favour of network solutions).

5.54. There are safeguard measures to prevent some of these conflicts coming about. Some examples are as follows:

(a) Distributors are required under Part 4 of the Commerce Act to consider whether non-network solutions are a viable alternative to network solutions and present this in their asset management plans.

(b) The Commerce Commission has designed the price-quality path regulatory regime so there is no preferential regulatory treatment of capital expenditure versus operating expenditure.[113] Network investments are generally capital

112 Energy Systems Integration Group, 2022. DER Integration into Wholesale Markets and Operations: A Report of the Energy Systems Integration Group's Distributed Energy Resources Task Force, p. 24, available at: www.esig.energy/reports-briefs.

113 This consideration is relevant only to the 16 distributors that are subject to price-quality path regulation under Part 4 of the Commerce Act.

expenditure, while non-network solutions (or 'non-wire alternatives') are generally operating expenditure. The Authority notes, however, that some distributors still perceive there to be a bias in favour of capital expenditure.

(c) Transpower, like distributors, is required under Part 4 of the Commerce Act to consider whether non-network solutions are a viable alternative to network solutions.

(d) As noted in section 3 of this paper (see paragraphs 3.37 to 3.43), Transpower has measures in place to ensure independence between its role as system operator and any other roles that Transpower has under the Code, in particular as a transmission network owner.

5.55. Some jurisdictions have introduced changes to ensure there are no conflicts of interest for parties with more than one role in terms of electricity network ownership, planning and operation. For example:

(a) The United Kingdom is currently establishing an energy 'Future System Operator' to address, amongst other things, potential conflicts of interest between transmission network ownership, planning and operation.[114]

(b) Ofgem has also decided on governance changes at the energy distribution level, to ensure the optimal delivery of three core energy functions needed to ensure a low-cost transition to zero emissions – energy system planning, market facilitation of flexible resources, and real-time operations. Part of the rationale for Ofgem's decision is to help mitigate the potential for conflicts of interest.[115]

5.56. Over the years, there have been reviews of Transpower's impartiality.[116] The relevant findings from these reviews would inform any future work undertaken by the Authority in this area.

5.57. It is important to highlight that the Authority does not yet have a view on whether there are significant conflicts of interest for parties with more than one role across network ownership, network operation and network planning, including distribution networks.

5.58. The Authority is seeking information and evidence around the existence and significance of any conflicts of interest and whether they might emerge or become more significant as New Zealand transitions to net zero emissions.

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114 In 2021 the United Kingdom government and Ofgem jointly consulted on the establishment of an energy 'Future System Operator' for the United Kingdom. The impact assessment for the likely costs, benefits and distributional impacts of the policy options considered in the consultation paper identified the "potential for conflict of interest between National Grid Plc's role as the SO in recommending changes to the system to support system operability, and National Grid Plc's role as a transmission company whose remuneration comes from building additional network to support these needs. While there is no evidence of this conflict being acted upon, the perception and potential for conflicts can nevertheless make it challenging for the system operators to fulfil their existing roles, and it would be even more challenging to give them some of the potential new roles needed to fulfil net zero." See Department for Business, Energy & Industrial Strategy and Ofgem, 2021, Future of the System Operator, Impact Assessment, p. 6, available at: gov.uk/fso-impact-assessment.pdf.

115 See:

- Ofgem, 2023, Future of local energy institutions and governance – Consultation, p. 39.
- Ofgem, 2023, Future of local energy institutions and governance – Decision, pp. 19, 28, and 34–35.

116 See for example, Security and Reliability Council, 2021, Paper on impartiality, separation between Transpower services, available at: Security and Reliability Council | Electricity Authority (ea.govt.nz).

Q8. Do you think there are significant conflicts of interest for industry participants with concurrent roles in network ownership, network operation and network planning? Please provide reasons for your answer.

Q9. Do you have any further views on whether this is a good time for the Authority to assess future system operation in New Zealand, and whether there are other challenges or opportunities that we have not covered adequately in this paper? Please provide reasons for your answer.

Appendix A More about the regulatory arrangements for power system operation

A.1. This appendix provides further detail on the regulatory arrangements underpinning power system operation in New Zealand. It summarises obligations related to power system operation under the Code, Part 4 of the Commerce Act, and the Electricity (Safety) Regulations.

The regulation of power system operation under the Code

Part 7 of the Code sets out the system operator's main functions

A.2. Part 7 of the Code sets out the system operator's main functions. Consistent with the Act, these are:

(a) the real-time coordination of the power system

(b) the provision of information and short-to-medium term forecasting on security of supply, and the management of supply emergencies.

A.3. In relation to power system operation, Part 7 provides for the following matters described in section 3 of this paper:

(a) the PPOs of the system operator in relation to the real time delivery of common quality and dispatch

(b) the reasonable and prudent system operator standard

(c) the separation of Transpower's system operator role from other roles Transpower has under the Code and the Act.

A.4. By way of elaboration on section 3, the system operator's PPOs may be summarised as follows:

(a) to dispatch available assets in a manner that avoids cascade failure of assets resulting in a loss of electricity to consumers, and to maintain frequency within a 'normal band' of 49.8–50.2 Hz except during contingent events[117] and extended contingent events,[118] where the system operator must:

(i) for a contingent event, maintain frequency at or above 48Hz

(ii) for an extended contingent event, maintain frequency at or above 47Hz in the North Island and 45Hz in the South Island.

(b) to restore frequency to 49.8-50.2Hz as soon as practicable if frequency deviates outside this band

(c) to ensure that any deviations from New Zealand standard time in the power system, caused by variations in system frequency, are eliminated once a day, and otherwise do not exceed five seconds

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117 A contingent event is an event affecting the power system where the impact, the probability of occurrence, and the estimated costs and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and dispatch processes pre-event. See clause 12 of the policy statement.

118 An extended contingent event is an event affecting the power system for which the impact, probability, cost and benefits are not considered to justify the controls required to totally avoid demand shedding or maintain the same quality limits defined for a contingent event. See clause 12 of the policy statement.

(d) to report to the Authority the number of frequency fluctuations in specified frequency bands, in each of the North Island and South Island in the previous month

(e) at the request of industry participants, to investigate and resolve a security of supply or reliability problem arising from non-compliance with a standard in the following clauses of the connection code:[119]

(i) clause 4.7—harmonic levels

(ii) clause 4.8—voltage flicker levels

(iii) clause 4.9—voltage imbalance of less than 1%.[120]

Part 8 of the Code relates to common quality

A.5. Part 8 of the Code regulates common quality on New Zealand's transmission network, referred to in the Code (and in this appendix) as the 'grid'.[121]

A.6. Part 8 regulates power system operation by:

(a) expanding on the system operator's PPOs in relation to the real time delivery of common quality and dispatch

(b) placing performance obligations on 'asset owners', who are:

(i) the owners or operators of equipment or plant that is connected to or forms part of the transmission network and which generates or conveys electricity, including equipment or plant that is intended to become connected to the transmission network

(ii) embedded generators

(iii) consumers with a point of connection to the transmission network.

(c) setting out arrangements concerning ancillary services (being black start, frequency keeping, instantaneous reserve, over frequency reserve, voltage support)

(d) in the form of technical codes, specifying technical standards for assets and defining obligations on asset owners and the system operator, intended primarily to enable the system operator to plan to comply, and to comply, with its PPOs.

Expanding on the system operator's PPOs – the policy statement

A.7. A key way in which Part 8 of the Code describes how the system operator will meet its PPOs is by requiring the system operator to prepare a 'policy statement'. This is a document, incorporated by reference in the Code,[122] which includes:

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119 The connection code is Schedule 8 of the default transmission agreement template (formerly the benchmark agreement) (Schedule 12.6 of the Code). The purpose of the connection code is to set out the technical requirements and standards that transmission users must meet in order to be connected to the transmission network owned by Transpower.

120 Clauses 7.2 – 7.2E of the Code.

121 The Code defines 'grid' to mean the system of transmission lines, substations and other works, including the HVDC link, used to connect GIPs and GXPs to convey electricity throughout the North Island and the South Island of New Zealand.

122 Clause 8.10 of the Code.

(a) the policies and means the system operator considers appropriate for it to observe in complying with its PPOs

(b) the policies and means by which the scheduling and dispatch of electricity are adjusted to meet the dispatch objective set out in Part 13 of the Code, including details of the processes that enable the system operator to meet the dispatch objective, such as the methodologies the system operator uses for:

(i) planning to meet the dispatch objective during the period leading up to real time

(ii) meeting the dispatch objective in real time.

(c) a policy on how the system operator will manage any conflict of interest that arises in the performance of its obligations under the Code.[123]

Asset owner performance obligations

A.8. Part 8 of the Code specifies performance obligations and technical standards for the owners of equipment or plant:

(a) that is connected to or forms part of the transmission network

(b) that is intended to become connected to the transmission network

(c) of an embedded generator.

A.9. These obligations and standards assist the system operator to comply with its common quality and dispatch PPOs.

A.10. Some performance obligations are common to all asset owners, for example:

(a) having in place specified facilities for communication between the system operator and the asset owner

(b) the asset owner providing the system operator with certain information, such as:

(i) information about an asset's capability

(ii) the intended output of an embedded generator's station(s) with a capacity of more than 10MW

(iii) if required by the Authority, the intended output of a group of embedded generating stations that have a total capacity of more than 10MW and which are connected to the same GXP

(iv) SCADA information at least once every eight seconds (in the case of generators, only if a generating unit's maximum continuous rating is more than 5MW).[124]

A.11. Other performance obligations are specific to different types of asset owner or different sizes of asset owner.

A.12. Performance obligations and technical standards on generators include:

123 Clause 8.11 of the Code.

124 Clause 8.25 of the Code, and clause 3 of Technical Code A of Schedule 8.3 of the Code and Technical Code C of Schedule 8.3 of the Code.

(a) generators (while synchronised) must support frequency, including during an under-frequency event[125]

(b) transmission network-connected generators must operate within a range of voltages,[126] and voltage imbalance levels must be maintained below a certain limit[127]

(c) transmission network-connected generating units and associated voltage control systems must support the system operator in meeting its PPOs (eg, avoiding cascade failure during voltage excursions)[128]

(d) electrically connected generation assets must ride through faults on the transmission network, as follows:

  (i) remain stable and electrically connected during and immediately after a short circuit on the transmission network or a trip of the HVDC link, provided system voltage remains within a defined under- and overvoltage range/envelope[129]

  (ii) generate reactive current to oppose voltage changes (dips) that occur during and immediately after faults on the AC transmission network[130]

  (iii) provide active power output during and immediately after a short circuit on the transmission network.[131]

(e) during the occurrence of extreme variations of frequency or voltage at its GIP, a generator must act to minimise the transmission network emergency (eg, by increasing/decreasing energy injection, synchronising/re-synchronising and loading generation units)[132]

(f) if the system operator reasonably considers it necessary to assist the system operator in planning to comply, and complying, with its PPOs and achieving the dispatch objective, an embedded generator may be required to provide information regarding:

  (i) the intended output of each of its embedded generating stations with a capacity of more than 10MW

  (ii) the intended output of a group of embedded generating stations that total greater than 10MW in capacity and that are connected to the same GXP.[133]

(g) generators that inject at least 30MW into the transmission network, and which are not wind powered, must be tested periodically, typically every 4–10 years depending on the type of equipment, to ensure their assets comply with the AOPOs set out in Part 8 and Technical Code A of Schedule 8.3.[134]

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125 Clause 8.17 and clauses 8.19–8.20 of the Code.

126 Clause 8.22 of the Code.

127 Refer to clause 4.9 of the connection code.

128 Clause 5(1)(a)(i) of Technical Code A of Schedule 8.3.

129 Clause 8.25A.

130 Clause 8.25B of the Code

131 *Ibid*

132 Clause 9 of Technical Code B of Schedule 8.3.

133 Clause 8.25 of the Code.

134 Clause 8(1) of Technical Code A of Schedule 8.3 and appendix B of Technical Code A of Schedule 8.3.

A.13. Performance obligations and technical standards on transmission network owners include:

(a) the design and configuration of transmission network assets and associated protection arrangements must be consistent with maintaining the system operator's ability to comply with its PPOs[135]

(b) the HVDC link must support frequency, including during an under-frequency event[136]

(c) transmission network assets must operate within a specified range of voltages,[137] and voltage imbalance levels must be maintained below a certain limit[138]

(d) transmission network assets in the South Island must be able to perform load shedding to prevent the collapse of network voltage[139]

(e) communication facilities must be provided

(f) transmission network assets must be tested periodically, typically every 4–10 years, to ensure they comply with the AOPOs set out in Part 8 and Technical Code A of Schedule 8.3.[140]

A.14. Performance obligations and technical standards on distributors that are the owner or operator of a local network and on consumers that are connected directly to the transmission network include:

(a) ensuring their assets are capable of being operated, and operate within a specified range of voltages[141]

(b) for those connected to the transmission network in the North Island, ensuring their assets can perform load shedding to prevent the collapse of network voltage.[142]

A.15. All asset owners and purchasers have an obligation to cooperate with the system operator as may reasonably be required by the system operator in carrying out its functions.[143]

A.16. The system operator monitors, in accordance with the policy statement, the ongoing compliance of generators and transmission network owners with their AOPOs and the Part 8 technical codes. The system operator has the discretion to not dispatch an asset or configuration of assets that the system operator is not satisfied:

(a) complies with the relevant AOPOs or provisions of the technical codes, or

(b) has/have a valid equivalence arrangement or dispensation from the relevant AOPOs or provisions of the technical codes.[144]

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135 Clause 8.25 of the Code.

136 Clause 8.17 and clauses 8.19–8.20 of the Code

137 Clause 8.22 of the Code.

138 Refer to clause 4.9 of the connection code.

139 Clause 8.24 of the Code.

140 Clause 8 of Technical Code A of Schedule 8.3 of the Code, and Appendix B of Technical Code A of Schedule 8.3 of the Code.

141 Clause 8.22 of the Code.

142 Clause 8.24 of the Code

143 Clause 8.26 of the Code.

144 Clause 8.27 of the Code.

Equivalence arrangements and dispensations

A.17. The system operator may approve an 'equivalence arrangement' or grant a dispensation from an AOPO or a provision of the Part 8 technical codes.

A.18. Under an equivalence arrangement, the owner of assets or a configuration of assets that do not strictly comply with an AOPO or technical code puts in place technical or commercial arrangements that will, in the system operator's reasonable opinion, achieve compliance with the AOPO or technical code.[145]

A.19. The system operator must grant a dispensation from an AOPO or a provision of the Part 8 technical codes if the system operator:

(a) reasonably expects it can continue operating the existing power system and meet its PPOs, and

(b) can readily quantify the costs on other persons of the dispensation.[146]

Excluded generating stations

A.20. Generating stations that export less than 30MW to the transmission network or to a distribution or embedded network do not have to:

(a) support system frequency in the same way as generating stations exporting 30MW or more

(b) meet the fault ride through standards in Part 8 of the Code.[147]

A.21. Upon application by the system operator, the Authority may, if it is satisfied there is a benefit to the public, direct that these smaller generating stations:

(a) support system frequency in the same way as larger exporting generating stations

(b) meet the fault ride through standards.[148]

A.22. However, to date the system operator has not applied to the Authority for the Authority to issue such a directive.

Arrangements concerning ancillary services – the procurement plan

A.23. The 'procurement plan' is a document incorporated by reference in the Code,[149] which contains, amongst other things:

(a) the principles the system operator applies in assessing how much of an ancillary service to procure, which must include:

(i) determining the requirements for complying with the PPOs

(ii) determining the requirements for achieving the dispatch objective

(iii) assessing the contribution that compliance by asset owners with the AOPOs will make towards the system operator's compliance with the PPOs

145 Clause 8.30 of the Code.

146 Clause 8.31 of the Code.

147 Clause 8.21 of the Code.

148 See clause 8.38 of the Code. Part 1 of the Code defines "benefit to the public" as meaning a public benefit net of any costs and detriments, including those detriments associated with a lessening of competition as those concepts are applied under the Commerce Act 1986.

149 Clause 8.42 of the Code.

(iv) assessing the impact that dispensations and alternative ancillary services arrangements held by asset owners will have on the quantity of ancillary services required to enable the system operator to comply with the PPOs

(b) a methodology for assessing how much of each ancillary service to procure

(c) the process the system operator must use to procure an ancillary service, taking into account that the system operator must use:

(i) market mechanisms to procure ancillary services wherever technology and transaction costs make this practicable and efficient

(ii) transparent processes that encourage all potential providers to compete to supply ancillary services required to meet common quality standards at the best economic cost.

(d) the administrative costs for the proposed procurement of an ancillary service

(e) the system operator's technical requirements and key contract terms to support the procurement plan.[150]

A.24. The system operator must use reasonable endeavours to implement the procurement plan for each ancillary service by entering into contracts with ancillary service providers (ancillary service agents) in the manner specified in the procurement plan.[151]

A.25. The system operator may depart from the processes and arrangements set out in the procurement plan if the system operator reasonably considers it necessary to do so to comply with its PPOs.[152]

A.26. If authorised by the system operator, an industry participant may enter into an arrangement, either with someone else or involving only themselves, for an ancillary service that would otherwise be provided in accordance with the procurement plan. An industry participant that has entered into such an arrangement ('alternative ancillary service arrangement') does not need to pay for the equivalent ancillary services procured by the system operator.

A.27. The system operator must authorise an 'alternative ancillary service arrangement' if:

(a) the proposed arrangement complies with the technical requirements for that ancillary service as set out in the current procurement plan

(b) the implementation of the proposed arrangement will make the ancillary service available for dispatch by the system operator in substantially the same manner as if the ancillary service had been procured in accordance with the procurement plan.[153]

The Part 8 technical codes

A.28. Schedule 8.3 of Part 8 contains several technical codes that:

(a) define obligations for asset owners and technical standards for assets that are supportive of, or more detailed than, those set out in subpart 2 of Part 8, in

150 Clause 8.43 of the Code.

151 Clause 8.45 of the Code

152 Clause 8.47 of the Code.

153 Clause 8.48 of the Code.

order to enable the system operator to plan to comply, and to comply, with its PPOs, for example:

(i) an obligation to prepare commissioning and testing plans for certain assets and to obtain a final assessment from the system operator that these assets meet the requirements of the AOPOs and technical codes[154]

(ii) an obligation to periodically test assets (except wind generating units) and automatic under-frequency load shedding (AUFLS) systems.[155]

(b) set out the basis on which the system operator and industry participants must plan for, anticipate, and respond to emergency events on the grid that affect the system operator's ability to plan to comply, and to comply, with its PPOs

(c) state the minimum requirements for the communications required under the Code between asset owners and the system operator, in order to assist the system operator to plan to comply, and to comply, with its PPOs

(d) set out the obligations of asset owners to give written notice of planned outages of assets that affect common quality, and to set out the obligations of the system operator in relation to outage coordination and the provision of timely advice to asset owners on the power system security implications of notified planned outages.

The system security forecast

A.29. Every two years, the system operator must prepare a 'system security forecast'. This must:

(a) identify risks to the system operator's ability to meet its PPOs over the ensuing period of at least 36 months, and indicate how those risks can be managed

(b) take into account the capabilities of the transmission network and connected assets based on information known to, and able to be disclosed by, the system operator.

A.30. Every six months, the system operator must review the most recent system security forecast.

Part 13 of the Code regulates arrangements for wholesale electricity trading

A.31. Part 13 of the Code regulates arrangements for trading electricity in the wholesale electricity market. Within this broader regulatory scope, Part 13 regulates power system operation, by specifying arrangements for the scheduling and dispatch of electricity.

The system operator must prepare pre-dispatch schedules

A.32. In the week leading up to the dispatch of resources to manage electricity demand and supply in real time, the system operator must use reasonable endeavours to prepare pre-dispatch schedules that:

(a) match expected electricity supply with expected electricity demand

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154 Clause 2 of Technical Code A of Schedule 8.3 of the Code.

155 Appendix B of Technical Code A of Schedule 8.3 of the Code.

(b) allocate ancillary service offers and transmission offers to match expected grid conditions.[156]

A.33. To inform these pre-dispatch schedules, the system operator receives:

(a) offers and bids from electricity generators, a small sub-set of purchasers,[157] and ancillary service providers

(b) standing data on the capability of the transmission network, from transmission network owners (this information is additional to the asset capability information that transmission network owners must provide under Part 8 of the Code).

A.34. The system operator also uses its own information to inform the pre-dispatch schedules, eg, the system operator forecasts electricity demand at GXPs with a predictable demand profile.

The system operator must dispatch electricity in accordance with a dispatch objective

A.35. Near real time, the system operator must prepare a dispatch schedule that forms the basis of dispatch instructions and notifications for generation, ancillary services, and demand in real time as well as generating dispatch prices that form the settlement price for the wholesale electricity spot market.

A.36. The system operator must prepare a new dispatch schedule as frequently as the system operator considers necessary to meet the system operator's dispatch objective.[158] This dispatch objective is as follows:

> *To maximise for each half hour the gross economic benefits to all purchasers of electricity at GXPs, less the cost of supplying electricity at GIPs and the costs of ancillary services purchased by the system operator under Part 8 of the Code, subject to:*
>
> *(a) the capability of generation, dispatch-capable load stations for which a nominated dispatch bid was submitted, and ancillary services and the configuration and capacity of the grid and information made available by asset owners*
>
> *(b) achieving the PPOs and any arrangements in which power quality levels are more stringent than those specified in the PPOs*[159]
>
> *(c) meeting the requirements of clause 8.5 of the Code in relation to restoration of the power system*
>
> *provided that in the case of any conflict between paragraphs (b) and (c), paragraph (c) takes priority.*[160]

A.37. Clause 8.5 of the Code relates to the restoration of the power system. Under this clause, the system operator must, if an event disrupts the system operator's ability to

156 Once a day the system operator must endeavour to prepare a week-ahead dispatch schedule for the period from 14:00 hours the following day to 23:59 hours six days' hence (clause 84D of the policy statement). Every two hours the system operator must endeavour to prepare a pre-dispatch schedule for the next 36 hours (clause 13.62 of the Code).

157 Clauses 13.7 and 13.7AA of the Code specify when an electricity purchaser must submit a bid to the system operator

158 Clause 13.69A of the Code.

159 Under clause 8.6 of the Code, a person can contract with the system operator for more stringent levels of quality than those specified in the system operator's PPOs. This is subject to the system operator identifying the incremental costs of the more stringent levels and recovering these costs from the person contracting with the system operator.

160 Clause 13.57 of the Code.

comply with the PPOs, re-establish normal operation of the power system as soon as possible, given:

(a) the capability of generation, and ancillary services

(b) the configuration and capacity of the transmission network

(c) the information made available by asset owners.

A.38. When re-establishing normal operation of the power system, the system operator must have regard to the following priorities:

(a) first, the safety of natural persons

(b) second, the avoidance of damage to assets

(c) third, the restoration of electricity offtake

(d) fourth, conformance with the PPOs

(e) fifth, full conformance with the dispatch objective.

A.39. A participant must comply with a dispatch instruction properly issued by the system operator unless an exception permitted by the Code applies. Examples of such exceptions include:

(a) personnel or plant safety is at risk

(b) the participant will break a law by following the dispatch instruction

(c) a generator is making the maximum possible injection contribution to maintain frequency within the 49.8 – 50.2Hz normal band or to restore frequency to this band.

A.40. The system operator may depart from the dispatch schedule only if doing so is necessary to meet:

(a) the dispatch objective, or

(b) the requirements of clause 8.5 in relation to restoration of the power system.

A.41. The system operator may, at any time, declare a 'grid emergency', which is a situation where:

(a) in the system operator's reasonable opinion, one or more of the following events has occurred, or is reasonably expected to occur, and urgent action is required of the system operator or participants to alleviate the situation:

(i) The ability of the system operator to plan to comply, and to comply, with its PPOs is at risk or is compromised.

(ii) Public safety is at risk.

(iii) There is a risk of significant damage to assets.

(iv) Independent action has been taken in accordance with Technical Code B of Schedule 8.3 of the Code to restore the system operator's PPOs.

(v) The system operator expects demand at a GXP will be unable to be supplied by offers, or

(b) fast and independent responses from generators and ancillary service agents is needed to alleviate extreme variations of frequency or voltage at the points at which their assets are connected to the network.

A.42. If the system operator has declared a grid emergency:

(a) Generators and ancillary service agents may not reduce their supply in the electrical or geographical region affected, unless they have a bona fide physical reason.

(b) Purchasers may not increase their demand at the GXPs affected, unless they have a bona fide physical reason.

Other parts of the Code that regulate power quality

A.43. The other parts of the Code that regulate power quality are Parts 6, 9, 12, and 12A.[161]

Part 6 of the Code regulates the connection of distributed generation

A.44. Part 6 of the Code regulates distributed generation, which is generation connected directly to a distribution network or indirectly via a consumer installation. Part 6 specifies, amongst other things, a framework to enable the connection and continued connection of distributed generation if the connection is consistent with distributors' connection and operation standards.[162]

A.45. Part 6 regulates power system operation on distribution networks insofar as it empowers distributors to apply their connection and operation standards to the connection and operation of distributed generation. As the name indicates, connection and operation standards are requirements that relate to:

(a) the operation of a distribution network

(b) connecting distributed generation to a distribution network, or to a consumer installation that is connected to a distribution network.

A.46. Connection and operation standards include a distributor's:

(a) congestion management policy

(b) emergency response policies

(c) safety standards.

A.47. Connection and operation standards include requirements relating to the planning, design, construction, testing, inspection, and operation of distributed generation that is, or is proposed to be, connected to a distribution network.

A.48. Until 1 September 2026, a distributor's connection and operation standards may include the distributor's policies for specifying:

(a) available maximum export power amongst categories of distribution network users

(b) a maximum export power threshold for applications under Part 1A of Schedule 6.1 of the Code[163] and the methodology used to determine that threshold.[164]

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161 Part 1 of the Code, which defines various terms used in the regulation of power quality is excluded from this list because it does not contain regulatory obligations in relation to power quality like other parts of the Code.

162 Clauses 6.1–6.2 of the Code.

163 Part 1A of the Schedule 6.1 provides for a simplified 1-stage application process for distributed generation with a nameplate capacity of 10 kW or less in total.

164 Clause 1.1 of the Code – the definition of 'connection and operation standards'.

A.49. A distributor's connection and operation standards are important for enabling distributed generation to be connected in a manner that does not adversely affect power quality (in particular, voltage and harmonics) on the distribution network.

