Meeting Date: 16 March 2023

DEMAND RESPONSE IN THE WHOLESALE MARKET

SECURITY AND RELIABILITY COUNCIL

This paper introduces a paper from the Authority on regulatory arrangements for Demand Response in the wholesale market, including the principles that underpin demand response, Authority workstreams underway and issues to be addressed

Note: This paper has been prepared for the purpose of the Security and Reliability Council (SRC). Content should not be interpreted as representing the views or policy of the Electricity Authority except where specifically noted.

Demand Response

1.1.1 The SRC has asked the secretariat to provide information on regulatory arrangements for the Demand Response in the wholesale market, as part of the theme of demand response for this meeting.

1.1.2 The secretariat has arranged for a paper from Authority staff to provide an outline of the Authority's current work program activities relating to the integration of demand response in the wholesale market.

1.1.3 The Authority paper (Appendix A) sets out:

a. the guiding principles for demand response, noting the particular focus on promoting efficient use of demand side resources in the wholesale market

b. how the principles operate and the key premises they are based on

c. Examples of the practices demand response includes

d. Benefits of demand side flexibility (DSF)

e. The role of third-party agents

1.1.4 The paper notes the implementation of the final part of the real time pricing (RTP) project, scheduled for April this year, is aimed at facilitating increased demand response.

1.1.5 The paper gives detail about the dispatchable demand participation mechanism implemented in 2012 and some of the issues experienced, which RTP is designed to address.

1.1.6 The paper notes other Authority workstreams relating to demand response, including *updating the regulatory settings for distribution networks* and *future security and resilience* (FSR) and the Market Development Advisory Group's previous work on *price discovery in a renewables-based power system* (see Appendix A for links).

1.1.7 The paper concludes with an outline of demand side issues still to be addressed.

1.1.8 Representatives from the Authority's Market Policy - Operations team will present and be available for questions.

Questions for the SRC to consider

The SRC is asked to consider the following general questions.

Q1. What further information, if any, does the SRC wish to have provided to it:

Q2. What advice, if any, does the SRC wish to provide to the Authority?

Appendix A: Authority work program regarding demand response mechanisms in the wholesale market

Purpose

1. The purpose of this paper is to outline the Authority's current work program activities relating to the integration of demand response in the wholesale market.

Recommendation

2. The Authority recommends that the SRC notes that:
   a. The Authority's program of work focusses on promoting efficient use of demand side resources in the wholesale market
   b. The recent implementation of the real-time pricing project is a significant step to enabling efficient participation of demand response and distributer energy resources in the wholesale market.

Background

1. In June 2018, following consultation, the Authority updated and published its *Guiding regulatory principles for demand response*[1] (the demand response principles).

2. The demand response principles paper intends to:
   a. explain the Authority's stance on stakeholders' demand response initiatives
   b. help stakeholders understand the ideas motivating the Authority's demand response initiatives
   c. provide guidance for stakeholders in planning future demand response initiatives.

3. Few demand response initiatives will fully satisfy every single principle. If an initiative does not satisfy one or more principles (for instance, because it is not feasible to do so), then:
   a. the initiative can still proceed
   b. however, the proponent should consider how (if at all) it can modify the initiative to better satisfy the principles.

4. Two key premises are that:
   a. markets are usually the best way of achieving efficient outcomes
   b. the wholesale electricity spot market is the primary means of signalling the cost and value of electricity so it is critical that spot prices are efficient.

5. The principles are set out in Table 1 below:

[1] https://www.ea.govt.nz/assets/dms-assets/23/23654Guiding-regulatory-principles-for-demand-response-2018-update.pdf

Table 1: Summary of the Authority's updated demand response principles

Principle 1: best-possible incentives	Incentives to undertake demand response should reflect the marginal benefit of that response to the electricity system. Any payment for providing demand response should be funded by those benefiting from that response.
Principle 2: openness	Demand response should be able to participate in market arrangements, wherever practical. Anybody should be allowed to provide demand response services, including consumers and their agents. Demand response initiatives should not unreasonably restrict the technologies used to provide that response.
Principle 3: choice	Consumers should be free to choose when, how much, and by what technology they are willing to provide demand response, considering the costs and rewards they face. Consumers should be free to contract with third parties to provide demand response on their behalf. Any party buying demand response services should also be free to choose who, when, and how it is provided to them.
Principle 4: transparency	Arrangements for demand response should provide transparent information, enabling consumers and other parties to: (a) assess the potential value of offering demand response in its various forms (b) make sound decisions about offering and using demand response.

