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ENABLING PARTICIPATION OF NEW GENERATING TECHNOLOGIES IN THE WHOLESALE ELECTRICITY MARKET

MARKET DEVELOPMENT ADVISORY GROUP
RECOMMENDATION TO AUTHORITY BOARD

MARKET DEVELOPMENT ADVISORY GROUP

Note: This paper has been prepared for the purpose of the Market Development Advisory Group. Content should not be interpreted as representing the views or policy of the Electricity Authority.

Contents

1. Executive summary

1.1 The Authority has requested MDAG's advice

1.1.1 The Authority is seeking MDAG's advice on:

a) appropriate first steps to achieving the Authority's aim of ensuring, as far as practicable, that the Electricity Industry Participation Code (Code):

i. enables new generating technologies to participate in the wholesale electricity market (wholesale market) without inefficient barriers / hurdles

ii. signals each generating technology's costs and benefits in relation to promoting electricity reliability

b) a future development plan for achieving the Authority's aim

c) prioritisation of work under the development plan.

1.2 Summary of MDAG's key recommendations

1.2.1 MDAG recommends the Authority should take a first principles approach to achieving the Authority's aim set out above. MDAG considers this would better promote efficiency and long-term consumer benefits, compared with an ad-hoc, piecemeal approach.

1.2.2 As part of a first-principles approach, the Authority should:

a) clearly set out a vision or strategy for enabling the participation of generating technologies in the wholesale market

b) communicate its vision and a development plan to stakeholders, to reduce the likelihood of unnecessary costs on consumers and other stakeholders

c) use key principles to guide the design of Code arrangements for new generating technologies.

1.2.3 MDAG considers the Authority is better placed than MDAG to prepare a development plan with assigned work priorities. However, to assist the Authority in this task, MDAG has:

a) identified a number of key issues associated with generating technologies participating in the wholesale market

b) identified several "quick wins" the Authority could focus on initially

c) prepared a list of possible criteria for the Authority to use when prioritising medium to long-term areas of work.

1.3 Summary of key issues identified by MDAG

1.3.1 The key issues identified by MDAG in relation to generating technologies participating in the wholesale market can be summarised as follows:

a) there are constraints on some generating technologies' participation in the wholesale market, caused by Code provisions and legacy market systems

b) the prices for ancillary services (including compulsory ancillary services provided via asset owner performance obligations (AOPOs) do not always reflect underlying costs/values

c) there is a need to update ancillary services arrangements and the AOPOs because of changing power system characteristics

d) the existing regulatory settings that rely on a generator's capacity and/or connection type may no longer be fit for purpose

e) improvements in the efficiency of arrangements for the offering and pricing of energy are possible.

1.3.2 Section 5 of this report elaborates on these issues.

1.3.3 MDAG considers the Authority can address some of these issues in the short term, thereby gaining some "quick wins" in achieving the Authority's objective. These quick wins are discussed in section 7 of this report. MDAG is aware the Authority is already progressing some of these matters.

1.3.4 The Authority can focus on the remaining identified issues over the medium to longer term. Section 7 of this report lists possible criteria for the Authority to use when prioritising the consideration of these issues and any other issues the Authority identifies.

1.4 Learning from other jurisdictions

1.4.1 Several overseas island power systems already operate at certain times with very high levels of wind and solar photovoltaic (solar PV) generation. Managing variability of electricity generation output and uncertainty is increasingly challenging at higher levels of wind and solar generation. New Zealand can learn from approaches taken in overseas jurisdictions.

1.4.2 For the Authority, these learnings can be in relation to the framework overseas jurisdictions have put in place to enable new generating technologies, as well as in relation to the technical requirements used to ensure new generating technologies support an efficient electricity market and secure power system.

1.5 Drawing on MDAG's expertise and experience

1.5.1 MDAG believes the Authority's aim of facilitating the participation of generating technologies in the wholesale market is a significant piece of work. MDAG welcomes this work being undertaken and looks forward to assisting the Authority.

1.5.2 MDAG considers it can add most value to this work by acting as a "sounding board" or "reviewer" for Authority policy proposals.

2. Introduction

2.1 MDAG's purpose

2.1.1 The Market Development Advisory Group (MDAG) provides independent advice to the Authority on issues in the Authority's work programme that relate primarily to:

a) pricing and cost allocation

b) risk and risk management

c) operational efficiencies.

2.2 The Authority wants to enable participation of new generating technologies in the electricity market

2.2.1 The Authority believes its statutory objective is promoted by having regulatory arrangements that facilitate innovation and the emergence of new participants or providers of services to consumers.

2.2.2 To this end the Authority is aiming to ensure, as far as practicable, that the Code:

a) enables new generating technologies to participate in the wholesale market without inefficient barriers/hurdles

b) signals each generating technology's costs and benefits in relation to promoting electricity reliability.

2.3 MDAG's brief

2.3.1 The Authority seeks advice from MDAG on:

a) appropriate first steps to achieving the Authority's aim

c) a future development plan for achieving the Authority's aim

d) prioritisation of work under the development plan.

2.4 The purpose of this paper

2.4.1 This paper sets out MDAG's recommendations on the three matters the Authority has sought MDAG's advice on (referred to hereafter as "the Authority's request").

2.5 MDAG has interpreted "generating technologies" broadly

2.5.1 MDAG notes the Authority's proposal to amend the definition of "generating unit" in the Code, to clarify that the Code regulates generators that produce electricity other than via a machine (eg, solar PV and batteries).[1]

2.5.2 In preparing this advice to the Authority, MDAG has interpreted "generating technologies" as including non-mechanised generating technologies and storage technologies.

[1] https://www.ea.govt.nz/dmsdocument/25654-consultation-paper-code-review-programme-number-4-september-2019

2.6 MDAG has considered existing as well as new generating technologies

2.6.1 Strictly speaking, the Authority has sought MDAG's advice on enabling "new" generating technologies to participate in the wholesale market.

2.6.2 However, MDAG has also considered whether the Code could better enable the participation of existing technologies in the wholesale market.

2.7 How MDAG's work interacts with the work of IPAG

2.7.1 The Innovation and Participation Advisory Group (IPAG) has in its terms of reference the reduction of inefficient barriers to mass-market distributed energy resources and aggregators of these resources.[2]

2.7.2 MDAG believes technological innovation will lead to a significant percentage of New Zealand's electricity generation being non grid-connected. Much of this is likely to be behind-the-meter.

2.7.3 This will have a range of implications for the wholesale market's operation, including the system operator's activities.

2.7.4 Therefore, MDAG considers small-scale generating technologies should be included in the Authority's consideration of how best to enable the participation of new generating technologies in the wholesale market.

2.7.5 However, conscious of the need to minimise any overlap with IPAG's work, MDAG has considered small-scale generating technologies only in the context of 'virtual power plants'.

[2] https://www.ea.govt.nz/dmsdocument/21667-terms-of-reference-for-the-security-and-reliability-council-and-other-advisory-groups

3. Background

3.1 Generating technologies are changing—ensuring the Code is fit-for-purpose

3.1.1 The Code needs to be fit-for-purpose in relation to changing generating technologies. That is, the Code should facilitate the efficient entry, operation and exit of generating technologies now and in the future.

3.1.2 Climate change has increased Government and public concerns about the impact of fossil fuel generating technologies on our environment. In 2019 the Government amended the Climate Change Response Act 2002 to include a target of zero net emissions of greenhouse gases other than methane by 2050. The Government set an aspirational goal of 100% of electricity to be generated using renewable energy sources by 2035.

3.1.3 Over the past decade, there has been a shift from the use of fossil fuels in electricity generation to renewable energy sources. Geothermal and wind projects are now among the least-cost generation options, and New Zealand's first utility-scale solar generation is under development at Marsden Point. Tidal generation and wave generation, while still in their infancy, are attracting more attention. These technologies make operation of the grid more challenging, by increasing intermittency and inflexibility.

3.1.4 Distributed generating technologies have the potential to make electricity consumption in the home and workplace less reliant on grid-supplied electricity. Photovoltaic panels and solar water heating are becoming more common, reducing demand for grid-supplied electricity. Similarly, battery technology could enable the storage and flexible use of electricity from intermittent generation.

3.1.5 Appendix A provides an overview of emerging generating technologies and their possible implications for the wholesale market.

3.2 The Authority's strategy and work programme look at evolving technologies and business models

3.2.1 The Authority is focusing on four key strategies to meet its statutory objective. The first of these key strategies is to reduce barriers to the entry, expansion and exit of parties in electricity markets, especially for new and potential entrants. By focusing on reducing barriers, the Authority aims to provide the conditions for innovation in business models, whether by retailers or non-traditional businesses wanting to supply an electricity-related product or service to consumers.

3.2.2 To achieve this strategy, the Authority is continuing its work towards reducing inefficient barriers to parties wanting to generate, store, transport and purchase electricity. The Authority is also increasing its focus on providing open networks and making it easier for wider participation in electricity markets.

3.2.3 A programme of work covers initiatives to reduce inefficient barriers to the development and use of evolving technologies and business models across the supply chain.

3.2.4 A project in this programme of work is "*Participation of new generating technologies in the wholesale market*".

3.2.5 The project is to investigate any barriers in the Code to the efficient operation of new generating technologies in the wholesale market (eg, offer, dispatch, spot price arbitrage and participation in the ancillary services market).