A.50. Under Part 8 of the Code, some distributed generation has obligations related to power system operation that are in addition to the obligations in Part 6. For example, distributed generators with generating stations that export 30MW or more to a distribution network or embedded network must support system frequency and meet the fault ride through standards in Part 8 of the Code.[165]

Part 9 of the Code regulates security of supply

A.51. Part 9 of the Code provides for:

(a) the management and coordination of planned outages as an emergency measure during energy shortages

(b) the urgent temporary removal of interconnection assets from service, or temporary reconfiguration of the transmission network, in order to improve security of supply

(c) a framework under which each retailer must have a customer compensation scheme for all of the retailer's qualifying customers, including determining when the system operator commences and ends an official conservation campaign (OCC), during which a retailer must make payments under its customer compensation schemes.

A.52. Part 9 regulates power system operation by empowering the system operator to:

(a) direct industry participants to implement power outages or take any other action specified by the system operator in order to achieve reductions in electricity consumption

(b) request Transpower, as a transmission network owner, to temporarily remove from service one or more interconnection assets, or to temporarily reconfigure the transmission network.

Directing power outages under a supply shortage declaration

A.53. Part 9 of the Code says the system operator may make a 'supply shortage declaration', if there is a shortage of electricity supply or transmission capacity such that the system operator considers:

(a) the normal operation of the electricity spot market is, or will soon be, unlikely to facilitate supply always matching demand, and

(b) that, if planned power outages are not implemented, unplanned power outages are likely.[166]

A.54. While a supply shortage declaration is in force, the system operator may (in writing) direct specified participants to contribute to achieving reductions in the consumption of electricity by implementing outages or taking any other action specified in the direction.

165 Clause 8.21 of the Code.

166 Clause 9.14 of the Code

The system operator rolling outage plan

A.55. The ‘system operator rolling outage plan’ (SOROP) is a document incorporated by reference in the Code under Part 9. The SOROP provides for the management and coordination of planned outages as an emergency measure during shortages of electricity supply or transmission capacity.[167]

A.56. The SOROP contains, amongst other things:

- (a) how the system operator intends to determine what directions to give to address a shortage of electricity supply or transmission capacity that gives rise to a ‘supply shortage declaration’ by the system operator
- (b) specify criteria, methodologies, and principles to be applied by participants in implementing outages, or taking any other action specified or approved by the system operator.

A.57. The system operator must have regard to the SOROP when making a supply shortage declaration.[168]

A.58. The SOROP identifies ‘specified participants’ that must develop a ‘participant rolling outage plan’. A participant rolling outage plan sets out the actions the specified participant will take to achieve, or contribute to achieving, reductions in electricity consumption following a direction from the system operator.[169] Specified participants are distributors, line owners, retailers and consumers directly connected to the transmission network.

Urgent temporary grid reconfigurations

A.59. The system operator may request Transpower to temporarily remove interconnection assets from service, or to temporarily reconfigure the transmission network, only if the system operator considers that exceptional circumstances exist:

- (a) that are likely to lead, for a period of at least three weeks, to:
  - (i) a shortfall in fuel for thermal generating stations (eg, coal, gas, wood pellets), or
  - (ii) a shortfall of water inflows for hydro generating stations, or
  - (iii) the loss of a large generating asset, and
- (b) that make it necessary or desirable in the public interest to temporarily remove one or more interconnection assets from service or temporarily reconfigure the transmission network.

Part 12 of the Code regulates Transpower, as a transmission network owner

A.60. Part 12 of the Code regulates Transpower, as a transmission network owner. Part 12 contains a number of provisions that regulate power system operation. These include:

- (a) transmission network reliability standards (known as ‘grid reliability standards’)
- (b) interconnection asset service measures
- (c) outage management obligations

167 Clauses 9.1 and 9.4 of the Code.

168 Clause 9.14 of the Code.

169 Clause 9.8 of the Code.

(d) a default transmission agreement template (formerly the ‘benchmark agreement’), which includes connection standards.

A.61. When exercising its functions and powers under Part 12 of the Code, the Authority must have regard to the desirability of Parts 7 and 8 and Part 12 operating in an integrated and consistent manner.[170]

The grid reliability standards provide a basis for appraising investments in the transmission network and in transmission network alternatives

A.62. Part 12 of the Code requires the Authority to determine one or more standards for reliability of the transmission network (‘grid reliability standards’). The purpose of these is to provide a basis for Transpower and other parties to appraise opportunities for investments in transmission and in transmission alternatives.[171]

A.63. The Code says the transmission network satisfies the grid reliability standards if:

(a) the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all economic reliability investments were to be implemented (the economic limb of the grid reliability standards), and

(b) with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state[172] during and following a single credible contingency event occurring on the core grid (the deterministic limb of the grid reliability standards).[173]

A.64. Generally speaking, the core grid has been defined to include any transmission assets servicing over 150MW of load.

A.65. Consistent with their purpose, the grid reliability standards are used in the Commerce Commission’s decision-making process for major capital expenditure transmission investment proposals put forward by Transpower.

Interconnection asset measures

A.66. Part 12 of the Code sets out a framework for the regulation of transmission interconnection services.[174] Under this framework:

(a) Transpower must identify and provide interconnection assets

(b) the Code specifies the capacity/service measures and levels for interconnection assets and requires Transpower to report against them

(c) the Authority monitors Transpower’s performance and, if necessary, enforces performance through the Code breach processes.

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170 Clause 12.3 of the Code.

171 Clause 12.56 of the Code.

172 Clause 1.1(1) defines ‘satisfactory state’ to mean that none of the following occur on the power system:

a) insufficient supply of electricity to satisfy demand for electricity at any GXP,

b) unacceptable overloading of any primary transmission equipment,

c) unacceptable voltage conditions,

d) system instability

173 Clause 2 of Schedule 12.2 of the Code.

174 Refer to subpart 6 of Part 12 of the Code.

A.67. The categories of service measures for interconnection asset services under this asset availability approach comprise measures of capacity, availability and reliability.

A.68. The capacity measures for interconnection asset services involve Transpower making its interconnection assets available to the system operator for dispatch at the capacity levels and configurations set out in the Code.

A.69. Availability measures identify the proportion of time that interconnection assets are not available for service. They include:

(a) annual interconnection circuit unavailability due to planned outages

(b) annual interconnection circuit unavailability due to unplanned outages.

A.70. Reliability measures record the number of transmission outages leading to electricity supply interruptions. Reliability measures are:

(a) the number of planned and unplanned interruptions to supply due to interconnection assets

(b) the estimated unserved energy resulting from transmission network outages.

The outage protocol

A.71. Under Part 12 of the Code, Transpower must prepare an ‘outage protocol’, which:

(a) specifies the circumstances in which Transpower may temporarily remove any assets forming part of the transmission network from service, or reduce the capacity of assets, to efficiently manage the operation of the transmission network

(b) specifies procedures and policies for Transpower to plan for outages and for carrying out outages to:

(i) ensure Transpower involves its transmission customers in making decisions on planned outages as much as possible

(ii) ensure coordination between Transpower and its transmission customers

(iii) enable Transpower to efficiently manage the operation of the transmission network

(c) specifies procedures and policies for Transpower to deal with unplanned outages of the transmission network as quickly as reasonably possible and in a way that minimises the costs and, if relevant, maximises the benefits arising from an unplanned outage.[175]

A.72. Principles the outage protocol must give effect to include:

(a) the need for a fair and reasonable balance of interests between Transpower, as a transmission network owner, and its transmission customers

(b) the desirability of the connection code and Part 8 of the Code operating in an integrated and consistent manner, if possible

(c) the need to ensure Transpower, as a transmission network owner, can meet all obligations placed on it by the system operator for the purpose of meeting common security and power quality requirements under Part 8 of the Code

175 Clause 12.143 of the Code.

(d) the need to ensure that the safety of all personnel is maintained

(e) the need to ensure that the safety and integrity of equipment is maintained.

The default transmission agreement template (formerly benchmark agreement)

A.73. The default transmission agreement template is in Schedule 12.6 of the Code. The purpose of the default transmission agreement template is to:

(a) facilitate commercial arrangements between Transpower and its transmission customers by providing a basis for negotiating transmission agreements that meet the requirements of Transpower and its transmission customers

(b) provide the basis for default transmission agreements.

A.74. The default transmission agreement template includes:

(a) an obligation on the parties to design, construct, maintain and operate all relevant plant and equipment in accordance with:

(i) relevant laws

(ii) the requirements of the Code (including obligations on Transpower's transmission customers to provide information to facilitate system planning)

(iii) good electricity industry practice and applicable New Zealand technical and safety standards

(b) an obligation on Transpower's transmission customers to comply with Transpower's reasonable technical connection and safety requirements

(c) an obligation on Transpower's transmission customers to pay prices calculated in accordance with the transmission pricing methodology

(d) arbitration or mediation processes for resolving disputes

(e) service definitions, service levels, and service measures for transmission services other than interconnection asset services.

A.75. The default transmission agreement template must be consistent in all material respects with the grid reliability standards.

A.76. The following principles underpin the default transmission agreement template:

(a) It should reflect a fair and reasonable balance between the requirements of Transpower's transmission customers and the legitimate interests of Transpower as asset owner.

(b) It should reflect the interests of end use customers.

(c) It should reflect the reasonable requirements of Transpower's transmission customers at GIPs and GXPs, and the ability of Transpower to meet those requirements.

(d) It should reflect the differing needs of different classes of transmission customers.

(e) It should be appropriate to the technical requirements of services provided at a point of connection to the transmission network, but not duplicate requirements more appropriately included in the grid reliability standards.

(f) It should establish common standards for a common configuration based on factors such as size of connection and voltage level.

(g) It should encourage efficient and effective processes for enforcement of obligations and dispute resolution.[176]

The connection code

A.77. The connection code is included as Schedule 8 of the default transmission agreement template. The purpose of the connection code is to set out the technical requirements and standards that industry participants must meet in order to be connected to the transmission network owned by Transpower ('designated transmission customers') and that Transpower must comply with.[177]

A.78. The connection code must provide for the following matters:

(a) Connection requirements for designated transmission customers.

(b) Technical requirements for assets, including assets owned by Transpower, and for other equipment and plant that is connected to a local network or an embedded network or that forms part of an embedded network or embedded generating station if the operation of that equipment and plant could affect the transmission network assets.

(c) Operating standards for equipment that is owned by a designated transmission customer, used in relation to the conveyance of electricity, and that is situated on land owned by Transpower.

(d) Information requirements to be met by designated transmission customers before equipment is connected to the transmission network and before changes are made to the equipment.

(e) An obligation on Transpower to provide a 10-year forecast of the expected maximum fault level of each point of service to designated transmission customers set out in the transmission agreement between Transpower and each designated transmission customer.[178]

A.79. The connection code must give effect to the following principles:

(a) The principles of the default transmission agreement template.

(b) The desirability of the connection code and Part 8 of the Code operating in an integrated and consistent manner, if possible.

(c) The need to ensure Transpower, as a transmission network owner, can meet all obligations placed on it by the system operator for the purpose of meeting common security and power quality requirements under Part 8 of the Code.

(d) The need to ensure that the safety of all personnel is maintained.

(e) The need to ensure that the safety and integrity of equipment is maintained.[179]

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[176] Clause 12.30 of the Code.

[177] Clause 12.17 of the Code.

[178] Clause 12.20 of the Code.

[179] Clause 12.21 of the Code.

Part 12A of the Code regulates distribution agreements

A.80. Part 12A of the Code regulates distribution agreements. Part 12A contains a default distribution agreement (the 'default distributor agreement'), which includes provisions that regulate power system operation. These include:

(a) compliance with distribution network connection standards

(b) outage management obligations

(c) load management responsibilities

(d) power outage and power quality service measures and service levels

(e) the management of distribution system emergencies.

The regulation of power system operation under Part 4 of the Commerce Act

Price-quality path regulation of Transpower

A.81. Part 4 of the Commerce Act provides for the Commerce Commission to determine an individual price-quality path for the electricity transmission lines services and system operator services provided by Transpower. [180] This individual price-quality path is to set:

(a) the annual maximum revenues Transpower may recover from its customers for its electricity lines transmission services and system operator services

(b) the annual minimum quality standards Transpower must meet for its electricity lines transmission services and system operator services.

A.82. The Commerce Commission has determined that the revenues and costs associated with Transpower's system operator services need not be included in Transpower's individual price-quality path. This is on the basis that the existence of an arm's-length contract between Transpower and the Authority for these services[181] should result in outcomes consistent with the Part 4 purpose for the services.[182]

Quality incentive measures (grid output measures) and quality standards

A.83. Under its individual price-quality path, Transpower must propose specific types of quality incentive measures related to its transmission services (known as 'grid output measures'). Transpower can also propose other such measures. The Commerce Commission then decides what grid output measures will apply to Transpower — the Commission may set different grid output measures from those proposed by Transpower.[183]

A.84. Grid output measures quantify the output or benefit (where 'benefit' may include reduction in risk) delivered by the transmission network, investment in the transmission network, or expenditure facilitating or enabling future transmission network investment. [184] Grid output measures relate to:

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180 Part 4 of the Commerce Act regulates 'electricity lines services'. Section 54C(1) of the Commerce Act defines 'electricity lines services' to include services performed by Transpower as system operator.

181 The system operator service provider agreement (SOSPA).

182 Commerce Commission, 29 August 2019, Transpower's individual price-quality path from 1 April 2020, Decisions and reasons paper, paragraph A10.

183 Commerce Commission, 29 August 2019, Transpower's individual price-quality path from 1 April 2020: Decisions and reasons paper, p. 136.

184 Commerce Commission, 29 January 2020, Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination) (consolidated version), p. 14.

(a) the capability or utilisation of the transmission network ('asset capability grid output measure')

(b) the condition / fitness for service of the transmission network ('asset health grid output measure')

(c) the performance of the transmission network, particularly in relation to availability, reliability, and how transmission network performance affects New Zealand's electricity market ('grid performance measure'[185]).[186]

A.85. Grid output measures may, or may not, be linked to Transpower's revenue. Under a revenue-linked grid output measure, Transpower is financially rewarded for outperforming performance targets and financially penalised for underperforming performance targets. Non-revenue-linked grid output measures may be used to better understand Transpower's performance.[187]

A.86. The Commerce Commission decides what, if any, quality standards are to be associated with (or be independent of) the grid output measures it determines.[188] The Commerce Commission may set quality standards in any way it considers appropriate. This may, in relation to electricity lines services, include:

(a) reliability of supply

(b) reduction in energy losses

(c) voltage stability or other technical requirements.

A.87. Requirements relating to quality standards for Transpower must be based on, and be consistent with, quality standards for Transpower that are set by the Authority (under Part 12 of the Code).[189]

A.88. The Commerce Commission may prescribe quality standards in any way it considers appropriate (eg, targets, bands, or formulae).[190] The Commission may set a quality standard for a grid output measure that Transpower did not propose.[191]

Price-quality path regulation of distributors

A.89. Under Part 4 of the Commerce Act, the Commerce Commission is responsible for determining a price-quality path for the electricity lines services provided by 16 distributors.

A.90. Price-quality paths set:

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185 Also referred to as 'service performance measure' and 'asset performance measure'.

186 Refer to:

- Commerce Commission, 29 January 2020, Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination) (consolidated version), p. 14.
- Commerce Commission, 29 August 2019, Transpower's individual price-quality path from 1 April 2020: Decisions and reasons paper, p. 44.

187 Commerce Commission, 29 August 2019, Transpower's individual price-quality path from 1 April 2020: Decisions and reasons paper, p. 41.

188 Commerce Commission, 29 August 2019, Transpower's individual price-quality path from 1 April 2020: Decisions and reasons paper, p. 42. (Refer to section 53M(3) of the Commerce Act.

189 Section 54V(6) of the Commerce Act.

190 Commerce Commission, 29 August 2019, Transpower's individual price-quality path from 1 April 2020: Decisions and reasons paper, p. 123

191 Commerce Commission, 29 August 2019, Transpower's individual price-quality path from 1 April 2020: Decisions and reasons paper, p. 42

(a) the maximum average price or total allowable revenue that a regulated distributor can charge

(b) standards for the quality of the services that each regulated distributor must meet. This is to ensure the distributor does not have an incentive to lower the quality of its services in order to maximise profits under its price-quality path.[192]

'Default' and 'customised' price-quality paths

A.91. There are two types of price-quality paths — a 'default' path and a 'customised' path.

A.92. A default price-quality path specifies price and quality standards for each distributor using a relatively low-cost regulatory approach that places an emphasis on:

(a) using industry-wide factors and applying the same or substantially similar treatment to all distributors on a default price-quality path

(b) using existing information that distributors must disclose and setting distributors' starting prices/revenues and quality standards/incentives with reference to historical levels of expenditure and performance, where appropriate.[193]

A.93. The emphasis on using industry-wide factors includes setting a distributor's price path based on the long-run average productivity improvement rate achieved by electricity distributors in New Zealand and/or electricity distributors in comparable overseas countries, using whatever productivity measures the Commerce Commission considers appropriate.[194]

A.94. It would be costly to take into account all distributor-specific information when the Commerce Commission resets default price-quality paths because full audit, verification and approval processes would be required. Audit, verification, and approval processes are the biggest contributor to the costs of setting price-quality paths.[195]

A.95. However, using an approach based on industry-wide factors may disadvantage some distributors, by omitting from the price- and quality-setting analysis factors that are specific to the distributor. For example, productivity-based price paths can disadvantage distributors that face comparatively more adverse cost conditions than other distributors, due to business-specific environmental (or other) factors largely outside the control of the distributor's management team.[196]

A.96. A customised price-quality path is intended to provide the opportunity for individual distributors to have an alternative price-quality path that better meets their particular circumstances.[197] Compared to default price-quality paths, customised paths use more business-specific information, and rely on more in-depth audit, verification, and evaluation and approval processes.

192 Commerce Commission, 27 November 2019, Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision, Reasons paper, p. 59.

193 *Ibid*, p. 63.

194 Section 53P(6) of the Commerce Act

195 Commerce Commission, 30 November 2012, Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors, pp. 42–43.

196 Commerce Commission, December 2010, Input Methodologies (Electricity distribution and gas pipeline services) reasons paper, p. 47.

197 Section 53K of the Commerce Act

Quality incentive measures and quality standards

A.97. The Commerce Act requires the Commerce Commission, when setting price-quality paths for distributors, to set quality standards that must be met by those distributors subject to a price-quality path. Quality standards may include without limitation, in relation to electricity lines services:

(a) reliability of supply

(b) reduction in energy losses

(c) voltage stability or other technical requirements.[198]

A.98. The current quality standards set by the Commerce Commission for default price-quality paths are based on the duration and frequency of electricity supply interruptions on the distribution network that distributors' customers experience in aggregate. These interruptions are measured primarily by:

(a) the 'system average interruption duration index' (SAIDI), which is the average total duration, in minutes, of interrupted electricity supply in a year per customer, and

(b) the 'system average interruption frequency index' (SAIFI), which is the average number of interruptions to electricity supply per customer in a year.

A.99. Both SAIDI and SAIFI exclude interruptions originating on the low voltage portion of the distribution network.[199]

A.100. The Commerce Act permits the Commerce Commission to set, for each distributor subject to a price-quality path, financial incentives to maintain or improve the distributor's quality of supply.[200]

A.101. The current default price-quality paths for distributors contain revenue-linked quality incentives for planned and unplanned SAIDI.[201] There are no revenue-linked quality incentives for SAIFI. This avoids the risk of double counting the SAIFI impact, since SAIDI is a function of the frequency (ie, SAIFI) and length (ie, 'CAIDI')[202] of electricity supply interruptions to distributors' customers.[203]

A.102. A distributor's quality standards and incentives under a customised price-quality path may be varied from those that would otherwise apply to the distributor under its default price-quality path. This is to better reflect the 'realistically achievable performance' of the distributor over the regulatory period for the customised price-quality path.[204]

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198 Section 53M of the Commerce Act.

199 Commerce Commission, 27 November 2019, Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision, Reasons paper, p. 130.

200 Section 53M of the Commerce Act.

201 Commerce Commission, 27 November 2019, Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision, Reasons paper, p. 131.

202 'Customer average interruption duration index'. CAIDI includes only those distribution customers who experienced an electricity supply outage, whereas SAIDI includes all of the distributor's customers.

203 Commerce Commission, 27 November 2019, Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision, Reasons paper, p. 141

204 Commerce Commission, 20 May 2020, Electricity Distribution Services Input Methodologies Determination 2012, p. 162

Information disclosure regulation of Transpower

A.103. The 'Transpower information disclosure determination 2014' sets out information disclosure requirements for both the electricity transmission lines services and system operator functions provided by Transpower.[205]

A.104. Transpower is required to disclose only financial information for its system operator role. Information to be disclosed includes return on investment, regulatory profit, revenue, operating expenditure, capital expenditure, and the value of fixed assets.[206]

A.105. For its transmission lines services, Transpower must disclose financial information and transmission network planning and management information. Examples of the financial information Transpower must disclose include regulated revenue, operating expenditure, base capital expenditure, major capital expenditure, the value of Transpower's regulatory asset base, and the calculation of Transpower's vanilla (ie, tax-free) and post-tax return on investment.[207]

A.106. The transmission network management information Transpower must disclose includes:

(a) transmission network statistics, eg, transmission network length, overhead and underground circuit length, HVDC submarine cable length

(b) transmission network demand and supply, eg, energy volume and maximum peak demand information for GIPs, GXPs and HVDC link transfers

(c) GXP connection capacity compared against actual and forecast electricity demand

(d) quality of supply, eg, planned and unplanned circuit unavailability, planned and unplanned unserved energy

(e) asset age and health and Transpower's asset management maturity assessment.[208]

Information disclosure regulation of distributors

A.107. The 'Electricity distribution information disclosure determination 2012' sets out the information disclosure requirements that apply to 29 distributors.[209]

A.108. Distributors are required to disclose the following information:

(a) Financial information.

(b) Pricing and related information.

(c) Non-financial information relating to network assets.

(d) Asset management plans and forecast information.

A.109. The financial information distributors must disclose includes regulatory profit, operating expenditure, capital expenditure, the value of the distributor's regulatory asset base, and a comparison of forecasts to actual expenditure.[210]

205 Commerce Commission, 3 April 2018, Transpower Information Disclosure Determination 2014

206 Commerce Commission, 28 February 2014, Transpower Information Disclosure Schedules.

207 *Ibid*

208 *Ibid*

209 Commerce Commission, 18 May 2023, Electricity Distribution Information Disclosure Determination 2012.

210 *Ibid*, pp. 50–58

A.110. The pricing and related information distributors must disclose includes:

(a) the distributor's prices and the methodology used by the distributor to calculate prices

(b) the distributor's capital contributions policy

(c) the distributor's allocation methodology for, and value of, financial distributions from an ownership interest in the distributor

(d) prescribed terms and conditions of contracts.[211]

A.111. The non-financial information relating to network assets that distributors must disclose includes:

(a) a register and age profile of distribution assets

(b) a report on overhead lines and underground cables

(c) a report on embedded networks connected to the distributor's network(s)

(d) a report on network demand

(e) a report on network reliability

(f) the distributor's customer charter (if the distributor has one).[212]

A.112. The asset management plans and forecast information that distributors must disclose includes:

(a) an asset management plan that:

(i) relates to the electricity distribution services supplied by the distributor

(ii) meets the purposes of disclosing asset management plans.[213]

(b) a report on the distributor's asset management maturity.[214]

A.113. A distributor may complete and publicly disclose a shortened form of an asset management plan in some years.[215]

A.114. A distributor's information disclosure requirements under a customised price-quality path may be varied from those that would otherwise apply to the distributor. For example, this may be to improve the visibility of the distributor's performance, and its accountability to its customers and stakeholders, in delivering the following:

(a) proposed projects and programmes approved as part of the customised price-quality path

211 *Ibid*, pp. 58–66.

212 *Ibid*, pp. 66–67.

213 Amongst other things, the purposes of disclosing asset management plans include providing interested persons with sufficient information to assess whether—

- assets are being managed for the long term
- the required level of performance is being delivered
- costs are efficient and performance efficiencies are being achieved.

214 Commerce Commission, 18 May 2023, Electricity Distribution Information Disclosure Determination 2012, pp. 71–73.

215 *Ibid*, pp. 73–74.

(b) proposed improvements to processes and practices approved as part of the customised price-quality path.[216]

The regulation of power system operation under the Electricity (Safety) Regulations

Part 3 – Systems of supply

A.115. Part 3 of the Safety Regulations deals with 'systems of supply'. Obligations in Part 3 relevant to power system operation include requirements about:

(a) the frequency of electricity supplied, including maximum and minimum levels that apply except for momentary fluctuations

(b) the voltage supplied to installations, including maximum and minimum levels that apply except for momentary fluctuations

(c) the quality of supply, in respect of requirements relating to harmonics and flicker

(d) the safety of supply in respect of an obligation to ensure the maximum prospective fault currents on the supply system are limited to reasonable levels.

Frequency of electricity supplied

A.116. The Safety Regulations require the frequency of electricity supplied to be maintained within 1.5% of 50Hz (ie, 49.25 – 50.75Hz), except for momentary fluctuations. The Safety Regulations permit this requirement to be varied for electricity supplied at other than standard low voltage,[217] if the electricity supplier and the person receiving the electricity supply agree.[218]

Voltage supply to installations

A.117. The Electricity (Safety) Regulations[219] require the voltage of electricity supplied to an installation to be:

(a) at 230–460 volts AC (standard low voltage) and kept within 6% of that voltage except for momentary fluctuations, for installations operating at a voltage of 200–250 volts AC[220]

(b) at a voltage agreed between the electricity retailer and the customer and kept within 6% of the agreed supply voltage unless the electricity retailer and customer agree otherwise, for installations operating at other than standard low voltage.[221] [222]

216 Commerce Commission, 23 July 2019, Notice to supply information to the Commerce Commission under section 53ZD of the Commerce Act 1986.

Commerce Commission, 31 August 2021, Aurora Energy Limited Additional Information Disclosure Requirements, Final reasons paper, pp. 9–17.

217 230 volts AC to 460 volts AC.

218 See regulation 29 of the Electricity (Safety) Regulations.

219 See regulation 28 of the Electricity (Safety) Regulations.

220 Calculated or measured at the point of supply.

221 *Ibid*

222 The Authority notes that Electricity Networks Aotearoa has put a proposal to MBIE to increase the maximum allowable low voltage limit in New Zealand from 6% above 230 volts to 10% above 230 volts.

A.118. New Zealand's adoption of 230 volts AC for standard low voltage is consistent with the International Electrotechnical Commission (IEC) standard IEC 60038. Most countries internationally have adopted this standard.

