Price discovery in a renewables-based electricity system

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MARKET DEVELOPMENT ADVISORY GROUP

ELECTRICITY AUTHORITY
TE MANA HIKO

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Contents

Preliminary

Purpose

1.1 This document accompanies the report entitled 'Price Discovery in a Renewables-based electricity system: Options Paper'. That report sets out the options that are being proposed by the Market Development Advisory Group (MDAG) to ensure the electricity market is well prepared for the future state when electricity will be generated mostly or entirely from renewable sources.

Range of options and level of analysis

1.2 In this paper, we describe our currently preferred options to address the challenges that we anticipate will arise in moving to a renewables-based system. We want to emphasise that the options are intended to address specific challenges. These challenges are:

(a) Ensuring reliable and efficient operational coordination

(b) Ensuring effective risk management and efficient investment

(c) Lifting demand-side participation

(d) Strengthening competition

(e) Increasing public confidence in the electricity system.

1.3 We also describe other options that were considered but which are not preferred at this point. In both cases we set out reasoning for our views, in particular how options will help address the challenges or not.

1.4 In addition, there are a few options not evaluated in detail which came into view during our work on the future shape of the electricity market. These were not pursued further based on analysis in earlier reports or studies. For completeness these are listed in Appendix A of the Options Paper.

Stakeholder submissions will inform the next phase of work

1.5 We are keen to hear submitters' views on our assessment of options and their relative importance. This feedback will be a key input to our final recommendations paper in 2023.

1.6 To be clear, this paper outlines the options at a relatively high level. In the third and final stage in this project, we will go to the next level in specifying our preferred options and undertake a more thorough evaluation of costs and benefits, which will inform our final selection of options for our Recommendations Paper, which is due around May-June next year.

2. Ensuring reliable and efficient operational coordination

A1 – Improve short-term forecasts of wind, solar, and demand

2.1 Participants need good information to help make their plans in the lead-up to real time. For example, whether to charge a large storage battery for use later in the day, whether to release water from a head pond so it can be used for generation the next morning, or whether to reschedule an industrial process to take advantage of an expected period of lower electricity prices.

2.2 A significant amount of forecast information is already provided to participants to assist their short-term operational decisions via the wholesale information and trading system (WITS). This includes schedules with forecast prices and demand/supply quantities ranging from a week ahead through to the next four hours.[1] While this information helps participants to plan ahead, the forecasts ultimately rely on the accuracy of underlying inputs for projected demand and intermittent generation.

2.3 A recent study found that inputs to the forecast schedules were a contributing factor to problems experienced on 9 August 2021. The study also identified variations among wind generators in the accuracy of their short-term forecasts, and that recent changes by the system operator had materially improved the accuracy of projected demand inputs.[2]

2.4 The accuracy of these inputs will become even more important as the system becomes more reliant on intermittent supply sources and as grid demand becomes more affected by the use of batteries. We think that it is very important to continue (and if possible accelerate) the work to improve forecasts of intermittent generation and demand because of its importance for short-term coordination.

2.5 We also think there is merit in seeking feedback from participants on whether additional types of forecast information would be useful for short-term planning decisions. For example, most existing forecasts are in the form of point estimates – i.e. single central estimates. It is possible that greater use of sensitivity measures might be useful, such as forecast cases that have lower wind generation. This type of information could be particularly useful for parties facing decisions about whether to commit[3] slower-starting resources (such as thermal units) for possible use.

2.6 Finally, we think there is value in regularly reviewing the accuracy of forecast inputs. Our understanding is that such reviews do occur, but on an ad-hoc basis. More regular reviews would provide a greater spur to make further forecasting improvements over time. In the Australian NEM reviews of forecasting accuracy are undertaken each year and the results are published.[4]

Issue: Short-term forecasts (e.g. for 12 hrs ahead) can be misleading and cause inefficiencies or reliability problems	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Improve short-term forecasts and identify options to ensure ongoing continuous improvements	High	~1 year	Very high

1 See functional specification of WITS at www.ea.govt.nz/assets/dms-assets/30/20220408_WITS_FS_v10.0.pdf.

2 See www.ea.govt.nz/assets/dms-assets/30/Accuracy-of-Wind-and-Load-Forecasts.pdf.

3 'Commitment decisions' are traditionally used to refer to decisions by slower start thermal units to prepare their plant for use some hours into the future. However, we are using the term in a generic way to refer to all resource owners that cannot respond quickly in real time to changing conditions and need to commit their resources one way or the other some hours before real-time.

4 See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

A2 – Strengthen governance for next phase of FSR project

2.7 The Authority is undertaking the 'Future Security and Resilience' (FSR) project to look at how the future power system will operate in (or close to) real time. The project is (initially) focused on the core transmission grid and how it operates.

2.8 The FSR project and this project are complementary in nature and the two project teams have maintained regular contact. One of the main differences between the initiatives is the FSR project is intended to have a longer duration (some years) compared to this project (complete in 2023). This is in part because the FSR project has a very strong technical focus and is examining issues in detail. By contrast this project is intended to provide higher-level advice and is applying a lens focused on the long-term benefits for consumers.

2.9 Given that the FSR project is expected to run for some years and have a strong influence on future system coordination, we see use in augmenting the terms of reference for the project. In particular, we think it would be useful for the Authority to add some guiding principles to assist the system operator (and other participants) as project moves forward, particularly in identifying and addressing economic and technical trade-offs.

2.10 Drawing on the principles developed by MDAG in its 2020 paper, "Enabling Participation of New Generating Technologies in the Wholesale Electricity Market", the following principles are proposed to guide the development of proposals by the FSR project:

(a) Take a first-principles approach – 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 which would (i) be likely to raise significant barriers to having a coherent, optimal Code over time and (ii) 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).

(b) Create a durable framework that allows efficient adaptation – the framework should be durable across a range of uncertain future scenarios, while allowing efficient evolution of rules to enable better ways of achieving required outputs.

(c) Favour arrangements that are technology-neutral to foster competitive neutrality – define services 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. 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. (For example, don't give a competitive advantage in the Code to a generating plant based on technology, size or connection type).

(d) Encourage competitive solutions – recognise the importance of fostering and capturing the benefits of innovation over time, which means encouraging competition on an on-going basis to provide services across the spectrum. Also recognise the benefits of market-based arrangements, making fully transparent the cost of providing/using energy services and ancillary services.

(e) Signal the full costs and benefits of potential solutions to participants – signalling marginal costs is crucial to foster competition and innovation with the marginal cost serving as the price to beat for alternative solutions.

(f) Prioritise – effort should be directed towards issues with greatest expected benefit to consumers, while also taking account of lead times to achieve results.

2.11 In addition to adopting guiding principles, we think there would be benefits in broadening the engagement processes for the project. Strong engagement with the grid owner/system operator is a critical requirement, and the project provides for this via Transpower's role as technical adviser to the Authority. In respect of other stakeholders, we understand input has been via workshops and written submissions.

2.12 As the project moves forward we expect that obtaining high quality input from wider stakeholders will become even more important. In particular, some design choices could have very significant longer-term implications. Experience from other jurisdictions suggests that regular and close engagement between the core project team and a stakeholder reference group could be beneficial to supplement formal (and less frequent) written consultation processes.

2.13 We also propose an external reference group to help:

(a) Identify and address key economic and technical trade-offs,

(b) Oversee that application of the guiding principles;

(c) Examine issues where Transpower (or the Authority) may be perceived as having potential conflicts of interest – such as the best division of responsibility between national and 'local' system operation, or the merits of an independent system operator model[5]; and

(d) Support periodic stakeholder engagement.

2.14 In conclusion, we see merit in:

(a) Adding guiding principles to the terms of reference for the FSR project

(b) Appointing an external reference group to carry out the functions outlined above.

Issue: Strengthen planning of future power system operation	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Provide guiding principles for Future Security and Resilience project and establish an external reference group to carry out the functions outlined above	Med-high	6 months	Low-medium

A3 – Update shortage price values

2.15 Spot prices are normally set by the intersection of demand and the stack of supply offers.[6] However, if there are insufficient supply offers to meet demand (and provide normal levels of instantaneous reserves) spot prices will be based on administratively determined values[7] intended to reflect the estimated cost of involuntary load reduction to consumers. (In the industry, this is often called the 'value of lost load' or 'VOLL').[8]

5 See for example the comments on distribution system operators in the submission from the Independent Electricity Generators Association on the Issues Paper.

6 This is a simplified description of what happens inside the market system.

7 In technical terms they are constraint violation penalties for different types of shortage (i.e. levels of energy or reserve deficit).

8 The Code uses the term "value of expected unserved energy". In the Australian NEM the term "value of lost load" (VCR) is used.

2.16 These shortage values are defined in the Code and we refer to them collectively as shortage price values. Although values will be used only on rare occasions, they provide an important anchor for the overall structure of spot prices because they signal the values that are expected in various levels of shortage.

2.17 As Professor William Hogan explains: “[W]ith greater reliance on zero-variable-cost resources that can change availability over short horizons, the scarcity component of spot pricing becomes ever more important” [9 and 10].

2.18 We think there is merit in periodically reviewing the values used in the Code for shortage pricing arrangements. This should include examination of the value of reliability to consumers as this could change with electrification of more sectors of the economy (i.e. the underlying ‘VoLL’ estimate). As far as we can tell, the values themselves were last reviewed in 2011, although the way they will apply was reviewed more recently as part of the forthcoming introduction of real-time pricing.