3.2.6 A key catalyst for the project was Mercury Energy's grid-connected 1 MW battery at Southdown in Auckland. Another key driver for the project is the planned connection of grid-scale solar generation.

3.2.7 Removing any barriers to different forms of generating technologies in the wholesale market is expected to:

a) improve competition

b) contribute to reliability

c) potentially improve the operational efficiency of the electricity industry.

3.3 What is the wholesale market?

3.3.1 The Code defines the wholesale market to mean:

a) the spot market for electricity, including the processes for setting:

i. real time prices

ii. forecast prices and forecast reserve prices

iii. provisional prices and provisional reserve prices

iv. interim prices and interim reserve prices

v. final prices and final reserve prices

b) markets for ancillary services

c) the hedge market for electricity, including the market for financial transmission rights (FTRs).

The wholesale market is primarily governed by Parts 13 and 8 of the Code

3.3.2 Part 13 of the Code contains most of the rules governing the spot market and the hedge market.

3.3.3 Part 8 of the Code contains the rules governing the ancillary services necessary to ensure electricity reliability. The markets for ancillary services provide a significant proportion of these services. The remaining ancillary services are provided via AOPOs. Appendix B provides further information on ancillary services and AOPOs.

3.3.4 Parts 14, 14A and 15 contain supporting provisions for Parts 13 and 8. Part 14 relates to settlement of the wholesale market. Part 14A relates to wholesale market participants' management of prudential security. Part 15 relates to the reconciliation of quantities of electricity traded in the wholesale market. Appendix C summarises key generator obligations under the Code.

4. MDAG's approach to considering the Authority's request

4.1 MDAG considered context

4.1.1 Upon receipt of the Authority's request, MDAG first considered the context surrounding the Code enabling new generating technologies to participate in the wholesale market.

4.1.2 This included:

a) the potential landscape for new generating technologies, noting that grid-scale batteries and solar are the most recent generating technologies that need to be accommodated under the Code

b) that the existing Code framework is based on earlier rules, which have had significant resources and time invested in them over many years

c) that there are several interdependencies with other Authority projects—in particular:

i. are there barriers to renewables in the wholesale market?[3]

ii. additional consumer choice of electricity services (ACCES)[4]

iii. open networks development programme[5]

iv. real-time pricing (RTP)[6]

v. dispatch service enhancement (DSE)[7]

vi. review of Code provisions for wholesale market arrangements (a discretionary project, which may have fewer resources assigned to it by the Authority than the other projects listed above).[8]

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3 This project is to investigate whether there are any impediments in the wholesale market to achieving the Government's commitments relating to renewable electricity generation.

4 This project is investigating the benefits of enabling additional consumer choice of electricity services, and any barriers that may prevent this choice. The project will effectively allow for the unbundling of electricity service offerings.

5 This programme is identifying ways of providing for the uptake of new technology on distribution networks. The project is being undertaken to ensure distribution networks remain flexible and open to emerging consumer preferences and new technologies, including for example; greater use of distributed generation and electric vehicles.

6 Under this project, the wholesale spot electricity market will be settled using prices determined in real time. The project includes extending dispatch arrangements to make it easier for both smaller-scale purchasers and generators to participate in the wholesale spot electricity market.

7 Amendments to the Code and the Approved Systems Document are needed to enable the system operator to replace GENCO as the approved system for issuing dispatch instructions, with two alternate communication protocols (Inter-Control Centre Communications Protocol (ICCP) and web services).

The project aims to improve efficiency and competition in the wholesale market by lowering entry and operational costs for dispatch and enabling potential new features. DSE is regarded as a key enabling project for settling the wholesale market using real-time pricing, and for greater participation in dispatch by new technologies.

8 This project will involve reviewing the trading arrangements in Part 13 of the Code, including the electricity spot market (eg, offering, scheduling, dispatch and pricing), the hedge market, and FTR trading information. The work would include removing unnecessary barriers to new technologies.

4.2 MDAG confirmed the scope

4.2.1 MDAG discussed whether it should consider 'behind the meter' generation services. MDAG noted this would require input from, and liaison with, IPAG, because IPAG is currently looking at behind the meter services as part of the ACCES project. MDAG decided to consider "behind the meter" generation services only as part of MDAG's consideration of 'virtual power plants' participating in the wholesale market.

4.2.2 MDAG also discussed whether it should consider issues associated with the Code enabling the participation of *all* generating technologies in the wholesale market, rather than just *new* generating technologies. MDAG decided to consider the participation of all generating technologies in the wholesale market. This is because the way in which the Code facilitates the participation of new generating technologies will affect the participation of existing generating technologies.

4.3 MDAG made some key assumptions

4.3.1 MDAG made some key assumptions—namely:

a) security and quality standards relating to frequency and voltage across the grid and distribution networks remain the same as currently

b) distributed energy resources are likely to be increasingly offered into the wholesale market in the future.

4.4 MDAG identified issues associated with generating technologies

4.4.1 MDAG held a facilitated workshop to consider issues associated with generating technologies participating in the wholesale market.

4.4.2 The issues identified by MDAG can be grouped as follows:

a) there are constraints on some generating technologies' participation in the wholesale market, caused by Code provisions and legacy market systems

b) the prices for ancillary services (including compulsory ancillary services provided via AOPOs) do not always reflect underlying costs / values

c) there is a need to update ancillary services arrangements and the AOPOs because of changing power system characteristics

d) the existing regulatory settings that rely on a generator's capacity and/or connection type may no longer be fit for purpose

e) improvements in the efficiency of arrangements for the offering and pricing of energy are possible

f) other issues.

4.5 MDAG prioritised the issues it identified

4.5.1 MDAG assessed two approaches that could be used by the Authority to address the issues MDAG identified in relation to generating technologies:

a) clustering the issues and considering each cluster of issues in turn (the *evolutionary* approach)

b) taking a first-principles approach, considering what rules should apply to all generating technologies used by participants undertaking activities regulated by the Code (*first principles* approach).

4.5.2 MDAG then identified the "quick wins" the Authority could focus on initially.

4.6 Overseas jurisdictions' experience facilitating new generating technologies

4.6.1 MDAG is aware that several overseas island power systems already operate at certain times with very high levels of wind and solar photovoltaic generation – including Ireland (85%), Tasmania (70%) and Great Britain (67%).

4.6.2 Australia is at the forefront of connecting wind and solar photovoltaic generation, with one of the highest penetrations of residential solar PV generation in the world (20% of homes). The Australian Energy Market Commission (AEMC) has progressively updated its National Electricity Rules (NER) to accommodate new forms of generation and to manage security issues. In 2018, AEMC amended the NER to make significant changes to the conditions for connection of generators.

4.6.3 MDAG recognises lack of visibility of distributed energy resources compromises the system operator's ability to securely manage the power system. Several jurisdictions have recently mandated improved inverter functionality for small-scale solar PV generation. This has been in recognition of the impacts on the power system of increasing penetrations of residential photovoltaic generation,

4.6.4 Managing variability and uncertainty is increasingly challenging at higher levels of wind and solar generation. New Zealand can learn from approaches taken in Ireland and California, including the assessment of system ramping requirements and generating fleet capability. Likewise, New Zealand should consider international approaches to frequency management in power systems with high amounts of renewable generation, including approaches to maintaining sufficient inertia on the power system.

5. Issues identified

5.1 Generating technologies' participation in the wholesale market constrained by Code provisions and legacy systems

Code definitions may be inhibiting the participation of some generating technologies

5.1.1 MDAG identified that some Code definitions may be inhibiting the participation of generating technologies in the wholesale market. Two such definitions are:

a) instantaneous reserve

b) grid.

The definition of "instantaneous reserve" is restrictive

5.1.2 The Code permits three forms of instantaneous reserve:

a) interruptible load

b) partially loaded spinning reserve (PLSR)

c) tail water depressed reserve (TWDR).

5.1.3 While only hydro generation can provide TWDR, the intent is for PLSR and interruptible load to enable, respectively, generation and load to participate in the reserves market. Although the definition of interruptible load enables batteries to participate, by ceasing to charge, the definition of PLSR does not enable batteries to participate by discharging energy (ie, acting as generation).

The definition of "grid" may be too broad

5.1.4 Owners of lines that connect generating stations may inadvertently be treated as a grid owner under the Code.

5.1.5 Note the Code provides for multiple grid owners.

Connection arrangements in the Code may be inhibiting the participation of some new generating technologies

5.1.6 Part 12 of the Code regulates, amongst other things, transmission agreements. The benchmark agreement, which has not been reviewed since 2008, may be inhibiting the participation of some new generating technologies. This is because of the high transaction cost associated with making variations to it (eg, changing service levels).

Market systems/processes restrict participation of some generating technologies

5.1.7 Some market systems effectively constrain the participation of certain generating technologies in the wholesale market, even though the Code contains no such restriction. Key examples include:

a) limitations within the frequency keeping procurement systems:

i. frequency keeping providers must be > 4 MW. This limits participation by technologies that are inherently smaller scale, such as batteries

ii. frequency keeping offers must be from generation plant that is being offered into the (wholesale) energy market. Again, this may limit participation by generating technologies such as batteries

b) system limitations that reduce the ability of electric vehicle batteries to efficiently participate in the wholesale market, with examples of such systems including:

i. the systems used to coordinate electric vehicle charging and vehicle-to-grid injection on local distribution networks, to prevent thermal and voltage limits being exceeded

ii. the systems used to address capacity scarcity on a regional or national level

iii. the systems used to manage grid restoration after a loss of supply.