Quality of supply requirements

A.119. The Safety Regulations require that the use of fittings and appliances must not unduly interfere with the satisfactory supply of electricity to any other person, or impair the safety of, or interfere with the operation of, any other fittings or appliances.

A.120. In relation to harmonics, this obligation is met by complying with whichever of the following standards is applicable:

(a) NZECP 36: 1993

(b) IEC 61000–3–2

(c) IEC/TS 61000–3–4

(d) IEC 61000–3–12.[223]

A.121. In relation to flicker, this obligation is met by complying with whichever of the following standards is applicable:

(a) IEC 61000–3–3

(b) IEC/TS 61000–3–5

(c) IEC 61000–3–11.[224]

The safety of electricity supplied and protection against fault currents

A.122. As part of ensuring the supply of electricity is safe, the Safety Regulations require, amongst other things, that reasonable steps are taken to ensure the maximum prospective fault currents on the power system are limited to reasonable levels.[225]

A.123. In addition, the Safety Regulations require a person who supplies line function services to a consumer to provide a fitting that can interrupt the supply of electricity to that consumer's installation. This protective fitting must be of an appropriate rating for protection against short circuits or earth faults on the mains fittings used in supplying electricity to the consumer. [226]

Part 4 – Safety of works

A.124. The Safety Regulations require the owner of 'works'[227] to ensure the works have adequate electrical protection against short circuits and earth faults. Fittings that are part of any works and which are used to protect against over-current, short-circuiting, earth fault current, overvoltage, under-voltage, and no voltage, must be designed and installed to achieve the maximum practicable sensitivity and minimum practicable operating times, within certain limits.[228]

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223 Regulation 31 of the Electricity (Safety) Regulations.

224 *Ibid*

225 See regulation 30 of the Electricity (Safety) Regulations.

226 Regulation 32 of the Electricity (Safety) Regulations.

227 Section 2 of the Electricity Act 1992 defines 'works' as follows:

(a) means any fittings that are used, or designed or intended for use, in or in connection with the generation, conversion, transformation, or conveyance of electricity

(b) does not include any part of an electrical installation.

228 Regulation 34 of the Electricity (Safety) Regulations.

A.125. The Safety Regulations specify how electricity generators and distributors (with a capacity of ≥10MW and ≥10MVA respectively), must implement and maintain a safety management system. The safety management system must prevent, so far as is reasonably practicable, the assets of the generator or distributor presenting a significant risk of:

(a) serious harm to any member of the public, or

(b) significant damage to property owned by a person other than the generator or distributor.[229]

229 Section 61A of the Electricity Act 1992 and regulations 47–56 of the Electricity (Safety) Regulations.

Appendix B Format for submissions

Submitter	

Questions	Comments
Q1. Do you consider section 3 to be an accurate summary of the existing arrangements for power system operation in New Zealand? Please give reasons if you do not agree.	
Q2. Do you agree that we have captured the key drivers of change in New Zealand's power system operation? Please give reasons if you do not agree.	
Q3. Do you have any feedback on our description of each key driver?	
Q4. What do you consider will be most helpful to increase coordination in system operation? Please provide reasons for your answer.	
Q5. Looking at overseas jurisdictions, what developments in future system operation are relevant and useful for New Zealand? Please provide reasons for your answer.	
Q6. Do you consider existing power system obligations are compatible with the uptake of DER and IBR-based generation? Please provide reasons for your answer.	
Q7. Do you consider we need an increased level of coordination of network planning, investment and operations across the New Zealand power system? Please provide reasons for your answer.	
Q8. Do you think there are significant conflicts of interests for industry participants with concurrent roles in network ownership, network operation and network planning? Please provide reasons for your answer.	
Q9. Do you have any further views on whether this is a good time for the Authority to assess future system operation in New Zealand, and whether there are other challenges or opportunities that we have not covered adequately in this paper? Please provide reasons for your answer.	

Appendix C Future system operations – international literature review

Future System Operations

International Literature Review

31 March 2023

EY
Building a better working world

Release Notice

Ernst & Young (“we”) has been engaged by the Electricity Authority (the “Client”) to deliver an international literature review of the challenges, opportunities and responses related to the arrangements for power system operations to support the Future System Operations workstream within the Future Security and Resilience work programme, in accordance with the Engagement Agreement (Consultancy Services Order) dated 7 February 2023.

The enclosed report dated 31 March 2023 (the “Report”) sets out the outcomes of Ernst & Young’s work, including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety, including this notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

Purpose of our Report and restrictions on its use

Ernst & Young has prepared the Report on the instructions of the Client, solely for the purpose of supporting the Client to conduct research on international challenges, opportunities and responses related to power system operations as one part of the EA’s broader review of Future System Operations within the Future Security and Resilience work programme. The agreed purpose of this Report includes it being used as a supporting document for a public consultation process as an attachment to materials produced by the Client. In carrying out our work and preparing this Report, we have worked solely on the instructions of the Client and for the Client’s purposes. The Report should not be used or relied upon for any other purpose.

This Report and its contents may not be quoted, referred to or shown to any other parties except as provided in the Agreement. We accept no responsibility or liability to any person other than to the Client or to such party to whom we have agreed in writing to accept a duty of care in respect of this Report, and accordingly if such other persons choose to rely upon any of the contents of this Report they do so at their own risk.

Nature and scope of our work

The scope of our work, including the basis and limitations, are detailed in the Engagement Agreement and in this Report. Our work was limited to reviewing the jurisdictions and covering the topics agreed with the Client.

Our work commenced on 10 February 2023 and was completed on 31 March 2023. Therefore, our Report does not take account of events or circumstances arising after 31 March 2023, and we have no responsibility to update the Report for such events or circumstances.

In preparing this Report, we have considered and relied upon information from a range of publicly available sources believed to be reliable and accurate. We have not been informed that any information supplied to us, or obtained from public sources, was false. Neither Ernst & Young nor any member or employee thereof takes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided to Ernst & Young. We do not imply, and it should not be construed, that we have verified the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose.

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1 Introduction

Background & Context

The Electricity Authority (EA) is considering how to ensure New Zealand's power system remains secure and resilient as the country transitions towards a low-emissions energy system.

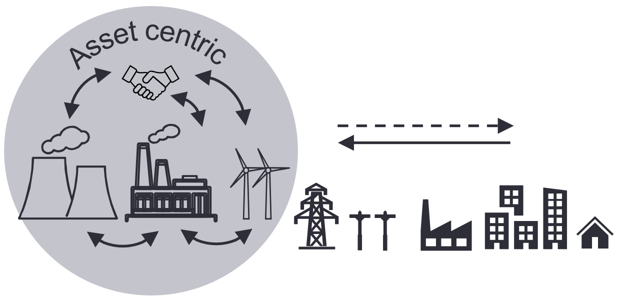
This work is part of the EA's Future System Operations workstream of the Future Security and Resilience work programme. This multi-year work programme is focused on how the electricity system may need to change over coming decades to remain secure and reliable as new technologies emerge and the electricity system becomes more renewable.

Decarbonisation and evolving technologies are creating challenges and opportunities for how power systems around the world operate.

These electricity system shifts create both challenges and opportunities for system operators. The EA's Future System Operations workstream under the Future Security and Resilience programme is seeking to understand these challenges and opportunities and identify any potential new tools, roles or responsibilities needed to address these for the benefit of consumers. As part of this, the EA is interested in what lessons could potentially be learned from international jurisdictions and how these might apply to New Zealand.

Current state

- Large and centralised generation
- One-way transmission / distribution flow
- Relatively stable and predictable demand growth
- Fossil fuel energy storage to balance supply-demand
- Infrastructure built for peak demand



Consumers are largely a demand center

'New World'

- Distributed, intermittent renewable generation providing a significant proportion of generation
- Two-way transmission / distribution flow
- Rapid demand growth due to electrification (e.g. electric vehicles, industrial heat, domestic heating)
- Exit of fossil fuel baseload and peaking
- Smart grid / network operations to balance supply-demand

Consumers become prosumers

Purpose & Scope

The purpose of this report is to provide the findings of an international literature review on key challenges and opportunities experienced in relation to the arrangements for power system operations, and the planned or actual responses in different jurisdictions.

The aim of this report is to provide insights from international experience which can support the EA's Future System Operations workstream within the Future Security and Resilience work programme.

The scope of this review covers the drivers, impacts and responses for a range of key challenges and opportunities across six international jurisdictions.

This review covers power system operation in its broader senses, including both transmission and distribution system operation. The international review has covered the following six jurisdictions:

- Australia
- Great Britain (England, Wales and Scotland)
- Ireland (Republic of Ireland and Northern Ireland)
- The Nordic region, including Norway, Sweden, Denmark and Finland
- California (the California Independent System Operator, CAISO)
- PJM ("Pennsylvania, New Jersey and Maryland", the independent system operator for electricity in all or parts of 13 states on the east coast of the USA)

This report covers the following review questions:

- What problems or opportunities with system operations are overseas jurisdictions experiencing?
- How are these jurisdictions planning to address / capture these problems / opportunities?
- What is common and unique across the approaches taken by the different jurisdictions?
- What are the commonly used / accepted definitions for key system operations terminology?

For each problem / opportunity identified for each jurisdiction, information is provided on the 'driver' (i.e. why this problem / opportunity is happening), the 'impact' (i.e. what this means for power system operations), and the 'response' (i.e. what the jurisdiction is doing to address / capture this problem / opportunity). This allows the drivers and impacts to be compared with what is happening in New Zealand, to enable the relevance of the problem / opportunity to be understood and considered in a New Zealand context.

The report has been developed based on the facts available through a literature review of publicly available information. This was supplemented by interviews with subject matter resources from the EY global network, who were able to provide on-the-ground insights from working within the researched jurisdictions. The scope of work was limited to reviewing the jurisdictions and covering the topics agreed as above.

Jurisdictions Reviewed

The key characteristics of each jurisdiction researched as part of this review are outlined below.

Jurisdiction	Key characteristics of the power system	Reasons for selection to be reviewed
Australia	▸ Three islanded large-scale power systems / markets ▸ 8 transmission system operators (TSOs) and 15 distribution network operators (DNOs) ▸ Approximately 29% renewable generation (in 2021[1]) ▸ Changing fuel mix as thermal generation is retired and solar (both grid-scale and distributed) and wind generation expands	▸ World-leading rates of distributed (rooftop) solar adoption, already accounting for 8% of electricity generation[2] ▸ Advanced responses for managing high penetration of distributed energy resources, particularly solar ▸ Emerging operational challenges associated with high levels of instantaneous non-synchronous renewables penetration
Great Britain	▸ Synchronous grid across Great Britain (excluding Northern Ireland), interconnected with Ireland and mainland Europe ▸ One TSO and 14 DNOs ▸ Approximately 40% renewable generation (in 2021[3]) ▸ Reducing coal use and increasing use of wind and solar generation	▸ Advanced consideration of facilitating flexibility and integrating DER into power system operations ▸ Unique proposal for future energy system institutional framework and governance, including a new 'Future System Operator' ▸ Similar weather patterns to NZ (e.g. winter peaking, solar resources)
Ireland	▸ One TSO and two DNOs (one in the Republic of Ireland, one in Northern Ireland) ▸ Approximately 25% renewable generation (in 2021[4]), around 50% generation by natural gas	▸ Small synchronous grid, similar size and population to NZ ▸ Experiencing operational challenges associated with high levels of instantaneous non-synchronous renewables penetration (wind) ▸ New significant loads from data centres ▸ Examples of TSO / DSO coordination
Nordics	▸ Synchronous inter-Nordic system includes the transmission grids of Finland, Sweden, Norway and eastern Denmark ▸ Very high per-capita electricity consumption, due to electric heating, energy-intensive industry and high electric vehicle uptake ▸ Electricity generation dominated by hydro and nuclear	▸ Very high electric vehicle penetration in some countries ▸ Winter peaking challenge ▸ Significant build of new renewable generation needed to support electrification
CAISO	▸ One independent system operator for California ▸ Nine distribution companies within the CAISO area ▸ Approximately one-third renewable generation (in 2021[5])	▸ Very high utility-scale and distributed solar capacity, currently leading to periods of curtailment during high supply / low demand ▸ Advanced consideration of integrating DER and future DSO models
PJM	▸ PJM is the independent system operator for 13 US states ▸ 40+ electric distributors within the PJM area ▸ Approximately 6% renewable generation, 33% nuclear, 61% thermal[6]	▸ Very large system operator, with 65m+ customers ▸ Significant demand increase (electrification, data centres) along with thermal retirement ▸ Reliability challenges, particularly during winter peaks

2

International Trends

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key findings

All jurisdictions researched are actively considering the new tools needed to operate the future decarbonised, decentralised and digitalised electricity system, and considering the appropriate instutional framework, roles and responsibilities for future system operations.

The most relevant and pressing system operations challenges and opportunities for each jurisdictions vary depending on the characteristics of their energy system. The responses to similar challenges and opportunities also differ to some degree. However, there are some key themes that apply to all six jurisdictions researched, and that apply to New Zealand as well.

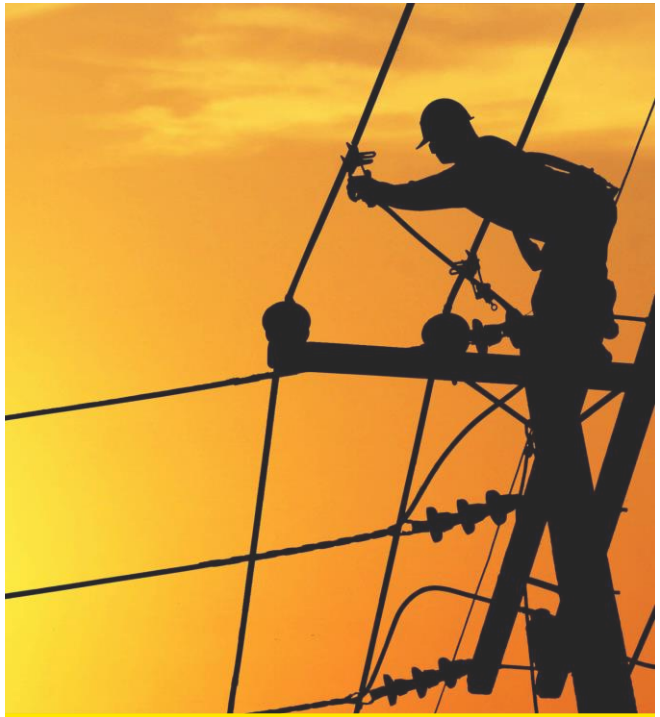
All six jurisdictions are facing challenges and opportunities relating to the following key energy transition drivers:

- Electricity demand is increasing and load profiles are becoming 'peakier' due to electrification of sectors like transport and heating, as well as new loads like data centres
- Fossil fuel electricity generation is increasingly being replaced by intermittent renewable generation, which has quite different operating characteristics
- The electricity system is becoming more decentralised, with increasing penetration of DER bringing more decentralised generation and more dynamic loads to distribution networks

While the exact responses are tailored to each jurisdiction, all jurisdictions researched are using a combination of the following approaches:

- New and enhanced capabilities are needed, including the capabilities of existing system operators, capabilities provided by new system and market actors, and technological capabilities
- Energy markets, regulations and standards are being reformed to adapt to changing system operations requirements
- Increasing levels of coordination are needed between different energy system actors, which may require some change to system institutional frameworks and governance

These key findings, including examples from the jurisdiction reviews, are presented in this section. The relevance of each key finding to the New Zealand context is signalled, based on domestic trends and initiatives. Full details on the challenges / opportunities, drivers, impacts and responses for the six jurisdiction reviews are provided in the following sections of the report.



Summary

Our research shows that all jurisdictions are actively considering how system operations might evolve to maintain security and reliability in response to new technologies and decarbonisation. Common across responses is the need for new system operation capabilities, supported by updated regulation and increased coordination across the system.

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key Driver 1:	System operators are facing the challenge of increasing demand and 'peakier' load profiles, as a result of electrification and new loads

While demand has remained relatively flat in most jurisdictions for some time, electrification of transport, industry and heating is causing significant demand growth (both average and peak) in all jurisdictions. Great Britain is projecting peak demand to nearly double by 2035[1], and both California and the Nordics are predicting an increase in average demand by more than 60% by 2040.[2,3] In New Zealand, scenarios indicate electricity demand could increase 68% by 2050.[4] This is creating a need to increase the capacity of generation, transmission and distribution infrastructure, potentially at a significant cost, though most jurisdictions are also considering alternatives to infrastructure expansion to support increasing demand (see Key Response 1).

All jurisdictions researched are predicting significant growth in EV penetration. Electrification of transport is a key enabler for most jurisdictions' decarbonisation goals. All jurisdictions researched have set targets for EV sales, EV penetration and/or phasing out of internal combustion engine vehicle sales, and most are supporting this through incentive and grant programmes. In both Norway and Iceland, EVs already represent around an 80% share of private passenger vehicles, and these countries are now experiencing the increase in electricity demand association with EV charging; five million Norwegians use as much electricity as 10 million residents of Sweden.[5] In jurisdictions with currently low EV penetration, networks (particularly at the distribution level) are needing to cope with near exponential growth in charging demand. In Stockholm, where EV sales grew by 253% in 2019, growth is outpacing local grid capacity, limiting ability for new chargers to be installed.[6] As well as increasing average demand, peak demand impacts can be significant where charging coincides with existing peaks; jurisdictions are predicting EVs could make up around 10-16% of peak demand. All jurisdictions are recognising the need for managed charging to mitigate demand peaks and potential congestion, capacity and system security impacts. In New Zealand, a target for 30% of the light fleet to be zero-emissions by 2035 is being supported by grants and tax exemptions for EVs. New Zealand is experiencing rapidly accelerating uptake, with imports of fully electric vehicles more than tripling from 2021 to 2022[7], though EVs still currently only make up around 1% of the total light vehicle fleet.[8]

Some jurisdictions are seeing demand increases from new loads, like data centres. Both Ireland and PJM are seeing a high level of interest in new data centres, as jurisdictions seek to strengthen their position as strategic locations for digital services, with potential associated economic, technological and social benefits. These high energy users are adding significantly to average demand. In Ireland, data centres use 14% of the country's electricity, and this is forecast to double by 2030.[9] This has implications for the local distribution networks, the transmission network, and resource adequacy at the system level, especially as this growth coincides with electrification of other sectors. Where new connections are happening too quickly for electricity infrastructure to keep up, such as in Dublin, jurisdictions are being forced to pause new applications until upgrades to transmission and distribution, and build of new generation, can be completed. Jurisdictions are exploring how data centres can be active participants in the electricity system, such as through onsite generation, storage and demand response. In New Zealand, it is anticipated the electricity demand from data centres could increase more than four times, from 69MW in 2020 to 302MW in 2030.[10] This is expected to come with potentially significant benefits; two data centres in Auckland are projected to boost the economy by NZ$1.4b and provide around 500 jobs.[11]

Electrification of heating and cooling is also increasing demand, and this is causing particular system operator challenges during unusually hot or cold weather. Jurisdictions that have traditionally used fossil fuels for heating (e.g. gas) are seeing significant load increases from the transition to electric heating, and some countries are also seeing demand spikes for cooling during heat waves. Extreme cold / hot weather, and the associated spike in demand, has significantly disrupted electricity systems and markets in Australia, California and PJM in recent years, and Ireland is forecasting consumers could be without supply for up to four hours at a time during winter. New Zealand's highest consumption occurs in winter, and the country experienced its highest ever peak electricity demand during unusually cold weather in August 2021, which resulted in supply interruptions for 34,000 customers.[13]

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key Driver 2:	As fossil fuel generation is replaced by intermittent renewable generation, balancing supply and demand and maintaining grid stability are increasingly challenging

Electricity generation in all jurisdictions is shifting to a higher share of intermittent renewables and a lower share of fossil fuel generation. All jurisdictions researched have set emissions reduction and net zero targets, with many setting targets for renewable or zero-carbon electricity generation, typically in the range of 80-100% by mid-century. Additionally, the majority of fossil fuel plants are reaching an age where they require either replacement or retirement, and emissions reduction targets are driving thermal exit. Jurisdictions with currently high shares of fossil fuel generation are seeing significant generation capacity retirement; PJM and Australia are expecting 21% and 13% of capacity to retire by 2030, respectively.[1,2] New Zealand has set an aspirational target for 100% renewable electricity generation by 2030. Almost 3,000MW of capacity, including all large coal and gas generation, is scheduled to retire by 2050.[3]

New renewable generation needs to come on at pace. Much higher renewable generation capacity is needed to achieve renewable energy targets, replace exiting thermal generation and support increasing demand. Due to its intermittent nature, to replace 1MW of thermal generation, more than 1MW of renewable capacity is required. The required build-out is significant, with most new generation being solar and wind. In New Zealand, the Climate Change Commission has forecasted 47% growth in renewable electricity generation by 2035, with wind generation capacity increasing by up to sixfold, and solar at least tenfold, during this period. By 2035, wind and solar may account for around a quarter of generation.[4] In some jurisdictions, connection and permitting processes are limiting the pace at which new generation is being brought online, with PJM having to pause interconnection applications while it clears a backlog where some applications have been in the queue for over three years. In 2022, Transpower released a new connection framework in response to seeing a surge in connection enquiries from around five enquiries per year historically up to 124 in FY22.[5] Some jurisdictions are seeing fossil fuel retirements occurring at a faster pace than new renewable generation is coming online, impacting resource adequacy and contributing to supply interruptions. PJM is seeing decreasing reserve margins for the first time in recent history, and unplanned outages of coal plants contributed to Australia's market suspension in 2022. This is requiring some jurisdictions to delay retirement of aged fossil fuel plants.

Electricity systems need to account for different generation characteristics of intermittent renewables. Solar and wind generation have different operating characteristics to the largely fossil fuelled generation sources that have traditionally met electricity demand. While traditional sources are flexible and dispatchable, so generation can be dialled up or down to follow increases or decreases in demand, wind and solar generation are intermittent and output is dependent on the weather. In most jurisdictions, this can result in insufficient supply during demand peaks, such as calm and cloudy evenings. However, in California and Australia where solar penetration is very high, this also means supply is much higher than demand in the middle of the day, resulting in curtailment and 'spill' of generation. Both problems require mechanisms to firm the intermittent generation and 'time-shift' loads. In New Zealand, coal and gas currently help to fill the gaps when demand is high and renewable generation limited, but alternative firming solutions will be needed to replace this, particularly as the penetration of intermittent wind and solar increases. As well as firming during calm and cloudy periods, New Zealand has an additional challenge achieving supply security during dry years when hydro generation is limited.[4]

Increasing penetration of renewables is also creating grid stability and balancing challenges. While traditional fossil fuel (and hydro and geothermal) generators are synchronous (i.e. operate at the same frequency as the grid) and provide the grid with inertia, wind and solar generation are non-synchronous. As fossil fuels exit the system, alternative mechanisms are needed to provide reactive power services, including inertia, frequency response and voltage management. Jurisdictions are researching technologies and exploring market mechanisms to provide these services without fossil fuels to ensure the grid operates securely at very high levels of non-synchronous renewable penetration. Ireland and Australia, where instantaneous non-synchronous penetration is already reaching near 100% for periods of time, are particularly focused on this. New Zealand has also identified that displacement of synchronous coal and gas generation will require new solutions to manage grid inertia and regulate frequency and voltage.[6]

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key Driver 3: Distributed Energy Resources (DERs) pose both a potential challenge for system operators to manage and an opportunity for new system services

All jurisdictions researched are grappling with the shift towards a decentralised, two-way electricity system. Electricity systems have traditionally received generation from a small number of large generators and conveyed electricity, via transmission and distribution networks, in one direction to customers, and system and market frameworks were designed for this. Future electricity systems will have high levels of distributed generation (e.g. solar), storage and dynamic loads (e.g. smart appliances and EV charging), and customers will be active participants in the system. Some jurisdictions, including Australia and California, are already experiencing high penetration of DER, particularly distributed solar, driven by decreasing costs along with incentives. In 2021, rooftop solar accounted for 8% of Australia's electricity generation, and the system is seeing decreasing operational grid consumption as a result.[1] DER could contribute up to 45% of Australia's generation capacity by 2045.[2] These jurisdictions are actively considering how to obtain visibility, understand DER behaviour, ensure regulation and standards are fit-for-purpose, and achieve maximum system benefits from DER. Distributed solar generation in New Zealand is currently limited, though this is expected to grow, with the Climate Change Commission's Demonstration Path outlining potential growth from 0.03TWh in 2021 (less than 0.1% of generation) to 1.3TWh in 2035 (around 3% of generation).[3]

All jurisdictions researched have also identified the potential services DER can provide at all levels of the systems. While the potential generation or demand management provided by one DER is minimal, if a large number of DERs combine their output, this could provide services similar to a traditional large-scale power system. DER can therefore play an important role in balancing supply and demand, maintaining grid reliability and achieving resource adequacy. Within local networks, DER can support with managing local congestion, constraints and system strength. Research commissioned by the Electricity Authority has indicated DER could provide up to NZ$650m of value per year by 2035 in New Zealand, particularly from energy arbitrage, resource adequacy, instantaneous reserve and simulated inertia services.[4]

Traditional electricity system capabilities and roles are not designed for high DER penetration. The traditional distribution network owner is required to ensure the physical distribution network reliably conveys electricity from the transmission network to a passive customer. With increasing DER, the distribution network is increasingly dynamic, with two-way flows and new system security challenges, requiring new capabilities for distribution system operations and planning. Australia, California and Great Britain in particular are considering the future roles of distribution system operators (DSOs) and other market participants to ensure efficient real-time distribution system operations like flexibility deployment and dispatch instructions. These jurisdictions are also considering how to avoid conflicts on interest between these functions and the asset upgrades and network solutions that network operators are traditionally responsible for. In New Zealand, several existing network operators are considering the potential future active DSO and what their roles and capabilities might include.[5,6]

Jurisdictions are considering how to obtain maximum benefit from DER at both distribution and transmission levels. Electricity markets were traditionally established to allow participation only by large generators. For both customers and the electricity system to fully realise the benefits of DER, existing or new markets need to facilitate trade of electricity and ancillary services from DER. Jurisdictions are proactively considering how to enable DER owners to actively trade electricity and provide flexibility services to both distribution and transmission systems. Efficient service provision, decision-making and dispatch is recognised to need much more coordination between system operators, transmission system operators (TSOs) and DSOs. This may require establishing new operating models, technologies and capabilities at both levels. In the US, an order by the Federal Energy Regulatory Commission (FERC), Order No. 2222, requires system operators to enable DER to participate in wholesale markets, in recognition of their potential to provide flexibility and ancillary services and to maintain grid reliability and stability.