2.19 Between periodic reviews, there may also be merit in indexing shortage values to inflation as occurs in the Australian National Electricity Market.

Issue: Default spot price values in Code that apply in a shortage may not reflect cost of curtailment to consumers	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Periodically review the shortage price values and mechanisms to ensure they provide accurate signals	Medium/high	~2 years	Possible

A4 – New reserve product to cover sudden reduction from intermittent sources

2.20 The spot market provides for the procurement of sufficient energy to satisfy demand in a trading period. It also provides for procurement of additional resources to provide cover for risks of various kinds. One of the more important is reserve to counter the sudden unexpected loss of a major supply source during the trading period. This is called instantaneous reserve (IR) and there are technically four products – fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) for each of the two islands. FIR must respond within 6 seconds and last up to 60 seconds. SIR must respond within 60 seconds and last up to 15 minutes. Reserve can be provided by load shedding or stand-by generation, and procurement is co-optimised with the energy spot market.

2.21 The design of these products reflects the historical need in the New Zealand system, which has been to respond to the unexpected loss of the largest supply risk in each island, generally a large generator unit or transmission circuit.

9 Prof William W. Hogan, “In My View, Best Electricity Market Design Practices”, (forthcoming in IEEE Power & Energy), available at Microsoft Word - 7_Best_Practices (Hogan)_RCH_03_10_18MIH_rev_final_072518.docx (harvard.edu) .

10 Scarcity rent” is broader than the shortage or VOLL price. “Scarcity rent” is the component of the price necessary to reduce demand to the point where it is met by available capacity (see 1). Short-run efficiency requires clearing prices to reflect economic cost, which includes opportunity cost and scarcity rent (see 2). Reference(1): Bushnell, J, Flagg, M, Mansur, E, Electricity capacity markets at a crossroads, DEEP WP 017, UC Davis Energy, and Economics Program, page 11). Reference (2): Yarrow and Decker, Nov 2014 at p.4, 2nd to last para.

2.22 As noted in earlier, the system's characteristics are changing as the share of intermittent renewable generation increases. One particular issue to consider is the potential for unexpected large reduction in supply from intermittent sources during a trading period. This type of risk may not be readily addressed by spot price signals alone.[11] Some markets address this by carrying another form of reserve that is slower starting (e.g. 15 minutes) than the current IR products but can be sustained for longer periods.

2.23 This is sometimes referred to as 'standby-reserve' and could be provided by demand response, or flexible generation or batteries. The amount of stand-by reserve could be varied to reflect system conditions (as occurs with current IR products). As with the current IR products, the aim should be to create accurate signals for all participants. This would mean that arrangements are neutral as far as possible between demand- and supply-side solutions, and reserves should be co-optimised with the energy spot market wherever feasible. In addition, as with current IR products, costs should be allocated to causers as far as practical.

2.24 Changes would be needed to market information technology systems to introduce a new ancillary service product. Alternatively, if there is a need for a quicker solution, it might be possible to refine the existing products – for example by accounting for intermittent supply risk when calculating the reserve requirement.

2.25 We think an additional or modified reserve product(s) should be considered as a way to address the reliability risks associated with sudden changes in supply from intermittent sources.

Issue: Reliability risks associated with sudden reduction in supply from intermittent sources are not covered by existing ancillary service products	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Develop an additional or modified reserve product to address the risk of sudden reduction in supply from intermittent sources.	High	1-2 years depending on option	High

A5 – Offer price reductions after gate closure

2.26 The Code currently has a one hour 'gate closure' after which suppliers are not permitted to revise their offers.[12] This provides the system operator with a stable menu of offers from which to select the least-cost supply and demand response mix and undertake the security checks needed to ensure reliable operation. While gate closure is useful in these respects, it does present challenges for some types of resource.

2.27 In particular, some generators (and perhaps demand response providers) are not well suited to being on the margin. This is because they are required to be able to vary their output to respond to varying conditions inside the trading period. For example, we understand that it is very costly to operate some open cycle thermal stations at partial output. Some hydro stations may face similar issues because of the interplay of resource consent requirements and their physical characteristics.

11 The adoption of real time pricing should help to address this issue because a redispatch of the system would occur if there was a sudden reduction in intermittent supply. However, this presupposes that there is some resource (demand response, batteries or supply) that can response sufficiently rapidly to counter a reduction in supply.

12 There are some limited exceptions, such as to respond to a bona fide unforeseen event.

2.28 Operators of such resources currently have relatively limited options to avoid being the marginal provider. One option is to offer at a low price (such as 1c/MWh) to ensure dispatch. To assess revenue adequacy, they must rely on forecasts in the lead-up to gate closure. Alternatively, they can offer their resource in a way that makes it unlikely to be dispatched (for example offer above the expected clearing price, or with zero quantities). All other things being equal, this would have the effect of lifting spot prices or reducing the available supply margin – neither of which is particularly desirable.

2.29 One possible way to address this issue would be to allow parties that have been dispatched on the margin to then reduce their offer prices. This would allow a resource provider that is ill-suited to marginal operation to bid its true reservation price at gate closure. If it is dispatched but is on the margin, it could reduce its offer price to ensure full output is dispatched. This would mean that another resource would then become the marginal provider (that resource in turn might subsequently re-offer if it did not wish to remain as the marginal provider). The result should be a greater willingness of parties with limited flexibility in their output to make offers.

2.30 It is important to note the partial reopening of gate closure would only apply to a resource provider that is on the margin and only offer price reductions would be allowed. These restrictions would be designed to ensure that parties could not use the modified gate closure provision to game spot prices.

2.31 We propose that this option should be considered further to assess the scale of its potential benefits and whether there are any unforeseen costs or risks.

Issue: Avoid inflexible generators (or DR) from becoming supply at margin	Potential net benefit	Likely lead time to implement	Useful for transition
Allow marginal resource providers to reduce their offer price inside the gate closure window	Medium	1-3 years depending on option	Medium

A6 – Investigate + develop ahead market

2.32 No matter how good forecasts become there will be some uncertainty about how conditions will actually turn out in real-time. This uncertainty can present significant challenges for some participants because they need to make their commitment decisions hours before real-time.

2.33 A tool used in some other countries to address this is a formalised ahead market in which all wholesale buyers and sellers of physical electricity must participate. In 2017 the Authority looked at the potential introduction of a formal ahead market. It decided to not pursue an ahead market at that time, but noted possible changes to the electricity system could make it worthwhile reconsidering an ahead market in the future.[13]

2.34 In simple terms, an ahead market creates a two-stage settlement process. The first set of binding financial commitments (the ahead market) would be formed some hours ahead of real time. Parties whose actual demand or generation deviated from their cleared ahead-market quantities would settle those differences based on prices calculated in the real-time spot market (which effectively becomes a balancing market).

13 See www.ea.govt.nz/assets/dms-assets/21/21777Improve-information-leading-into-real-time.pdf and www.ea.govt.nz/assets/dms-assets/22/22436Price-forecasts-decision-paper.pdf.

2.35 The effect of these arrangements is to give buyers and sellers price certainty, provided they act in accordance with the level of demand/generation contracted in the day-ahead market. However, if they deviate from the day-ahead commitment, they no longer have price certainty because mismatches are settled at the balancing price, which is not known until real time.

2.36 An ahead market could be useful to parties for whom price certainty ahead of real-time is very important. For example operators of batteries (or other storage devices) could find this helpful to schedule their charging and discharging decisions over the next (say) 8 hours. Similarly, demand response providers who need to plan ahead could benefit from the price certainty provided by an ahead market, as it would allow optimisation with distribution markets and give distributors better visibility of DER activity.

2.37 An ahead-market should also be beneficial for thermal unit commitment decisions for operators of slower-start units. This is expected to be an important issue during the transition to a renewables-based system. There is also the possibility that some slower-start thermal units will be used beyond the transition if it is economic to operate on bio-fuels.

2.38 The key drawbacks with ahead markets are that they introduce additional complexity and processes for participants to manage. Some parties also consider that ahead markets unduly favour parties who can readily predict their output or demand, as they can insulate themselves from balancing prices (which like spot prices can be very volatile). Having said this, to the extent that ahead markets improve coordination, they should help to reduce price volatility in both ahead and balancing prices.

2.39 Introducing an ahead market would take significant time to introduce because of the changes needed to market systems. There could also be transitional issues to address, such as the effect on existing hedge contracts (e.g. whether they settle against ahead or balancing prices).

2.40 However, an ahead market has the potential to better deliver reliable and efficient operational coordination of the system in a manner that is more consistent with market principles and more durable. By contrast, many other measures for dealing with coordination issues – like the system operator having discretion to commit slow start plant to cover possible peaks – tend to be ad hoc and cause unintended consequences.

2.41 We propose that work should be undertaken to investigate and develop an ahead market for adoption later in the decade. In the meantime, voluntary use of short-term products (such as day ahead contracts) should be encouraged to aid with operational planning and coordination (see measures to strengthen contract market in Chapter 0).

Issue: Participants' ability to plan and coordinate plant and DR in lead up to real time is impaired by uncertainty	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Develop ahead market mechanism.	Med-high	~2-3 years	Lead time reduces usefulness for transition

A7 – Remove UTS over-ride of trading conduct provisions

2.42 Participants' reliance on spot price signals is likely to be compromised if they believe there is significant chance that prices could be revised after the time they apply. In particular, providers of last-resort resource will likely be quite sensitive to the potential for high spot prices to be reduced after a tight supply event, as such events can generate concern about high prices, even if such prices were an accurate signal at the time. This does not mean that spot prices should never be revised. On the contrary, it is important that high prices are subject to proper scrutiny. However, it does mean the triggers and framework method for reviewing prices should be well defined.