Market systems/processes may restrict participation of 'virtual' participants

5.1.8 MDAG notes the Code does not appear to prevent the participation of 'virtual' participants in the energy and/or ancillary services markets. These are participants who aggregate the capacities of multiple smaller generating, or demand-side management, technologies for the purpose of participating as a single 'virtual' generator or 'virtual' load.

5.1.9 However, the requirements of some market systems may restrict the participation of 'virtual' participants in the wholesale market. For example, the system operator's systems may require the submission of offers at a specific grid exit point. This is not conducive to a virtual power plant making offers when that virtual power plant comprises smaller generating technologies spread across multiple grid exit points. This may also be the case for some virtual loads.

5.2 Prices for ancillary service arrangements do not always reflect underlying costs / values

5.2.1 MDAG has identified that the current ancillary service arrangements, including the AOPOs and technical standards, are causing inconsistent price signals:

a) between different generating technologies, and

b) between different sizes of generating technologies.

5.2.2 MDAG has identified the following potential issues:

a) Ancillary services are not always being charged on a 'causer pays' basis—for example:

i. intermittent generators are not receiving some proportion of the costs of frequency keeping, even though they cause a proportion of frequency keeping resources to be procured

ii. instantaneous reserves costs are not being allocated in proportion to the extent to which different-sized generators contribute to the need for instantaneous reserves

iii. generators and (non-linear) loads are not always paying their full share of the cost for Transpower to rectify harmonic or phase problems caused by their connection.

b) The dispensation regime may be causing an inefficient allocation of costs between generators with and without dispensations from an AOPO. This can occur when the cost of a dispensation cannot be readily identified—for example, the cost of some generators not providing governor response.

c) AOPOs defined in insufficient detail result in generators changing settings to reduce the costs they face, but in doing so they impose greater costs on others. For example, the obligation for generators to make contributions to maintain frequency within the normal band is not specific about required performance when frequency is within the normal band.

d) The requirements arising from technical standards for small-scale generation are potentially different to the requirements arising from AOPOs on large generators. For example, the obligation to export, or import, reactive power only applies to grid-connected generators.

5.2.3 The potential outcomes from the above inadequacies include:

a) Inefficient investment in, or retirement of, generating technologies at the margin. An initial qualitative evaluation suggests this is unlikely to be causing major inefficiencies—the scale of the cost impact is insufficient to substantially alter the relative merit order of investment / retirement decisions between different types and sizes of generating technologies.

b) Incentives on generators to alter equipment settings to reduce their costs, leading to more procurement of market-based ancillary services. For example, generators altering governor settings can result in more frequency keeping services being needed. A significant proportion of this cost may be a wealth transfer—the same quantity of frequency keeping services may be provided to the wholesale market, but with different payers.

c) Overall degradation of system security, through:

i. uptake of generating technologies with lower security characteristics *and*

ii. the system operator being unable to adequately monitor aggregate system security impacts and thus not procuring adequate resources to compensate for the lower security characteristics.

d) Wealth transfers, as parties providing ancillary services are incurring costs but are not receiving compensation from those parties not providing ancillary services. These wealth transfers can lead to inefficient behaviour by market participants.

5.3 Changing power system characteristics require updated ancillary services arrangements and AOPOs

5.3.1 The development of new technologies (eg, wind) is causing, and is expected to continue causing, the retirement of some conventional generating plant (eg, large-scale thermal generation). The resulting changes in power system characteristics may warrant changes to the design of some ancillary service arrangements.

Changing system inertia affects instantaneous reserves, AUFLS and frequency keeping requirements

5.3.2 In many cases, thermal generation is being replaced by non-synchronous generation, which does not provide inertia. This reduction in the inertia of generating plant connected to the power system means system frequency will change more rapidly in response to supply / demand imbalances. This in turn requires, for a given level of demand, an increased supply of resources for frequency keeping, instantaneous reserves and automatic under-frequency load shedding (AUFLS).

5.3.3 Currently, there is no specific procurement of, or payment for, inertia. Nor is some proportion of the cost of procuring instantaneous reserves and frequency keeping allocated to generators that do not provide inertia.

Fewer large-scale generating units affect instantaneous reserves requirements

5.3.4 The progressive retirement of very large thermal generating units is resulting in much less frequent large supply interruptions.

5.3.5 As a result, constantly procuring instantaneous reserves of sufficient scale to cover the remaining few large-scale risks may be inefficient, relative to covering such risks by AUFLS (as occurs in some overseas markets).

Performance standards needed for inverter-connected resources

5.3.6 Wind, solar and batteries are three examples of generating technologies that asynchronously connect to a network through inverter-based power electronic devices.

5.3.7 The power electronics used in inverters can be configured to assist in avoiding cascade failure from frequency or voltage excursions, thereby providing the same functionality as synchronous generation. However, minimum standards for inverter protection functions, monitoring capability and stable operating performance are required for this configuration to occur.

5.3.8 The current generator AOPOs were developed primarily for synchronous generating units. The mix of generating technologies in New Zealand is expected to continue changing, with increasing amounts of new renewable generating technologies such as wind and photovoltaics. In addition, battery energy storage systems will enable surplus energy from generation to be stored and used at another time.

5.3.9 Hence, there is now a need to develop AOPOs specifically for asynchronous inverter-connected technologies, to ensure reliability issues do not emerge for these devices.

Additional intermittent generation may affect scheduling of transmission outages

5.3.10 It is likely that additional intermittent generation will make the scheduling transmission outages more difficult, because of the variability of the generation output. This may require a change to the ancillary services arrangements.

5.4 Existing regulatory settings reliant on a generator's capacity and/or connection type may no longer be fit for purpose

Existing capacity-based thresholds for some Code obligations on generators may be inefficiently high/low

5.4.1 Certain Code obligations apply to generators only if the generator's capacity exceeds a certain amount.

5.4.2 With the advent of new generating technologies, it is appropriate to review these capacity thresholds in the Code, to ensure they remain fit for purpose.

5.4.3 For example:

a) the forecasting requirements on intermittent generators may impose inefficient costs on smaller-sized generators—it is possible that such forecasts may be more cost-effectively (and potentially more accurately) produced by a central agency

b) some smaller-sized generators should perhaps be contributing to the maintenance of frequency within the normal band.

5.4.4 Possible adverse outcomes from generators' Code obligations being determined by capacity-based thresholds that are inefficiently high/low include:

a) distortion of generation investment patterns—over-investment in some types or sizes of generation, and under-investment in others

b) inefficient transaction costs.

The system operator has limited visibility of smaller-scale generators

5.4.5 The system operator has limited, and often no, visibility of the type, disposition and expected output / performance of generators with generating units less than 1 MW in capacity.

5.4.6 This limited visibility will become increasingly material to the system operator's management of grid security as more small-scale generators connect to distribution networks. MDAG believes this limited visibility has the potential to reduce the system operator's ability to:

a) model the behaviour of the grid in response to contingencies

b) procure sufficient ancillary services accordingly

c) manage emergencies.

The grid owner has limited visibility of smaller-scale generators

5.4.7 The grid owner also has limited, and often no, visibility of the type, disposition and expected output / performance of generators with generating units less than 1 MW in capacity.

5.4.8 This limited visibility means the grid owner is unable to manage transmission system availability and reliability as efficiently as it could. In particular, because the grid owner cannot see smaller embedded generation, it is disabling its auto-reclose system [on transmission circuits with "N" availability] to minimise the risk of damage to this embedded generation in the event of an unplanned outage of the circuit. This lowers system availability and reliability.

Generators get paid differently based on connection type

5.4.9 The payment made for energy produced by a generator is influenced by that generator's connection type.

5.4.10 For example, a person with behind-the-meter generation may be paid more than the economic value of the energy produced, due to the consumer tariff used to "pay" for the energy not being cost-reflective. Under the consumer tariff:

a) fixed network and retail costs may be recovered via variable charges

b) the cost of wholesale generation and network costs may be recovered via a non-time-varying charge, which is not aligned with the profile of the behind-the-meter generation.

5.4.11 Another example is distribution-connected generators being paid different amounts for avoided transmission costs than transmission-connected generators, due to the operation of the transmission pricing methodology. This can distort generation investment patterns.

5.5 Possible improvements in the efficiency of arrangements for offering and pricing energy

Possible inefficiencies in the structure of storage technologies' offers

5.5.1 More efficient dispatch may be achievable if combined offers and bids are used for storage technologies that can almost instantaneously inject into, and draw from, the grid.

5.5.2 The benefits of more efficient dispatch could include:

a) a reduced requirement for the electricity system to have peaking assets

b) more efficient generating unit commitment decisions.

5.5.3 While not a major issue now, large-scale uptake of electric vehicles with vehicle-to-grid technology could make this a bigger issue in the future.

Ensuring the energy-only market design can accommodate a high proportion of intermittent generation

5.5.4 As the power system moves to having a higher proportion of renewable energy, much of it intermittent in nature, there is the potential for increased extremes of surplus / scarcity of electricity supply. MDAG considers possible adverse consequences include:

a) insufficient generation at times of scarcity (eg, periods of unusually low generation output and high demand)

b) poor outcomes at times of surplus, through inefficient scaling back of generators during periods when available generation exceeds demand.