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key Response 1: Various new and enhanced system capabilities are needed to continuously match increasingly dynamic supply and demand and efficiently manage an increasingly distributed electricity system

System operators need new capabilities to manage increasingly dynamic and decentralised supply and demand. New capabilities are needed to operate power systems, both at the transmission level and increasingly at the distribution level. New capabilities identified within the jurisdictions researched include:

- Enhanced investment planning (including better understanding where non-network solutions should be deployed in place of network investment)
- Improved forecasting and modelling for dynamic power flows and intermittent supply, along with dynamic operations to respond to changing system conditions
- Enhanced visibility (particularly at the low-voltage level), and data capture and sharing (e.g. between transmission and distribution operators)
- Integration of flexibility services, demand response and services from DER into grid operations and planning for grid development
- Streamlining and standardising the connection process for new energy resources, including DER
- Improved coordination between the different electricity system actors (e.g. between TSOs and DSOs and/or across energy vectors)

For example, the AEMO in Australia and CAISO in California are both focusing on improving their ability to forecast DER adoption and performance, and this is supported by new registers / databases for DER. CAISO and PJM are focusing on their ability to forecast variable renewable generation, which is more difficult than forecasting traditional fossil fuel based resources. The Nordic TSOs have established a joint Regional Security Coordinator to provide enhanced operational planning services, including outage planning, adequacy forecasting and capacity calculations across the region.

Several jurisdictions, especially those with currently high DER penetration and/or flexibility requirements (Australia, California, and Great Britain) are actively considering the enhanced capabilities required to effectively operate the power system and considering the most appropriate roles and governance structures to deliver these capabilities. In Great Britain, Ofgem has identified key future DSO capabilities to include coordinated and efficient network planning and real-time operations, with facilitation of distributed flexibility services to be provided by a new entity, the Future System Operator. In California, there is currently a significant focus on capabilities to integrate DER into distribution systems, including improving connection processes, forecasting adoption and performance and integrating impacts of DER into system planning.

New Zealand electricity system actors have identified the need for many of these future system operator capabilities. For example:

- The Electricity Authority, when considering potential updates to regulatory settings for distribution networks, identified the need for distributors to choose non-network solutions where they are the efficient option and to integrate these flexibility services into network planning.[1]
- The Future Security and Resilience project identifies the need to improve data collection, visibility and forecasting of demand and intermittent generation, including system operator visibility of DER within distribution networks.[2]
- The Energy Networks Association has identified a number of capabilities for electricity distributors to develop, including visibility and forecasting of DER, standardising DER connections and procurement of non-network alternatives.[3]
- Some of New Zealand's existing distribution businesses have identified new and enhanced capabilities they need to develop to manage the distribution system, from enhanced data collection[4,5] and incorporating consideration of non-network solutions into network planning,[6] through to actively orchestrating DER in a coordinated way.[7]

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key Response 1 (continued):	Various new and enhanced system capabilities are needed to continuously match increasingly dynamic supply and demand and efficiently manage an increasingly distributed electricity system

The electricity system also requires new technology capabilities, and jurisdictions are investing in development and deployment. For supply to continue to closely match demand with more dynamic generation, firming capacity is required. All jurisdictions researched have identified increasing storage resources, both short- and long-duration, as a key tool to manage intermittent generation. Storage is being used whether the challenge is curtailment and capturing high levels of generation during periods of low demand, such as in California, or ensuring supply is reliably available when demand is high, such as in Ireland. Jurisdictions are ensuring regulatory treatment, licensing, charging and market incentives encourage investment in storage. Researching and investing in emerging long-duration storage technologies is a priority, including in Great Britain, as well as Australia and Finland, where pumped hydro storage investment is a key tool for security of supply. In New Zealand, in 2022, construction commenced on the first utility-scale battery storage system in Huntly[1], and consent was granted for a 100MW grid-connected battery to alleviate congestion and improve resilience of the grid north of Auckland.[2] New Zealand has identified a key challenge of an increasingly renewable electricity system will be meeting demand during dry years, when hydro generation is lower than normal. Pumped hydro and other potential long-duration storage technologies are being investigated through the NZ Battery project.[3]

Jurisdictions experiencing very high levels of instantaneous non-synchronous penetration, including Australia and Ireland, are implementing new reactive power technologies, including synchronous condensers and grid-forming inverters, to manage system strength and inertia. Although inertia and voltage management have been identified as a potential future challenge for New Zealand, applications are likely to be localised in the near term until penetration of non-synchronous renewables increases. Reactive power devices, including synchronous condensers, have been identified through the Waikato and Upper North Island Voltage Management study.[4]

To efficiently manage increasing demand from EV charging, all jurisdictions researched are trialling and implementing smart charging and vehicle-to-grid (V2G) technologies to manage grid reliability and stability. Implementation of these technologies is currently limited in New Zealand, but some network operators are conducting smart charging trials. These include Vector's trial of active management of 200 customers' smart EV chargers to minimise demand peaks[5], and a Northpower V2G technology trial to test potential benefits for the customer and the network.[6] In 2022, EECA consulted on the importance of smart and managed EV charging in New Zealand and potential options to support their implementation.[7]

Electricity systems and markets need new capabilities to optimise benefit from DER and flexibility services. All jurisdictions researched are exploring new capabilities to increase system flexibility, in many cases as a preferential solution to traditional infrastructure upgrades. Mechanisms have been trialled to allow system operators, TSOs and DSOs to procure flexibility services, including from DER. Enabling efficient trading of flexibility has been identified to require further new capabilities, including marketplaces and trading platforms. For example, both Australia and Sweden have established proof-of-concept DER marketplaces for provision of services to both the wholesale market and local network. All jurisdictions researched have identified a new electricity system role for aggregators to act as an intermediary and coordinate supply and/or demand response from energy asset owners, particularly DER owners.

New Zealand is not yet at the stage of trialling or implementing marketplaces for flexibility and DER services at scale. However, ripple control demand response of hot water systems has been in place for several decades, and some other aggregation demonstration projects are emerging, including solarZero's Virtual Power Plant (VPP) which provides network and grid support services.[8,9] Several reports identify the potential benefits to New Zealand of trading DER services.[10,11] Transpower's Demand Response programme piloted use of a platform for industrial and business consumers to provide demand response services[12], and this was identified as a starting point for future flexibility markets in New Zealand.[13]

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key Response 2: Energy regulations, markets and standards are being reformed to better accommodate a more dynamic and decentralised energy system

Existing markets are being amended to ensure emerging energy technologies can effectively participate. Electricity markets have been designed on the basis that a relatively large proportion of demand is met by thermal generation, which typically has low investment costs and high operating costs, in contrast with renewable generation, which has low operating costs. Jurisdictions are currently updating existing market rules and regulations to ensure new renewable generation technologies are adequately accounted for and to incentivise investment in new generation, firming and security of supply. For example, PJM is ensuring there are clear rules for participation of hybrid (generation plus storage) resources in existing energy, capacity and ancillary services markets, while Great Britain has prioritised enabling storage to participate in its capacity market. PJM is also amending its capacity market rules to more adequately reflect risk and performance, to both better manage security of supply and more effectively reward the services provided by renewable technologies. In New Zealand, in 2018, the Electricity Authority investigated barriers to participation of new generating technologies (and particularly battery storage) in the wholesale market for energy and ancillary services.[1] The Market Development Advisory Group is focused on identifying changes required to the wholesale electricity market to support a 100% renewable electricity system[2], and the Ministry for Business, Innovation and Employment (MBIE) is considering electricity market measures needed to support the transition to a highly renewable electricity system.[3]

Jurisdictions are recognising the need for new markets for services needed to support grid reliability and stability. All jurisdictions researched are considering what future markets for flexibility services might look like. While Great Britain began with tweaks to existing markets to encourage flexibility, like standardising flexibility products and lowering minimum thresholds to participate in energy and capacity markets, it has identified that flexibility will likely be best delivered by establishing new marketplaces for trade of local flexibility services. There is the potential for DER to provide both wholesale market and local network services, and most jurisdictions are at the phase of assessing and trialling different market designs for DER participation. FERC Order 2222 requires the US system operators to enable DER participation in wholesale markets, and CAISO and PJM are enabling this via aggregators. FERC observed some US jurisdictions were more advanced than others in integration of DER into markets and sought to standardise this through Order 2222. As noted previously, New Zealand is currently at the early stages of considering the need for new flexibility markets.

A second key market reform focus is system services, including reactive power, operating reserves and inertia response. Ireland has implemented a System Services programme to incentivise investment in reserves, ramping and inertia response services, to support operation of very high levels of non-synchronous generation. Great Britain has considered market design for a reactive power market for voltage management, and Australia is considering introducing an operating reserves market. New Zealand has introduced an instantaneous reserve market as part of its ancillary services market, and in 2022, solarZero traded energy grid stability services from its VPP in the electricity reserves market.[4] The Electricity Authority's Future Security and Resilience Roadmap highlights the need to develop suitable market products and tools for system strength, and focuses on procurement tools for managing system inertia, and is part of the programme from around 2025.[5]

Standards are being introduced where consistency is important for the system to operate efficiently and effectively. Several jurisdictions, including Australia, California and Great Britain are introducing technical performance frameworks and/or standards for smart technologies, including appliances, storage and EV chargers, focusing on interoperability, data communications and cybersecurity protection. This is intended to support system operators by facilitating visibility and operability of DER, and to enable customers to more easily provide flexibility services. In New Zealand, there are non-mandatory guidelines for EV chargers for both commercial[6] and residential use[7], as well as for smart homes.[8] Under the Electricity Industry Participation Code, distributed generation with an inverter that complies with AS/NZ Standard 4777.2:20 (which includes minimum operation standards) uses a more streamlined process to connect to the distribution network, though non-complying inverters are still able to connect via a slower process.[9]

Question: What is common across the challenges / opportunities / responses in these jurisdictions? What is unique?

Key Response 3: Increasing levels of coordination are needed between different electricity system players and broader stakeholders

Several jurisdictions researched are considering changes to electricity institutions and governance to achieve desired future outcomes. All jurisdictions researched have identified new and enhanced capabilities needed at the distribution level to manage the increasingly dynamic distribution system. Great Britain and California in particular have been actively considering emerging DSO models, and the potential need for an independent organisation to undertake DSO roles (such as distribution market facilitation). All jurisdictions researched are considering the emerging role of the 'DER aggregator', who might be taking on this role and how this role might operate alongside other parties in transmission and distribution systems and markets (and the rules and regulations needed to support this). In Great Britain, Ofgem is in the process of establishing a new role of a Future System Operator (FSO). This is in response to a range of challenges it has identified, including accountability for cross-energy vector (i.e. electricity, gas and emerging energy technologies) and cross-geography planning, lack of consistency and potential conflicts of interest within current roles. While this is currently at consultation stage, the FSO is proposed to have the following key functions:

- An independent Regional System Planner (RSP) role, supported by regional offices / capability, who will develop and own a regional whole system strategic plan covering all distribution and transmission in that region and coordinate local actors – the RSP's work will inform local network planning by distributors
- Develop market rules and standardised products and facilitate local flexibility markets – distribution network operators would still be responsible for real-time network operations, including procurement and dispatch of flexibility

In New Zealand, the Electricity Authority has identified potential capability and capacity limitations of existing distributors, as well as potential conflicts of interest when utilising and competitively procuring non-network solutions.[1] It has flagged the potential for one (or more) new DSO entities as a separate party to network operators[2], but it has acknowledged that there does not seem to be consensus on the meaning of DSO or how the DSO function might operate in New Zealand.[1]

Increased coordination across the electricity value chain and with the broader energy system has been identified as an important feature of a future system. One of the key drivers for Ofgem's proposed electricity governance changes is to improve coordination between the national, regional and local systems, as well as beyond electricity with other vectors like gas, heating, transport and new technologies. The proposed independent FSO therefore has a national and regional coordination role across electricity, gas and new energy technologies like hydrogen. Ireland, where there is one TSO and two DSOs, has a TSO-DSO coordination workplan, focusing on achieving better coordination, visibility, decision-making and integration of new technologies and processes. This includes developing a future DSO-TSO operating model, covering data exchange, operational interfaces and coordination of planning, services, connections and operations. California's DER Action Plan seeks to improve coordination across different distribution utilities relating to grid planning, flexibility, market integration and customer programmes, noting California has also had challenges with dispersed responsibilities for resource adequacy across different organisations. The Nordic countries are considering improving coordination, particularly of flexibility, between TSOs and DSOs and between countries.

In New Zealand, there is one transmission grid operator and 29 electricity distributors, who have differing populations and areas served, challenges, capabilities and regulations they are subject to. Coordination across the large number of operators will be potentially challenging but likely to be important as systems become more complex, decentralised and dynamic.[3] It has been identified that any wind down of gas pipelines, as has been proposed, will need to undertaken in a coordinated manner, particularly with the electricity system, to enable switching to alternative energy sources.[4] The Gas Transition Plan is intended to outline transition pathways for gas. Government has identified the need to develop innovative market structures for hydrogen, with a market intended to be in place between 2025-2030, but it is not yet clear who would take responsibility for this.[5]

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3

Jurisdiction 1: Australia

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1: Maintaining security of energy supply is challenging with a changing generation mix, along with increase in electricity demand

Driver

- By 2040, 70% of the coal fleet in the National Electricity Market (NEM) will be 50 years or older, and will require replacement.[1]
- Electricity generation is the largest contributor to Australia's greenhouse gas emissions, accounting for around 34% of total emissions.[2] Much of the 71% of total electricity generation currently provided by fossil fuels[3] will require replacement with renewables for Australia to meet its emissions reduction targets.
- In 2021, renewables formed more than 30% of total generation in Australia, and this could increase to 82% by 2030.[4]
- Underlying residential consumption is forecast to increase from 57TWh in 2020-21 to 59TWh by 2030-31. Over the same period businesses consumption is forecast to increase from 129TWh to 140TWh in 2030, primarily due to electrification of industry and growth in the commercial and industrial sectors from 2025-26 onwards.[5]
- Extreme weather, including both heatwaves and cold snaps, has led to high demand for electricity for cooling and heating.

Impact

Increasing electricity demand coupled with retirement of dispatchable fossil fuel generation and an increasing share of intermittent renewable generation means Australia will more frequently experience difficulty in matching supply and demand. More than 10,000km of new transmission lines and 9 times the current amount of large-scale renewable generation is needed in coming years to cater to the rising demand and increasingly intermittent supply of electricity.[6]

In the short to medium term, without additional investment, the Australian Energy Market Operator (AEMO) forecasts reliability gaps in South Australia (2023–24), Victoria (2024–25) and New South Wales (2025–26). In the longer term, it forecasts gaps across all mainland regions.[7] New South Wales (NSW) could face a shortfall of nearly 3GW by 2030.[8]

In 2022, an early winter cold snap caused a significant spike in demand, resulting in the AEMO suspending the wholesale electricity market in the NEM.

This has flow-on effects for electricity prices, with winter peaks in electricity prices likely to be exacerbated as coal power generation retires.[9]

Response

The AEMO has forecast that about 9GW of new firming capacity will be required by 2030, and this could climb to 60GW by 2050. The NEM has a strong pipeline of proposed generation and storage projects, totalling three times the current generation capacity, including large-scale solar, wind and batteries. This is coupled with AU$28b of transmission projects.[10]

The Snowy 2.0 initiative, led by the Australian Government, is a major pumped hydro energy storage scheme to help deal with intermittency of renewables and provide security of supply.

Utility-scale batteries are also being used to provide energy storage. The NSW Government has committed to install the 700MW/1400MWh Waratah Super Battery to make up for some of the supply shortfall forecast from 2025-26.[11]

AEMO is also considering establishing an Operating Reserves Market in the NEM to help respond to unexpected changes in supply and demand. The proposal suggests a dispatchable, raise-only service procured in real-time and co-optimised with other energy market services.[12]

To ramp up renewable electricity generation, some States have introduced renewable energy zones to encourage investment.[13]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 2: Managing increasing penetration of EVs may present an opportunity to support grid operations if smart charging and vehicle-to-grid technologies are used to enable EVs to effectively provide flexibility services

Driver

EV sales in Australia tripled from 6,885 in 2020 to 20,665 in 2021. By 2030, EVs are forecast to be cost-competitive with internal combustion engines, and 50% of new car purchases are expected to EVs by 2030.[1]

This growth is supported by regulations and incentives, including rebates and registration exemptions, along with increasing provision of public charging stations.

Currently, there are 291 fast chargers and 1,580 regular charging locations in Australia.[2] This will need to grow to support the projected future fleet of EVs.

Impact

With this continuous rise in EV uptake, the demand for electricity will also increase. Electricity consumption of EVs is projected to be around 5-7TWh in 2030 and up to 40TWh by 2050.[3] EVs could contribute to an increase in overall electricity demand of 3-4% in 2030.[4] By 2039-40, EV charging is projected to represent 2-16% of peak demand, depending on the region.[5]

Unmanaged EV load would add 1TWh of new consumption to the NEM each year from the late 2020s.[6] This will require significant investment in generation and transmission infrastructure and/or use of managed charging to mitigate the demand peaks.

Uncontrolled EV charging can lead to congestion, impact capacity limits and affect power system security. Locally, the potential for concentrated EV charging activity, such as a street where multiple EV owners charge their vehicles when returning from work, might give rise to localised distribution network capacity issues.

EV penetration may result in sustained under-voltage conditions which would deteriorate the service voltage quality in residential low voltage (LV) feeders.

Response

The size of EV batteries in Australia is projected to be 180GWh by 2050, making V2G technology a viable option to support grid operations. In the future, this technology may enable EV owners to participate in wholesale demand response mechanisms and provide flexibility services during peak times.[7] The government is currently looking into options to address gaps and barriers for EV grid and market integration.

An AU$6m project, the Realising Electric V2G Services (REVS) trial, is supporting installation of 51 bidirectional chargers.[8]

AEMO is leading a variety of Distributed Energy Integration Programme (DEIP) working groups and taskforces including two EV taskforces[9] looking to support:

- EV uptake and demand impact modelling
- More detailed system stability modelling
- Evidence-based research to inform public policy and infrastructure planning
- Enabling EVs to participate in energy and services markets
- Targeted, efficient investment in charging infrastructure

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 3: As generation shifts from synchronous to variable inverter-based renewable generation (IBR), the grid operator will need to evolve planning and operation of the transmission system

Driver

Ageing coal plants are exiting the NEM, potentially faster than new renewables and storage projects are coming on-line. At least 8.3GW of coal-fired generation capacity is planned to go offline by 2030, equivalent to 14% of the NEM's total capacity. By 2040, 70% of the coal fleet in the NEM will be 50 years or older, and the deteriorating condition of these plants may lead to more unplanned outages and/or sooner exit than planned.[1] About 3GW of coal-fired generation went offline due to sudden unplanned outages in June 2022, catalysing suspension of the NEM wholesale market.[2]

Instantaneous penetration of renewable generation reached a record high of 57% twice in 2021, primarily from wind and solar. South Australia and Tasmania have operated for periods with 93% and 82% instantaneous penetration of renewables, respectively.[3,4]

Australia is considering what is required for the power system to operate in a future with 100% instantaneous renewables penetration, and AEMO has set a goal to engineer the power system to operate at 100% instantaneous penetration of renewables by 2025.[5]

Impact

New devices like synchronous condensers will need to be deployed to replace the retirement of traditional synchronous generation sources (fossil fuels) due to their ageing condition and to meet emissions reduction targets.

As more renewables and less traditional synchronous generation sources are connected to the grid, this can lead to inadequate levels of system strength and inertia. This relates to the ability of the power system to manage minor fluctuations in supply or demand while maintaining stable voltage and frequency levels. Lack of system strength and/or inertia brings an increased risk of system instability and supply interruptions. South Australia and Tasmania, which have already achieved high renewable penetration, have started to experience inertia and system strength challenges.

In its Engineering Roadmap to 100% Renewables, AEMO states that better sources of firming capacity, system restoration and system strength services are required for an increasingly renewable electricity system. This analysis indicated the equivalent of up to 40 large synchronous condensers may be needed for 100% renewable penetration.[6]

Response

Australia's first synchronous condenser was installed adjacent to Musselroe Wind Farm in Tasmania in 2012. In 2019, the AEMO approved AU$166m for ElectraNet, the transmission network operator in South Australia, to install four synchronous condensers. This was selected as the preferred option for South Australia over sourcing system strength services from existing synchronous generators in the region.[7] Several new renewable generation developments are being required by AEMO to install synchronous condensers to maintain grid operations.

In its 2021 white paper on the Application of Advanced Grid-Scale Inverters, AEMO provided recommendations toward enabling the application of advanced inverter technology to support the NEM as the amount of inverter-based resources (IBR) increases and synchronous generation online reduces.[8]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4: Increasing decentralisation of power is a challenge for traditional grid operations and fit-for-purpose standards, regulatory arrangements, and tools need to be established to operate a secure and reliable system with high levels of DER penetration

Driver

Australia's electricity ecosystem is rapidly transforming towards a decentralised, two-way system, driven by the rapid uptake of household solar generation, energy storage and other DER.

In particular, decreasing costs for rooftop solar have led to an increase in adoption across Australia. In 2021, rooftop solar accounted for 24.9% of Australia's renewable generation and 8.1% of total electricity generation.[1] DER (particularly rooftop solar) could contribute up to 45% of Australia's electricity generation capacity by 2050.[2]

Impact

Significant uptake of distributed solar can reduce operational grid consumption, particularly at times when solar energy is high. According to AEMO's 'Central' scenario, operational consumption is forecast to reduce from 178TWh in 2020 to 163TWh in 2025, largely due to distributed solar uptake.[3]

New services will be needed to operate a power system with a high penetration of distributed PV like providing frequency control ancillary services (FCAS), fast frequency response (FFR) and recovery services, load shifting, and active management of DER.

There is currently a lack of power system security capabilities, suitable DER regulatory and market frameworks and social licence which makes it difficult to integrate DERs fully into the system.

Response

To address the opportunities, and the technical and operational challenges, associated with increasing DER, AEMO has established the NEM DER Programme, a collaboration across government, industry and consumers. AEMO is uplifting its foundational capabilities to be able to forecast, plan and operate a secure and reliable system with high levels of DER penetration.[4] Initiatives to better allow for / incorporate DER include:

- Updating standards and guides to ensure optimal technical performance, energy system security, interoperability and cybersecurity protection
- Developing a database of DER installations (the DER Register) to provide visibility of DER locations and specifications
- Developing tools to understand DER behaviour and address system security parameters such as under-frequency load shedding
- Establishing fit-for-purpose regulatory arrangements, and network and participant responsibilities for managing extreme system conditions
- Developing a 'Control Room of the Future' and Future Operations Framework to identify changes needed to system architecture, data processes and flow, and operational technology tools to support a more dynamic energy system at both transmission and distribution levels[5]
- Implementing an emergency backstop mechanism, enabling AEMO to switch off distributed solar exports when demand falls below supply[6]

The Western Australia Government has also published a DER Roadmap, setting out key actions required over a five-year period. Initiatives include grid support measures, deploying grid storage, piloting time-based tariff structures, enhanced information sharing for consumers and piloting coordination of DER by aggregators.[7]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 5: There is the opportunity to efficiently operate increasing volumes of DER to provide both wholesale and local network services through aggregators and virtual power plants

Driver

Alongside rapid uptake of household solar generation, energy storage and other DER, the increasing affordability and penetration of smart appliances, batteries, smart meters and other digital technologies means both Australia's energy system and consumer expectations have changed.

Rather than electricity being generated by big, centralised power stations, it is now starting to come from millions of homes and businesses. New customer products and services are emerging, such as peer-to-peer energy trading and becoming part of a Virtual Power Plant (VPP).

Impact

While the potential generation from one DER is minimal, if a large number of DERs combine their output, this could provide services similar to a traditional large scale power station. There is the potential for DER to provide both wholesale market and local network services, including providing additional generation and supporting balancing of generation and demand.

However, integrating DER at large scale into the NEM is complicated, as the power system and market frameworks were designed to facilitate one-way trades and flows of electricity. For both consumers and the electricity system to fully realise the financial, environmental and operational benefits of DER investments, energy systems and markets need to facilitate dynamic and bidirectional trade and flows of electricity.[1]

Response

- Project-EDGE is a proof-of-concept DER marketplace being trialled in Victoria that enables aggregated DER to deliver both wholesale and local network support services. The EDGE marketplace enables trade of wholesale market services with AEMO and local market services with the distribution operator. It incorporates communication of operating envelopes from DSO to aggregator, wholesale market interactions and the data exchange required to facilitate trades. A mix of residential, commercial and industrial customers are included. The project is intended to scale to around 1,000 customers or 10MW of DER. The project was initiated in 2020, with platform development and testing occurring through 2022, and operational trials commencing in 2023.[2]
- Project Symphony is a large DER Orchestration Pilot in Western Australia, which has been established to support effective integration of DER into the wholesale electricity market and transmission network. This will orchestrate about 900 DER assets, including rooftop solar, batteries and large appliances, across 500 households and businesses into a VPP totalling up to 9MW of capacity, enabling aggregation and dispatch of electricity generated and stored by DER assets. The pilot will help inform regulation, policy decisions and market arrangements.[3]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 6: Influences on global fossil fuel markets are causing high and volatile energy prices in Australia, requiring new solutions to maintain security of supply alongside maintaining affordability

Driver

Due to the Ukraine war, there has been a global limit or ban on imports of Russian thermal coal, which has impacted Australia in terms of higher prices of imported coal. With limited spare capacity in global thermal coal traded markets, increasing prices for non-Russian thermal coal exports have led to an overall price hike in Australian energy prices, as coal acts a major source of power generation.[1]

Gas shortages have forced some States to turn to diesel generation in order to meet demand, while some industrial production has been reduced in response to volatile gas prices.[2,3] This is prompting calls for a faster transition away from fossil fuels with shortages and volatile prices anticipated to continue.[4]

Impact

High and volatile prices of fossil fuel imports have recently significantly impacted Australian electricity prices. During times of peak demand, the AEMO sets a AU$300/MWh administered pricing cap to limit financial risk during extreme conditions. In June 2022, amid a combination of coal plant outages, fuel shortages, high demand and transmission outages, this price cap was initiated, but was insufficient to cover the short run costs of the majority of electricity generators, leading them to withdraw capacity. The AEMO was forced to suspend the market across the NEM.[5]

Retailers are also exposed to high price risk, and small retailers at times are required to use load shedding to manage supply and prices.[6]

High and volatile prices passed on to consumers may force them to adjust their activity in order to avoid high prices in winter and summer (for example, by using less heating or cooling)[7], however their ability to respond to short-term pricing peaks is limited due to the fixed structure of electricity retail tariffs.