2.43 With these factors in mind we have identified a specific area of concern in relation to the Undesirable Trading Situation (UTS) provisions in the Code. These are deliberately broad because they are designed as a backstop provision to address events that are not readily covered by other provisions in the Code. These provisions allow the Authority to undertake many actions to correct a UTS, including resetting prices if that is deemed desirable.

2.44 This breadth of the UTS provision does create some uncertainty, but this is narrowed somewhat by a safeguard clause that states the UTS provisions cannot be invoked by the Authority if, in its reasonable opinion, the situation in question could be satisfactorily resolved by other mechanisms available under the Code.[14]

2.45 The sole area where this safeguard does not apply is in relation to the trading conduct rules in clause 13.5A of the Code. The trading conduct provisions are more specific than the UTS provisions and are designed to address the abuse of market power (including in tight supply periods). They have now been in place for more than a year and appear to be operating effectively. We think the ability of the UTS to over-ride the trading conduct clause may create uncertainty. For example, an event might be addressed under the trading conduct rules, and then re-examined as a UTS.

2.46 We see merit removing the ability of the UTS provisions to over-ride the trading conduct provisions.

Issue: Confidence around pricing – UTS rules create uncertainty relative to 'trading conduct' rule	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Remove the ability of the UTS provisions to over-ride the trading conduct provisions	Medium	~1-2 years	Not directly

A8 – Negative offers/prices – *not preferred at this time*

2.47 Some electricity markets allow generators to offer their supply at negative prices. For example the Australian NEM and Germany's wholesale electricity market allow negative-price offers. Negative offers can produce negative settlement prices in the spot market depending on the marginal source of supply.

2.48 Allowing suppliers to offer at negative prices provides a mechanism to allocate the right to dispatch based on willingness to pay. This can be useful where generators face significant shut down costs or have other reasons to run (generally to earn support payments outside the wholesale market such as the Australian renewable energy certificate scheme),[15] and demand is low relative to supply. Negative prices can also stimulate new forms of demand response, such 'opportunistic' demand that ramps up if prices are low or negative. Alternatively negative prices could incentivise the development or use of additional energy storage capacity.

14 See definition of "undesirable trading situation" in clause 1.1(1) of the Code.

15 This could also occur where wind or solar generators have physical offtake power purchase agreements with a guaranteed price.

2.49 Currently the New Zealand Code does not allow negative-price offers and generators that are concerned about being turned off can use the must-run dispatch auction to ensure dispatch. In principle the introduction of negative offers would provide a more efficient mechanism to manage such situations as it would be more fully integrated into spot price computation and hence provide more efficient price signals. For this reason, if the capability to handle negative offers/prices could be easily activated, we would propose this as an option for adoption. However, we understand that from a technical perspective this option is not straightforward for the New Zealand market system.[16]

2.50 There is also some uncertainty about the extent to which negative offers would actually be used as 'must-run' generation appears unlikely to be a marginal supply source in New Zealand. This is because wind generation (the likely predominant source of new supply) has a positive short run marginal cost and does not receive subsidies. Hence, operators appear unlikely to wish to offer at negative prices. Furthermore, the main 'must run' generation in the past in New Zealand has been thermal generation with take-or-pay fuel contracts. Such generation has been fading from the system and will decline further as it transitions to a renewables-based system.

2.51 Overall, we think a change to allow for negative offers/prices does not warrant further work at this time. However, the issue should be kept under periodic review and reconsidered if circumstances change.

Issue: Right to dispatch should include generator's willingness to pay – stimulate demand response and enable generator to keep running	Potential net benefit	Likely timeframe to implement	Useful for transition
Action: Allow for negative offers and spot prices – **not preferred at this time**	Low	~3 years	Unlikely

A9 – Centralised commitment based on complex offers – *not preferred*

2.52 Under current arrangements, resource owners make decentralised self-commitment decisions, with each owner taking account of system data (forecast market prices etc) and their own situation (start-up and running costs, contract position, etc).

2.53 The alternative approach is to collect information from all wholesale market participants and have one party determine the 'optimal' commitment plan based on this information. This would likely involve inter-temporal optimisation over a period of time (typically a day) rather than isolated half-hour trading periods.

2.54 This type of approach was used in the England and Wales pool (since superseded by NETA and then BETTA) and the original Ireland design (since superseded by I-SEM). Generators submitted complex offers that included information on factors including start-up, no-load, running and ramp costs. The system operator used software to determine an overall commitment plan that was least cost based on all of the inputs. The original design of the SEM in Ireland (since superseded by I-SEM) was similar, being optimised over the next 24 hours with an additional 6-hour "look ahead".

16 We understand the specific issue relates to the treatment of transmission losses, which are currently approximated in the market system via piecewise linear functions. To allow negative offers/prices, the representation of losses would need to be reviewed and updated. This would require very substantial changes to market system's software.

2.55 Although this approach is conceptually attractive in some ways, it is likely to face some practical trade-offs. Firstly, each resource provider faces its own unique set of constraints. For example, the hydro fleet has many different energy management and resource constraints. This could mean there would be a very large number of inputs and constraints to take account of. In the England and Wales pool and the SEM in Ireland this was more straightforward because the system was dominated by thermal plant, with a relatively clear set of parameters to be optimised.

2.56 Another issue is that centralised optimisation would likely make the system even more of a black box. Well-resourced parties can invest in understanding the nuances of the optimisation process and potentially use that to obtain financial benefit. However, it is harder for other parties (typically the demand-side) to monitor and scrutinise offer behaviour. This was a criticism of the old England & Wales Pool approach.

2.57 For the above reasons, we do not recommend that central commitment based on complex offers be pursued further at this time.

Proposed action	Level of benefit	Likely lead time to implement	Useful for transition
Introduce centralised commitment based on complex offers – **not preferred at this time**	Low	3+ years	Not directly due to timeframe

A10 – Warming contracts – *not preferred*

2.58 Various forms of 'warming contracts' have been raised in the past as a possible solution to unit commitment issues.[17] As noted earlier, the potential for such issues to arise in the transition to a renewables-based system is growing as intermittency supply increases (making forecast conditions less certain) and rising fuel and carbon costs make thermal unit commitment more expensive.

2.59 In this option the system operator would enter into umbrella contracts with thermal plant owners (and/or potentially other parties). The contracts would allow the system operator to 'call' for a unit to be committed in return for a contract payment. Costs would be recovered by a levy across all wholesale purchasers or some similar approach.

2.60 We understand a mechanism of this broad type is currently used in Great Britain. In that system, National Grid uses the so-called 'BM start-up' facility to contract with resource providers. BM start-up contracts allow National Grid to require a unit to be brought to hot stand-by, or for a unit to be maintained in that state.[18]

2.61 In principle, warming contracts offer a pathway to reduce the likelihood that slow-start units will be unavailable when required. This would be achieved by transferring responsibility for (at least some) unit commitment decisions from resource providers to the system operator.

2.62 Although this approach could possibly be introduced relatively quickly, there are potential risks that warrant careful consideration:

(a) A fundamental source of unit commitment risk is uncertainty about future system conditions. It is not clear why the system operator would have better information than participants on this front.

(b) If warming contract revenue becomes available in the market, it is possible that some providers who routinely commit their resources could change (or threaten to change) their

17 For example the option was looked at in 2007-2008 in response to concerns about thermal unit commitment issues.

18 See BM start up | National Grid ESO.

behaviour to expand the coverage of contracts. This could even have the perverse effect of reducing reliability.

(c) Cost control may be a challenge. Providers may view the system operator as an unduly motivated buyer. It could be difficult for the system operator to maintain negotiating tension unless it can walk away from negotiations or impose a price on sellers. Neither of these options would be straightforward to apply.

(d) Purchasers' incentives to manage risk via forward contracting may be undermined. This could have longer term effects on investment behaviour.

2.63 Overall, we think warming contracts have significant risks and effort would be better directed towards other solutions.

Proposed action	Level of benefit	Likely lead time if implemented	Useful for transition
Warming contracts – not recommended at this time	Low	1 year	Yes in principle

3. Ensuring effective risk management and efficient investment

B1 – Greater transparency of hedge info (esp non-base load) covering offers, bids + agreed prices

3.1 The Code requires all industry participants to disclose information about hedge contracts they sign [19] The information to be disclosed includes each contract's volume, price and duration and must be loaded onto an electronic platform approved by the Authority. The information is published on the platform in a way that does not identify the names of the counterparties.[20]

3.2 Parties looking to enter into hedge contracts can view details of recent and past deals and this can assist them with their own hedging decisions. While the existing disclosure regime and platform are very useful, they could be enhanced in a number of areas. These include:

(a) Provision of more information on non-baseload (shaped) products. For example, it could be useful to add new types of contracts that will become more relevant in future – such as power purchase agreements for intermittent generation output, or to firm such output. At present these types of contracts are not handled well (they are grouped into a catch-all category of fixed price variable volume contracts).

(b) Information on prices for contract modifications. It appears that extensions or modifications to existing contracts may not trigger a fresh disclosure. This means that substantial contracts may not need to be disclosed, even though they are substantively new agreements.