Demand response can help deliver a reliable electricity system at lower cost

6. The electricity system usually works by generators supplying enough electricity to match the total amount being used at every point in time—this amount is known as demand. Sometimes however, generating and delivering electricity can become quite costly. At these times, it may be better to use less electricity, rather than supply it at high cost.

7. This is demand response: consumers using less electricity when supplying it would cost more than the electricity is worth to them.

8. There is a general trend of increasing consumer participation in the electricity sector. Consumers are increasingly unwilling to use electricity passively. Instead, they want more control over how much electricity they use—and the ability to reduce their costs when they do. Participating is also becoming easier for consumers, such as by using ‘smart’ appliances and other technologies that help manage the electricity they use.

The Authority defines demand response as intentionally altering electricity consumption patterns in response to an incentive

9. It's important to carefully define what the Authority means by 'demand response'. There are many similar terms used around the world, and these varied definitions can sometimes be ambiguous or contradictory.

10. The Authority defines demand response to mean intentionally altering the normal electricity consumption patterns of an end-use consumer in response to an incentive. That incentive could be:

    a. avoiding buying electricity at a higher price

    b. a payment from some other party for using less electricity at certain times[2].

11. The normal electricity consumption pattern of an end-use consumer could be intentionally altered by:

    a. using the same amount of electricity but at another time

    b. using less electricity in total from now on.

12. Demand response therefore encompasses a wide range of practices across varying time scales. For clarity, the Authority regards the following examples as forms of demand response:

    a. consumers choosing to directly control their own electricity use in the manner they see fit in response to electricity prices

    b. controlling the electricity consumption of consumer devices (timing of consumption and/or amount being consumed), such as ripple control of hot water storage by distribution networks

    c. consumers choosing to use more electrically efficient devices; ie, permanently using less electricity for the service the device provides through energy efficiency[3]

    d. consumers contracting with another party to manage some or all of their electricity use. These parties might be the consumer's retailer, network operators, or third-party agents like load aggregators or energy management companies.

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[2] These could be times when electricity prices are high, when system reliability is jeopardised, or to efficiently defer investment in network infrastructure

[3] Minimum performance standards have raised the energy efficiency of domestic appliances markedly over recent decades. Energy rating labels also give consumers vital information about energy consumption when making purchasing decisions. Despite this, the Authority notes some consumers may not intend or be aware they are using more energy efficient devices. For example, a consumer might buy a new LCD television simply because it provides better features and higher quality than their old plasma model, without paying much attention to energy rating labels. Or a consumer deciding to replace an old model fridge or washing machine will choose from new models that are more energy efficient (driven by performance standards), even if they didn't set out to buy a more efficient appliance. Regardless of buying intent, the Authority considers energy efficiency is a form of long-term demand response

Demand response brings flexibility and lowers costs

13. Effective demand response makes the electricity system more flexible by using less electricity when generation or network capacity is scarce. That flexibility in turn helps avoid investing in generation or network capacity that would only be used rarely. Demand response also encourages voluntary reductions in consumer load when the electricity system is under stress, making forced load shedding less likely.

14. Demand response can therefore help deliver a reliable electricity system at lower total cost to consumers.

15. New technologies and new business models open up opportunities to further develop and expand demand response in New Zealand's electricity system—and to capitalise on the experience New Zealand already has through long-established schemes like ripple control.

Third party agents could play an important role in helping consumers manage their demand response

16. An important aspect of the principles is the potential for consumers to contract with third-party agents to manage their demand response. The Authority therefore defines a 'demand response provider' to mean the party actively participating in market (or other) arrangements to help manage an end-use consumer's load. For example, by controlling the load directly using remote technologies.

17. Third parties might also help consumers in other ways, such as by providing targeted information, or advising on appropriate equipment. These are important roles which encourage demand response. But parties would not be demand response providers when they perform these roles, because they are not actively participating on the consumer's behalf.

18. All third-party agents actively participating on a consumer's behalf are then demand response providers, as are end-use consumers that are directly participating.