5.5.5 In relation to scarcity of electricity supply, various arrangements are in place in the wholesale market to send efficient price signals to participants as to the relative value of generation at times of scarcity and surplus. Other arrangements are designed to incentivise consumers (or their agents, in the form of retailers) to contract with providers of infrequently required forms of generation (or demand response) at times of scarcity.

5.5.6 These arrangements should continue to send efficient price signals, even at high proportions of renewables. The Authority is planning to investigate this in more detail as part of its project *Are there barriers to renewables in the wholesale market?*

5.5.7 However, MDAG notes this may require more active demand-side participation, including through aggregated demand response from large numbers of consumer-scale technologies (eg, electric vehicles, heat-pumps, etc). It will likely also result in greater spot price extremes between periods of surplus and scarcity.

5.6 Other issues

5.6.1 MDAG has identified some other issues that it considers are worthy of investigation:

a) The extent of restrictions on distributors owning or operating technologies that participate (wholly or partly) in the wholesale market on a competitive basis. Key examples include:

   i. provision of consumer-scale technologies such as solar panels and batteries

   ii. planning for, and investment in, electric vehicle charging infrastructure.

b) Current wholesale market arrangements, and network pricing and access arrangements, potentially limiting the ability of some technologies to capture value along the entire electricity supply chain.

6. Principles to guide design of Code arrangements for generating technologies

6.1 MDAG has identified six key design principles

6.1.1 MDAG has identified six key principles to guide the design of Code arrangements for new generating technologies:

a) *output-based competitive neutrality* – The Code should be defined in terms of required outputs and remain neutral as to which technology can deliver the required output in the most economically and technically efficient manner. The Code should set a "level playing field" from a competition standpoint -- that is to say, it should not "pick winners" or give some technologies special treatment relative to others.

b) *signal costs and benefits* – the Code should signal each generating technology's costs and benefits in relation to providing outputs required under the Code, including reliability, security of supply, voltage support and frequency keeping

c) *full costs* – the Code should signal the full costs of alternative technologies on the system, including costs imposed on other parties

d) *market-based approaches preferable* – the Code should use market-based approaches for the provision of outputs required by the Code, including reliability, security of supply, voltage support and frequency keeping

e) *durable framework that allows efficient adaptation*– the Codes' framework should be durable across a range of uncertain future scenarios, allowing within the framework efficient evolution of rules to enable better ways of achieving required outputs.

f) *efficient Code development* – the Authority should ensure the Code development costs it and stakeholders incur are efficient.

These design principles are intended to give effect to the Authority's statutory objective.

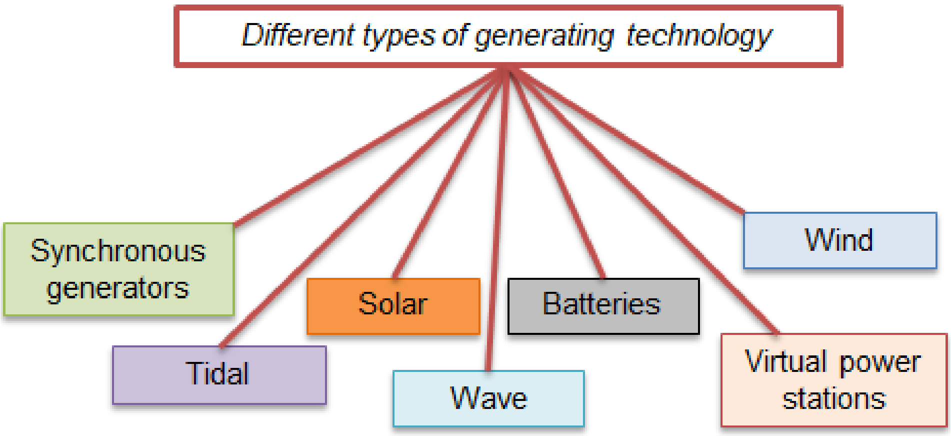
6.2 Elaborating on the first design principle: *output-based competitive neutrality*

6.2.1 The Code should be re-framed under the principle of output-based competitive neutrality. The Code should be defined in terms of required outputs, including reliability, security of supply, voltage support and frequency keeping. The Code should also remain neutral as to which technology can deliver the required output in the most economically and technically efficient manner

6.2.2 The Code should not give a competitive advantage to a generating plant based on technology, size or connection type. By "connection type", MDAG means whether the generating plant is connected to a transmission network, a local distribution network or an embedded distribution network.

6.2.3 With more generating technologies entering the electricity market, there is an increasing range of performance capabilities across generating technologies (refer to Figure 1 below).

Figure 1: Electricity generating technologies



6.2.4 The Code is not technology neutral—rather, it is technology specific. An excellent example is the different, less onerous, AOPOs on wind generation compared with other forms of generation.

6.2.5 It is likely the Code will need to continue to be technology specific at least in relation to the differing technical and performance characteristics across different generating technologies (compare synchronous geothermal generation plant with non-synchronous solar generation plant connected to a network via an inverter).

6.2.6 However, the crucial thing is that, as outlined above, the Code should be defined in terms of required outputs and remain neutral as to which technology can best deliver the required output.

6.2.7 The same point applies to generating technologies of different sizes and connection types. Currently, the Code grants more concessions to a generating plant connected to a distribution network (local or embedded), and with an installed capacity of less than 30 MW, than it does to grid-connected generating plant with an installed capacity of 30 MW or more.

6.3 Elaborating on the second, third and fourth design principles: *signal costs and benefits, full costs, market-based approaches preferable*

6.3.1 MDAG notes that signalling the extent to which a generating technology deliver or promote the Code's required outputs – including grid reliability, security of energy supply, voltage support and frequency keeping – is crucial. It involves:

a) identifying the range of energy-related services and ancillary services that a generating technology offers in the wholesale market

b) identifying the cost of these services, and

c) having appropriate arrangements for pricing / recovering the cost of these services.

6.3.2 The signalling of costs needs to reflect full costs, including costs imposed on other parties

6.3.3 Market-based arrangements make transparent the cost of providing / using energy services and ancillary services. This approach can be applied in the provisions of various outputs required by the Code, including for example the provision, or use, of services that support voltage and frequency. Under this approach there would be a need to:

a) determine how much a generating technology supports frequency / voltage

b) determine the cost of frequency / voltage support, by provider

c) allocate the cost of frequency / voltage support to each user of the service.

The AOPOs are increasingly out of date

6.3.4 In passing, MDAG notes the AOPOs covering the mandated services that generators must provide are becoming increasingly out of date. More flexible arrangements will be needed to accommodate new technologies with a variety of different performance characteristics.

6.3.5 A key matter to be considered is whether different AOPOs should be put in place for each type of generating technology supplying energy and/or reserves in the wholesale market. If this were to occur, it would:

a) make transparent each generating technology's contribution to frequency / voltage support

b) remove administrative costs of dispensation / equivalence arrangements.

6.4 Elaborating on the fifth design principle: *durability and adaptability*

6.4.1 The re-developed Code should be durable across a range of uncertain future scenarios. MDAG considers this can be facilitated by:

a) the Code promoting competitive neutrality (as discussed above)

b) minimising prescription in the Code, to the extent practicable.

6.4.2 While the Code's framework should be durable across a range of scenarios, it should also allow efficient evolution of rules to enable better ways of achieving required outputs. New information and capabilities will continue to emerge, and the Code needs to enable adaptation of rules within the Code to capture those benefits.

Minimise prescription in the Code where practicable

6.4.3 MDAG believes that adopting an outcomes-based approach to Code provisions governing the participation of generating technologies in the wholesale market appears a sensible way of reducing the number and size of future Code changes made to accommodate new generating technologies. Prescriptive Code provisions:

a) could stifle innovation in how generating technologies participate in the wholesale market

b) are typically more expensive to design and develop than outcomes-based provisions.

6.4.4 Having said this, MDAG notes that prescriptive Code provisions may be necessary for some generating plant obligations (eg, to enable an obligation to be enforceable). Where required, detailed prescriptive provisions could be placed in documents sitting outside the Code, which are easier to keep updated. Such documents include the system operator's procurement plan and the ancillary services procurement contract.

6.5 Elaborating on the sixth design principle: *efficient Code development*

6.5.1 MDAG notes there is a trade-off between perfection and pragmatism in designing Code arrangements to facilitate the participation of new generating technologies in the wholesale market.

6.5.2 MDAG believes the Authority will often need to be pragmatic when designing these Code arrangements. At times the transaction costs associated with developing Code arrangements that offer a theoretically "pure" solution to an issue may outweigh the expected benefits.

6.5.3 An area where MDAG believes this may arise is signalling the relative costs / benefits of different technologies participating in the wholesale market. For example, MDAG considers the Authority should only develop Code arrangements that recover the wholesale market costs imposed by a generating technology if the improved resource allocation outcomes from the Code arrangements are expected to outweigh the costs of developing and implementing the arrangements.

7. Recommendations

7.1 MDAG's advice

7.1.1 As noted in this paper's introduction, the Authority is aiming to facilitate the participation of new generating technologies in the wholesale market. The Authority has asked MDAG:

a) to consider the range of possible work that could be undertaken to facilitate the participation of new generating technologies in the wholesale market, and

b) to provide the Authority with advice on a proposed programme of work to facilitate the participation of new generating technologies in the wholesale market, including prioritisation.