(c) There could be merit in providing price information on contract offers/bids that were declined. This should be possible for more standardised products, and could provide useful additional information about contract price trends.

3.3 We see considerable merit in making enhancements to the hedge contract disclosure regime.

Issue: Make it easier for participants to compare hedge contract prices, especially for shaped (i.e. non baseload) contracts	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Enhance hedge contract information disclosures	Med-high	1-2 years	Yes in principle

B2 – Market-making for longer dated futures (for price discovery)

3.4 The exchange traded electricity futures market performs two key functions:

(a) Electricity market participants use it directly and indirectly to manage their spot price risk, and

(b) Participants and other interested parties use the forward price curve the futures market creates to inform a wide range of investment and operational decisions.

19 See sub part 5 of part 13 of Electricity Industry Participation Code.

20 To view hedge disclosure data see www.electricitycontract.co.nz.

3.5 The Code supports the electricity futures market via market-making[21] provisions. In essence, these provide for market-making in baseload contracts for some years ahead. A commercial market maker (currently Bold Market Making NZ Ltd) has been engaged to provide 20% of the total volume of market-making contracts, with the remaining 80% being provided by regulated market makers (currently the four largest generator-retailers). The commercial market-maker is paid a contract fee to provide services, and these costs are recovered via a levy from retailers and generators in proportion to their market shares.

3.6 We think there would be benefits in extending the time horizon for futures contracts supported by market making. In particular, a longer forward curve would help parties facing investment and/or retirement decisions. The latter are especially important in the transition to a renewables-based system.

3.7 We note that the European Energy Exchange (EEX) has recently extended its listed baseload and peak derivatives to 10 years (previously 6 years, up from 3 years originally), motivated by the role these products can play in providing hedging to complement (or substitute for) Power Purchase Agreements, with the commensurate benefits that exchange traded products provide (e.g., counterparty default risk management)[22].

3.8 While is unlikely to be cost-effective to provide market-making for very long-term futures (e.g. 10 years or more), it would be good to extend the current time horizon which varies between 3 ¼ and 4 ¼ years into the future.[23]

Issue: Investment/retirement decisions would be improved if more information was available on expected forward prices	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Extend market making for longer term contracts (subject to cost effectiveness test)	Med-high	1-2 years	Yes in principle

B3 – Publish aggregated information on pipeline of new developments, energy and capacity adequacy

3.9 Participants need robust information about the supply and demand outlook to make good contracting and new investment decisions. While a lot of information is already collected and published, there is room for improvement.

3.10 For example, there is currently little visibility about new projects (demand, supply or batteries) in the development pipeline unless a developer chooses to disclose its projects. While this lack of visibility may be beneficial for some developers, it does contribute to increased uncertainty about the system as a whole.

21 "Market-marketing" refers to service where parties post both buy and sell offers for a contract product with a pre-defined maximum spread between the buy and sell prices. Market-makers must refresh their offers within a defined period if an offer is accepted. To protect market-makers from undue financial exposure, there are generally limits on the contract volumes that can be transacted.

22 See https://www.eex.com/en/newsroom/detail?tx_news_pi1%5Baction%5D=detail&tx_news_pi1%5Bcontroller%5D=News&tx_news_pi1%5Bnews%5D=3152&cHash=cd67d41e25db6f5ce75f168cf4b35386.

23 On 1 October each year, market making commences for quarterly contracts for the calendar year that is four years into the future. For example, from 1 October 2022 market making commenced in contracts for the 2026 calendar year.

3.11 In the past, this uncertainty was less problematic because new developments had long lead times and tended to be highly visible. For example, it took many years to build hydro, geothermal or thermal stations. Demand was also relatively predictable, so the likelihood of major surprises was low.

3.12 Some technologies are now very quick to deploy (such as solar farms and batteries which can be built in less than 12 months). Demand is also less predictable with the potential for significant step changes as some large users retrench and others grow.

3.13 We think there is a good case for publishing much more information on the supply and demand outlook along the lines of the approach in the Australian NEM where the rules require that the system operator collect and publish information on the new project pipeline down to project level.[24]

3.14 Transpower has much of the necessary information via its grid connection team but is often unable to publish it due to confidential obligations. We recommend New Zealand adopt the NEM approach. As a corollary benefit, we expect that enhanced information provision would be pro-competitive. This is because under current arrangements, participants must rely more on their own resources to collect information, and this is generally easier for the larger established parties.

Issue: Provide more information to help participants with contracting and investment decisions	Potential net benefit	Likely lead time to implemented	Useful for transition
Action: Improve information on supply and demand	High/medium	1 year	Yes in principle

B4 – Enhance stress testing regime

3.15 The current stress testing regime is designed to reinforce the obligation on participants to actively consider and manage their exposure to electricity price risks. It does this by requiring participants to calculate their financial exposures based on standardised tests and disclose these results to their Boards and to a registrar (currently NZX). The registrar collates the results and provides them to the Authority in an aggregated and anonymised form.

3.16 We see benefit in making two changes to the stress testing arrangements:

(a) Extend the time horizon for applying tests. At present this regime only applies tests for the coming quarter as it was primarily designed to address risks associated with near term droughts or transitory capacity shortages. As a result it does not provide any information about exposure to longer term risks, such as investment delays or changes in demand growth. Recent experience shows these factors are very important and participants need to consider the forward horizon as well as the current quarter in their hedging decisions. We suggest that the stress test horizon be extended to 2-3 years (noting that different tests would need to be applied for forward periods than the coming quarter).

(b) Provide participants with information on how their stress test results compare to all other parties. The comparator results would need to preserve confidentiality for other parties. The information should be useful for participants when assessing the reasonableness of their risk position and extend the sign-off obligations to relative position information (i.e. how they are placed relative to others).

24 See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

3.17 We think the changes could be made relatively quickly as they should not require significant changes to market IT systems.

Issue: Help ensure that participants are actively considering and managing their exposure to spot price risk	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Enhance stress testing regime	Medium	1 year	

B5 – Develop standardised 'shape' product(s)

3.18 With the expected increase in wholesale price volatility, it is more important that market participants have hedge products available which help them manage that risk, and provide opportunities to provide liquidity in these products.

3.19 The Electricity Authority and market participants have previous investigated an option to list cap products on the ASX. These cap products were intended to be of a similar design to those listed for the Australian market. Based on conversations MDAG have had with ASX, we understand that these products are likely to require high margins from traders.

3.20 Further, we remain unconvinced that American/European options (of the type listed for the Australian electricity market) are the best product to manage the future 'shape' risk in the New Zealand market. There are a number of aspects of both the supply of, and demand[25] for these products which motivate a joint industry-regulator design process.

3.21 Once agreed, a standardised shape product (or products) can be used as a basis for trade in the OTC market. Alternatively, it could be more formally listed. The listing could be provided by ASX, or other local providers (e.g., NZX).

3.22 Once made available, if trading is perceived to be illiquid after a sufficient period of time, **Option B8** (market making in shape products) should be investigated.

Issue: Hedge products need to evolve to manage the future shape of wholesale risk	Potential net benefit	Likely lead time to implement	Useful for transition
Action: A joint industry-regulator design process of shape-related hedge product(s)	Medium	2-3 years	Likely

B6 – Develop long-term flexibility access code (non-price elements)

3.23 We think 'flexibility contracts' that complement the output of intermittent generation will become much more important in the future.[26] Such contracts could be useful for independent parties seeking to develop intermittent generation, or customers wanting to purchase a product to use alongside a separate intermittent-based supply arrangement.

3.24 As discussed in the section on 'strengthening competition', the hydro generation fleet is likely to form a major portion of the physical resources to underpin such contracts, and ownership of this generation is currently quite concentrated.

3.25 This raises two potential concerns:

25 There is an important linkage here to **Option C4,** which seeks the design of a hedge product that large consumers could sell as a way to smooth their cashflows from using wholesale DSF, thus providing liquidity into the contract market.

26 These could take a variety of forms including power purchase agreements, caps, collars, or sleeving arrangements.

(a) Whether parties with a substantial share of the system's physical flexibility will deal with requests from other parties for 'flexibility contracts' in a reasonable manner.

(b) If requests for flexibility contracts are being dealt with reasonably, would there be sufficient information to allow a robust view to be formed.

3.26 To address these issues we see merit in introducing a 'flexibility access code'. In summary this code would place obligations on participants that hold a substantial proportion of the system's longer duration flexibility resources. The obligations would focus on how these participants receive and respond to requests for flexibility contracts. The proposal is modelled loosely on the code being developed in the supermarket industry to address similar types of concerns, and is described more fully below.

Issue: Ensure all participants have reasonable access to 'flexibility contracts'	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Introduce flexibility access code	High	1-2 years	Possible

B7 – Extend trading conduct rules for hedge market

3.27 The Code was amended in 2021 to modify the trading conduct rules. The new rules require spot market participants to make offers that are consistent with those expected from a party if no parties had significant market power.[27] The rules are designed to give all market participants, and especially consumers, confidence that prices are efficient even when competitive pressures are relatively weak.

3.28 A post-implementation review undertaken by the Authority 13 months after the new rules came into effect stated "the new provisions appear to be having an impact on generator behaviour" and that "offer prices appear to be reflecting underlying conditions and economic costs more closely".[28] Having said that, the review also stated that "the new rule may have no effect on the exercise of market power that occurs at the margin, as it is difficult to detect this".