19. The Authority has four significant projects underway that seek to address potential barriers and opportunities for demand response in the near-term, through the transition to a low carbon energy system and in the future as the power system operates in the low carbon world with a significant proportion of low marginal cost generation.

20. The four projects are:

    a. Real time pricing implementation
    b. Updating the regulatory settings for distribution networks
    c. Future security and resilience
    d. Market Development Advisory Group's (MDAG) 100% renewables project

Real time pricing implementation

21. On 27 April 2023, the final phase of the real time pricing project will go live. This software release will implement two additional enhancements aimed at facilitating more demand side participation in the wholesale market.

Enhancement 1 - Dispatchable demand enhancements

22. The dispatchable demand participation mechanism for large industrial consumers was implemented in 2012. This mechanism allowed large industrial consumers to signal their price sensitivity for their flexible demand and receive dispatch instructions that optimized their consumption based on their indicated price sensitivity.

23. Technical limitations at the time of implementation meant that the dispatch instructions for dispatchable demand could not be implemented as a part of the generation dispatch process, they were incorporated in the forecast schedules instead. This resulted in a disconnect between the prices that the demand side were being dispatched from and the actual grid conditions at the time they were forecast to respond to them. The provider would be paid constrained on or off payments if the final price for the trading period did not reflect the actions they were dispatched to take based on their bid prices, but this did not necessarily compensate sufficiently for lost production or other operational costs linked to starting and stopping an industrial process.

24. Another outcome of the dispatch implementation was that those demand side participants who also offered the same load as interruptible load in the instantaneous reserve market sometime received conflicting dispatch instructions. A provider could be dispatched to reduce demand in the dispatchable demand instruction but also scheduled to provide interruptible load reserves using the same demand. These instructions are mutually exclusive: interruptible load provision requires the party to be consuming electricity and automatically reduce demand in response to a drop in grid frequency, however, a dispatchable demand instruction to reduce demand in response to price would require that demand to be reduced meaning the interruptible load could not be provided. This led to operational confusion for both the providers and the system operator as the coordinators resolved the conflict and instructed the desired outcome.

25. In the scheduling implementation of dispatchable demand, demand bids were treated in the same way as generation offers in that the demand could be scheduled incrementally through its bid quantities. For example, if the dispatchable demand participant bid a reduction of 20MW, if they were the marginal bid, they could be instructed to reduce only part of that 20MW if that was the most efficient outcome. While a generator can ramp incrementally through its offered generation quantity, a large industrial consumer may be bidding in the load associated with discrete processes. These processes are either on or off and generally cannot operate at variable levels of consumption in between. Upon receiving such an instruction, the participant would have to contact the system operator to determine whether or not they needed the process to be shut down completely or could manage the power system while they were consuming normally.

26. The implementation of the real time pricing project provided the opportunity to move dispatchable demand dispatch into the real-time dispatch schedule. This allowed further enhancements to be made to resolve the issues described. Dispatch prices would now be aligned with the grid conditions at the time of consumption. Providers can now signal to the system operator when a dispatchable demand resource is also being offered into the instantaneous reserve market and the dispatch for the

two can be co-optimised automatically, providing the most efficient outcome for the market as a whole. Finally, dispatchable demand providers will be able to indicate whether their bids can only be dispatched in whole tranches i.e. each dispatchable demand bid tranche represents a discrete process or quantity of demand that can only be dispatched on or off, not incrementally. The market system will now calculate the most efficient result based on this constraint.

Enhancement 2 - Dispatch notification

27. While dispatchable demand provided a pathway to market participation for large industrial consumers, the technical and compliance overheads associated with the regime precluded the participation of smaller consumers and aggregators. As a part of the real-time pricing project, the Authority is implementing a wholesale participation pathway for these participants: Dispatch Notification.

28. Dispatch notification participation does not require 24hr operational communication with the system operator – participants will only need to be contactable when they actually bid their resources into the market. Similarly, there is no need for real-time load or generation indications to be provided. The market system will assume that the participant has responded to their most recent instruction and adjust the system operator load forecast accordingly. This is acceptable for these participants given the small scale of their resources[4]. Dispatch compliance monitoring will be conducted on a monthly basis using half-hour metered data.

29. Dispatch instructions will be able to be received via webservices over domestic internet connections. This significantly lowers the cost for dispatch systems setup.