Response

State energy ministers, the Energy Security Board (ESB) and the AEMC have proposed a capacity mechanism (the Capacity Investment Scheme) as a solution to the pricing issues currently being experienced in Australia. This will allow payments to be provided to generators to remain on standby for generation to be dispatched when demand is high and supply is under pressure. This is anticipated to result in AU$10b of investment and at least 6GW of renewable energy generation and storage to stabilise the grid.[8]

Fossil-fuel based provisions are also used to mitigate volatility, including Australia's minimum stockholding obligation (MSO) for industry. The Boosting Australia's Diesel Storage programme made up to AU$260m of grant funding available to help build and maintain domestic fuel storage, to support increasing the country's diesel stockholdings by 40%.[9] The Western Australian Government's Domestic Gas Policy reserves domestic LNG equivalent to 15% of exports for domestic use.[10]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 7: The 'duck curve' effect, resulting from high penetration of residential solar, means system operators are needing to take a more active role in the management of DER

Driver

Australia has one of the highest levels of residential solar penetration in the world. There are over 3m PV installations in Australia, with a combined capacity of nearly 30GW.[1]

Initially, this growth was driven by government incentives such as generous feed-in tariffs. However, even after incentives have been reduced, the scale of the residential market in Australia, coupled with falling PV prices globally has meant installing solar has remained affordable for a large proportion of the population. In addition, increasing electricity prices over the last decade, and in particular the last year, have meant many people in Australia are looking to solar as a way of mitigating the risk of rising retail electricity prices.

When households and businesses can supply more of their own energy with behind-the-meter systems, such as rooftop solar PV units, they demand less energy from the grid. In the 2020-21 financial year, rooftop solar provided 8.5% of total electricity used in the NEM and 13.5% in Western Australia's Wholesale Electricity Market (WEM). AEMO forecasts the installed capacity of residential solar to more than double over the next decade.[2]

Impact

The high penetration of residential solar has led to several challenges for networks and system operators:

- Residential solar has led to record minimum operational demands in the NEM, including a low of just under 14GW in October 2020. A record maximum of 35% of demand was met by rooftop solar. AEMO estimates at least 4-6GW of operational demand is required in the NEM at any given time to maintain system security.[3]
- During periods of high solar production, grid instability can occur, which presents as power factor issues, frequency fluctuations and inflated voltage values that can damage equipment.[4]
- Residential solar can offset demand to the point where power flows on the LV feeders are reversed at times (common when solar share reaches 40% of load[5]). This can result in several integration challenges within distribution networks.[4]

Response

- The updated AS4777 is a standard specifying the performance and behaviour of inverters, including being able to respond to signals sent remotely for shut off or ramp down.[6]
- In the short term, programmes have been introduced to enable rooftop solar systems to be dialled down, including the emergency backstop mechanism enabling the AEMO to switch off distributed solar exports in periods of very low demand.[7] In the longer term the intention is to develop markets where DER, including rooftop solar, actively participates to provide services required by the grid.[8]
- Dynamic Operating Envelopes are being considered by some States, which can vary export (and possibly import) limits over time depending on available capacity.[4]
- The Network Transformation Roadmap outlines the need for networks to have the capability to 'orchestrate' energy flow, including reverse flow, between local LV networks and into higher voltage networks. It also notes the need for networks to have the visibility and the market tools to economically balance energy flows without the need to "build out" constraints.[8]

Question: What are the commonly used / accepted definitions for key systems operation terminology in this jurisdiction?

Definitions

Systems operations	Operational activities required to maintain a safe, secure and reliable energy network.[1]
Network operations	Not defined
System operator	The National Electricity Rules define this as 'a person whom AEMO has engaged as its agent, or appointed as its delegate to carry out all or some of AEMO's rights, functions and obligations'.[2] The AEMC's website describes this as 'a central body that manages an energy network (gas or electricity) to ensure there is a safe, secure and reliable supply of energy to participants and customers'.[1]
Transmission Network Service Provider (TNSP)	A person who engages in the activity of owning, controlling or operating a transmission system.[2]
Network operator	Network operators in Australia are responsible for maintaining the assets (towers, substations, poles, wires and pipes) that make up the distribution network and which supply gas and electricity to almost end users. They can be privately held, public or a mix of both.[3]
Distribution Network Service Provider (DNSP)	A person who engages in the activity of owning, controlling or operating a distribution system.[2]
Distribution System Operator	The National Electricity Rules define this as 'a person who is responsible, under the Rules or otherwise, for controlling or operating any portion of a distribution system (including being responsible for directing its operations during power system emergencies) and who is registered by AEMO as a Distribution System Operator'.[2] Energy Networks Australia define this as 'a DSO undertakes the conventional role of a distribution network owner but would also make full use of smart techniques to create value for the wider electricity system'.[4]
Distribution system operations	Not defined
DER Coordination	Coordinating and optimising the operation of DER to meet various needs of the power system between bulk power system and distribution operators and DER market participation.[5]
DER Orchestration	DER aggregator coordinated behaviour enabling large numbers of distributed resources to act as if they are one virtual resource.[5]

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4

Jurisdiction 2: Great Britain

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1: Electricity demand is increasing significantly, and there is an opportunity to defer grid investment, and ultimately lower prices for consumers, by harnessing the potential of flexible generation and demand

Driver

Electrification of heat, transport and industry is increasing electricity demand which is creating a need to increase the capacity of generation, transmission and distribution infrastructure. This increase in demand is not necessarily an increase in baseload, but an increase in peak demand.

According to Ofgem estimates, peak demand is estimated to rise to approximately 90-105GW by 2035, up from the current peak demand of 55-60GW.[1] The government's heat pump sales target (which is to reach 600,000 by 2028) could add 14TWh to electricity demand by 2030.[2]

Impact

If a traditional approach is taken to respond to increased peak demand, significant upgrades would be required to generation, transmission and distribution infrastructure, which would put significant upwards pressure on prices for consumers.

Ofgem estimates that deploying low carbon flexibility, including storage, demand-side response (DSR) and interconnectors instead could save up to £10b per year by 2050.[3]

Response

The electricity industry adopted a 'flexibility first' approach in 2018 to actively consider flexibility solutions alongside grid reinforcement.[4]

- The UK government and Ofgem have published the Smart Systems and Flexibility Plan, outlining numerous commitments to enhancing flexibility (see next slide).[5]
- The Department for Business, Energy and Industrial Strategy (BEIS) announced £65m through its Flexibility Innovation Programme to enable large-scale widespread electricity system flexibility, including marketplace and trading platform development.
- UKPN launched its largest flexibility tender, aiming to unlock 500MW of capacity and save £400m of network investment.[6]
- Demand Flexibility Service (DFS) allows National Grid (the system operator) to work with retailers or other aggregators to offer flexibility services directly to end consumers.[7]
- Ofgem is exploring options to support more large industrial and commercial consumers to provide DSR, such as availability payments. Ofgem's research indicates there may be potential for 3GW reduction in demand.[8]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1 (continued):	Electricity demand is increasing significantly, and there is an opportunity to defer grid investment, and ultimately lower prices for consumers, by harnessing the potential of flexible generation and demand

Response (continued)

The Smart Systems and Flexibility Plan sets out actions to enhance the ability to harness flexibility across four key areas[1,2]:

1. Facilitating flexibility from consumers:
   - Supporting deployment and use of smart technologies (including a technical framework), while protecting consumers (e.g. embedding cybersecurity)
   - Removing barriers to the provision of consumer flexibility services (e.g. technical frameworks / standards)
   - Increasing use of smart tariffs, including for smaller consumers (supported by half-hourly settlement)
   - Appropriate regulation for flexibility service providers (e.g. for the 'load controlling' role)
2. Removing barriers to flexibility on the grid, including electricity storage and interconnection
   - Addressing policy and regulatory barriers to storage, especially small and large scale (e.g. cost exemptions, simplifying planning permissions)
   - Facilitating increased interconnector capacity and efficient and flexible access to cross-border markets
   - Developing a non-mandatory technical specification for Grid Forming and Virtual Synchronous Machine capability, including inertia, and consulting on Reserve Product Reform
3. Reforming markets to reward flexibility
   - Electricity market arrangements to unlock flexibility (e.g. lowering minimum thresholds to participate in the energy and capacity markets)
   - Obligations for DNOs to procure flexibility where this is a cost-effective alternative to network build, with a consistent set of flexibility products from 2023
4. Digitalising the system, including a smart meter policy framework, aiming for consistent market-wide roll-out of smart meters, including enhanced functionality (e.g. greater precision to control loads like EV charge points)

A consultation on The Future of Distributed Flexibility was released in early 2023. This outlines three proposed common digital energy infrastructure archetypes:

1. The 'thin' archetype – a directory that lists market operators and flexibility providers
2. The 'medium' archetype – an exchange platform that hosts multiple markets to facilitate and coordinate market participation and operation
3. The 'thick' archetype – a central platform that contains multiple markets, undertaking every step of the market process and co-optimising across them

The paper provides a preliminary assessment of the three options against delivery of core functions, useability and feasibility. It also outlines initial delivery considerations, including delivery model, ownership and financing options.[3]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1 (continued): Electricity demand is increasing significantly, and there is an opportunity to defer grid investment, and ultimately lower prices for consumers, by harnessing the potential of flexible generation and demand

Timeline: Flexibility

2015

In January 2015, Ofgem published an open letter explaining the launch of a new flexibility project to develop Ofgem's strategy to enable and enhance the efficient provision and use of flexibility across the supply chain.

In September 2015, Ofgem published a position paper that set out the scope of the work triggered by this open letter and outline priority areas of focus.

2016

Ofgem published a "Call for evidence" on how the government and the regulator can create the right environment for consumers to benefit from a smarter, more flexible energy system at its fullest potential.

2017

The government and Ofgem published the initial Smart Systems and Flexibility Plan to enable a flexible system by[1]:

- Enabling participation of storage and demand side response in the capacity market
- Enabling participation of customers in the demand response market
- Setting up open network projects with the Energy Networks Association to outline a roadmap for the DNO to DSO transition.

2018

Metering requirements for DSR were simplified.

Revenue stacking between capacity market and balancing services was allowed.

DNOs committed to opening up network requirements to markets and competition from May 2017 to July 2018.

2019

DNOs issued tenders for flexible solutions, creating revenue for non-traditional options like storage, DSR, and energy efficiency. This is part of the shift from DNOs to DSOs who actively manage networks, using innovative solutions to avoid reinforcement. Ofgem's regulatory / pricing framework supports this.

DSOs have committed to coordinate with the ESO to prevent conflicting signals across the energy system.

2020

DNOs advertised 2GW of distribution flexibility services, resulting in £15m worth of contracts.

Various platforms for flexibility markets have emerged, simplifying participation for potential providers.

Smaller-scale assets now participate in balancing mechanisms, including EVs and domestic batteries.

2020-2021

Ofgem has awarded funding to all DNOs to carry out flexibility pilots and enable the development of local market flexibility. For example, Flexible Power is a collaboration between Western Power, SP Energy Networks, Northern Power Grid, SSEN, and Electricity Northwest.

The government and Ofgem published an updated Smart Systems and Flexibility Plan outlining numerous actions to continue enhancing flexibility.

2023

Ofgem published a consultation document on The Future of Distributed Flexibility, outlining that a coherent ecosystem that enables DER flexibility is unlikely to emerge organically fast enough to keep pace with DER uptake.

The document proposes three archetypes for a common digital energy infrastructure, from a directory of flexibility providers through to a central platform containing multiple markets.[2]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 2: Maintaining security of supply is a challenge in an era where there is 100% penetration of renewables, and Great Britain is deploying a combination of storage, interconnectors and demand side response

Driver

Renewable electricity generation is at the centre of the UK's strategy to reach net zero by 2050. The government has set energy providers a target for all electricity to come from 100% zero-carbon generation by 2035.[1] A significant portion of this generation is likely to come from renewables, particularly wind and solar; the government has set targets to increase both solar and offshore wind capacity to nearly five times the current operational capacity.

Increasing penetration of intermittent renewables (like wind and solar) is driving the need to deploy new solutions to manage this intermittency and integrate renewables without incurring reinforcement costs. Intermittent generation disrupts conventional methods for planning the daily operation of the electric grid. Growing wind and solar capacities can also lead to overcapacity which requires the development of flexible assets to store excess production.

Impact

As fossil fuels are replaced by intermittent renewables for electricity generation, there is a growing need to manage the intermittency of renewables to maintain the security of electricity supply. If a traditional approach is taken, the burden of maintaining system reliability falls mostly on the flexible operation of thermal generation units, such as coal and natural gas, but this is inconsistent with the UK's aspirations to reach net zero.

According to research conducted by Aurora Energy research (consultancy based in Oxford), up to 46GW of energy storage will be required to manage renewable intermittency to achieve the net zero emission target for electricity by 2035, including around 24GW of longer duration storage, up to weeks and months.[2] However, such long-duration zero-carbon storage is not currently widely available, with pumped hydro being the only option currently fully market ready. System operations will be required to play a role in managing intermittency, especially in the short-term as storage capabilities grow.

Response

The UK's Climate Change Committee[3] recommends three alternatives to manage intermittent generation: deploying storage, building interconnectors, and enabling DSR. Considerable efforts have been made to enable these solutions:

- In 2022, Ofgem released a consultation document to facilitate the deployment of large-scale and long-duration electricity storage by understanding current barriers from industry participants.[4] BEIS has awarded funding of £32.9m for development of new storage technologies.[5]
- Interconnectors with Europe will be a key pillar in managing intermittency. National Grid indicates the net benefits of 8-9GW of interconnection could be as much as £3m per day.[6] In 2021, BEIS committed to work with European developers to double interconnector capacity (18GW) by 2030.[7]
- Ofgem has taken a number of actions to support DSR, including enabling industrial and commercial consumers to participate in demand response markets (per the previous slide).[8]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 3: Maintaining grid stability is a challenge in an era where there is 100% penetration of renewables, and Great Britain is deploying trialling new mechanism to provide reactive power services

Driver

Intermittent generation fluctuations over multiple time horizons can cause the frequency and voltage of electricity systems to fluctuate.

The next decade will bring changes in consumer demand patterns and electricity generation and distribution modes. The use of EVs, heat pumps, and distributed solar is increasing, causing an exaggerated difference between minimum and maximum loads on LV feeders that are not always on the same feeders at the same time. This necessitates an increase in voltage regulation further down the network.[1]

Additionally, current grids rely heavily on the rotating turbines and generators in conventional power stations to provide frequency stability. As renewable sources lacking rotating inertia replace these conventional sources, alternative methods will be necessary to maintain frequency stability.[2]

Impact

Reactive power services have traditionally been used by the National Grid to regulate voltage fluctuations on the system. This has been accomplished by instructing generators or other asset owners to absorb or generate reactive power to keep voltage levels within a specific range. Traditionally, these services were provided by fossil fuel-powered plants. However, with the shift to renewable energy sources, renewable sources will need to provide reactive power services.

According to a trial conducted by National Grid ESO and UKPN, savings of up to £100m could be made with the introduction of a national reactive power market.[3]

Response

- In October 2020, National Grid conducted a trial with UKPN to showcase how wind, solar and battery storage can provide market-based reactive power services. The trial, part of the Power Potential project, provided reactive power services across Kent and Sussex and unlocked 1.5GW of capacity in the southeast.[3]
- DSOs, such as Western Power Distribution, are exploring the use of flexibility services at the distribution level to address voltage regulation issues.[4]
- The National Grid is investigating the use of battery storage to offer frequency regulation services. In October 2020, the system operator launched its new fast frequency response service, 'Dynamic Response,' to quickly respond to energy flow disturbances around the grid and keep the system close to 50Hz. In the first round of the tender process, six tenders were received, and two battery energy storage units were accepted to provide 90MW of fast response services over 24 hours.[5,6]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4: There are potential barriers to the existing electricity and gas system operators adopting the capabilities needed for the future energy system, including ownership / operation conflicts, balancing shareholder and consumer interests and achieving cross-sector coordination, and an independent 'future system operator' is proposed

Driver

Great Britain's energy system is split into two areas, electricity and gas. National Grid (publicly listed) owns the electricity transmission network, and the Electricity System Operator (ESO) is a legally separate entity within the National Grid Group. This separation (in 2019) was completed to provide greater transparency and confidence that National Grid is not impeding competition.[1] National Gas owns and operates the gas transmission network, as the Gas System Operator (GSO). National Gas was majority owned by National Grid until early 2023, when a majority stake was sold to private owners (Macquarie Asset Management and British Columbia Investment Management).[2]

Both the ESO and GSO have insight into system operation with engineering, technological and system expertise. However, to reach net zero emissions by 2050, while ensuring affordability and security, there is a need for a step-change in whole system coordination, planning and strategy, as well as new system operation capabilities. This includes real-time system balancing, greater coordination and planning of the network, effective use of data and digitalisation and a whole-energy system view (including emerging technology like hydrogen).[3]

Impact

A review by Ofgem of Great Britain's energy system operations identified potential barriers to the existing system operators being able to perform the functions needed to get to net zero[3]:

- Potential asset ownership conflicts of interest (e.g. perception of lack of independent advice, overinvestment in the transmission network, possible bias in facilitating competition) – for example, National Grid could use its system operator role to over-procure capacity or favour generation over demand response for the benefit of its asset owning business – but there is no evidence of this conflict being acted on[4], and analysis demonstrates the likelihood of conflict arising is low[5]
- Challenges aligning the commercial interest of the system operator's shareholders with consumer interests (e.g. limited appetite for risk taking in complex areas, short-term focus driven by corporate reporting cycles)
- Discrete electricity and gas system operation frameworks impacting coordination and the development of cross-energy sector expertise

Cost-benefit analysis indicates an independent body coordinating across electricity, gas and hydrogen can provide benefits of up to £2.8b.[6]

Response

In April 2022, BEIS/Ofgem agreed to establish a Future System Operator (FSO) by 2024[7] after gaining broad support across all categories of stakeholders, with a common recognition that net zero creates challenges that demand a more strategic and independent body to focus on and accelerate the transition. The future FSO will manage trade-offs and synergies between achieving net zero and ensuring security of supply, efficiency, and affordability, across different energy vectors.

The proposed FSO will be a transparent, unbiased body with the remit and expertise to meet Great Britain's energy goals. It will be a public corporation with operational independence from the government and transmission owners.[8]

The FSO remit will extend across electricity, gas and emerging technologies (e.g. hydrogen and carbon capture), and roles will include future network planning, long-term forecasting, market design and development (including for new markets like hydrogen), and managing those markets in real time.[4]

The FSO role will be at the transmission level, but they may have a role in setting frameworks and standards for distribution.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4 (continued):	There are potential barriers to the existing electricity and gas system operators adopting the capabilities needed for the future energy system, including ownership / operation conflicts, balancing shareholder and consumer interests and achieving cross-sector coordination, and an independent 'future system operator' is proposed

Timeline: Future System Operator

2019

Parliament approved legislation requiring the UK to bring all greenhouse gas emissions to net zero by 2050.

National Grid ESO became a legally separate entity of the National Grid Group to address potential concerns about transparency and promoting competition.

2021

The UK government announced a world-leading climate change target (the sixth carbon budget).

Ofgem identified that the transition to net zero will require a more integrated energy system and new capabilities across both electricity and gas. Barriers to the existing system operators adopting these capabilities included conflicts of interest, balancing shareholder and consumer interests and achieving cross-sector coordination.

2021

BEIS and Ofgem launched a consultation to propose the development of a FSO, based on:

- The new functions emerging from system changes and integration
- Greater coordination required to make effective use of technologies and resources
- Key strategic decisions needing to be informed by whole-system insight and impartial, technical advice.

2021

The BEIS/Ofgem consultation ran from July to September 2021. Consultation indicated broad support for the government's proposals to establish an independent FSO. Following consultation, the government and Ofgem jointly published the FSO consultation response, which sets out the government's commitment to proceed with the creation of the FSO.

2023

Ofgem released further consultation on the Future of Local Energy Institutions and Governance, further clarifying roles for the FSO at the regional and local levels. This includes establishing Regional System Planners within the FSO framework, to be responsible for cross-regional network planning, as well as facilitation of local flexibility markets.

2024

The FSO could be established by 2024, with new roles and capability being introduced in a phased approach. Primary and secondary legislation is required to create the new public corporation; therefore, these timelines are subject to change.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 5: Great Britain's DNOs are currently facing a challenge to transition from their traditional role towards dynamically operating and managing the distribution network, which is needed to manage increasing penetration of DER and two-way flows

Driver

The grid is becoming decentralised, resulting in two-way energy flows. This is driven by significant growth in DER, including distributed solar panels, as well as evolutions in small-scale battery storage and smart devices. Consumers will no longer be just passive users of electricity but active contributors to the operation of the electricity grid.

Great Britain is not currently at the point of DER penetration being high enough to require the DSO role, but is preparing for this in the future.

Great Britain's existing DNOs have traditionally been responsible for one-way flows of electricity from the transmission grid to consumers, with limited balancing roles, so this is a significant change.

Impact

To support increasing distributed generation, demand response and EVs (including vehicle-to-grid capabilities), distribution networks need to develop capabilities that can[1]:

- Streamline the connection process for DER (including EV chargers)
- Improve their forecasting capabilities for dynamic power flows across their network
- Enable them to operate their networks dynamically to maximise the hosting capacity and respond to changing situations
- Integrate the procurement of flexibility services into how they operate the grid and plan for grid development.

DNOs will be required to procure flexibility in the first instance, and only build out the grid if there are insufficient flexibility services available to manage constraints.

Response

Ofgem published a position paper to outline the responsibilities of the future DSO. The transition to DSO was also enabled by incentives offered by Ofgem. For instance, under RIIO-ED1 (the price control for the electricity distribution network), an incentive of £70m of funding per year has been offered under the National Innovation Competition Scheme.[2] This comes at the time when all DNOs are preparing regulatory plans for the next five years.

As a result, all of Great Britain's DNOs have set out their roadmaps for transitioning to a DSO. There are diverging views about what this looks like among the six DNO owners.

One DNO, UKPN, has laid out five priority areas[3]:

- Facilitate cheaper and quicker connections
- Enable flexibility
- Develop enhanced System Operator capabilities
- Collaborate with industry and others to enable GB wide benefits
- Prepare and facilitate the uptake of electric vehicles

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 6: Great Britain is considering the most appropriate arrangements for distribution system operations, including addressing potential (perceived or actual) conflicts of interest associated with DNOs performing DSO functions

Driver

Ofgem considers current local energy governance arrangements are not fully fit for purpose given the energy system changes that are needed to deliver net zero. To support a transition to a net zero economy there will need to be significant new investment in network infrastructure at the distribution level, as well as trade of flexibility services to minimise the need for large-scale infrastructure. Trade of flexibility services at scale should make the whole power system more efficient.

Impact

Future distribution system operations will require long-term planning, market facilitation of flexible resources and real time operation of flexible networks. There is a (perceived or actual) conflict of interest if DNOs as asset owners perform these roles[1]:

- On network planning: DNOs could be, or are perceived to be, conflicted in decision making between short-term flexibility deployment and long-term asset upgrades. DNOs earn regulated income for owning and maintaining distribution networks, which could incentivise more network build.[2] DNOs may also have a technical / risk bias toward asset solutions, causing under-utilisation of flexibility.[3]
- On flexibility markets: A neutral market facilitator owning a valuable, contributing asset like the distribution network inherently does not provide a level playing field.[2] Such conflicts (or perceptions) could limit the growth of the flexibility market.[3]

Great Britain initially sought to resolve conflicts through enhanced transparency and internal separation of DSO / DNO decision-making, but the position remains that DNOs taking on long-term planning and market facilitation roles is not a fit-for-purpose model.[1]

Response

In April 2022, BEIS and Ofgem launched a call for input, proposing four alternatives for local / regional system arrangements[3]:

- Internal separation of DSO roles within DNOs
- Independent Distribution System Operator (IDSO), a new independent institution to take on DSO roles
- Regional System Planner and/or Operator, a regional institution to take on DSO roles as well as wider cross-vector planning roles
- Interacting organisations, where DSO roles are dispersed between different organisations (e.g. regional / local).

In March 2023, Ofgem proposed preferred new institutional and governance arrangements to remove the potential bias of DSO being the asset owner and operator, namely[1]:

- Energy system planning: Introduce new Regional System Planners (RSPs) as local branches of the new FSO, to ensure there is accountability, independence and specialist cross-vector planning skills in regional energy system planning
- Market facilitation of flexible resources: Assign a market facilitation function to the new FSO, as a single entity with sufficient expertise and capability, to deliver more accessible, transparent and coordinated flexibility markets. It is proposed that the FSO would facilitate a single distribution level flexibility market platform that DNOs would use to procure local flexibility services. This is seen as more efficient than each DNO running their own separate flexibility markets. It also removes the perceived conflict of interest associated with the DNO running those markets.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 7: As the vehicle fleet transitions to EVs, Great Britain is identifying how to manage EV charging to limit the increase in peak demand and therefore limit the capacity increase needed

Driver

In 2020, the UK government committed to phase out the sales of new petrol and diesel cars and vans by 2030, and that all new cars and vans will be fully zero emissions from 2035. Estimates by Ofgem indicate that EV charging could add between 90-105GW of peak demand by 2035.[1] As a result, the transition to EVs will not only need charging infrastructure but will also require additional grid capacity and changes to grid operations.

Impact

To manage the potentially significant increase in peak demand associated with EV charging could require significant investment in increasing generation, transmission and distribution capacity. Grid operations will play a role in managing EV charging to limit the increase in peak demand and therefore limit the capacity increase required.

This includes enabling smart charging by deploying V2G technology or introducing smart tariff programmes. Research has shown the V2G technology has the potential to save £3.5b per year in areas such as grid infrastructure reinforcement, storage and generation, as a result of the support it offers during periods of increased energy demand.[2]

Response

BEIS and Ofgem are working together to enable the development of smart charging infrastructure in Great Britain:

- In January 2023, they published the Electric Vehicle Smart Charging Action Plan, to make smart charging the preferred method of long duration charging by 2025.
- £16m in funding has been made available to support EV smart charging technologies under the Net Zero Innovation Portfolio.[3]
- Great Britain's DNOs, including WPD, UKPN and SSN, have laid out their EV charging strategy as part of their business plans and have been carrying out V2G trials to demonstrate benefits. WPD carried out a project worth around £3m to explore and report on the impact of V2G charging on the LV network utilising end-user charging data.[4]
- The UK government consulted on consumer experiences with EV public charging. Recommendations from this included introduction of smart charging and tariff mandates (all chargers must be smart and have default setting to charging off-peak).