7.2 The Authority should adopt a first-principles approach

7.2.1 MDAG has concluded the Authority should take a first principles approach to enabling the participation of new generating technologies in the wholesale market over the medium to longer term. MDAG considers this would better promote efficiency and long-term consumer benefits, compared with an ad-hoc, piecemeal approach.

7.2.2 MDAG does not favour a piecemeal approach to addressing MDAG's identified issues because, in particular:

a) it would be likely to raise significant barriers to having a coherent, optimal Code over time

b) it would raise the risk of inefficient investment decisions in new generating technologies (due to a lack of information for stakeholders on expected changes to regulatory settings).

7.2.3 MDAG recommends the Authority adopt the six key principles in section 6 to guide the design of Code arrangements for new generating technologies. MDAG believes these would usefully guide the Authority's Code development, within the overarching direction provided by the Authority's statutory objective.

7.2.4 MDAG recommends the Authority learn from overseas jurisdictions' experience facilitating new generating technologies, starting with the frameworks they have put in place to facilitate new generating technologies. The Authority can then overlay these learnings with New Zealand-specific context (eg, the relatively small size of New Zealand's electricity system and the consequential effects of different types and sizes of generation on the system and on consumers' electricity supply quality and reliability).

7.3 The Authority should have a vision and a development plan

7.3.1 Change in generating technologies is coming. New Zealand needs to have a process in place to ensure the Code accommodates new generating technologies. MDAG believes the Authority should consider the long-term picture. To this end, MDAG recommends the Authority clearly set out a vision or strategy for enabling the participation of generating technologies in the wholesale market.

7.3.2 MDAG considers that facilitating the participation of generating technologies in the wholesale market would be a substantive programme of work for the Authority over the coming years. MDAG concludes the Authority should have a plan for progressing the work to achieve this vision or strategy, by way of progressive changes to regulatory settings over time—with the use of progressive changes necessary because of the scale and complexity of the work.

7.3.3 MDAG recommends the Authority communicate its vision and development plan to stakeholders. This is to reduce the likelihood of inefficient investments being made that impose unnecessary costs on consumers and other relevant stakeholders.

7.4 Appropriate first steps: some quick wins can be achieved

7.4.1 MDAG considers the Authority can achieve several short-term wins in enabling generating technologies to participate in the wholesale market. Specifically, MDAG recommends the Authority:

a) ensure the Code accommodates the offer and dispatch of solar generation in the wholesale market

b) enable batteries to inject energy as a reserve product in the wholesale market

c) put in place performance requirements for generation connected to networks via an inverter and which is not governed by any inverter standard under Part 6 of the Code.

7.4.2 MDAG is aware the Authority has already initiated work on enabling batteries and solar PV (utility-scale or aggregated consumer-scale) to offer energy and ancillary services in the wholesale market. As part of this work, the Authority should assess the extent to which solar PV can be accommodated under the existing intermittent generation offer requirements and gate closure times, which were designed originally with wind generators only in mind.

7.4.3 Issues considered should not be limited to the effect these technologies have on wholesale market outcomes. For example, when looking to enable solar PV to participate in the wholesale market, the Authority should consider ensuring the standards for solar PV inverters enable appropriate voltage management on distribution networks.

7.4.4 Beyond these “quick wins”, MDAG considers the Authority should adopt a staged approach to enabling the participation of new generating technologies in the wholesale market. As noted above, MDAG believes this would be a substantive programme of work for the Authority to lead over the coming years.

7.5 Prioritising the medium to long-term work

7.5.1 MDAG has prepared the following list of possible criteria for the Authority to use when prioritising medium to long-term areas of work:

a) how much of a barrier to generating technologies participating in the wholesale market today is the matter?

b) what is the size of the potential economic benefit if the matter were to be addressed?

c) what amount of effort and length of time is required to consider the matter and implement any recommendations?

d) what is the potential for large economic distortions to arise if consideration of the matter is deferred for several years?

e) what is the impact on the operation of the power system if the matter were to be addressed?

7.6 MDAG can act as a “sounding board”

7.6.1 MDAG believes it can add most value to the Authority’s future work facilitating the participation of generating technologies in the wholesale market by acting as a “sounding board” or “reviewer” for Authority policy proposals.

7.6.2 MDAG considers the Authority is best placed to lead the design work.

7.7 Take care to not underestimate resource requirements

7.7.1 The current Code provisions governing generating technologies have been developed over many years. The bulk of Parts 8 and 13 were developed during the 1990s and early 2000s, with the involvement of:

a) large, dedicated project teams containing relevant subject matter experts

b) stakeholder working groups that regularly reviewed the evolving design of the draft arrangements and provided input to the project teams on the design and on the associated draft rules

c) technical groups that assisted the project teams with technical input to the design of the arrangements and the draft rules.

7.7.2 MDAG considers that, while this project will not be as large as these earlier projects, it will be substantial, requiring significant resources from the Authority and industry at various times.

Appendix A New and emerging generating technologies—overview and possible implications

Introduction

A.1 Technology change is driving new and evolving forms of electricity generation.

A.2 This appendix summarises grid-scale technologies not in widespread use in New Zealand today, but which may be used at scale in the next 5–20 years.

A.3 The appendix then briefly canvasses possible implications of new generating technologies for the wholesale market.

New and emerging generating technologies

A.4 The new and emerging generating technologies covered in this appendix are:

(a) battery storage

(b) “green” thermal generation

(c) hydrogen generation, including stationary hydrogen fuel cells

(d) pumped hydroelectric storage generation

(e) solar generation (grid scale solar PV, concentrated photovoltaics, concentrated solar power)

(f) tidal and wave energy.

A.5 Small-scale generating technologies within the meaning of distributed energy resources are not covered in this overview. Refer instead to the Authority’s ‘Enabling mass participation’ project.

Battery storage

A.6 Other than energy arbitrage, grid-scale batteries could provide:

(a) capacity adequacy (ie, fulfilling a peaking role), competing with open cycle gas turbines (OCGTs)

(b) ancillary services (eg, reserves, frequency regulation, voltage support, black start).

A.7 Total installed costs of batteries:

(a) are cheaper on a per-unit of power capacity basis (i.e. $ / MW) for batteries of shorter duration than for long-duration batteries

(b) are cheaper on a per-unit of energy capacity basis (i.e. $ / MWh) for long-duration batteries than for batteries of shorter duration.

A.8 The levelised cost of energy storage (2018): approximately $305–$705 / MWh (NZD 1: USD 0.67)

A.9 Sources: *Lazard 2018b, U.S. EIA 2018, Transpower 2017, Rocky Mountain Institute 2015*

"Green" thermal generation

A.10 The three more commonly referred to types of green thermal generation are:

(a) biomass-fuelled gas turbines

(b) hydrogen-fuelled gas turbines (*see the next section below*)

(c) carbon capture at source.

A.11 In New Zealand, biomass-fuelled gas turbines are perhaps more likely for OCGTs fulfilling a peaking role. This is because of the availability and cost of sufficient amounts of biomass-derived gas in New Zealand that is of the necessary quality to be used in gas turbines.

A.12 An example of carbon capture at source is the Allam Cycle. This is where CO2 flows over the blades of the turbine to make the rotor spin.

A.13 <u>Sources:</u> *Crolius 2019, Sapere 2018*

Hydrogen generation

A.14 Two means by which to create hydrogen are:

(a) from water, via electrolysis

(b) from fossil fuels, via gas reforming (with carbon capture and storage to reduce the carbon footprint).

A.15 Hydrogen could replace natural gas as a fuel for generating plant.

A.16 The life cycle efficiency of electrolysis, storage and generation use for hydrogen is 25–35%.

A.17 Producing hydrogen from natural gas incurs an efficiency penalty of around 65–80%.

A.18 The production-only cost of hydrogen (2018):

(a) electrolysis: $175–$190 / MWh

(b) steam methane reforming: $70 / MWh with $100 / tonne CO2 carbon cost.

A.19 <u>Sources:</u> *Concept Consulting 2019, Committee on Climate Change 2018, Sapere 2018*

Stationary fuel cells

A.20 With stationary fuel cells, an electro-chemical reaction generates energy.

A.21 Fuel cells can be distinguished by operating temperature, catalyst, fuel types (eg, hydrogen, natural gas, biomass), and hydrogen purity.

A.22 Fuel cell types include:

(a) polymer electrolyte membrane (also known as proton exchange membrane) (PEM)

(b) solid oxide

(c) molten carbonate

(d) alkaline

(e) phosphoric acid

(f) direct methanol.

A.23 Stationary fuel cells have a relatively high thermal efficiency in converting energy (circa 50–60%).

A.24 The PEM fuel cell cost (2018): approximately $350–$430 / MWh on a levelised cost of electricity basis (NZD 1: AUD 0.95)

A.25 Sources: *Proctor 2019, CSIRO 2018, IEA 2017*

Pumped hydroelectric storage generation

A.26 There are two main types of pumped hydroelectric storage (PHES) generation:

(a) Pure, or off-stream PHES – uses only pumped water

(b) Combined/hybrid PHES – uses pumped water and natural stream flow water.

A.27 The round-trip efficiency of modern PHES generation is circa 70–85%, although PHES generation is still a net consumer of electricity.

A.28 Wind or solar power generation coupled with PHES is now being developed.

A.29 PHES reservoirs that are in use, or have been planned, include:

(a) flooded mine shafts

(b) underground caves

(c) oceans.