3.29 At present the trading conduct rules only apply to the spot market and exclude hedge (contract) market transactions. From a first principles perspective, there is merit in extending the coverage of the trading conduct rules to the contract market. This should help to address competition concerns in the contract market itself and have the additional benefit of applying a common legal and economic framework across the wholesale electricity market. From a practical perspective extending the coverage of the trading conduct rules should be relatively straightforward to implement. The main area to consider is whether there could be any unexpected adverse consequences.

3.30 We think there is merit in extending the trading conduct rules in the Code to cover hedge market transactions by electricity industry participants.

Issue: Ensure that contracts are offered on terms consistent with effective competition	Potential net benefit	Likely lead time to implement	Useful for transition
Extend the trading conduct rules to the hedge market	High/Medium	1 year	Yes in principle

27 See clause 13.5A(2) of the Code.

28 See Long-form report (ea.govt.nz), page ii.

B8 – Market making in caps or other shaped products

3.31 While the existing baseload products covered by market-making are very useful for identifying expected trends in average spot prices, they provide little information about the expected shape of future spot prices.[29] By 'shape' we mean how the price varies for contract profiles other than a baseload product. This information is likely to become much more critical in the future for the reasons outlined earlier.

3.32 Furthermore, if shaped contract products were more readily available, that should reduce the scope for generators to exercise any substantial power they have in the spot market. This is because participants would have greater means to use contracts to mitigate their exposure to spot prices. In addition, a more transparent forward price curve for shaped products should reduce generators' ability to exercise market power in the contract market. This is because the availability of such forward prices should make it easier for parties to make investment decisions in flexibility alternatives, such as storage devices or demand response capability.

3.33 An option to address the above needs would be to introduce shaped contracts that are exchange traded and supported by regulated and/or commercial market-making. Examples of shaped contracts used in some other countries are cap futures that mitigate exposure when spot prices are above a defined level (such as A$300/MWh) and peak futures that provide cover during certain hours on business days (i.e. when demand and spot prices are typically higher).

3.34 Careful consideration would need to be given to the particular form of the shaped contract(s) that are best suited to New Zealand as these may differ from other jurisdictions. The work would need to balance various design goals. Clearly the hedging requirements of participants would be very important. However, consideration would also need to be given to the margining requirements on a futures exchange for shaped products, and the scope to obtain cost-effective market-making.

3.35 We see merit in introducing new shaped contract products that would be supported by market-making.

Issue: Create forward price discovery and market liquidity for a shaped contract	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Introduce market-making for shaped contracts (such as a cap contract).	High	2-3 years	Yes in principle

B9 – Capacity mechanisms – *not preferred*

What are they?

3.36 Capacity mechanisms (CMs) are designed to provide assurance that sufficient capacity will be built to serve demand. CMs take a wide variety of forms, all of which impose an obligation on wholesale buyers to hold a certain level of contract cover in given circumstances. Types of capacity mechanisms include a capacity market for firm capacity (or firm energy), strategic reserves, targeted capacity payments and market-wide capacity payments, call option, and reliability certificate (retail reliability obligation).

29 At present the information is limited to the shape of prices across seasons, as the products are quarterly or monthly in duration.

3.37 In essence, they regulate the level and nature of forward contracting between suppliers and wholesale purchasers. The spot market continues to exist to provide operational incentives but is typically subject to a relatively 'low' price cap[30] as suppliers derive much of their revenue from capacity payments. They key difference with capacity mechanisms is that wholesale purchasers cannot choose how much capacity cover to buy – a central body forces all purchasers to buy a minimum level. Wholesale purchasers also do not have choice as to who to buy capacity cover from.

Why are they used?

3.38 Key reasons why capacity mechanisms have been used are as follows:

(a) "Missing money": Concern that energy-only market will provide insufficient revenue to ensure ongoing investment in capacity. Examples include:

(i) Australia NEM: price cap causes missing money problem (free riding)

(ii) Australia NEM: conflicting state-level policies (such as subsidies for new renewables in some states) may depress wholesale prices and raise likelihood of disorderly thermal retirements

(iii) Alberta: Low price cap (C$1000)

(iv) Alberta, Colombia: Low tolerance for high prices (in Colombia prices > US$200 raise political concern)

(v) Alberta: Increasing carbon costs

(vi) Singapore: Over-supply leading to concern of insufficient revenue and therefore investment for baseload, peaking

3.39 Other objectives: These vary depending on scheme, but the main other objectives are:

(a) Preference for more central control/less trust in market processes

(b) Support key existing plant, eg 'strategic' legacy thermal, eg Singapore

(c) Support investment in particular types of plant, eg last resort plant, renewables (though note the limitations of this below)

How do the work? What are their key features?

3.40 The main features of capacity market for firm capacity include:

(a) Explicit reliability target – they all specify an explicit target level of capacity (or energy) adequacy, and place physical or financial obligations on retailers and other wholesale purchasers to achieve this target.

(b) Purchaser obligations – purchasers are required to hold sufficient capacity rights to match their assessed share of the overall system demand over the (say) next three years. These rights can be from self-supply (if they have generation), or via purchasing rights from other parties.

30 It is often capped around the level of a peaker operating on liquid fuels. This is still very expensive but is 'low' relative to the value of lost load which tends to guide the price caps applied in systems without a capacity mechanism.

(c) Supply monitoring – to provide assurance that capacity being procured is real, generators and demand response providers cannot sell more than their 'qualified' capacity. Assessment is normally overseen by a regulator, following rules covering issues such as fuel availability for thermal plants, derating factors for intermittent generation, definitions of plant retirement and commissioning etc.

(d) Registry – CMs need a registry to record the number of qualifying capacity rights available for sale by each supplier, the holdings of each wholesale purchaser (to match their assessed demand), and sales and purchases of rights between participants. The registry must also account for generation investments/retirements, and movements in consumers between parties due to retail competition.

(e) Contracting horizon – the obligation to purchase capacity rights typically covers future years to provide investment assurance (noting the lead-time to build new generation is more than one year). This can be challenging for purchasers whose future needs are uncertain such as large industrial users with fluctuating demand.

(f) Capacity payments – purchasers make capacity payments to providers. The prices can be set centrally (typically based on an auction process) or via bilateral negotiation.

What do they typically achieve?

3.41 Capacity mechanisms in general have been effective at achieving their intended objective –ensuring adequate capacity investment is built ahead of time. However, it is generally held that consumers pay more with CMs because there is an inherent tendency to over-procure resources. This arises because the cost of any under-procurement is very visible (power cuts) whereas the cost of over-procurement is harder to measure.

3.42 Capacity mechanisms have had a mixed record at achieving operational reliability. For example capacity markets in North America had near-miss events in the mid-2010s when unexpectedly large volumes of plant were not available to run when required. As Wolak noted, the CM's focus on capacity adequacy rather than operational reliability is analogous to ensuring there are enough bakeries, rather than enough bread.[31]

3.43 Research suggests that in practice CM-based approaches tend to have higher costs, because they are more likely to over-procure as costs are not borne directly by those making key decisions.

3.44 A 2016 survey of capacity markets found[32]:

> "experts generally contend that the capacity markets have achieved the goals of providing the required reserve margin, but in an economically inefficient way [and] these costs appear to be mainly due to a higher reserve margin than would be economically optimal"

How are they viewed overseas now?

3.45 More recently there has been a focus on sharpening operational incentives for CMs in North America – including introducing penalties for non-performance that mimic scarcity pricing in spot markets. This issue has become increasingly important as electricity systems decarbonise, and operational incentives (for example when to charge and discharge batteries) becomes much more important.

3.46 Indeed, the rising share of intermittent renewables on systems around the world is undermining two of the key planks in CM designs:

31 Wolak, F. A. (2004). *What's wrong with capacity markets?* Stanford University.

32 Bhagwat, P. C. et al. (2016). Expert survey on capacity markets in the US: Lessons for the EU. Utilities Policy 38.

(a) First, CMs are oriented towards achieving reliable supply during archetypal risk events – such as extremely high demand on a very hot day due to air-conditioning load. Archetypal risk ‘events’ are much less well defined in systems with high renewable penetration. For example, they could arise in periods of high demand, low wind, or low solar or a combination of these factors. The risk profile can also change over time as the system mix evolves.

(b) Second, the supply contribution from resources has been relatively well defined in the past because it came mainly from thermal stations with high degree of predictability. That is not the case with renewables because of their intermittent nature. More importantly, the firm supply contribution from any single renewable plant will depend on what else has been built because of diversity effects. These factors make it increasingly difficult to operate CMs because they require a lot of prescription in their standard, contract forms and auction rules.

3.47 Opinion among leading international experts appears to be shifting away from CMs toward bilateral contracting as the preferred approach to ensure resource adequacy. For example we understand the European Union Agency for the Cooperation of Energy Regulators has been leaning towards this model.[33] Professor James Bushnell has written that:

> “As resources become more diverse, the challenge of forecasting their value for reliability months and years in advance greatly increases. This could necessitate an increased reliance on short-term performance measures, of which energy prices are the most sophisticated.”[34]

3.48 Similarly, Professor Peter Cramton, a leading international expert and former proponent of CMs thinks that rising renewables will increasingly challenge CMs. In this context, it is interesting that Alberta and Singapore have both reversed earlier decisions to introduce CMs in the last few years.