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 8: As heating of homes and businesses shifts from fossil fuels to electricity, network operators are identifying how to manage increasing electricity demand, often coinciding with existing peaks, without straining the grid

Driver

Decarbonising energy used in buildings is a key part of the UK's Clean Growth Strategy. There are about 30m buildings in the UK. In total, these buildings are responsible for around 30% of UK national emissions. Most of these emissions result from heating, which contributes 79% of building emissions and about 23% of all UK emissions.[1] Over 90% of UK homes are heated by fossil fuels, accounting for a third of UK total gas use.[2] This means households are particularly exposed to gas price volatility.

Decarbonising heat calls for improving energy efficiency of buildings, changing the way buildings are heated and cooled (especially by electrifying these processes) and improving the performance and efficiency of energy-related products.

Impact

A number of initiatives are being taken to decarbonise heat and buildings, including[1]:

- Providing £5,000 grants to consumers installing an air source heat pump
- Increasing the supply chain to install 600,000 hydronic heat pump systems per year by 2028.

Electrifying heat and installing heat pumps increases electricity demand, and particularly can cause significant spikes in peak demand (for example, on cold evenings). Customers are not subject to any cost-reflective temporal tariffs in the UK to encourage customers to manage their electricity consumption for heating in response to changes in supply and demand.[3] This has impacts on the capacity requirements of generation, transmission and distribution.

Response

Great Britain's DNOs are exploring ways to avoid the peaks of grid strain and shift heating loads to times when the grid can accommodate it.

- National Grid requires customers installing electric heat pumps to notify their DNO and provide them with technical data. This enables the DNO to confirm there is sufficient grid capacity to support the installation.[4]

Innovative solutions are in research phases:

- BEIS launched the Interoperable Demand Response programme in 2022, supporting development of energy smart appliances for domestic consumers, and a framework for participation in small-scale DSR.[5]
- The Energy Superhub trial was launched in Oxford in 2019, deploying 300 ground source heat pump systems along with grid-scale battery storage. Software is used to optimise the trading of battery storage with the timing of heat pump activation.[6]
- The Customer-Led Network Revolution project, jointly led by grid and research participants, tested time-of-use tariffs, load control incentives and direct load control for heat pump loads.[7]

Question: What are the commonly used / accepted definitions for key systems operation terminology in this jurisdiction?

Definitions

Systems operations	Management of transmission and distribution network operations to manage the grid in real time to deliver electricity from generation to consumers[1]
Network operations	Not defined
System operator	The National Electricity Transmission System (NETS) System Operator is the entity responsible for operating the GB electricity transmission system to ensure optimal flow of energy across the network and for entering into contracts with those who want to connect to and/or use the electricity transmission system[2]
Network operator	A Distribution Network Operator is a company which operates the electricity distribution network which includes all parts of the network from 132kV down to 230V. It is responsible for distribution of electricity downstream from the national transmission grid to consumers. It also maintains and operates the infrastructure involved in electricity distribution.[2]
Distribution system operator	An organisation that does not yet exist in Great Britain, but is being developed. These organisations would manage and maintain distribution-level energy systems, addressing local constraints in a way the current ESO is currently unable to do[3]
Distribution system operations	The engagements undertaken by the distribution network operator pursuant to the operation of the distribution system, being planning and network development, network operation and market development of the distribution system[4] A set of functions and services that need to happen to run a smart electricity distribution network, not necessarily undertaken by a single party[5]
Future system operations	Integrated system operations, with whole system coordination and planning, that enables the transition to net zero and away from fossil fuels while delivering resilience, security of supply, and efficient use of networks[6]
Future system operator	The Future System Operator (FSO) is an independent accountable and expert body that will have 'whole system' roles in operations, strategic network planning, long-term forecasting, and market strategy. The FSO will be independent of asset ownership and other commercial energy interests. The FSO role will cover electricity, gas, and emerging energy technologies (e.g. hydrogen).[7]
Flexibility services	Modifying generation and/or consumption patterns in reaction to an external signal (such as a change in price) to provide a service within the energy system.[8] Great Britain has defined four flexibility services – Sustain (for scheduled constraint management), Secure (for pre-fault constraint management), Dynamic (for post-fault constraint management), and Restore (for restoration support management).[9]
Aggregator	A company or other body that acts as an intermediary between energy asset owners and the flexibility market, acting on the owners behalf. Aggregators can be independent organisations or market actors combining roles.[3] Aggregators have access to the Balancing Mechanism, the real-time electricity market the ESO uses to balance supply and demand.

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5

Jurisdiction 3: Ireland

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1: There is an opportunity to leverage battery storage and other emerging technologies to manage reliability and stability of the system as renewable penetration increases to high levels

Driver

Ireland has committed to halving their greenhouse gas emissions by 2030 and reaching net zero by 2050. The Climate Action Plan sets a target to produce 80% of electricity from renewable sources by 2030.[1]

Ireland is also required to abide by the European Union's Clean Energy Package, which includes policy provisions for energy storage, clarifies the role of storage in the energy system, and facilitates harmonisation of national policy frameworks. Key provisions for storage in the Clean Energy Package include:

- Providing a technology neutral definition of energy storage
- Recognising energy storage as an essential element in the energy transition
- Requiring system operators to move towards market-based tendering of flexibility services and to consider energy storage in system planning

Impact

Much of Ireland's new renewable generation will be from wind and solar, including 9GW of onshore wind, 8GW of solar, and at least 5GW of offshore wind by 2030.[1]

Ireland has recognised that short and long duration storage will be required to help smooth electricity supply and demand between times of high and low variable renewable production and high and low demand, which do not always occur at the same time.

Energy storage helps the integration of renewables at all stages by ensuring that generation is not wasted, reducing oversupply by up to 60%, constraint volumes by up to 90%, and curtailment by up to 100%.[2]

By contributing to security of supply, helping to support renewable capacity, and displacing fossil fuels in the balancing market, Ireland has identified that energy storage can deliver a net saving to end consumers of up to €85m per year.[3]

Response

Ireland's all-country electricity system already has 500MW of connected energy storage, while over 1GW of projects have planning permission.[3]

Ireland has introduced two mechanisms to help incentivise battery storage to connect to the Single Electricity Market (SEM):

- The SEM Capacity Market has been introduced and aims to ensure that sufficient existing and new capacity (including storage, demand side response, and interconnector capacity) is delivered to balance demand and operational security requirements for the short-to-medium term.[4]
- The Delivering a Secure Sustainable Electricity System (DS3) System Services programme incentivises investments in generation that can provide grid-wide services that ensure the power system can operate securely with higher levels of non-synchronous renewable generation (from 75% up to 95% instantaneous penetration). This includes reserves, ramping, and inertia response services from any technology.[5]

Ireland is also reviewing the regulatory treatment of storage including licensing, charging, and other market incentives.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 2: Maintaining security of supply is a growing challenge for Ireland as the system experiences increased demand while fossil fuel power plants are phased out

Driver

The phasing out of fossil fuel-fired power stations, the deteriorating state of older plants, and unplanned technical issues restricting interconnector capacity might create security of supply issues for Ireland. Additionally, natural gas currently provides over 50% of Ireland's electricity and the war in Ukraine has put gas supply under strain, leading the EU to ask member states to reduce gas consumption by 15%. Lack of liquid natural gas (LNG) as an alternative is adding to the challenge.[1] Loss of existing generation capacity is coinciding with strong demand growth, which is forecast to be 180MW/year up to 2025.[2]

Since January 2020, Ireland has received eight system alerts due to periods of very low wind, limited interconnector support from Great Britain, and prolonged outages at two large gas generators.

In addition, approximately 500MW of contracted capacity has failed in its commitment to deliver. In 2021, 365MW of capacity was awarded which has been withdrawn, on top of 266MW previously withdrawn. This means that most new predictable capacity expected to come online over the coming years has now been withdrawn.[3]

Impact

EirGrid is the transmission system operator for all of Ireland. EirGrid analysis of capacity adequacy states an initial deficit position in all scenarios and has identified a potential capacity shortfall of 260MW for 2022/2023, rising to 1,050MW in 2023/24 and 1,850MW in 2024/25.[1]

According to Ireland's utilities regulator, the country may be forced to curb electricity usage to prevent power cuts in the winter months as temporary emergency generators may not be up and running in time.

The Loss of Load Expectation (LOLE) in Ireland for the winter period is 51 hours. The LOLE has increased significantly from 17.4 hours last winter and is well outside the standard of 8 hours per year. There is an expectation that the system will enter the Alert State at times of low wind and low interconnector imports. There is also a high probability of the system entering the Emergency State at times, due to insufficient generation being available to meet demand. Electricity consumers could potentially be without supply for approximately four hours at a time over the winter period.[4]

Response

A review has been launched into the security of supply of Ireland's electricity and gas systems. This has identified a list of potential actions[5]:

- The delivery, through capacity auctions, of over 2,000MW of flexible gas-fired generation
- Procurement of 700MW of temporary emergency generation
- A floating LNG facility to operate during periods of material risk of demand disruption
- An additional interconnector to France
- Investment in additional large-scale renewable storage (hydroelectric, biomass)
- Increased secondary fuel storage beyond the current five-day storage requirement
- Conversion of gas plants to hydrogen
- Extending the operation, on a temporary basis, of older generators
- Enhancing demand side response / efficiency

The Energy Efficiency Obligation Scheme requires larger energy companies to help consumers (residential / commercial) save energy by supporting them (financially or otherwise) to implement energy saving practices or to carry out energy upgrades to their property.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 3: Catering to increasing electricity demand from data centres is an emerging challenge for Ireland, so decisions on their development are being informed by the impact on / benefits to the energy system

Driver

Data centres represent core digital infrastructure for both Ireland's and Europe's digital economies and for strengthening Ireland's position as a strategic international location for IT services. There are currently about 70 data centres in Ireland.[1]

Approximately 1,700MVA of demand capacity is contracted to data centres at the transmission level, and a further 600MVA is contracted at the distribution level. The last 4 years have seen annual increases in electricity demand usage of around 600GWh from data centres alone, equivalent to the addition of 140,000 households to the power system each year. Demand from data centres is forecasted to increase by between 425-1,395MVA by 2030, with data centres representing around 28% of electricity demand.[2]

Electricity demand from data centres will be increasingly difficult for Ireland's electricity system to support, particularly alongside rising demand from electrification of other sectors, including demand from EVs and heat pumps.

Impact

Data centres are anticipated to make up 25-33% of Ireland's electricity demand by 2030, which could substantially threaten security of supply. Many of these data centres require large loads at a specific site. The average data centre connection request to EirGrid is for a capacity of 80MW. This has ramifications not only for the distribution and/or transmission network in that location, but also to power system adequacy at a national level.[3]

In the Dublin region, the transmission system has been extended to cater for additional demand, in particular from data centres, with new substations and transmission works. However, in 2020, the grid enforced a moratorium on new data centre grid connections in the Dublin area, citing the inability of the grid to accommodate facilities and risk blackouts. New requests will not be accepted until significant reinforcement of the transmission network is delivered, through the Power Up Dublin Plan.[4]

Data centres are large facilities and, if managed well, have extensive energy management capabilities and the potential to provide local flexibility services and support the secure and efficient operation of the local electricity system.

Response

EirGrid has introduced new guidelines for data centre connections, requiring them to have on-site generation (and/or battery storage). To support decarbonisation goals, this generation should also be capable of running on renewably sourced fuels (e.g. renewable gas or hydrogen) when supplies become more readily available.[3]

The government has agreed a set of national principles that should inform and guide decisions on future data centre development; preference is for developments that[3]:

- Efficiently use the electricity grid, using available capacity and alleviating constraints (supported by collaborating with respective system operators)
- Provide clear additionality in renewable energy delivery, proportionate to the impact of their energy demand
- Are in locations with potential to co-locate a renewable generation or storage facility
- Provide benefits for regional locations / communities (e.g. through place-making and community engagement)

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4: Ireland can leverage demand side management and flexibility services to avoid costly network upgrades and balance a system with increasing renewable generation and electrification

Driver

Ireland plans to halve their carbon emissions by 2030 and reach net zero by 2050. They are targeting 80% renewable generation by 2030, with much of this coming from new solar and wind generation. This is coupled with significant electrification, including of transport, heat and industry.[1]

Meeting these targets will require approximately 22GW of additional renewable generation capacity, and corresponding upgrades to the grid, but it is also essential to activate demand side management to enable matching of supply and demand without significant overbuild of renewables. As a result, Ireland has set a target for 15-20% of electricity demand to be flexible by 2025, and 20-30% to be flexible by 2030.[1]

Impact

Ireland has analysed the impact of introducing demand side response and/or flexibility services by reviewing international markets. According to ESB Network's Flexibility Market Development Plan, flexibility services can provide the following benefits in future[2]:

- Provide generation and demand customers with quicker and lower cost connections
- Reduce dispatch down of renewables
- Manage local security of supply
- Manage short circuit level challenges
- Manage dynamic stability
- Support customers maintaining supply under extreme weather / storm conditions.

Response

Tariff-based schemes are currently used to encouraged consumers to move their usage to cheaper off-peak times. Examples include Economy 7 (Northern Ireland) and NightSaver (Ireland). EirGrid also operates two system operator-based schemes aimed at large electricity users: Short Term Active Response (STAR) and Powersave, which are used to keep the system secure at times when the system is stressed.[3]

In addition to customers individually participating in the electricity market, medium to large electricity users can participate in a Demand Side Unit (DSU) or Aggregated Generating Unit (AGU). A DSU consists of one or more demand sites that can reduce their demand when instructed by the grid operator. The DSU must be capable of responding within one hour and maintaining demand reduction for at least two hours. An AGU consists of one or more small (under 10MW) generating units who can aggregate generation and sell it into the SEM.

Currently Ireland does not have an operational flexibility market. ESB Networks, the distribution network owner and operator across the Republic of Ireland, has started a National Local Connections Programme under which it is proposing a multi-year flexibility programme. ESB will develop a flexibility platform to enable consumers to use DER to participate in flexibility markets and to offer services to both Ireland's TSO and DSO.[4]

Ireland's utilities regulator has granted an initial provision of €16.9m to further facilitate the use of flexibility to address medium or high voltage reinforcement needs.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 5: Electrification of transport will add significant load to Ireland's electricity network, but the impact on the grid can be reduced with smart charging and demand management

Driver

Transport accounts for one-third of Ireland's energy-related greenhouse gas emissions. The drive for decarbonisation, along with oil scarcity and price volatility, is leading Ireland to electrify transport. Ireland has set a target for there to be 180,000 EVs in Ireland by 2025, and 936,000 EVs by 2030. This is being enabled through grants for EV purchase and home charging and tax relief for EVs.[1,2]

The pace of EV uptake has been accelerating over recent years. In 2021, more than 16,000 EVs were registered. accounting for around 16% of new vehicle registrations.[3]

EU targets and requirements also apply to Ireland – from 2035, sale of cars or vans with internal combustion engines will not be allowed.[3]

Impact

Electric vehicles will have a significant impact on electricity demand. The electricity demand from EV charging is anticipated to be 40,000MWh per week in 2030. The grid, particularly the distribution network, will need to cope with near exponential growth in EVs. Unmanaged charging could result in voltage deviations and heavily loaded grids could become bottlenecks during the EV rollout.[4] By 2050, EVs could account for nearly 16% of Ireland's electricity demand, one of the higher proportions in Europe.[5] The EV Charging Infrastructure Strategy will see €100m spent on public charging infrastructure over the next three years.

Response

Initiatives to manage the impact of EV charging on the electricity system include:

- Ireland has considered off peak charging as an effective way to reduce demand, and static time-of-use tariffs are being used to encourage this. Overnight charging can cut costs by 80% compared to daytime charging, with off-peak rates as low as 6 cents/kWh (during the hours of 2-5am), while peak charging rates are almost four times as high at 32 cents/kWh.[6]
- The Home Charger scheme, which provides grants for installing EV chargers, will only support smart chargers to help prevent excessive electricity demand and facilitate better integration with renewable energy sources.[7]
- Government is working closely with the Sustainability Energy Authority of Ireland (SEAI) to launch a funding scheme for apartment buildings. Consideration will be given to innovative EV charger technology developments, such as smart charging and V2G technologies, that have the potential to regulate electricity demand.[7]
- ESB Networks is using IBM's Intelligent EV Enablement Platform to operate and manage smart chargers installed throughout Ireland (initially, public charge points only).[8]
- ESB Networks is also testing control systems to coordinate real-time network data with smart EV chargers on very short timescales (down to one second) to support supply-demand balancing and emergency response.[9]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 6: Obtaining maximum whole-of-system benefit from increasing DER penetration requires a system level approach for coordination between the TSO and DSO

Driver

Achieving the significant changes required to Ireland's electricity system over the next decade(s) requires the transmission operator (EirGrid) and the two distribution network operators (ESB Networks and NIE Networks) to work closely in coordination with each other. In particular, there will be increasing generation, storage, and flexible demand at the distribution level, which will require data sharing and collaboration between the TSO and DSO to balance the system and ensure generation and capacity adequacy.[1,2]

In 2021, ESB Networks launched the National Network, Local Connections Programme (NNLC), in collaboration with stakeholders from across the energy sector and broader Irish society. The programme enables and drives all customers' active participation in local and system wide services. DSO-TSO coordination is central to ensuring that NNLC is delivered in a coordinated and collaborative manner.[2]

Impact

Joint coordination between the TSO and DSOs has been identified to deliver the following benefits[2]:

- Improved monitoring and visibility
- Better decision support for the system operators, over time contributing to greater supply reliability
- Improve Ireland's capability to manage security, congestion and renewables penetration at a local level and alleviate transmission constraints
- Enable distribution customers to participate in wider markets and provide a more efficient and flexible market
- Facilitate integration of new technology, systems and processes
- Enable more efficient dispatch and better mitigation of voltage-based constraints through improved coordination of reactive power

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 6 (continued):	Obtaining maximum whole-of-system benefit from increasing DER penetration requires a system level approach for coordination between the TSO and DSO

Response

A Joint System Operation programme was introduced by EirGrid in 2021 to ensure that the system operators are working together in a collaborative and effective manner to jointly address electricity system needs and deliver whole of system solutions.[1] The multi-year programme is broken down into four key areas:

1. Whole System Approach, including the following initiatives:
   - The development of a future DSO-TSO operating model, covering data exchange, operational interfaces and coordination of network planning, local and system services, connection rights, scheduling and dispatch and emergency states
   - Improved visibility and monitoring through enhanced control centre capabilities
   - Evolution of the grid code and distribution code to meet the future system needs
2. Facilitating New Technology and System Services, including the following initiatives:
   - Piloting the DSO's use of local flexibility services to manage local congestion
   - Domestic and commercial behavioural demand response campaigns, using different mechanisms to reward customers reducing demand during peak
   - Testing technical modalities (registration, qualification, dispatch arrangements) of distribution customers in the TSO system services market
3. Reducing Dispatch Down of Renewable Generation, including the following initiatives:
   - Improving DER visibility, forecasting and modelling
   - Improving wind and solar generation forecasts
   - Improving DSO-TSO coordination on constraints and reactive power management (improved utilisation of reactive power capabilities on the distribution network and coordination of reactive power exchanges at the DSO-TSO interface)
4. Secure Power Systems, including the following initiatives:
   - Protection settings for largest customers
   - Review of power system restoration processes and black-start technologies

Question: What are the commonly used / accepted definitions for key systems operation terminology in this jurisdiction?

Definitions

System operations	Not defined
Network operations	The ability of the network to operate, control and communicate the volume of electricity, forecast and manage the network load to maintain network security and capacity limits[1]
System operator	Ireland's system operator delivers connection, transmission and market services to electricity generators, suppliers and customers utilising the high voltage electricity system[2]
Distribution system operator	The Distribution Code defines the DSO as being responsible for operating and maintaining a secure, reliable and efficient electricity distribution system (which transports electricity to or from the transmission system or from generating units to the final customer.[3] Note, the code does not define a Distribution Network Operator. NIE Networks, in their DNO to DSO evolution, defines a DSO as an entity that securely operates and develops an active distribution system comprising networks, demand, generation and other flexible DERs. As a neutral facilitator of an open and accessible market it will enable competitive access to markets and the optimal use of DERs on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation. A DSO enables customers to be both producers and consumers, enabling customer access, customer choice and great customer service[4]
Distribution system operations	Ensuring efficient operation of the distribution grid in real time while maintaining the security of the grid and facilitating connections to ensure participation of grid connected energy resources[4]
Joint system operations	Joint System Operations focuses on optimising the whole electricity system rather than focusing on the transmission and distribution systems in isolation. Improved coordination between the DSO and TSO is important to deliver more efficient markets and a more resilient system[5]
Flexibility services	Used when a system operator (TSO/DSO) pays a third party to operate assets in a way that maintains power flow within network limits[6]
Aggregators	Market actors who aggregate demand or generation for the purpose of participating in energy, capacity and system operator services markets

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6 Jurisdiction 4: Nordics

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1: The rising renewable energy penetration in the Nordic region is creating challenges for meeting peak demand, increasing the need for ancillary services and strategic reserves

Driver

Nordic countries are focussing on electrifying heat, industry and transport to reach their decarbonisation targets. As a result, the region's electricity demand is forecast to increase more than 60% by 2040.[1] Increase in overall demand is coupled with increasing peak demand, especially in winter.

Traditionally, balancing of electricity supply and demand and meeting demand peaks has been provided by conventional power sources with controllable power output, including hydro generation and fossil fuels, as well as imports.

Impact

An increasing challenge for the Nordic power system is the ability to meet peak load as new intermittent renewable energy resources are added and flexible thermal capacity is decommissioned. Meeting peak load will increasingly rely on a combination of storage, to enable non-dispatchable renewable energy generation to be used when it is needed, interconnections / imports, and managing demand.

For the 2019/20 winter season, the Nordic TSOs identified a total Nordic import need of 4,900MW to cover a 10-year winter peak, compared with an import need of 3,000MW in the year before.[2] The challenge of balancing supply and demand with increasing renewables is occurring across Europe, so imports alone will not be a feasible long-term solution.

Response

Nordic countries are leveraging storage and ancillary services to balance supply and demand and meet peak demand. Initiatives include:

- The Frequency Containment Reserve (FCR) project aims to create a harmonised Nordic technical specification of FCR for normal operation (FCR-N) and FCR for disturbances (FCR–D), and to create a clear prequalification process for these reserves. These are active power reserves that are automatically controlled based on frequency deviation.[2]
- Sweden is consulting on the use of wind power to provide ancillary services, while Norway is considering utilising hydropower.[2,3]
- Primrock is the first company to provide frequency containment, balance and capacity services in Sweden from a decentralised energy storage system. The system provides stability to the Nordic electricity system and has a feed-in capacity that corresponds to the average electrical power needs of approximately 2,000 private homes in Sweden.[4]
- Nordic countries such as Sweden and Finland have strategic reserve mechanisms to ensure balance between supply and demand in extreme situations. Generating units are kept available for occasions when the market is not able to cover demand. Both power plants and loads may serve as peak load reserve. Power plants and loads that act as peak load reserve are fully reserved for the use of the peak load reserve system, hence they cannot participate in the commercial market.[5]
- The Nordic TSOs are implementing harmonised frequency restoration reserves rules across the region. This will enable better coordination across regions for TSOs to restore frequency after a disturbance.[6]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 2: There is an opportunity to use decentralised flexibility, via flexibility markets, to balance the increasing share of generation by intermittent renewables

Driver

The Nordic countries are bound by the EU renewable energy directive of producing 32% of total energy from renewables by 2030, and Nordic countries are aiming to become carbon neutral by 2050. This requires significant build-out of renewables to replace fossil fuel generation, and to support electrification of other sectors (like transport, heating and industry).

To achieve these goals, Nordic countries will need to generate another 290TWh of electricity by 2050, an increase of 75% from current levels. This requires installation of an additional 83GW of renewable energy sources. Most of this is anticipated to come from wind (onshore and offshore), as well as solar.[1]

Impact

Integrating 83GW+ of renewable generation and conveying this electricity to demand centres will require costly network upgrades. Due to the intermittent nature of new renewable generation, without demand-side flexibility, overbuild may be needed to ensure demand is met at all times.

Demand-side flexibility can help to balance demand and supply when renewable generation is not available and to avoid some of the investment that could be required in generation and grid upgrades. A literature review suggests the current potential for demand-side response could be around 10-40% of maximum demand in each country in the Nordics for a short time interval.[2] Pilots performed in the Nordic region suggest that a one-fold increase in flexibility service provider availability could lead to an increase of 10% in demand without the occurrence of Non-Served Flexibility.[3]

Response

The Nordic countries are currently at the phase of carrying out flexibility pilots to demonstrate value and identify the optimal market design:

- CoordiNet is an EU-funded project with flexibility demonstrations in Spain, Greece and Sweden that started in 2019. There have been market pilots in Sweden in the grid areas around Uppsala and Skåne each winter. Flexibility has been procured via the platform SWITCH, developed by E.ON as a part of the project.[4]
- Sthlmflex is a pilot project started in 2020 that uses a flexibility market to address the capacity challenges in the Stockholm area in Sweden. The project demonstrated coordination between the TSO and two DSOs who could bid for different flexibility services across all three networks through an independent marketplace called NODES.[5]
- Nordic Energy Research is researching market design options to incentivise DSO procurement of flexibility, including consideration of one or several flexibility marketplaces, the impact on flexibility providers being able to offer services in other marketplaces, and coordination needed between TSOs/DSOs and between countries. [2]
- Denmark recently introduced legislation called Market Model 3.0 to make the ecosystem for demand-side flexibility more attractive to stakeholders. Key aims are to ease aggregator access to provide ancillary services, and incentivise data transparency amongst DSOs. [6]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 3: The Nordic countries are prioritising smart charging and vehicle-to-grid technologies to manage high penetrations of EVs without significantly increasing peak demand and requiring associated grid upgrades

Driver

Electrification of transport is a key enabler for the Nordic countries' decarbonisation goals. A report by Nordenergi states that rapid electrification can reduce Nordic emissions by 60% by 2040.[1] There is an increasing drive to electrify transport in the Nordics. This includes:

- The Norwegian Parliament has a target of reaching 100% sales of new car sales being zero-emissions (EVs or hydrogen) by 2025, supported by favourable tax exemptions and other incentives.[2]
- Denmark has a target to put at least 775,000 electric or hybrid cars on Danish roads by 2030 to support reaching its ambitious target of reducing greenhouse gas emissions by 70% by 2030.[3]
- In Iceland, a combination of high fossil fuel prices, relatively low electricity prices, and favourable policies has resulted in EVs representing over 80% of the private passenger car market, with this expected to be over 95% by 2027.[4]

Impact

The rise in penetration of EVs will significantly increase electricity demand, which Norway is already experiencing. In February 2021, five million Norwegians used as much electricity as 10 million residents of neighbouring Sweden on one given day.[5]

Nordenergi, the collaboration between Nordic electricity producers, suppliers and distributors, has identified that Nordic electricity demand for transport will increase from 9TWh in 2020 to 111TWh in 2050.[1]

Additional electricity demand will require investment in grid upgrades. For instance, for a Norwegian city of 50,000 people, if all inhabitants have an EV, the cost of investment into the local grid would be an estimated £200m.[6] However, this investment can be largely avoided if smart charging is used. In total, Norway can save NOK$11b by moving EV charging from peak periods to low demand periods at night.[7]

If charging demand is not managed well, grid stability will be at risk. For instance, sales of EVs in Sweden grew by 253% in 2019. Demand for electricity in Stockholm and other cities is outgrowing local grid capacity, limiting ability for new chargers to be installed.[8]

Response

The Nordic countries have identified smart charging and V2G technologies as key to managing electricity demand from EVs.