30. Dispatch notification participants will be able to offer aggregated resources behind a single grid exit point. This will allow providers of domestic solar and battery systems, for example, to aggregate the response available for these systems and offer it into the wholesale market. This provision will also allow retailers to actively manage their exposure to spot prices, either directly or as a third-party aggregator on behalf of the retailer and provide an alternative to potentially expensive peak generation hedges. Consumers should receive a benefit from the retailer for the use of their resource, much like distributors currently offer lower connection charges for consumers with hot water ripple control systems.

Updating the regulatory settings for distribution networks

31. On 20 December 2022, the Authority opened consultation on *updating the regulatory settings for distribution networks* (consultation closed in early March 2023).[5] As a part of that consultation, the Authority sought feedback on operating agreements for flexibility services.

32. The Authority currently considers that there are no large issues with operating agreements for flexibility services to address at this point. The Authority does

[4] Generators must be below 30MW capacity and approved by the system operator for participation. There is no Code limit for demand side participation but the system operator assesses the impact of the participant's demand side variability and determine if the participant can use dispatch notification or must become a dispatchable demand participant.

[5] https://www.ea.govt.nz/development/work-programme/evolving-tech-business/updating-regulatory-settings-for-distribution-networks/consultations/#c19303

consider there will likely be value in providing some guidance on best practice, templates and / or standardisation, but considers that resource would be better prioritised to progressing the work in the other sections of the consultation. That said, where possible, the Authority will support industry-led work on this.

33. Submissions on the 2021 Discussion Paper of the same title did not provide evidence of any issues associated with operating agreements for flexibility services. This might be because there are very few agreements for flexibility currently being negotiated, or it could indicate parties are too far apart commercially to enter negotiations. The Authority has not had any submissions from flexibility traders that they are facing such problems, but even if they are, this does not necessarily indicate there are problems with the agreement process.

34. The Authority supports the IPAG's recommendation from its 2021 Review of Transpower's Demand Response Programme that Transpower should work with Aurora and distributors more generally to agree a standard offer form for procuring flexibility as a non-network service (NNS) and enforce the use of this standard nationally for procuring non-network inputs through default agreements. The Authority agrees that this should occur and will monitor progress, but at this time will not mandate it. The Authority will also continue to monitor whether issues associated with operating agreements for flexibility services are developing, and any relevant overseas developments.

Future security and resilience

35. The future security and resilience (FSR)[6] work program is investigating the requirements for a more dynamic and responsive power system as New Zealand transitions to a low carbon energy system.

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

37. New Zealand's power system is currently a typical centralised power system. The bulk of power supply is from large synchronous generating machines connected to the transmission grid. These large synchronous machines are the main contributors to system strength and inertia[7], which are critical attributes necessary to maintain stable system operation, good power quality, and predictable recovery following faults and disturbances. Generating stations are naturally located where the 'fuel' resources are on rivers, on geothermal fields, near coal mines and gas pipelines.

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

39. The transition to a low-emissions power system is expected to bring increasingly distributed sources of generation, located in many cases closer to end-consumers

[6] https://www.ea.govt.nz/development/work-programme/risk-management/future-security-and-resilience-project/consultations/#c19152

[7] Inertia is the ability of the electricity supply to withstand momentary fluctuations and disturbances, usually through the large physical mass of the rotating machinery

and including more new renewable generation technologies that are inverter based and do not have the large physical rotating mass directly connected to the system. Traditional methods for coordinating market and power system operations will need to transition these challenges. Operating distribution networks will require consideration of new approaches.

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

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

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

43. One of the potential challenges identified by the project is the rise of distributed energy resources, both generation and demand response, and the impact those resources will have on managing the power system.

44. As DER penetration increases, there is a substantial opportunity for it to offset some of the challenges that renewable energy (specifically solar PV) introduces. As solar PV penetration increases, the daily load curve starts to look quite different. Midday generation will potentially exceed demand, but evening demand peaks (after the solar generation has effectively ceased for the day) will be retained, creating a much steeper ramp for the System Operator to balance.

45. DER can shape the daily curve by reducing the daily peaks or increasing the daily trough if incentivised or otherwise controlled in a coordinated manner. The bulk of this will be achieved by shifting most EV charging to off-peak times. Additional effects will be seen from controllable load management, distributed generation and battery storage. These services could be incentivised through any combination of retail tariffs, bilateral contracts, time-of-use or other cost-reflective network pricing tariffs, response to real-time wholesale spot prices, and direct management of the resources by a third party.