A.30 The levelised cost of energy storage for PHES generation (2016): approximately $225–$295 / MWh (NZD 1: USD 0.67)

A.31 Sources: *Schmidt et al 2017, Lazard 2016, Luo et al 2014, Yang 2010, Chen et al 2009*

Solar generation

A.32 In 2017:

(a) 98 GW of solar generation was installed globally

(b) 70 GW of new fossil fuel generation was built globally.

A.33 This was the first time since the industrial revolution that a renewable energy form of generation exceeded the construction of conventional fossil fuel-powered electricity generation.

A.34 NZ has over 85 MW of distributed solar PV installed, almost half of which was installed over the past two years.

A.35 The levelised cost of energy for grid-scale (utility) solar PV (2018): approximately $40–$70 / MWh (NZD 1: USD 0.67).

A.36 Sources: *Transpower 2019, Lazard 2018a, Lilliestam et al 2018*

Solar PV vs. concentrated solar power

A.37 Solar PV uses sunlight through the ‘photovoltaic effect’ to generate direct current in a direct electricity production process. Concentrator PV uses lenses or curved mirrors to focus sunlight onto small, highly efficient, multi-junction solar cells.

A.38 Concentrated solar power (CSP) uses mirrors to reflect and concentrate sunlight onto a single point where it is collected and used to heat fluid to a high temperature (eg, oil, molten salt), which is then used to make steam and drive an electricity turbine.

A.39 CSP technologies include:

(a) parabolic trough

(b) linear Fresnel reflector

(c) power tower

(d) dish/engine systems.

A.40 CSP can provide dispatchable renewable power on a large scale.

A.41 The levelised cost of energy for concentrated solar power (CSP) (2018): approximately $150-$250 / MWh (NZD 1: USD 0.67).

A.42 <u>Sources:</u> *Lilliestam et al 2018, NREL 2019*

Tidal energy

A.43 There are two types of tidal energy scheme:

(a) Semi-permeable tidal barrages across estuaries, which allow tidal waters to fill an estuary via sluices and to empty through turbines

(b) Harnessing offshore tidal streams using tidal turbines.

A.44 A tidal range of at least 3–7 metres is required for economical operation and for enough head of water for the turbines.

A.45 Tidal energy schemes have low capacity factors – usually 25–30%.

A.46 Tidal power often misses peak demand times because of the 12.5-hour cycle of the tides.

A.47 The levelised cost of energy (pre-commercialisation) (2015): approximately $315–$700 / MWh (NZD 1: USD 0.67)

A.48 <u>Sources:</u> *Ocean Energy Council 2018, U.S. EIA 2018, Segura et al 2017, Ocean Energy Systems 2015*

Wave energy

A.49 The energy potential for waves is greatest between 30° – 60° latitude in both hemispheres, on west coasts. This is due to the global wind direction. New Zealand is located at 40° south.

A.50 On average, waves in New Zealand have a power density of 40–60 kW / metre.

A.51 Overall, wave energy technologies are in the early stages of development. They can be categorised as follows:

(a) Turbine-type (eg, oscillating water column, overtopping wave energy converter)

(b) Buoy-type or point absorber (eg, float type, tube type).

A.52 The levelised cost of energy (pre-commercialisation) (2015): approximately $315–$1,000 / MWh (NZD 1: USD 0.67)

A.53 Sources: *Ocean Energy Systems 2015, IRENA 2014, Muetze & Vining 2006, U.S. Dept of Energy 2006*

References

A.54 The full list of sources referred to in preparing the summary information above is as follows:

(a) Battelle Memorial Institute, 2016, Manufacturing cost analysis of 100 and 250 kW fuel cell systems for primary power and combined heat and power applications

(b) Chen et al, 2009, Progress in electrical energy storage system: A critical review

(c) Committee on Climate Change, 2018, Hydrogen in a low-carbon economy

(d) Commonwealth Scientific and Industrial Research Organisation, 2018, National hydrogen roadmap

(e) Concept Consulting Group, 2019, Hydrogen in New Zealand, Reports 1–3

(f) Crolius, 2019, The Allam Cycle's Nexus with Ammonia

(g) International Energy Agency, 2017, Global trends and outlook for hydrogen

(h) International Renewable Energy Agency, 2014, Wave energy technology brief

(i) Lazard, 2018a, Lazard's levelized cost of energy – version 12.0

(j) Lazard, 2018b, Lazard's levelized cost of storage – version 4.0

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(n) Muetze & Vining, 2006, Ocean Wave Energy Conversion – A Survey

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(p) Ocean Energy Council, 2018, Tidal Energy (http://www.oceanenergycouncil.com/ocean-energy/tidal-energy/)

(q) Ocean Energy Systems, 2015, International levelised cost of energy for ocean energy technologies

(r) Proctor, 2019, Fuel cell technology key to South Korea's energy future

(s) Rocky Mountain Institute, 2016, The economics of battery energy storage

(t) Schmidt et al, 2017, The future cost of electrical energy storage based on experience rates

(u) Sapere Research Group, 2018, Transitioning to zero net emissions by 2050: moving to a very low-emissions electricity system in New Zealand

(v) Segura et al, 2017, Cost assessment methodology and economic viability of tidal energy projects

(w) Staffell et al, 2019, The role of hydrogen and fuel cells in the global energy system

(x) Transpower New Zealand, 2017, Battery storage in New Zealand

(y) Transpower New Zealand, 2019, The sun rises on a solar energy future

(z) U.S. Department of Energy, 2013, Concentrating solar power basics (https://www.energy.gov/eere/solar/articles/concentrating-solar-power-basics)

(aa) U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 2006, Proceedings of the Hydrokinetic and Wave Energy Technologies Technical and Environmental Issues Workshop

(bb) U.S. Energy Information Administration, 2018, Tidal power – Basics (https://www.eia.gov/energyexplained/print.php?page=hydropower_tidal)

(cc) U.S. Energy Information Administration, 2018, U.S. battery storage market trends

(dd) Wang et al, 2018, Techno-economic challenges of fuel cell commercialization

(ee) Yang, 2010, Pumped Hydroelectric Storage.

Possible implications of new and emerging generating technologies

A.55 Using wind generation, and the new and emerging generating technologies summarised above, to supply, within 10 years, a very high percentage (eg, 95–98%) of New Zealand's electricity demand using renewable energy sources,[9] is expected to affect:

(a) the cost of meeting energy and capacity needs

(b) the demand for ancillary services

(c) the ability of the system operator and grid owner to fulfil their roles.

Possible effects relating to the demand for, and supply of, energy

A.56 Moving to a very high percentage of renewable generation within 10 years may have the following effects on the demand for, and supply of, energy:

(a) Increase the differential in electricity prices between periods of energy surplus and scarcity, as the cost of dry-year reserve generation would be higher than currently.

9 Based on the aspirational goal of 100% of New Zealand's electricity being generated using renewable energy sources by 2035.

(b) Technologies such as batteries (electric vehicle or static) may have the potential to contribute significantly to the supply of energy during peak demand periods, as an alternative to investment in:

(i) current peaking generating technologies (eg, OCGT), and/or

(ii) network capacity.

Possible effects relating to ancillary services

A.57 Moving to a very high percentage of renewable generation within 10 years may have the following effects on the demand for, and supply of, ancillary services:

(a) An increased proportion of intermittent generation may increase marginally the demand for frequency keeping, but with the extent of any such increase dampened by the geographic diversity of wind and solar.

(b) The quantity of instantaneous reserve and AUFLS required to manage under-frequency events would increase with the closure of thermal generators, due to a reduction in system inertia. However, the retirement of large thermal units would reduce the frequency with which instantaneous reserves of a significant scale were called upon to meet a supply interruption.

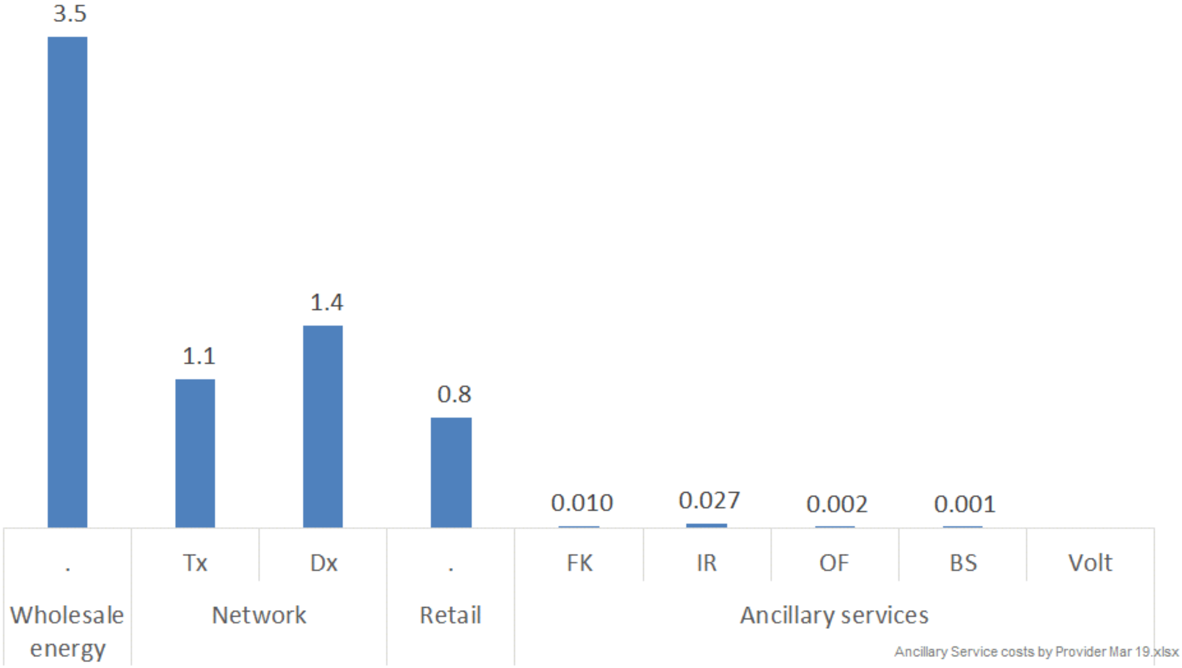
(c) Batteries could provide frequency keeping or instantaneous reserves services. The extent to which they could enable material cost savings would depend on whether there was surplus battery capacity to draw upon at times of system scarcity. The economic cost of batteries providing frequency keeping and instantaneous reserves would be heavily influenced by the cost of having the necessary battery capacity in place on the system. It could be the case that significant electric vehicle uptake, with coordinated charging and vehicle-to-grid injection may provide such surplus capacity.