- In Norway, Green Charge is piloting a smart control system for charging EVs at a residential development level. This will manage charging across the development to stay within grid limitations. The project will also consider integration of local generation and storage.[9]
- In Denmark, Frederiksberg, a Danish utility is trialling V2G technology with their own fleet. At night, when the cars are not in use, they are connected to the grid through bi-directional chargers and thus provide flexible services to the distribution network.[10]
- In Finland, a public bidirectional V2G EV charging point was installed, complementing an existing solar power plant and a stationary energy storage facility. This is enabling use of EVs for energy storage and to stabilise the electricity grid.[11]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4: The Nordic countries will need to address the problem of generation inadequacy to meet increased demand in the future

Driver

On the back of decarbonisation efforts, Nordic countries will experience increased electricity demand. This is a result of electrification of other sectors, including transport, heating and industry. Rapid electrification across the Nordics is likely to further increase interest in this region for industrial businesses, seeking to power their processes using clean energy.

In 2050, Nordic countries will have to cater to a demand of 664TWh as compared to 406TWh in 2020.[1] Electricity demand in Norway is set to grow by 60% to 220TWh by 2050 according to grid operator Statnett.[2]

To cater to high electricity demand scenarios, generation and transmission capacity need to be substantially upgraded. This increasing electricity demand coincides with phase out of fossil fuel power stations, which have traditionally played a significant role in providing security of supply during periods of lower generation and/or higher demand.

Impact

Lack of generation capacity to support rapid electrification can threaten security of supply:

- In Iceland, low hydro reservoir levels, transmission capacity constraints and power system faults led to a supply shortage event in December 2021.[3]
- Fingrid estimates Finland is likely to face increasing electricity shortages in winters due to lack of production and imports coinciding with peak demand for heating.[4]
- In Sweden, the needs of industry for electricity are currently growing much faster than the expansion of new electricity generation, and from 2027 there may be a shortage.[5]
- In Norway, electricity and gas prices soared in 2022 due to lack of hydro power generation coinciding with supply chain and other pressures. Electricity prices rose as high as US$1.86 per kWh, and Norway had to invest NOK$41b (US$4b) in subsidies to help households with electricity bills.[6]

Response

The Nordic countries are considering various measures to address security of supply:

- In the short term, Denmark will look to import gas from its European connections.[7]
- The European Commission approved €26.3m to support construction of an underground hydro pumped storage facility in Finland.[8]
- Norway has curbed electricity exports to manage power shortages in the short-term, but is planning to increase annual power generation by at least 40TWh by 2030, combining wind, solar and hydropower.[9]
- TSOs are seeking to increase system flexibility through balancing services and market price signals.[10]

Demand side response is being considered to address generation adequacy. Fingrid's new voluntary power system support procedure is targeted at industrial, commercial and public properties. The procedure utilises the potential flexibility available outside the balancing market and is activated in situations where there is a high risk of electricity shortages. In these events, Fingrid sends a support request to the sites that have signed up to the procedure and adjusts energy consumption to the desired level.[11]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 5: Increasing electricity demand is requiring investment in network infrastructure, along with alternative solutions to mitigate the need for grid upgrades

Driver

The Nordic countries are seeing significant growth in electricity demand and renewable energy generation.[1]

The rapid increase in renewable energy production and in electricity demand is giving rise to significant investment needs in the electricity grid. In Finland, this is particularly apparent on the west coast, where there is currently a shortage of transmission capacity.[2]

Impact

Norway is divided into five bidding zones, and the lack of transmission capacity from north to south results in large price differences between the regions, up to nearly 160 times.[3] Due to good international interconnections, prices in the south are linked to prices in continental Europe.[4] Sweden, Finland and Denmark experience similar grid constraint challenges.[5]

The Nordic power system is strongly interlinked, within the Nordics and with neighbouring markets such as Germany and Poland. Interconnector capacity limitations between the Nordic market and Germany leads to a loss of €20m per year (mostly by Sweden and Norway) in the form of consumer surplus, producer surplus and congestion rent.[6]

Response

The Nordic countries are considering and utilising the following responses to solve transmission capacity constraints:

- Fingrid has announced investment of €3b in the transmission network for the next 10 years to cater to increased electrification, including new transmission lines to the west coast.[7] Other countries are investing similarly in transmission.
- Sweden is implementing incentives and financial support for investments in the grid as many of the larger grid owners will be required to lower their tariffs and thus their income in the forthcoming regulatory period. Lower tariffs protect consumers, but are likely to result in reduced grid spend.[8]
- Dynamic Line Rating (DLR) could be introduced to provide more accurate information about the actual current-carrying capacity of the transmission grid under different weather conditions.
- The possibilities of rapid down- and up-regulation are being investigated. A synchronous compensator (a large synchronous machine without an energy source) is being trialled.
- Battery storage is being explored as a potential solution to address capacity constraints. In Sweden, Vattenfall has established 5MW battery storage which provides services both locally and to the transmission grid.[9]
- The Nordic Regional Security Coordinator (RSC) has been set up to provide operational planning services (outage planning, adequacy forecasting, capacity calculation etc) to Nordic TSOs, thus enhancing collaboration. Plans are to further expand the RSC into a Regional Coordination Centre.
- In Sweden, DSO E.ON is providing energy renovation as a service to improve the energy efficiency of customers on its network. It estimates that this has the potential to save up to 11TWh of electricity demand.[10]

Question: What are the commonly used / accepted definitions for key systems operation terminology in this jurisdiction?

Definitions	Finland	Denmark	Norway	Sweden
Systems operations	Not defined	The regulation of system operation and responsibilities related to system operation and also operational reserves, operational procedures, operational planning, staff training and emergency preparedness, requirements for control equipment in control centres and requirements for exchange of operational measurements (including real-time and operational status)[1]	Maintains physical balance between power production and consumption in the operational hour[2]	Not defined
System operator	Shall maintain, operate and develop its electricity system and the connections to other systems in accordance with its customers' reasonable needs, and to secure, for its part, the supply of sufficiently high-standard electricity to its customers[3]	Responsible for the daily operation of the electricity system and for maintaining security of supply[4]	Maintains the instantaneous balance of the power supply system, develops market-based solutions that promote efficient development and utilisation of the power supply system, and makes the maximum possible use of instruments based on market principles[5]	Ensures that the plants of the Swedish electricity system are working together in an operationally reliable way and that production and import corresponds to consumption and export[6]
Transmission System Operator	Responsible for the transmission of electricity in the main grid and ensures an undisrupted power supply in the country[7]	Owns, operates and develops the overall energy infrastructure and manages related tasks, thus contributing to the development of a climate-neutral energy supply[8]	Owns and operates the transmission grid while maintaining the balance between consumption and production, to provide a reliable power supply at all times[2]	Responsible for electricity supply in Sweden, and also provides maintenance service for the power lines between the producers and the high to medium voltage lines[9]

Question: What are the commonly used / accepted definitions for key systems operation terminology in this jurisdiction?

Definitions (continued)	Finland	Denmark	Norway	Sweden
Network Operations	Not defined	Not defined	Not defined	Not defined
Network operator	Responsible for providing relevant grid services on an impartial and non-discriminatory basis[1]	Responsible for operating and maintaining the distribution grid, which is any grid with customer connections, usually with a voltage level up to 60kV[2]	Not defined	Distribute electricity from the regional network to consumers within a certain geographical area[3]
Distribution system operator	A system operator in possession of a distribution system and engaged in licensed operation thereof[4]	Any natural or legal person responsible for the operation, maintenance and, if necessary, the expansion of the distribution system in a given area and, where appropriate, its interconnections with other systems and to ensure that the system can satisfy a reasonable demand for the distribution of electricity[5]	Responsible for distribution of electricity within a geographic area, own and operate distribution networks[6]	Any natural or legal person responsible for the operation, maintenance and, if necessary, the expansion of the distribution system in a given area and, where appropriate, its interconnections with other systems and to ensure that the system can meet reasonable long-term requirements for the distribution of electricity[5]
Distribution system operations	Not defined	Not defined	Not defined	Not defined
Flexibility	The modification of generation injection and/or consumption patterns in reaction to an external signal to provide a service within the power system[7]	The ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons[8]	A measure of indifference about the timing or fulfilment of electricity production or consumption, as well as the technical ability to make use of this indifference[9]	Sweden defines demand-side flexibility as 'a voluntary change in the demand for electricity from the grid during shorter or longer periods, caused by some type of incentive'[10]

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7

Jurisdiction 5: CAISO

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1: With the increasing penetration of renewables in the energy mix (solar in particular) CAISO is facing the challenge of periods of both oversupply and curtailment of renewable generation

Driver

To meet renewable energy targets (including 100% electricity generation capacity being low-emissions by 2045) along with electrification of transport, buildings and industry, significant growth in renewable generation capacity is required. Much of this will come from intermittent renewables. By 2045, the following new utility-scale resources are anticipated[1]:

- Additional 70GW of utility-scale solar
- Additional 12.5GW of onshore wind (in and out of state)
- Additional 10GW of offshore wind

These are all intermittent forms of generation, which means meeting demand is dependent on weather conditions.

Further, there is high penetration of distributed solar, which, along with utility-scale solar contributes to a significant 'Duck Curve' effect where there is a timing imbalance between peak demand (in the evening) and solar power generation (in the middle of the day), as well as steep ramping of load as the evening progresses.[2]

Impact

The intermittent supply of renewable energy and the absence of control over the output of renewable power plants makes it more challenging to maintain a balance between supply and demand.

Times when supply is high and demand is low (such as in the middle of a sunny day) may require curtailment of generation. This means plant generation is scaled back when there is insufficient demand to consume production. In 2015, CAISO curtailed around 187,000MWh of solar and wind generation, and by 2021, that number rose to more than 342,000MWh. During certain times of the year, it is not unusual to curtail 20-30% of solar capacity.[3,4,5]

Curtailing renewables is not only counterintuitive to California's environmental and economic goals, it also reduces the efficiency of existing plants and introduces risk into the investment case for new renewable generation.

Response

CAISO is considering several options to manage oversupply of energy, while reducing use of curtailment[4]:

- Increasing storage resources – grid storage rose from 150MW in 2020 to 1.5GW in 2021 (see the following slide for more information on storage)
- Enhancing demand response initiatives to enable adjustments in consumer demand (both up and down)
- Time-of-use rates to better match consumption with renewable generation
- Exploring policies to reduce minimum operating levels for existing generators, making room for more renewable production
- Expanding the Western Energy Imbalance Market (which extends CAISO's real-time market to other balancing authorities in the broader area, including Canada and Mexico)[6]
- Diversifying renewable generation investment
- Incorporating EV charging systems that are responsive to changing grid conditions
- Investing in fast-response resources to follow sudden changes in supply / demand

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1 (continued):	With the increasing penetration of renewables in the energy mix (solar in particular) CAISO is facing the challenge of periods of both oversupply and curtailment of renewable generation

Response (continued)

Storage is a key strategy being deployed for reducing renewable curtailment. As of October 2022, CAISO had around 4,300MW of storage capacity available for dispatch and is planning to increase the storage capacity to 10,000MW by 2024.[1] In its Preferred System Plan approved in 2023, the California Public Utilities Commission (CPUC) authorised 15,000MW of new storage and demand response resources by 2032, which is enough clean energy to power approximately 11.5 million homes.[2]

California is taking the following steps to increase the capacity of energy storage[3]:

- Short-Duration Energy Storage: California is replacing natural gas power plants with a combination of solar and lithium-ion batteries, called hybrid power plants. Around 50GW of stand-alone energy storage or energy storage in a hybrid configuration is under development over the next six years.
- Long-Duration Energy Storage: As California continues to build renewable energy projects, energy providers are required to incorporate projects which can store energy and discharge it over longer periods. The commercialisation of longer duration storage is a key challenge in achieving 100% clean electricity. California introduced US$126m in incentives to demonstrate new long-duration storage opportunities.[4]
- Mechanical Energy Storage: This form of storage utilises kinetic or gravitational forces to store energy. Mechanical energy is the most common form of long-duration storage used in California (most commonly pumped hydro) and the state currently has 4GW of capacity in this type of storage.
- Flow Batteries: This form of storage uses an electrochemical process to separate positive and negative ions across a membrane to produce electricity. In 2019, San Diego Gas & Electric started a project with a 1MW flow battery which can store 8MWh of energy.
- Green Hydrogen: The Borrego Springs Electric System Upgrade includes co-location of hydrogen and battery energy storage systems with a smart microgrid, allowing for 8+ hours of energy storage.[5]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 2: The increasingly dynamic nature of new generation and demand is driving a need for more sophisticated forecasting and modelling

Driver

Driven by incentives for renewable energy, grid-connected solar and wind reached 27% of total generation in the CAISO jurisdiction in 2021. California has set a target to reach 100% renewable electricity generation by 2045, with an interim target of 90% by 2035.[1] The vast majority of this growth will come from intermittent sources – solar and onshore / offshore wind.

Much of this renewable generation will also be distributed, with distributed solar capacity expected to increase from 14,000W in 2022 to nearly 25,000MW by 2030.[2]

At the same time, demand is increasing and becoming more dynamic, meaning both the amount of load and when it comes on is becoming more variable. Demand is subject to weather events (e.g. heat waves) and consumer behaviour (e.g. when consumers choose to charge EVs). This can have a particular impact on peak demand.[3]

Impact

In 2022, CAISO hit a record peak demand of 52GW when Northern California temperatures spiked during a heat wave that lasted nearly a week. CAISO urged customers to conserve power and issued its most stringent warning to utilities to prepare for rotating outages. Power was narrowly preserved through a combination of battery performance, demand response and wind output.[3]

Being able to accurately forecast changing supply and demand conditions is essential for accurately scheduling resources so that supply and demand are balanced and so demand is met in the most cost-effective manner. Forecasts are developed in both the short term (up to a few days) and the longer term (days, weeks or even years).

Forecasting variable renewable generation is more difficult than for traditional fossil-fuel based resources. Behind-the-meter distributed generation presents further unique forecasting challenges. From the CAISO perspective, this distributed generation is currently a small, undifferentiated component of total load, which makes forecasting its potential contribution to balancing supply and demand very difficult.[1]

Response

- CAISO is investing in advanced forecasting tools and real-time monitoring to detect any changes in load and supply instantaneously. CAISO is also exploring the use of machine learning algorithms to improve its load forecasting accuracy.[4]
- In 2020, CAISO partnered with IBM to develop a new system for managing the grid in real time called the Energy Management and Renewables System (EMRS). This will use IBM's artificial intelligence and weather forecasting tools to provide more accurate forecasts of renewable energy generation and grid demand.[5]
- CAISO has also partnered with Siemens to leverage its Spectrum Power advanced grid modelling software, which incorporates machine learning algorithms and other advanced techniques to improve load forecasting accuracy.[6]
- The California Energy Commission's Energy Research and Development Division is researching emerging techniques for modelling both utility-scale and distributed solar generation.[1]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 3: CAISO is required to remove barriers to DER participation in wholesale markets, and has proposed a new model to enable aggregations of DER to participate in wholesale energy and ancillary services markets

Driver

FERC Order 2222 was issued in 2020 requiring all U.S. independent system operators and regional transmission organisations to develop plans that give DER access to wholesale energy markets through aggregations.[1]

FERC recognised that DER penetration is growing quickly across the US, due to a number of factors:

- Swift progress in DER technology
- Increasing cost effectiveness of DER, including those that are integrated with artificial intelligence and machine learning technologies
- Growing consumer preferences for the operational savings potential of DER
- The growing ability for retail customers to directly interact with wholesale power markets in real-time

FERC recognised that DER will play an increasingly important role in stabilising the US power system.

California currently leads DER penetration in the US, and DER growth is expected to continue. The state's policy objectives (e.g. Senate Bill 100, which requires 100% zero-carbon electricity generation by 2045) are anticipated to further drive demand for DER in the area.[2] Growth is expected as follows[3]:

- Behind-the-meter solar generation is expected to increase from 15,800GWh in 2019 to 41,200GWh by 2030
- Behind-the-meter energy storage capacity is expected to reach 2,600MW by 2030, up from 340MW in 2019
- Consumption by EVs is expected to increase from 5,000GWh in 2019 to 18,500GWh by 2030

Impact

While there have been previous DER programmes in California, these had been viewed by some as unappealing to prospective participants. Examples of why CAISO's previous DER programme has been seen as unattractive include[4,5]:

- The requirement for resources to commit to CAISO on a 24/7 basis thereby limiting their potential for revenue generation from other sources
- The necessity for distinct meters and communication systems contributing to high costs
- Potential for DER to be subject to dual costs (wholesale and retail rates) if participating in both wholesale and retail programmes
- Restrictions on participation of DER to a single programme / service type
- Restrictions that constrained DER from receiving credit for the full amount of capacity they can provide

It was therefore important for CAISO to make changes to meet FERC Order 2222 and better enable DER participation in wholesale markets.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 3 (continued):	CAISO is required to remove barriers to DER participation in wholesale markets, and has proposed a new model to enable aggregations of DER to participate in wholesale energy and ancillary services markets

Response

In 2022, FERC issued its compliance filings on Order 2222 for the first two ISO submissions, CAISO and NYISO.[1] CAISO is one of the few ISOs that allows multi-nodal aggregation of DER at sub-load aggregation points (Sub-LAP).[2] This enables DER aggregators to bundle various DER technologies with greater flexibility. Aggregating at a single transmission node restricts the ability to participate independently in wholesale markets.

Recently, CAISO has introduced a proposal aimed at facilitating the provision of grid ancillary services by battery storage systems, specifically through "regulation up" and "regulation down" services. The proposal is designed to offer improved pricing signals to fully charged battery storage systems.[3]

Additionally, the CPUC's DER Action Plan 2.0 seeks to improve coordination across proceedings related to grid planning, affordability, load flexibility, market integration and customer programmes, outlining actions across four tracks to collectively advance the overall vision for a high DER future[4,5]:

1. Load Flexibility and Rates, which is focused on more effective, integrated demand response and retail rate structures that promote widespread, scalable and flexible load strategies. Notable initiatives in this track include:
   - A requirement for all customers to have access to dynamic and real-time pricing options by 2025
   - Assessing the potential for time-differentiated, dynamic transmission rates
   - Identifying and addressing affordability barriers to DER uptake, including alternative sources of funding and third-party load management services
2. Grid Infrastructure, which is focused on guiding utility infrastructure planning and operations to make the most of existing and future infrastructure and maximise the value of DER. This includes considering DSO models, roles and responsibilities. Notable initiatives in this track include:
   - Implementation of standards for data communications and advanced inverters that facilitate visibility and interoperability of DERs
   - Improving DER connection processes, including transparency, cybersecurity assessment, speed and cost certainty
   - Utilities integrate anticipated impacts of DERs into distribution planning to minimise costs and deploy supporting infrastructure
3. Market Integration, which is focused on efficient integration of behind and front of the meter DER into wholesale markets. Notable initiatives in this track include:
   - Providing fair compensation for multiple unique services from DER (i.e. wholesale, distribution capacity, bill management, back-up power)
   - Identifying key DER services and prioritisation of those services (including who has priority to dispatch) based on reliability and resiliency implications (by 2024)
4. DER Customer Programmes, which is focused on enabling all customers to effectively manage their energy usage in a manner that ensures equitable participation and distribution of benefits. Notable initiatives in this track include:
   - Making data from smart meters and other rate-payer funded 'smart' devices available for research while maintaining privacy protections

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4: There is an opportunity to leverage the increasing penetration of EVs for grid stability and reliability by designing appropriate grid codes, market incentives and supporting policies to enable load shaping

Driver

In 2021, California committed to phase out the sale of new petrol and diesel passenger vehicles by 2035, replacing them with zero-emissions vehicles. The transition to EVs is expected to increase load, including peak load, as a multitude of vehicles charge simultaneously.[1,2]

California is actively investing to enable the development of charging infrastructure via state and federal investments:

- The California Energy Commission (CEC) launched a US$30m incentive fund to build fast-charging stations in disadvantaged, low-income and tribal communities[3]
- The CEC approved an investment plan worth US$2.9b to achieve the state's 2025 EV charging goal of deploying 250,000 chargers[4]

Impact

The annual electricity consumption of EVs in California is expected to increase from around 2% of total demand in 2022 to nearly 22% of total demand by 2035. Of the 342m MW of annual electricity demand in California in 2035, approximately 75m MW will be used to charge EVs. Also, peak hour demand from EVs is expected to reach 10% of total peak electricity demand compared to less than 1% of peak electricity demand in 2022.[2]

As per the CEC, by 2030 the state is expected to require 1.2m public and shared chargers to meet the increasing charging requirement from the much greater number of EVs on the roads.[5]

Response

V2G technology has been identified as being able to help balance the CAISO grid by using electric car fleets to absorb excess electricity during low demand and discharge it during high demand periods, thus alleviating curtailment and oversupply issues.[6]

The Electric Power Research Institute has calculated that V2G can provide US$671m in annual grid benefits by 2030 and has 3 times the value of managed charging (assuming at least half of vehicles are V2G-enabled).[7]

A V2G pilot is underway at Los Angeles Air Force Base, with a fleet of 42 light and medium EVs using bi-directional charging stations. The fleet provided frequency regulation (up and down).[8]

Additionally, the CPUC's DER Action Plan requires utilities to offer commercial EV owners and fleet operators real-time pricing rate pilots by 2024.[9] Existing time-of-use rates are popular in California – utility PG&E's customers receive low off-peak rates, and 60-70% of EVs in the service area are charged during non-peak hours.[2]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 5: California's resource adequacy challenges have led to several grid emergencies in recent years, which could worsen as power capacity requirements are anticipated to triple

Driver

California has set a target for 100% of retail electricity sales to come from renewable, carbon-free sources by 2045. To achieve this, along with significant electrification of transport, buildings, and industry, California's electricity consumption is expected to increase as much as 68% by 2045.[1] It is anticipated California will need three times more power capacity to accommodate this.[2] CAISO is planning for a transmission requirement that assumes more than 4,000MW of new resources per year.[3]

California's resource adequacy is already being challenged. In September 2022, California narrowly escaped rotating outages, which was the third CAISO 'stage 3' emergency in two years.[4] Blackouts in 2020 were the result of a significant amount of generation (gas and solar) not being available when needed.[5] The transition to a greater share of intermittent renewables and increasing demand has the potential to worsen resource adequacy issues.[5]

In California, resource adequacy policy responsibilities are distributed between state agencies, including the CPUC and the CEC, and CAISO.[4,6]

Impact

If California's resource adequacy is not improved, this could lead to increasingly frequent brown- and black-outs, particularly during extreme weather conditions like heatwaves.[7] Insufficient supply could also lead to increase in electricity prices, putting pressure on end consumers.[8]

As responsibilities for navigating the energy transition are distributed, the risk of poor coordination increases the chances of increasing resource adequacy issues in the future.[4]

Response

California's Resource Adequacy Programme is undergoing reforms to ensure sufficient resources can be provided to CAISO when needed. The programme currently requires load-serving entities to demonstrate system adequacy (peak plus a reserve), local adequacy (using a 1-in-10-year weather event) and flexibility adequacy (looking at the largest three-hour ramp for each month). The CPUC, CAISO and market participants collaborate closely on these requirements.[9]

California has established an electricity reliability reserve fund to address extreme weather events outside of Integrated Resource Plan standard conditions.[10]

The CPUC is seeking proposals now for new generation developments during the 2026-2030 period to help reduce potential delays caused by bottlenecks in generation build, such as interconnection studies and permitting.[11]

The California legislature has approved delay of the retirement of its last nuclear plant by an additional five years to support resource adequacy as additional resources come online.[12]

To achieve a longer term outlook on transmission needs, CAISO produced a 20-Year Transmission Outlook (compared with the ten-year plan required). CAISO has identified US$2.9b in transmission upgrades to support grid reliability and new generation requirements.[3]

Calls to address the distributed responsibilities of resource adequacy (for example, moving this role to CAISO or increasing capability in CPUC) have not yet been addressed.[4]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 6: High DER penetration means the distribution system is becoming increasingly dynamic, leading California to consider models, roles and responsibilities for future distribution system operations

Driver

California leads the USA in growth of DER, and this is projected to continue with a 260% increase in behind-the-meter solar, 77% increase in behind-the-meter energy storage capacity, and 370% increase in EV demand from 2019 to 2030.[1]

The electricity grid has traditionally been designed to transport power from large power plants to end-use customers. Grid management typically occurs at the macro level (i.e. CAISO), with utilities (responsible for the distribution network) distributing electricity on a one-way basis to end users.[2] Identifying reforms to the traditional distribution system are important to meet the CPUC's High DER Future Proceeding order, which has the objective to guide public and private sector investment for a high DER future.[3]

Impact

Significant increases in DER penetration are likely to overstress the state's distribution systems.[3] While utilities have historically been able to treat load as being passive with power flows in one direction only, in future, distribution system will be active, with two-way flows, and may serve resources to the wider transmission grid. Utilities need new capabilities to manage the increasingly dynamic distribution system, including DER forecasting and integration into planning, active balancing of supply and demand, frequency and voltage maintenance and facilitating flexibility. Alternative approaches to distribution system planning and operations will be needed to integrate and operate DER at least cost while maintaining system safety and reliability.[4]

Response

The CPUC has undertaken a series of regulatory workshops to assess the options for DSO models, roles and responsibilities with stakeholders. This is considering[4]:

- 'Total TSO': wholesale markets operated by CAISO are extended to cover the distribution system and DER, CAISO's network model would include distribution networks and DER
- 'Total DSO': existing utilities establish new markets for distribution services provided by DER, and the DSO represents all DER within its footprint as a single net load / supply in wholesale markets
- 'Independent DSO': an independent organisation is created to operate the market for distribution services
- 'Hybrid': variations, including minor changes to the status quo (e.g. DER participation in existing markets, plus continuous improvement in distribution system coordination)

Future workshops will focus on legal, regulatory, procedural, technical and financial barriers to the potential future DSO models. There is currently strong contention between some power system incumbents and community representatives on who can participate and how to define a DSO.[3]

Existing utilities in California are considering better ways to integrate DER into their distribution systems. Southern California Edison (SCE) is preparing for a DSO transition, starting with improving its ability to forecast DER adoption and performance and reinforcing the local network, and considering options for DER market design and development.[5] SCE is piloting a partnership for customers to enrol with energy solutions providers to implement DER solutions.[6]

Question: What are the commonly used / accepted definitions for key systems operation terminology in this jurisdiction?