3.49 Capacity mechanisms come from, and are strongly influenced by, culture and politics. Capacity mechanisms tend to be based around thermal-dominated systems and in response to historical challenges, but not so well suited to the nature of innovation and opportunity in the coming years.

3.50 Professor Crampton observed in discussions with MDAG:

> “A capacity or firm energy market is not the tool to promote innovation and investment … They have so many ‘nobs and dials’, and everyone lobbies for their type of resource…”

3.51 On the other hand, we note the Australian NEM governments (Commonwealth, State and Territory) have made an in-principle decision to adopt a capacity market. We understand a key factor has been a concern over the potential for disorderly outcomes as constituent jurisdictions pursue different decarbonisation policies. For example, some jurisdictions are actively supporting renewable development with government-backed long-term contracts, while others appear comfortable in retaining coal-fired generation for longer. Australian officials are currently preparing a detailed capacity market design, and Ministers are expected to decide whether to proceed soon. We note that the jurisdictional conflicts do not apply in New Zealand and that this country adopted clear emissions reduction policies some years ago.

How has New Zealand performed on resource adequacy using an ‘energy-only’ system?

3.52 Experience suggests EOM-based approaches are better at incentivising *availability* – because spot prices typically create stronger and more dynamic signals to avoid shortages than the administrative tools used in capacity markets. Spot prices also apply to all resource providers, not just those covered by capacity contracts.

33 ACER indicates that capacity mechanisms are not long-term solutions, describing them as ”a temporary measure”. See Capacity mechanisms | www.acer.europa.eu.

34 See James Bushnell et al., *Capacity Markets at a Crossroads*, Working paper, Energy Institute at Haas, April 2017

3.53 Over the last 30 years, New Zealand's energy-only market has performed relatively well in ensuring sufficient capacity is built and retiring plant in an "orderly" way.[35]

Conclusion

3.54 Our view is that capacity mechanisms are unlikely to be the best way to ensure effective risk management and efficient investment in a system with increasing levels of renewable supply.[36] Nor would it address the key thermal transition challenge in the New Zealand system, which is operational coordination.

3.55 We are also mindful that designing and adopting a CM would be costly and take 3-4 years and would impede investment in the intervening period. Given these factors, we do **not** recommend further work on CMs at this time.

3.56 We consider that the other measures proposed in this paper will better ensure adequacy of supply over time and use of thermals in the transition.

3.57 It is important to identify the real source of any concerns about reliability as they may be unrelated to investment adequacy and the choice of market design. As the European Commission noted in November 2016, parties should first seek to "address their resource adequacy concerns through market reforms [..] no capacity mechanism should be a substitute for market reforms."

B10 – Strategic reserve – *not preferred*

What are they?

3.58 Strategic reserve schemes are a targeted capacity mechanism. They apply to a subset of resources on the system, rather than all resource providers. SRs are typically used to address low probability high impact events. An SR is viewed as the 'spare wheel' to cover very rarely occurring events that participants would not otherwise insure against:

(a) In essence, strategic reserve schemes make capacity payments to underpin retention or construction of *specific* resources; and

(b) Seek to preserve 'normal' incentives for all other resources as far as possible. To this end, resources in a strategic reserve scheme must be tightly quarantined from the rest of the system – otherwise their presence simply defers investment in another resource and overall reliability is unchanged.

3.59 Quarantine arrangements typically include:

(a) Rules that require very high minimum offer prices for strategic reserve resources, or for clearing prices to be set to shortage values (VoLL) when resources are used.

(b) Rules that provide for strategic reserve resources to be used only as last resort to keep lights on, and once all 'market' resources have been exhausted.

(c) A levy mechanism to recover costs not recouped via spot revenues.

35 For example see the security of supply annual assessments prepared and published by the system operator and available at www.transpower.co.nz.

36 Some submissions on the Issues Paper also noted it would not provide competition benefits. For example Electric Kiwi Haast stated "We consider that the capacity market options are a solution for the wrong problem."

3.60 As officials at the European Union Agency for the Cooperation of Energy Regulators pointed out in discussions with MDAG in July 2022, strategic reserves are designed to address events with very high impact and low probability. If used, wholesale spot prices are set at very high level to ensure investment incentives are not undermined. For example, in Germany if strategic reserve is used will see price of 20,000 Euros/MWh [around 32,000 NZ$/MWh].

How have the performed?

3.61 The key risk with strategic reserves is that they undermine incentives for contracting and investment. This is very likely to occur if parties view the quarantine arrangements as being unsustainable over time. Put simply, it can be very tempting for system operators/regulators to use strategic reserves in non-emergency situations to lower spot prices, especially when consumers are bearing their standing costs.

3.62 Overseas evidence indicates that strategic reserve schemes mainly support legacy thermals and tend to crowd out or delay the introduction of renewable alternatives.

3.63 Sweden, Germany and Belgium have strategic reserve schemes. We understand Sweden's scheme has been activated 10 times in the last 10 years. The Finnish and German schemes have to our knowledge not been activated. The government or regulator typically extends the life of the thermals under the SR scheme beyond the point when they would have been displaced by the market – e.g. the Swedish scheme was due to terminate in 2008 and has since been extended three times.

New Zealand experience

3.64 New Zealand introduced a strategic reserve scheme in 2003. The Whirinaki diesel fired station was the only resource actually procured, but there were plans to acquire additional demand response in 2008. Despite a strong intent at the outset, it proved impossible to maintain a proper quarantine for the scheme during an extended drought in 2008.[37] Subsequent to that event the scheme was reviewed and terminated.[38]

3.65 It has been suggested that a strategic reserve mechanism may be needed in the transition to a renewables-based system to ensure that:

(a) Thermal plant does not retire prematurely, or does has fuel or is serviced to operate when needed; and/or

(b) Thermal retirement will be "orderly".

3.66 For this to happen, one or more of the following root causes would need to occur:

(a) Market rules/processes suppress spot prices below true value in scarcity events, so thermal plant cannot earn sufficient revenue to justify retention: We have not found any real evidence to support the view. Indeed, the available market evidence suggests the market has produced sufficient revenue to support efficient retention decisions since 2010. Put simply, past thermal exits have been orderly (e.g. New Plymouth, Southdown, Otahuhu B);

(b) "Sensible contracting outcomes are frustrated by 'lumpiness' issues – i.e. large thermal units which face sizeable one-off capex to remain in operation, and there is only a need for a partial

37 See www.ea.govt.nz/assets/dms-assets/409Winter-Review-Report.pdf.

38 In 2009 the government accepted a recommendation from the Ministerial Review of the Electricity Market that the reserve energy scheme be abolished and the Whirinaki plant sold. See Whirinaki plant to be sold | Beehive.govt.nz.

unit to be retained: We do not consider ‘lumpiness’ to be a key issue in relation to the existing New Zealand thermal fleet[39]; or

(c) Misaligned price expectations between thermal owners and wholesale purchasers: Thermal owners seek contract prices based off next best alternative to buyers (new plant or demand cuts) whereas buyers may seek to prices based on written down value of older plant. Both prices could be economically efficient. The large range of possible efficient price outcomes could make it harder to strike a sensible deal. Arguably this phenomenon has applied in the past, but deals have eventually been struck. Such misalignment is likely to be due to (i) weak competitive pressure and/or (ii) information asymmetry between sellers and buyers and (iii) heightened uncertainty about future policy makes it hard for parties to contract: Some types of policy uncertainty could hinder forward contracting for flexible thermals – e.g. whether and when fossil-fuelled generation might be banned.

3.67 A strategic reserve scheme would not address any of these root issues. MDAG considers that the other preferred options in this section would be more effective solutions.

Conclusion

3.68 Our view is that a strategic reserve scheme is not desirable. If introduced there is a high likelihood it will not improve reliability because the presence of reserve resources will defer investment in some alternative resource. In that respect it may simply prolong the retention of thermal units (assuming that is the mainstay of any reserve scheme) that might otherwise be economically displaced. This risk is heightened in New Zealand by the experience with the last strategic reserve scheme.

3.69 Given these factors, we do not recommend further work on strategic reserve schemes at this time.

39 Lumpiness is relevant for the 400MW TCC plant (facing ~$80m cost to extend life). However, the scheduled closure in 2024 has been telegraphed well in advance and we are not aware of any concerns. In relation to other thermal plant, we are not aware of any large lumpy capital expenditures coming up. Capex lumpiness is relevant to TCC, but it seems unlikely an SR would contract to keep this plant on the system (costs appear large relative to benefits).

4. Lifting participation of demand-side flexibility (DSF)

Overcoming the muting of flexibility price signal

C1 – Monitor provision + uptake of DSF-rewarding tariffs

Description

4.1 This option proposes the Authority implement greater monitoring and reporting of:

(a) Available DSF-incentivising tariffs, potentially extending to the number of ICPs in different tariff categories;

(b) The proportion of consumption volumes being reconciled via profiles rather than half-hourly data;

(c) The usage and performance of its dispatch notification product (once introduced)

(d) In collaboration with the Commerce Commission, information relating to ripple control of hot water across the country.

Rationale

4.2 We are aware that a number of retail tariffs that reward DSF have emerged over time, some in the last 12 months.[40] This provides some evidence that retailers are making progress in this respect. However, there is no reliable information available on how many tariffs are available that reward customers for provision of flexibility, what broad types of tariffs are available (e.g., consumer-driven response or automated/intermediary-driven response), and what the uptake of those tariffs are.