(d) Batteries may assist with over-frequency management, due to their fast-response capabilities.

(e) The large-scale uptake of batteries could make black start (or restoration of power in a region) more challenging. Large amounts of empty batteries would want to immediately draw power from the network.

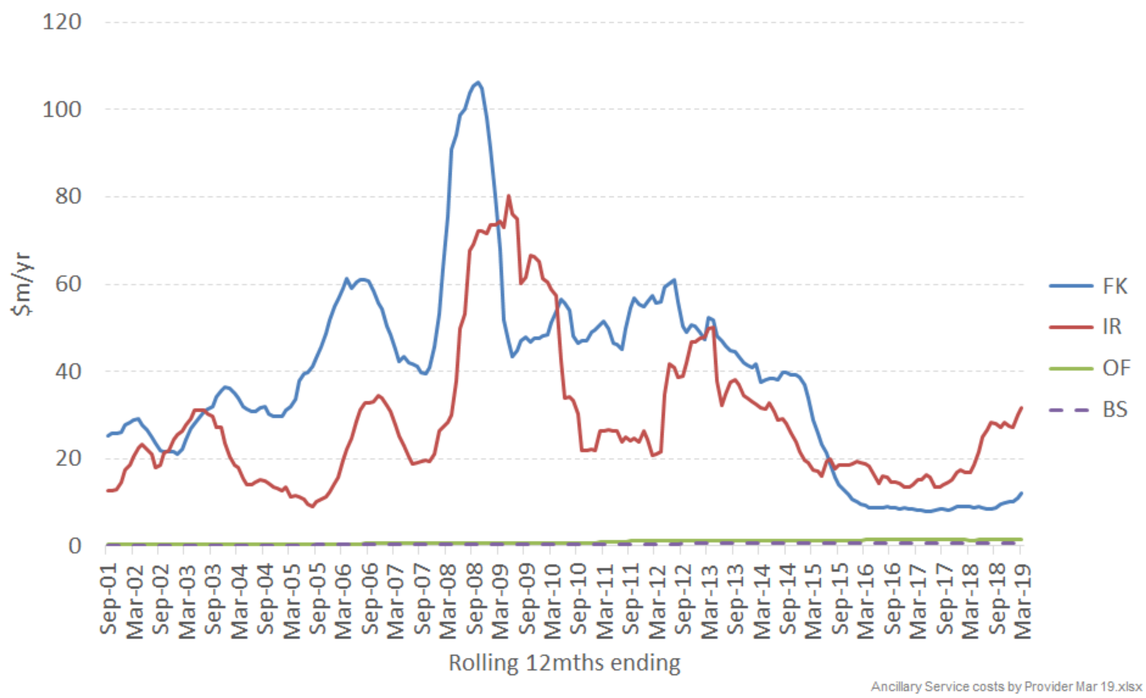
A.58 Figure 2 suggests mispricing of energy, network services and retail services has a far greater potential to cause distortions in technology investment than mispricing of ancillary services. Having said this, the inadequate provision of ancillary services has the potential to cause significant costs due to system security failures—particularly failures caused by the inadequate provision of instantaneous reserves and AUFLS.

Figure 2: Estimated cost breakdown of providing electricity services in 2018 ($bn)[10]



A.59 Further, as Figure 3 below illustrates, ancillary services costs have the potential to rise to significantly greater levels than those experienced recently. In this respect, as capacity margins tighten, the cost of providing frequency keeping and instantaneous reserves are expected to rise.

Figure 3: Historical cost of ancillary services procured through market-based mechanisms[11]



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10 Tx = Transmission; Dx = Distribution; FK = Frequency Keeping; IR = Instantaneous Reserves; OF = Over-Frequency Arming; BS = Black Start; Volt = Voltage Support.

11 FK = Frequency Keeping, IR = Instantaneous Reserves, OF = Over-frequency arming, BS = Black Start

Possible effects relating to the operations of the system operator and grid owner

A.60 The increasing uptake of small-scale generating technologies and dynamic demand-side technologies is likely to increase the challenges faced by the system operator over the visibility of:

(a) the electricity system’s composition (actual and potential generation and load, by location)

(b) how the electricity system will perform under various contingencies.

A.61 Increased proportions of intermittent generation would make system forecasting more challenging over the 24 hours leading up to real time. The consequences of errors in this forecasting would be reduced by the retirement of large-scale thermal units, thereby making thermal unit commitment less of an issue. However, river-chain management (eg, for the Waikato) would still benefit from good system forecasting.

A.62 Increased proportions of intermittent generation may also create increased challenges for the grid owner in planning transmission asset outages for maintenance.

Appendix B The spot market needs certain services relating to power system operation

B.1 The spot market for electricity needs certain ancillary services to ensure energy bought and sold in the spot market is delivered from sellers to buyers at an acceptable level of reliability.[12] Under the Code these ancillary services are obtained in three ways:

(a) By the system operator procuring an ancillary service through a half-hour clearing market process, whereby the provider of the ancillary service submits offers to the system operator to provide the service. The market for the ancillary service is priced and settled for each trading period based on the offers dispatched by the system operator, although the service may also be paid for by way of an availability price.[13] This type of procurement is referred to as "half-hour clearing market procurement".[14] Examples of ancillary services procured in this manner are instantaneous reserves and frequency keeping.

(b) By the system operator procuring an ancillary service on a fixed quantity and fixed price basis, where the system operator assesses there is a requirement for a fixed quantity of the ancillary service, or a high availability of it, irrespective of dispatch. This type of procurement is referred to as "firm quantity procurement". Ancillary services procured on a firm quantity procurement basis must be paid for by way of an availability price, an event price or both.[15] Examples of ancillary services procured in this manner are voltage support, black start, over-frequency arming.

(c) By Part 8 of the Code placing certain mandatory obligations on asset owners,[16] to enable the system operator to meet its principal performance

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12 Noting that reliability encompasses:

a) the quality of electricity supplied

b) the security of electricity supplied

c) the security of electricity supply.

Security of electricity supplied refers to a stable power system—that is, a power system where the supply of, and demand for, electricity is balanced in real time, as evidenced by:

a) frequency being between 49.8 Hertz and 50.2 Hertz (both inclusive) (refer to clause 8.17 of the Code)

b) voltage being approximately uniform across the grid (+/-10% across assets that are 110 kV or 220 kV; +/-5% across assets that are 50 kV or 66 kV) (refer to clause 8.22 of the Code).

Security of electricity supply refers to the electricity industry providing appropriate electricity system capabilities (such as generation and transmission capacity) and storable fuel supplies (such as water, gas and coal) to maintain a normal supply of electricity to consumers.

13 An availability price means a fixed price for the availability of an ancillary service**,** irrespective of dispatch or provision, expressed as dollars per period of availability.

14 Refer to paragraph 48 of the 'Ancillary services procurement plan, dated 1 December 2016', which is a document incorporated by reference into the Code.

15 Refer to paragraphs 48 and 49 of the 'Ancillary services procurement plan, dated 1 December 2016'.

16 The Code defines an asset owner to mean a participant who owns an asset used for the generation or conveyance of electricity and a person who operates such asset and, in the case of Part 8, includes a consumer with a point of connection to the grid.

The Code defines an *asset* to mean equipment or plant that is connected to or forms part of the transmission grid and, in the case of Part 8, includes equipment or plant that is intended to become connected to the grid and equipment or plant of an embedded generator.

obligation to dispatch available assets in a manner that avoids cascade failure. These mandatory obligations include:

(i) requiring synchronised generators and the grid owner to make the maximum possible injection contribution to maintain frequency between 49.8 Hertz and 50.2 Hertz (both inclusive)[17]

(ii) requiring synchronised generators to ensure their assets continuously operate in a manner that supports voltage and voltage stability on the grid[18]

(iii) requiring asset owners to have protection systems[19]

(iv) requiring generators to ensure their generating units can be synchronised at a stable frequency[20]

(v) requiring generators to ensure their assets ride through specified system faults[21]

(vi) requiring asset owners to provide asset capability information to the system operator for the purpose of power system modelling[22]

(vii) requiring asset owners to carry out routine testing of their assets[23]

(viii) requiring asset owners to plan for, and respond to, emergency events[24]

(ix) requiring asset owners to have operational speech and data communications with the system operator[25]

(x) requiring distributors and direct consumers to provide extended reserve.[26]

B.2 The Code governs the first two ways of obtaining the services necessary for electricity reliability through the rules for the ancillary services markets. The Code governs the third way of obtaining these services through:

(a) the AOPOs

(b) the dispensation and equivalence regime used to manage an asset owner’s partial or full non-compliance with the AOPOs.