Definitions

Systems operations	Real-time management of the high-voltage transmission system and the energy markets in California. This includes monitoring the flow of electricity across the grid, managing supply and demand of electricity, and ensuring system reliability and stability.[1]
Network operations	Not defined
Independent System Operator (ISO)	Manages the flow of electricity across high-voltage, long-distance power lines.[2]
Utility Distribution Company	An entity that owns a distribution system for the delivery of energy to and from the CAISO controlled grid, and that provides regulated retail electric services and regulated procurement service to end-use customers.[1]
Distribution system operator	‘An entity responsible for planning and operations on a distribution system’, or ‘a neutral facilitator of an open and accessible market for DER.’[3]
Distribution system operations	Not defined
Load flexibility	The practice of adjusting load (or energy usage) to match the supply of electricity.[4]
Total TSO Model	Allows DER to provide distribution services by extending centralised, open-access markets of an Independent System Operator to the distribution system, consolidating the market for wholesale and distribution grid services.[3]
Total DSO Model	Tasks the Utility Distribution Company with revising markets for distribution services, separate from the wholesale market. DER does not participate directly in the wholesale market but is balanced by the Total DSO.[3]
Independent DSO	An independent organisation (separate from distributions system ownership) is responsible for operating the market for distribution services.[3]

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Jurisdiction 6: PJM

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 1: The share of intermittent renewable energy supply in PJM is growing significantly, and PJM will need to enhance its capabilities to efficiently forecast and dispatch intermittent generation sources

Driver

Carbon-free sources made up 39% of generation in PJM in 2021 (including 32.8% nuclear and 6.2% renewable).[1] Targets for low-carbon energy are for at least 50% of generation capacity by 2035, or 70% under the 'accelerated' scenario.[2]

Recent developments in renewable generation in PJM include[3]:

- A record 1,512MW of solar capacity cleared in the latest PJM auction, an increase of 924MW from the prior auction
- The amount of wind also rose 312MW, totaling 1,728MW
- A growing number of offshore wind projects are under active development

Simultaneous retirement of fossil fuel capacity has put resource adequacy and reserve margins at risk. Around 40GW (21%) of PJM's installed capacity (fossil fuel based) is expected to retire by 2030. For the first time in recent history, PJM could face decreasing reserve margins, which are expected to drop to 8% in 2028 and 5% by 2030.[4,5]

Impact

PJM has identified that as wind and solar taper during the afternoon, this coincides with increasing electricity use, with a particular problem occurring in winter. The corresponding ramp-up required from other sources in 2035 could be as high as 73GW on some winter days.[5]

As the share of intermittent renewable generation increases, accurate dispatch of renewable generation and forecasting of near-term changes in resource output becomes increasingly important. It becomes increasingly difficult to manually manage dispatch. This has the potential to cause the following challenges / inefficiencies to occur in the system:

- Bid-in parameters (eco limits, forecasts) not in alignment with real-time capabilities, with lack of timely updates, so dispatch is based on outdated information
- Requirement for renewable generation curtailment, noting this does not exist for all renewable resources
- Inconsistent performance when following curtailments

Response

PJM is prioritising the following key initiatives to increase reliability of renewable resources during real-time operations, particularly when used for constraint control and balancing:

- A method of dispatch that covers all renewable resources
- Clear guidance and expectations on following PJM dispatch instructions
- Streamlined data exchange

PJM's Resource Adequacy Planning Department forecasts generation retirements and entries, along with loads, to understand PJM's Resource Adequacy Risk. PJM is focusing on capacity market modifications, interconnection process reform and clean capacity procurement to maintain the 'balance sheet' of retirements, new entries and load growth.[6]

PJM has also deployed a new tool, the Dispatch Interactive Map Application (DIMA), developed to enhance situational awareness of dispatchers. DIMA simplifies and consolidates important data from multiple sources into a single geospatial display, enabling operators to identify problems and coordinate the operation of the jurisdiction's transmission system more efficiently.[7]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 2: PJM will experience an increasing peak load due to increasing penetration of EVs in the jurisdiction, but smart and bidirectional charging presents the opportunity for EVs to positively contribute to grid operations

Driver

PJM's long-term load forecast predicts estimated load growth of 0.8% per year for summer peaks, 1% for winter peaks, and 1.4% for net energy over a 10-year planning horizon from 2023.[1]

Nearly all of the anticipated growth, particularly in net energy, is driven by expectations for new data centres, along with growing uptake of EVs, across the PJM footprint.[2]

The White House has set a target for 50% of vehicle sales being electric by 2030. This would mean more than one-third of cars in PJM would be electric by 2037.[3] Four of the thirteen states in PJM, and the District of Columbia, have EV targets.

Impact

PJM anticipates that[4]:

- Electricity use for EVs will increase by nearly ten times, from around 2,400GWh in 2022 to nearly 21,000GWh in 2032
- EV contribution to summer peak load is forecast to jump from 300MW this year to around 1,840MW in 2032

Response

- PJM is updating its load forecasting processes and transmission planning studies to ensure EV charging is accurately accounted for in market and transmission investment decisions.
- PJM is enabling EVs to provide grid reliability services by contributing to storage capacity through working with other parties to introduce public policy economic incentives for customers to implement smart chargers, V2G technologies and grid-integrated vehicles (GIV) which support two-way power flow between the vehicle and the grid.[5]
- PJM partnered with the University of Delaware and local utilities for a V2G trial where PJM pays the market rate for grid support services. This delivered roughly US$1,200 per year per vehicle in revenue.[6]
- In 2022, PJM member Dominion Energy has deployed 50 electric buses to Virginia school districts with the intention of them providing additional energy for the grid. When the vehicle is not in use the batteries can inject stored energy back into the system.[7]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 3: With increasing demand from data centres, PJM needs to take steps to manage security of supply, particularly during peak demand

Driver

With data centres totalling 12 million square feet, Northern Virginia is the largest data centre market in the world, according to Virginia-based utility company Dominion.[1]

This growth is largely driven by incentives provided by state and local authorities, presence of extensive electric and fibre infrastructure in the jurisdiction, and availability of a skilled workforce.

Data centres are increasingly becoming a dominant user of electricity. The electricity demand in Virginia is expected to increase by around 30-40% by 2035m largely driven by data centre growth.[2]

Impact

- In 2023, data centre providers in the US accounted for a nearly 67% share (around 40GW) of US corporate renewable contracts.[3] Around 2.8GW of both planned and operating solar capacity in Virginia is contracted to data centres, which has seen an increase from 1.7GW in 2019.[4]
- PJM forecasts that peak load increases will be largely driven by data centres, with data centres in Dominion Energy's service territory making up more than half the total forecast peak growth, and EV's making up most of the rest.[2]

Response

- The data centre load is mostly concentrated in parts of Virginia and North Carolina. State environmental regulators have made it easier for data centres in northern Virginia to run on diesel generators in the event of a grid emergency (reducing strain on the electrical grid and freeing up more electricity for residential customers).[5]
- PJM will approve emergency generation from those types of on-site power generators considered Tier II and Tier IV, where they are related to diesel-fuelled machines.[6]
- The increasing market penetration of natural gas, hydrogen generators and fuel cells, as well as battery storage, is anticipated to enable generators to reduce load on the grid during high demand periods using cleaner fuels in future.[7] As more economical and environmental fuels are used for onsite generation and storage, data centres can participate more actively in PJM's Demand Response programme, which allows customers to receive payments for demand curtailment.[8]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4: PJM is required to remove barriers to DER participation in wholesale markets, and has proposed a new model to enable aggregations of DER to participate in wholesale energy and ancillary services markets

Driver

In September 2020, the Federal Energy Regulatory Commission (FERC) Order 2222 was published, requiring regional transmission organisations and independent system operators to remove barriers keeping DER aggregators from participating in wholesale markets. FERC recognised that DER penetration is growing quickly across the US, due to a number of factors:

- Swift progress in DER technology
- Increasing cost effectiveness of DER, including those that are integrated with artificial intelligence and machine learning technologies
- Growing consumer preferences for the operational savings potential of DER
- The growing ability for retail customers to directly interact with wholesale power markets in real time

FERC recognised that DER will play an increasingly important role in stabilising the US power system.[1]

Prior to 2022, PJM lacked the provision to allow DER to participate in its wholesale energy markets. In many PJM zones, transmission and distribution charges have become far greater than capacity charges, reflecting the fact that PJM has become transmission and distribution constrained, while generation capacity has increased.

Impact

Prior to 2022, there were no opportunities for DER to be compensated for relieving congestion at the distribution system level. Legacy market rules force DER to participate only as demand response, even if they have generation or storage characteristics.

There was no framework or plan in place enabling DER to profit when energy prices are high or to contribute when able to relieve the grid during conditions of stress. PJM was missing a participation model that allowed DER to earn energy revenue.[2]

This restricted the increasing volume of DER in the PJM market from providing potential grid resilience and efficiency benefits.[3]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 4 (continued):	PJM is required to remove barriers to DER participation in wholesale markets, and has proposed a new model to enable aggregations of DER to participate in wholesale energy and ancillary services markets

Response

In 2017, PJM established a Distributed Energy Resources Subcommittee to investigate and resolve issues associated with markets, operations and planning related to DER.[1] Following this, and in response to FERC Order 2222, PJM has initiated the following[2]:

- Developing new market rules: PJM is developing new market rules to enable the participation of DER in its capacity and energy markets. These rules will allow aggregators of DER to participate in PJM's markets as a single entity.
- Expanding eligibility criteria: PJM is expanding its eligibility criteria to allow more DER to participate in its markets. For example, PJM is exploring ways to allow behind-the-meter resources, such as residential solar panels, to participate in its markets.
- Developing new forecasting tools: PJM is developing new forecasting tools to better predict the output of DER and integrate them into the grid.
- Engaging stakeholders: PJM is engaging with stakeholders, including DER aggregators, utilities and state regulators, to ensure that its new market rules and eligibility criteria are transparent and effective.

In 2022, PJM proposed a new model to enable aggregators of DER to participate in its markets[3]:

- The model accommodates the physical and operational characteristics of an aggregation without placing restrictions on resource or technology types – it allows both single-type and mixed DER aggregations to participate in all markets where they can provide services.
- The proposal defines a DER aggregator as having at least one DER component and being able to provide an energy and/or ancillary services market offer of at least 100kW (and up to a maximum of 5MW).
- The model avoids double counting by prohibiting DER like rooftop solar that receives compensation through retail net metering programmes.

The new DER model is accompanied by innovations in metering, sub-metering and settlement data.

While the plan was due to take effect in February 2026, in March 2023, FERC directed PJM to revise many aspects of its plans, particularly with respect to limiting DER aggregators to a single price node. Following calls for earlier implementation, FERC also noted that while earlier implementation could provide benefits for market participants, these would likely be outweighed by complications and burdens involved for PJM and other coordinating organisations.[3]

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 5: PJM is looking to use hybrid energy sources to enhance the contribution of renewables to the grid

Driver

Hybrid energy resources are those that combine multiple types of energy generation and/or storage or use two or more kinds of fuel to power a generator. The hybrid model can be applied to any type of generation (i.e. renewable or fossil fuel), but the most common mode of pairing for hybrid resources in PJM is solar and battery storage.

In the US, the factors propelling the demand for hybrid energy projects are:

- Declines in the cost of batteries and solar technology
- State government policies, federal tax policies, and other economic incentives to reduce GHG emissions
- Allows resource developers / owners to provide services a stand-alone resource could not provide
- Allows for sharing of permitting, siting, equipment and interconnection costs

Impact

As of 2021, solar and storage hybrids accounted for around 20,000MW of capacity in the PJM interconnection queue.[1] More than a quarter of the solar MW in the PJM interconnection queue in 2021 represented solar plus storage hybrid resources.[2]

Hybrid energy resources can:

- Allow intermittent or duration-limited resources to achieve a higher combined capacity factor
- Facilitate more efficient transmission system operations by reducing congestion and curtailment in areas with high penetration of intermittent resources
- Provide transmission operators with more controllable ancillary services than stand-alone intermittent resources

Enabling hybrid energy resources to operate in the market as a single integrated resource, rather than co-located but separate resources, allows the design and operation of the hybrid components to be optimised.

While hybrid resources can currently operate in PJM's energy, capacity and ancillary services market, very few are operating as hybrid sources.

Response

PJM has been working with stakeholders to amend their governance and business practice documents to ensure hybrid resources have clear rules to guide their participation in markets.

PJM has implemented Phase 1 of the hybrid energy sources project, focused on solar plus storage. Phase 2 is underway, focusing on different technology combinations.

Under Phase 1, hybrid resources submit a single energy market and regulation market offer, receive a single dispatch point, and have a single settlement value. The operator is able to balance their combination of resources as required to achieve PJM's dispatch requests, but PJM can limit resource operator flexibility when necessary to ensure reliability.[3]

The hybrid energy working group is examining whether any rule clarifications are necessary for metering, telemetry and minimum operating parameter values for scheduling.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 6: Extreme weather conditions are creating reliability and grid security challenges for PJM, requiring a focus on system resilience and risk management

Driver

Periods of extreme cold weather in the PJM jurisdiction can result in a combination of spiking demand and high levels of forced generation outage. This requires PJM to implement various emergency responses, including deployment of demand response to reduce load.

Such a situation occurred over the Christmas period in December 2022 during Winter Storm Elliott. Despite advance warning, the power supply mix became, at times, tighter than PJM's expectation. Multiple power plants failed during this period – by Christmas day, 46GW of power plants were out of service. About 70% of all outages were natural gas plants and 16% were coal. PJM experienced failures across its gas system due to low pressure and frozen compressors resulting in fuel unavailability.[1]

This situation is likely to worsen as existing fossil fuel plants are retired – around 21% of PJM's installed capacity is expected to retire by 2030.[2]

Impact

PJM's emergency procedures implemented during the extreme cold weather experienced in December 2022 included:

- A transmission system-wide Generation Emergency Action was declared
- Calls for synchronised reserves
- A call for emergency demand response

Despite these actions, PJM was missing approximately 57GW of its generation fleet by the morning peak of December 24, the coldest day of the holiday weekend.

More than 90% of the forced outages during this period, primarily gas power plants, came with less than one hour's notice.[3]

Response

A key factor in PJM's response is penalties for non-performance during stressed conditions. This ensures capacity offered in the market appropriately reflects performance risk, and units less likely to perform during stressed conditions are offered at higher prices to reflect this risk.[4,5]

Another response is to continue use of fossil fuel generation for longer. For example, NRG Energy Inc is planning to delay the retirement of a 410MW plant in Delaware.[6]

In February 2023, FERC approved two extreme cold weather reliability standards for US generators[7]:

- Emergency operation – this involves improving how transmission operators account for the overlap of manual and automatic load shed in their emergency operating plans.
- Extreme cold weather preparedness and response – this requires generators to put in place freeze protection measures, develop enhanced cold weather preparedness plans, conduct training, and implement corrective action plans to address freezing issues.

A second set of cold weather standards is proposed to be introduced in late 2023.

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 7: Long interconnection queues in the PJM jurisdiction are delaying the development of multiple new renewable energy projects, and this could be a challenge for maintaining energy security

Driver

Interconnection new service requests have drastically increased over the past few years in the PJM jurisdiction.[1] Much of PJM's grid (including the process for connections) was designed for large projects like fossil fuel power plants, while many new renewable projects are small.

A significant pool of solar, wind and battery storage projects are getting stuck in the grid operator's interconnection queue. Projects often need to wait years for the completion of technical and cost studies and receiving final approvals for connection to the grid. Delayed interconnection queues and backlogs are one of the most significant barriers to increasing the market's share of clean energy generation.[2]

Impact

Developers have more than 2,000 solar, wind, battery storage and hybrid projects waiting for approval in the PJM interconnection queue, totaling approximately 250-300GW of generating capacity. All projects waiting for an interconnection agreement have been waiting in the queue for a year or more, with many having been waiting more than three years.[1]

Between 2017-2022, developers have withdrawn more than 1,000 clean energy projects from the PJM interconnector queue. This includes more than 77GW of solar, wind and battery storage projects.[2]

Given the forecast retirement of fossil fuel generators, delays in connection requests have the potential to limit the system operator's ability to bring on the required level of new generation to maintain supply into the future.

Response

PJM proposed a two-year pause on formally accepting new interconnection applications so that the grid operator can focus on speeding up delayed projects and clearing some of the backlog.

PJM also conducted an interconnection review to study how proposed projects would affect the grid, determine what grid upgrades are needed to bring them online, and allocate those costs. The study helped PJM move to a 'first-ready, first-served' interconnection review process, as follows[3]:

- The plan includes a transition phase that will prioritise pending projects to help clear the existing backlog
- PJM will impose new requirements, such as 'readiness deposits', that aim to remove more speculative projects
- The developer will have three decision points to decide if they want to continue through PJM's connection study process
- Projects that do not require network upgrades or further studies will be expedited
- Cost responsibility of individual projects will be analysed and allocated accordingly

Question: What problems or opportunities with systems operation is the jurisdiction experiencing? How is the jurisdiction planning to address / capture this problem / opportunity?

Problem / Opportunity 6: PJM is needing to make changes to its capacity market rules to better reflect the capabilities and contributions of renewable and storage resources

Driver

PJM operates an energy and capacity market. The capacity market plays a key role in ensuring sufficient capacity is available to meet the expected future demand. However, the market was designed traditional fossil fuel generation, and is therefore not always well suited for intermittent renewables which have different operating characteristics. Valuing the contributions of variable energy resources is a particular challenge because their value declines as renewable energy and storage penetration increases.[1] Exacerbating this issue is the significant forecast demand growth, and planned retirement of fossil fuel generators. The new generation which will replace these plants will be made up of primarily intermittent and limited-duration resources, meaning multiple megawatts of these resources are needed to replace 1MW of thermal generation.[2]

Impact

- FERC Order 841 required system operators to integrate energy storage resources into their markets. PJM's initial response proposed a 10-hour minimum run-time requirement for capacity storage resources, which was criticised by renewables advocates who stated that this would undervalue the contributions of many energy storage facilities by shutting them out of the capacity market.[1]
- Following extreme weather in 2014, PJM introduced a capacity performance framework which imposes a fine for generators which do not deliver on their commitments to deliver electricity when needed in power system emergencies. In December 2022 about 46GW of generation was unavailable during a winter storm, resulting in potential fines between US$1-2b.[3]
- FERC has decided to hold a forum to examine PJM's capacity market, saying "the continuing disputes about its capacity markets warrant review". PJM needed to update its capacity market parameters following the December 2022 auction which led to unusually high prices without providing any reliability benefit.[4]

Response

- In 2021, FERC approved new capacity market rules which aim to more accurately value the grid reliability contributions of renewable and energy storage resources. These changes established three different types of Effective Load Carrying Capability resources: variable resources, limited duration resources and combination resources. The approved proposal establishes multiple storage classes with maximum durations of 4 hours, 6 hours, 8 hours and 10 hours.[4]
- Earlier in 2023, PJM started a fast-track stakeholder process to bolster its capacity market following widespread power plant outages during Winter Storm Elliott and a report showing the grid operator could face narrow reserve margins in 2028. As part of this they are considering ways to improve risk modelling, especially for the winter, enhance accreditation so a resource is paid in line with its reliability contribution, and ensure that capacity suppliers are fully paid for the risks they take.[5]

Question: What are the commonly used / accepted definitions for key systems operation terminology in this jurisdiction?

Definitions

System operations	Not defined
Network operations	Not defined
Independent System Operator (ISO)	An independent and federally regulated entity that coordinates regional transmission to ensure non-discriminatory access to the electric grid and a reliable electricity system.[1]
System operator	An individual who performs daily generation and/or transmission operations-related tasks on the PJM RTO electrical systems. System operators performing these tasks may be at Local Control Centres (LCCs), Market Operations Centres (MOCs), and a PJM control centre.[2]
Electric distributor	A PJM Member that owns (or leases with equivalent rights to ownership) electric distribution facilities that are used to provide electric distribution service to electric load within the PJM region.[3]
Distribution system operator	An entity that is responsible for the planning and operational functions associated with a distribution system that is modernised to accommodate and manage the operations of high levels of flexible assets while maintaining safe and reliable operation of the system.[4]
Distribution system operations	Not defined
Regional Transmission Operator (RTO)	RTO is a formal designation by the US Federal Energy Regulatory Commission (FERC). In most cases, RTOs and Independent System Operators (ISOs) are the same in the US. RTO coordinates, controls, and monitors the electric grid in a specific geographical, multi-state areas.[5]
DER Aggregator	An entity which is both a member as well as a market participant and uses one or more DER aggregations to participate in the energy, capacity, and/or ancillary services markets of PJM through the DER Aggregator Participation Model and has fully-executed DER aggregator participation service agreement.[6]
Hybrid resource	An energy resource or generation capacity resource composed of one generation component and one storage component behind the same point of interconnection operating the capacity, energy and/or ancillary services marker(s) as a single integrated resource.[7]

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Glossary of abbreviations and terms

Cascade failure	A cascade failure of the power system occurs when the failure or removal from service of an asset forming part of the power system causes other electrically connected 'healthy' assets on the power system to fail or be automatically removed from service, until a large part of the healthy power system, or the entire power system is no longer conveying electricity.
Common quality	The Code defines common quality to mean: *Those elements of quality of electricity conveyed across the grid (the Code's term for New Zealand's transmission network) that cannot be technically or commercially isolated to an identifiable person or group of persons.*
Demand Response (DR)	Demand response is a load management method that is used during periods of peak demand to relieve power system stress. For example, a charger or a load could be throttled to reduce energy consumption temporarily, until power system stress is relieved.
Distributed Energy Resource (DER)	A small-scale electrical device connected to a distribution network at low voltage (generally 230 or 400 volts AC) that can reduce its demand for electricity from the distribution network and/or export electricity into the distribution network. Also referred to as consumer energy resources or CER. Examples of DER are rooftop solar photovoltaic generation, standalone batteries, electric vehicle batteries, hot water cylinders, and electrically connected appliances such as heat pumps and refrigerators. DER is controllable if its demand for or supply of electricity can turned on or off or increased or decreased on demand.
Flexibility resource	A flexibility resource is a DER asset with controllable demand and/or generation that can be used to deliver a flexibility service. Small-scale and utility-scale DER (eg, utility-scale generation or batteries) can provide flexibility services.
Flexibility service	The provision of controllable electricity demand and/or generation available from a flexibility resource in response to a price signal or a control signal (eg, a ripple control signal).
Flexibility traders / DER aggregators	Entities that aggregate and manage portfolios of flexibility resources owned by others and/or themselves, and then sell (or allocate) the flexibility services provided by the flexibility resources.
Inertia	System inertia refers to the energy stored in the rotating components of generators, motors and other industrial plant as

	they rotate at a speed that is synchronised to the power system's electrical frequency. Only synchronous machines store energy in this way – IBRs do not inherently provide inertia. Inertia is particularly important for slowing the rate at which frequency changes due to a disturbance on the power system that affects the electricity supply/demand balance. By slowing the rate of change of frequency, inertia helps to limit the size of frequency deviations, because there is more time for actions to stop the frequency deviation.
Inverters and Inverter-based resources (IBRs)	An inverter is an electronic device that converts direct current (DC) electricity to alternating current (AC) electricity. (Electronic devices that convert AC electricity to DC electricity are known as rectifiers.) An inverter-based resource (IBR) is equipment that uses an inverter when functioning. Examples include wind generation, solar photovoltaic generation, and a battery energy storage system. This term distinguishes non-synchronous generators (inverter-based) from synchronous machines (hydro, thermal or geothermal plant).
Non-network solutions	Non-network solutions, also referred to as non-wire alternatives, are projects chosen to deliver flexibility services as an alternative to investing in greater network capacity.
Security, Resilience and Reliability	'Security' refers to the ability of the power system to withstand adverse events, ensuring a steady and stable network that delivers generation to where it is needed (ie, significant adverse events do not cause electricity outages). 'Resilience' refers to the ability to identify and mitigate high-impact, low-frequency threats to the power system quickly and efficiently, to minimise damage to infrastructure and support services, while enabling a quick recovery and restoration of the power system to a stable operating state. 'Reliability' refers to both the continuity of electricity supply (ie, the rate and duration of electricity outages, including those caused by insufficient fuel for electricity generation), and the quality of electricity supply (eg, the frequency and voltage of electricity).[230]

[230] See the following:

- Interpretation of the Authority's statutory objective, 14 February 2011, available at https://www.ea.govt.nz/documents/483/Interpretation_of_the_Authoritys_statutory_objective_izDdeF9.pdf.
- Section 5 of the FSR Phase 1 report prepared for the Authority by the system operator, available at http://www.ea.govt.nz/documents/1979/Appendix-A-Phase-1-final-report.pdf.

Glossary of abbreviations

Act	Electricity Industry Act 2010
AC	Alternating current
AOPO	Asset owner performance obligation
Authority	Electricity Authority Te Mana Hiko
BCG	Boston Consulting Group
Code	Electricity Industry Participation Code 2010
DC	Direct current
DER	Distributed energy resource/s
DOE	Dynamic operating envelope
EECA	Energy Efficiency and Conservation Authority
FSO	Future system operation
FSR	Future security and resilience
GIP	Grid injection point
GXP	Grid exit point
HVDC	High voltage direct current
IBR	Inverter-based resource
IoT	Internet of Things
IPCC	Intergovernmental Panel on Climate Change
MBIE	Ministry of Business, Innovation and Employment
MDAG	Market Development Advisory Group
NERC	North American Electric Reliability Corporation
NIWA	National Institute of Water and Atmospheric Research
Ofgem	Office of Gas and Electricity Markets (UK)
PPO	Principal performance obligation
SCADA	Supervisory control and data acquisition