46. The opportunities are not limited to daily load curve management. The increasing adoption of DER and the advancement of communication technologies to coordinate and manage DER provides an opportunity to:

    a. provide consumers with an option to manage their own energy usage to lower their costs and increase their energy efficiency and independence

    b. reduce energy transportation losses by reducing the physical distances between generation and load

    c. reduce transmission and/or distribution bottlenecks and reduce or defer transmission and distribution investment by managing demand

d. provide ancillary services to regulate frequency and voltage which will enhance security and resilience

e. provide balancing services to help the power system maintain the right generation and demand balance

f. provide back-up power during an outage.

47. For New Zealand to take full advantage of this opportunity, there needs to be:

a. clear expectations between the System Operator, electricity distribution businesses (EDBs) and flexibility traders on services delivered by DER

b. visibility of DER at both transmission and distribution levels

c. up-to-date technical requirements considering how DER operates, in order to support security and resilience, e.g. whether installed inverters should be grid forming rather than following

d. Incentives for consumers to use smart EV chargers that can be programmed to charge at a specific time and avoid increasing peak loads.

48. This opportunity affects New Zealand's entire power system. When New Zealand can take advantage of this opportunity will depend on how quickly the adoption of DER increases and required changes to the regulatory framework are made.

Market Development Advisory Group's (MDAG) 100% renewables project

49. On 6 December 2022, MDAG released its consultation paper on *price discovery in a renewables-based power system*[8]. Consultation closed on 6 March 2023.

50. One of the key areas of focus for that work is lifting demand side participation to manage high degrees of volatility from a significant level of installed intermittent generation.

51. The idea that consumers could play a more active role in managing how much and when they use electricity has been talked about a lot over the last 30 years, but not a lot has happened. Demand-side flexibility (DSF) still plays a relatively limited role in our system. This is due to several historical factors which have made the "size of the prize" for individual consumers less than the cost of capturing it for them.

52. However, the landscape for demand-side flexibility is changing markedly. New technology means that consumers will be able to react more easily to dynamic price signals via the use of sensors, automation and smart devices etc.

53. Unlocking the full potential of DSF also has larger benefits in terms of reduced system costs, improved competition, bolstered political sustainability, and a deeper consumer understanding of the benefits available from the wholesale market.

Demand-side issues to be addressed

54. The Authority's proposed package of options to lift DSF reflects the underlying philosophy of providing consumers with the right information about the value of their flexibility, and a sufficient range of options to contract that flexibility, for them to choose from.

[8] https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/100/consultations/#c19296

55. The Authority sees a number of “early wins” that can help unblock DSF:
    a. Understanding the availability of tariffs requires better monitoring of tariff availability. This should be implemented as soon as possible, since it underpins a range of future regulatory decisions.
    b. Accelerating the development of DSF tariffs requires a rapid adoption, by retailers, of the high frequency metering data that will underpin these tariffs.
    c. For larger consumers, financial contracts need to be developed to underpin their investment in enabling.
    d. To support the uptake of DSF tariffs, consumers need the best information available about their choices, and the potential rewards, as soon as possible.
    e. The way the market can optimize the efficient use of DSF requires a number of existing or planned initiatives to proceed with a focus on understanding and enabling.
56. Depending on the pace observed during the initial 1-2 years of monitoring, further requirements on retailers to develop DSF-rewarding tariffs may be required.
57. Consumers across the spectrum – from households to large industrial participants – are making electrification investment decisions today that would benefit from having flexibility being designed in at the outset. However, the DSF “market” is still very much in its infancy. The Authority believes a well-funded and extended trial of new DSF-rewarding tariffs, technology, relationships and market integration can accelerate the closing of information and knowledge gaps.
58. The trial should help to solve a number of critical “common” problems so that the industry has a cohesive framework of standards and protocols that will allow competition to thrive. A trial would also promote “learning by doing”[9], that should showcase innovation and lead to a sustained increase in DSF in the New Zealand market. The level of government funding here should reflect the sizeable economic benefit to New Zealand from unlocking greater DSF.

[9] See Newbery (2018), “Evaluating the case for supporting renewable electricity”