4.3 The Electricity Authority does not routinely collect this information. Hence there is no reliable quantitative and time-series basis on which to assess whether the retail market is progressing its development of tariffs that incentivise (in a profiled or dynamic way) demand response. Neither do we have any indication of the uptake of such tariffs. We believe this is vitally important market monitoring information which would provide an evidence basis for future improvements to the market design.

4.4 A more expansive monitoring regime would require:

(a) Development of a broad categorisation of tariff types (e.g., FPVV – flat rate, FPVV – TOU, spot, automated control),[41] which would be developed by the Authority

(b) Retailers periodically (e.g., quarterly[42]) reporting the number of tariffs they have available in each category, and each customer segment, as well as the number of ICPs currently on that tariff type.

4.5 Below we illustrate the types of retailer monitoring regimes used in other countries.

4.6 The absence of this data today does not, in our view, undermine the need for our other preferred options, except where noted (e.g., Option C3). If, following MDAG's recommendations, the Authority wished to obtain a snapshot of DSF tariffs across the retail market before proceeding to implementation, it could do so via a single information request to retailers.

40 For example, there has been a recent rapid introduction of TOU tariffs by Octopus, Electric Kiwi, Contact and Meridian.

41 Fixed price variable volume (FPVV), time of use (TOU).

42 This could align with the retailer returns submitted to MBIE.

4.7 Secondly, Option C2 reports on the asymmetry between the proportion of customer meters which are capable of providing half-hourly volumes for reconciliation and settlement, and the proportion of reconciled volumes where half-hourly data is actually being submitted. We recommend this metric is also routinely tracked and reported by the Authority.

4.8 Thirdly, in 2023 the Authority will introduce a “dispatch notification” product, which is a low-compliance demand-bidding option giving the DSF owner the opportunity to bid price-based offers of demand response capability into the market. Demand bidding is vitally important for price discovery, create “shape” in the demand curve. This becomes increasingly important as thermal offers – providing shape in the supply curve - are removed as plant is retired. Under dispatch notification, a customer’s ability to respond can be changed at short notice, as long as notice is given to the market. Changes in capability that are not notified to the market will be monitoring by the Authority, and a compliance threshold set. We understand aggregators/flexibility traders will be given a market participant category in order to participate, thus permitting them to be agents for customers in this respect (i.e., without having an underlying purchase exposure).

4.9 Even with the lower compliance threshold, we think it is unlikely that mass-market customers would want to interact directly with the market in this way. However, for flexibility traders and larger commercial DSF providers, it offers an opportunity to influence – and potentially set – prices in the wholesale market in a lower-cost way than they can today. We understand aggregators/flexibility traders will be given a market participant category, thus permitting them to be agents for customers in this respect (i.e., without having an underlying purchase exposure), and we commend this specific change to the Code.

4.10 We expect that the Authority will monitor the usage of dispatch notification, hence this option will proceed, and carries relatively little incremental cost. We suggest that reporting on number and volume of bids, and changes to bids, is reported on EMI. This would improve the evidence base for any future initiatives which may be required to encourage large consumers and aggregators to reveal their valuations of demand response.

4.11 Finally, our review of EECA and PSC’s 2020 report “Ripple Control of Hot Water in New Zealand” suggests that there are a number of concerns regarding the quality of data collected on demand (primarily hot water) controlled by ripple control in New Zealand[43]. Given the sheer significance of hot water control today as a form of demand response (~1,000MW as estimated by PSC), the potential for more, and the concerns over ripple control systems degrading over time, a better dataset would improve retailers’ abilities to assess the potential benefits and opportunities for greater wholesale DSF. As much of the data used by EECA and PSC has been collected by the Commerce Commission, we recommend the Authority discuss with the Commission how this could be improved and given greater transparency.

International examples

4.12 Some international jurisdictions collect this information from retailers, and publish it in a summarised way. In the Texas market, ERCOT conduct an annual survey of both competitive retail providers and municipality-owned retailers. This includes disaggregation of customers providing DSR into different tariff categories.

Table 1 – ERCOT Retail Electricity Provider Reported Price-Responsive Demand Response (DR) and Load Reduction Participation categories, based on 2014 - 2021 data. Note: ESIID is the Texas equivalent of an ICP.

43 EECA and PSC Consultants (2020), “Ripple control of hot water in New Zealand”.

	REP ESIIDs Participating							
Category	2014	2015	2016	2017	2018	2019	2020	2021
4CP	247	-	-	-	-	156	393	205
Block & Index	6795	9,534	14,372	20,967	27,153	47,109		
Real Time Pricing	10,701	5,621	9,806	16,339	22,905	42,090		
Indexed Real Time							103,531	96,804
Indexed Day Ahead							940	169
Indexed Other							-	48
Total Indexed	17,496	15,155	24,178	37,306	50,058	89,199	104,471	97,021
Other Load Control	19,296	14,927	8,729	7,292	3,597	2,739	10,461	19,412
Other Voluntary DR	1,458	4,923	35,958	60,489	235,647	6	-	18
Peak Rebate	439,664	494,141	512,162	468,484	486,429	502,589	94,329	93,995
Time Of Use	293,314	328,628	336,365	412,493	479,559	587,507	104,094	112,785
Free Days/Hours							469,354	486,495
Total TOU/FDH							573,448	599,280
Total Unique ESIIDs	763,014	847,498	906,992	978,525	1,231,110	1,165,493	764,773	809,931

4.13 Similarly, in Europe the Agency for the Cooperation of Energy Regulators (ACER) publishes an annual monitoring report on energy retail markets and consumer protection[44] which includes a summary of how widely (amongst member states) different types of electricity and gas offers are available to customers. This is a much less granular view than the ERCOT approach above.

Benefits and costs

4.14 The primary benefit of this option is that it would provide an evidence base on which decisions about other DSF market design or regulatory decisions can be evaluated (some of them included elsewhere in our menu of options, e.g., Option C3).

4.15 We do not see this option as having a significant design component, hence design costs should be low. There will, however, be some costs to retailers in amending their systems to produce the required information about tariff types and customer numbers, and reviewing/submitting this information, on a regular basis.

4.16 If the Authority or Commerce Commission were to pursue improved information about hot water control, there could be additional costs incurred by EDBs in extracting and providing this data.

Timing and priority

4.17 The primary purpose of this option is to determine trends in the uptake of DSF tariffs. Hence the sooner it is implemented, the sooner trends can be detected. Further, as identified below, this data may provide evidence that improves the design of other priority options.

4.18 We do not see this option as having a significant design component, hence should be able to be expedited quickly.

Issue: No reliable quantitative and time-series basis on which to assess retail market development and uptake of DSF tariffs	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**

44 https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring Report%202020%20-%20Energy%20Retail%20and%20Consumer%20%20Protection%20Volume.pdf.

Action: Require retailers to regularly disclose information relevant to DSF tariff progress; EA reports this on EMI.	High (supports other options)	~1 year	Depends on uptake

C2 – Sunset profiling if smart meters in place

Description

4.19 Our proposed option for a sunset date on the use of profiling – for those ICPs which have the capability to measure half-hourly data – was originally proposed by IPAG in *their "Advice on reducing barriers to customer access to multiple electricity services"* report[45]. We do not propose any changes to the wording of their original recommendation. IPAG proposed a second alternative option which would see a sinking cap on the percentage of a participant's half hour capable sites reconciled by profile. We have no strong views as to which is a preferable option, and invite submitter comments.

Rationale

4.20 In order for a retailer to get value from DSF, there are two key variables:

(a) To reduce its reconciled volumes in periods where the wholesale price is higher than its retail tariff

(b) To reduce demand from its customers sufficiently to reduce the wholesale price at that point in time

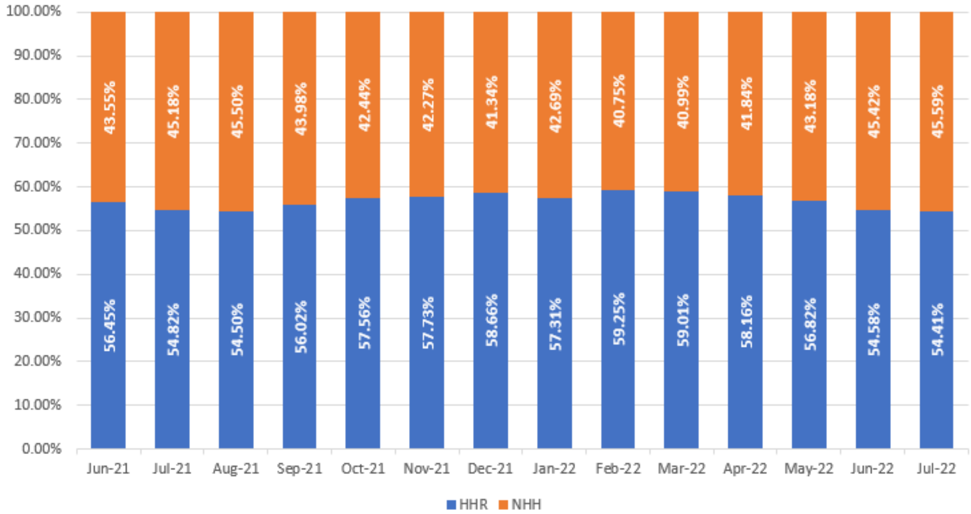
4.21 A retailer who is submitting half hourly metered quantities for reconciliation will be able to capture the full value of both (i) and (ii), as the response of its customers in the particular periods of high wholesale prices will be rewarded at that price. However, if the retailer is only submitting monthly metered quantities, and having a half-hourly shape created through a profile, customer demand response in any particular half hour will effectively be "smeared" across the month according to the profile, and the benefits accruing to the retailer (and thus the customers) will be a fraction of that achieved within the half hours when it was executed. This will significantly dilute the incentives for the retailer to utilise DSF.