B.3 AOPOs are effectively mandatory ancillary services.

17 Clause 8.17.

18 Clause 8.23.

19 Clauses 4 and 5 of Technical Code A of Schedule 8.3.

20 Clause 5 of Technical Code A of Schedule 8.3.

21 Clauses 8.25A to 8.25D.

22 Clause 2 of Technical Code A of Schedule 8.3.

23 Appendix B of Technical Code A of Schedule 8.3.

24 Technical Code B of Schedule 8.3.

25 Technical Code C of Schedule 8.3.

26 Subpart 5 of Part 8.

Appendix C What does a generator have to do to participate in the wholesale market?

C.1 This appendix summarises key minimum generator obligations under the Code.

Which generators can participate in the wholesale market?

C.2 Grid-connected generators[27] *must* participate in the wholesale market. For example, clause 15.11 requires a grid-connected generator to deliver submission information to the reconciliation manager.

C.3 Embedded generators *may* participate in the wholesale market. For example, clause 15.5 says an embedded generator is not required to deliver submission information to the reconciliation manager, if the embedded generator will not receive payment from the clearing manager. However, clause 8.25 says the system operator may require an embedded generator to offer, in accordance with subpart 1 of Part 13, the intended output of each of its embedded generating stations greater than 10 MW in capacity.

C.4 Embedded generators choosing to participate in the wholesale market may be connected to:

(a) a local distribution network

(b) an embedded distribution network.

A generator must first connect to a network: Key minimum generator obligations under Parts 6 and 12

C.5 Under Part 6, distributed generators[28] must, for networks (other than the grid) conveying at least 5 GWh:

(a) connect under regulated terms or under a connection contract with the distributor (clauses 6.5 and 6.6)

(b) meet the distributor's connection and operation standards (clause 6.2)

(c) pay, or be paid by, distributors in accordance with the pricing principles in Schedule 6.4 (clause 19 of Schedule 6.2).

C.6 Under Part 12, grid-connected generators must:

(a) enter into a transmission agreement with Transpower (clauses 12.8 and 12.29)

(b) meet technical requirements and standards in the Connection Code (clause 12.17)

(c) pay Transpower in accordance with the transmission pricing methodology (clause 12.77).

27 The Code defines a "generator" to include both:

i) a person who owns generating units connected to a network

ii) a person who acts, in respect of Parts 13, 14 and 15, on behalf of a person owning such generating units.

28 A distributed generator is typically equivalent to an embedded generator.

A generator must meet certain market prerequisites: Key minimum generator obligations under Parts 10, 11 and 14A

C.7 Under Part 10, a generator must:

(a) have a MEP (clause 10.18)

(b) have a metering installation at an installation control point (ICP) that is not also a network supply point or point of connection to the grid (clause 10.24).

C.8 Under Part 11, an embedded generator who sells directly to the clearing manager must have an ICP identifier for the point of connection (clause 11.3).

C.9 Under Part 14A, a generator must:

(a) establish and maintain an acceptable credit rating or provide acceptable financial security to comply with prudential requirements (clause 14A.2)

(b) inform the clearing manager if the generator's circumstances change (clause 14A.17).

A generator has common quality obligations: Key minimum generator obligations under Part 8

C.10 A generator planning to connect to the grid, or to a local distribution network, a generating unit with rated net maximum capacity of at least 1 MW, must advise the system operator of the generator's intention to connect, along with certain other information about the generating unit (clause 8.21).

C.11 A generator must ensure its assets operate within the grid's voltage range (clause 8.22).

C.12 A generator's assets must be able to ride through faults, unless the generator's assets are:

(a) an excluded generating station (a generating station that exports less than 30 MW to a local distribution network or to the grid), or

(b) a wind generating station operating at less than 5 % of rated MW (clauses 8.21, 8.25A, 8.25B, 8.25C, 8.25D).

C.13 Except for excluded generating stations, a generator's assets must contribute to maintaining frequency, by:

(a) making the maximum possible injection contribution (clause 8.17)

(b) remaining synchronised in an under-frequency event (clause 8.19).

C.14 Grid-connected generators must:

(a) export/import reactive power (clause 8.23)

(b) operate to support voltage and voltage stability on the grid, in compliance with the technical codes in Part 8 (clause 8.23).

C.15 A generator must always comply with the AOPOs and technical codes in Part 8, unless a dispensation is granted, or an equivalence arrangement is approved (clause 8.29).

C.16 A generator must pay:

(a) readily identifiable and quantifiable costs imposed on others due to the generator being granted a dispensation (clause 8.31)

(b) readily identifiable and quantifiable costs for ancillary services that are a condition of a dispensation (clause 8.55)

(c) availability costs for instantaneous reserve (clause 8.59)

(d) an event charge, if the generator is the causer of an under-frequency event (clause 8.64)

(e) voltage support costs (clause 8.67).

C.17 A generator must provide the system operator with, and operate in accordance with:

(a) an asset capability statement (clause 2 of Technical Code A)

(b) a commissioning plan or test plan, if:

(i) the generator is grid-connected, or

(ii) if necessary, for the system operator to meet the principal performance obligations (clause 6 of Technical Code A).

C.18 A generator must ensure that each of its generating units has a speed governor (clause 5 of Technical Code A).

C.19 Grid-connected generators must have a voltage control system (clause 5 of Technical Code A).

C.20 At some points of connection, a generator must ensure that its generating units have both main protection systems and back-up protection systems (clause 5 of Technical Code A).

C.21 A generator must carry out periodic testing of assets (clause 8 of Technical Code A and Appendix B of Technical Code A).

C.22 A generator must respond to grid emergencies by assisting to restore frequency / voltage to the appropriate level (clause 9 of Technical Code B).

C.23 Except for excluded generating stations (usually), a generator must have in place the means by which the generator can meet certain minimum requirements for communicating with the system operator—for example:

(a) primary and secondary means of voice communication and data transmission

(b) logging voice or electronic communication) (Technical Code C).

C.24 A generator must notify the system operator of planned outages of the generator's assets that affect common quality (Technical Code D).

A generator can then trade in the market: Key minimum generator obligations under Part 13

C.25 The Authority's approval is needed for a generator to have one or more generating units classified as an industrial co-generating station (clause 13.3).

C.26 A generator must have an interface with the wholesale information and trading system (clause 13.22).

C.27 A generator must disclose certain information (clause 13.2A) (see also Part 2 of the Code).

C.28 If a generator's generating station is more than 10 MW (clause 13.25), the generator must make lawful electricity offers:

(a) consistent with a high standard of trading conduct (clauses 13.5 and 13.5A)

(b) containing information required by the relevant Part 13 offer form (clause 13.9)

(c) based on generating unit (except if the generator is an intermittent generator), or generating station (clauses 13.11 and 13.66)

(d) based on a persistence model if the generator is an intermittent generator (clause 13.18A)

(e) that cannot be revised during the gate closure period except in certain circumstances (clauses 13.18 and 13.19)

(f) at $0, only if the generator is:

(i) an embedded generator (clause 13.26), or

(ii) successful in the must-run dispatch auction (clause 13.116).

C.29 A generator must comply with lawful dispatch instructions unless:

(a) there is a safety risk (clause 13.82)

(b) for intermittent generators, the system operator has not indicated in each dispatch instruction whether the intermittent generator is being dispatched at a quantity less than its intermittent generating station's potential output (clause 13.82(2)(d))

(c) for type B co-generators, the system operator has not advised there is a grid emergency or a system constraint directly affecting the type B co-generator (clause 13.82(2)(d))

(d) for type A co-generators, the dispatch instruction differs from the last dispatch instruction by less than or equal to 5 MW (clause 13.86)

(e) for remaining generators, the dispatch instruction differs from the last dispatch instruction by less than or equal to 1 MW (clause 13.86).

C.30 A generator must not reduce its offers in a grid emergency, unless there is a bona fide physical reason, or the generator is an intermittent generator (clause 13.97).

C.31 Using an approved system, a generator must provide half-hour metering information to the relevant grid owner (clause 13.136).

C.32 A generator must provide information to the electricity hedge disclosure system on risk management contracts entered into (clause 13.218).

C.33 A generator must prepare a spot price risk disclosure statement each quarter (clause 13.236A).

A generator can then trade in the market (continued): Key minimum generator obligations under Parts 14 and 15

C.34 Under Part 14:

(a) a grid-connected generator must sell to the clearing manager (clause 14.3)

(b) an embedded generator is not obliged to always sell to the clearing manager (clause 14.4). However, if an embedded generator sells electricity to a participant under clause 14.4, the participant must at the same time on-sell that electricity to the clearing manager (clause 14.5)

C.35 Under Part 15, a generator paid by the clearing manager must:

(a) deliver submission information to the reconciliation manager (clause 15.4)

(b) be certified to deliver submission information (clause 15.38)

(c) arrange to be audited regularly (clause 15.37A).