4.22 In their submission, Vector raised the importance of high frequency data to realising the benefits of demand side flexibility:

> "…it would appear critical that wholesale market transactions are settled and reconciled on the basis of high-frequency meter data, where it is available. Our understanding is that a large proportion of retail loads are still settled on the basis of average profiles, despite half-hourly data being widely available. The kinds of innovations in other jurisdictions MDAG referenced in its paper would seem to be possible only if customers' smart meter data is used for settlement and reconciliation. Further, the benefits of much of the Authority's recent reforms – for example, real-time pricing, transmission pricing and distribution pricing – rely on high-frequency data being used to the greatest extent possible. Again, MDAG should make this a clear recommendation to the Authority."

45 Innovation and Participation Advisory Group (2019), Advice on reducing barriers to customer access to multiple electricity services, 4 December 2019 (updated July 2021). Available at https://www.ea.govt.nz.

4.23 Information obtained by MDAG from the reconciliation manager show that between 41%-46% of reconciled volumes (excluding grid connected consumers) are non-half hourly volumes that are profiled, despite 88% of all ICPs having advanced meters that are certified for half-hourly data[46].



4.24 Moving from monthly volumes to half-hourly volumes is not costless for a retailer – internal systems and processes will need to be changed. However, the data above would appear that progress towards a greater use of half-hourly data has stalled; IPAG's recommendation was made based on similar data 2021[47]. Hence the slow – and perhaps stalled - transition to half-hourly data is potentially an impediment to retailers developing DSF-rewarding tariffs, and thus customers obtaining access to value through DSF. We welcome submitter comments on any factors that may have stalled the transition to the use of half-hourly data.

Benefits and costs

4.25 On the assumption that retailers will eventually move to half-hourly data for all ICPS which have advanced meters, the primary benefit of this option is that this transition would be accelerated. This would then allow retailers to accelerate development and/or availability of DSF-rewarding tariffs.

4.26 The costs of this option would be primarily be the retailers' expenditure on existing systems that would allow the elimination of profiles where advanced meters exist. Again, on the assumption that these costs would eventually be incurred by retailers, the costs of the sunset clause would be the degree to which these are accelerated.

4.27 We welcome feedback from retailers on the quantum of these costs, and whether there are other costs that would be incurred.

Timing and priority

4.28 As noted above, this option is not new - IPAG proposed it in 2019. This is not a complex option to design, hence could be expedited quickly.

4.29 The most critical aspect of the option is setting the sunset date. Receiving feedback from retailers regarding the barriers to moving to half-hourly data will be an important input to determining this date. It will be important to give retailers who have yet to fully move to half-hourly data sufficient notice regarding the sunset date.

46 Profile volume figures sourced from NZX as Reconciliation Manager. Smart meter penetration sourced from EMI "metering snapshot" data for August 2022.

47 Innovation and Participation Advisory Group (2019), Advice on reducing barriers to customer access to multiple electricity services, 4 December 2019 (updated July 2021). Available at https://www.ea.govt.nz.

Issue: Continued use of profiles is impeding retailers' development of DSF tariffs	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Set a sunset date on the use of profiles at ICPs which have advanced metering	Medium-High (depending on costs)	~1 year	Yes – ensures impediment to DSF removed

C3 – Require retailers to offer DSF tariffs

Description

4.30 Encouragement of wholesale DSF could be strengthened further by requiring retailers to offer a minimum number of tariffs which reward DSF, that could in turn be based on a set of DSF-relevant pricing principles.

Rationale

4.31 Orion suggested: "Stronger incentives or pricing principles are needed for retailers to pass on DSF incentives to consumers in simple, attractive and effective ways"[48].

4.32 As discussed in Option C1, we have little evidence regarding the availability of tariffs that may be characterised as "DSF-rewarding", due to the absence of any systematic tariff monitoring by the Authority. Any minimum requirements should follow evidence that there are too few offerings in the market to enable a reasonable degree of customer choice, i.e., once an initial picture is optioned through the implementation of Option C1 (or a one-off information request, as outlined previously).

4.33 In our view, any initial requirements for the tariff design should be relatively permissive so as not to stifle tariff innovation or competition, but instead focus on maximising availability. These initial requirements would allow for any pricing arrangement that rewarded the customer for shifting their demand (i.e., even a simple day-night tariff, or period of free power, should meet the requirements), or allowing the demand to be shifted remotely by an intermediary.

4.34 The initial requirements should ensure that these tariffs are available to as many customers as possible, across the spectrum of mass market and larger commercial and industrial consumers.

4.35 This option links to increased monitoring of the uptake of DSF tariffs (Option C1) the sunset date on profiling (Option C2), and the provision of information to domestic consumers (Option C14) to ensure it is easy for consumers to compare the available tariffs and assess the benefits (and any potential costs) of signing up for the tariff.

Benefits and costs

4.36 The primary benefit of this option is that it would ensure the widespread availability of DSF-rewarding tariff options, across all customer groups. The degree to which this improves the uptake of efficient DSF depends on the counterfactual – i.e., whether these tariffs would have eventually been developed anyway (and when). This is difficult to assess.

48 Orion (2022), submission to MDAG 100% Renewables Issues Paper.

4.37 We understand that the development and marketing of new tariffs, including the back-office systems to support measurement and billing, result in retailers incurring costs. The more sophisticated the tariffs are (e.g., remotely controlling EV charging), the higher the technology, people and systems costs (although this may be procured from a third-party flexibility trader). As above, if these costs were going to be incurred eventually anyway, then the cost of Option C3 is the degree to which these costs are increased or accelerated.

4.38 We note that Concept (2021) is quite emphatic regarding this form of tariff (which they term a "managed appliance tariff"):

> "Our evaluation is that by far the best long-term option for delivering flexibility from EVs and hot water are managed appliance tariffs. These grant the supplier the right to control an appliance to deliver flexibility – subject to meeting minimum service levels – in return for the consumer receiving a discount reflecting the value of such flexibility."

Timing and Priority

4.39 The need for such a requirement depends on how quickly retailers develop DSF tariffs over the coming years. Evidence gained from Option C1 may show that this is accelerating, in which case there would be little to be gained from imposing minimum requirements. If it showed slow development, a set of minimum requirements would be beneficial.

Issue: Retailers are potentially slow to develop DSF-rewarding tariffs	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Establish DSF pricing principles and/or set minimum requirements for DSF-rewarding tariffs	Uncertain	~1-2 years	Potentially

C4 – Develop standardised shape-related hedge products to reward DSF

Description

4.40 The design of any profile-related risk management product, as contemplated in MDAG's wider options development, needs to consider whether the design creates a barrier to liquidity from DSF providers. These barriers could be reduced by designing a product which has short duration – e.g., an anytime 3-hour cap product; or a morning and evening peak cap product that allows a number of hours for the response capability to be "recharged".

Rationale

4.41 A challenge for any investor relying on wholesale energy revenue (or cost reductions) is that the payoff will likely be volatile and uncertain. Large electricity users have provided MDAG with feedback that this makes funding and financing the equipment that enables DSF challenging. The same challenge potentially exists for mass market consumers, although there will already be an intermediary in place (retailer or, in the future, flexibility trader) who should be responding to these needs through tariff design.

4.42 Being able to convert an uncertain future revenue stream into an up-front payment, or series of reliable payments, would help financing the investment that enables the DSF. The payment of availability (rather than event) fees is one reason that we see significant involvement of DSF in the instantaneous reserve markets[49]. Financial contracts also offer a mechanism by which large DSF owners could obtain a more stable revenue stream – this is the essence of risk management products.

4.43 The MDAG issues paper highlighted the challenges with contract market liquidity as perceived by market participants currently. One common theme, especially amongst non-vertically integrated electricity purchasers, related to difficulty in securing risk management contracts that suited the "peakiness" of mass market consumers, such as cap products. In theory, DSF resources responding to high prices by reducing consumption could provide liquidity to cap markets, i.e., become cap sellers, as the payoff to the DSF provider responding to a high wholesale price by reducing demand mimics that of a cap product.

4.44 MDAG's competition and contract market analysis showed that a greater availability of profile-related risk management products, such as caps, will create numerous benefits for market participants in a 100% RE world. However, the typical conception of cap products (especially American/European options, such as the quarterly cap product listed on the ASX for the Australian market) can theoretically trigger a payoff in every trading period in a quarter, should spot prices persist above the strike price of the contract. This could create an untenable risk for many DSF providers who sold such a product, as their ability to respond in sequential periods is limited due to the capacity of underlying storage, thermal inertia or simply the increasing cost of interruption to the business.[50] An "energy limited" or 3-hour cap product would better suit the typical ability of a short-term demand-shifting DSF provider.

4.45 We note that selling financial contracts as anticipated here avoids the difficulties associated with "baselining" in negawatt schemes (see Option C7). The entities selling the products above are committing to make a payoff to the buyer based on a fixed MW denomination, rather than the deviation from a counterfactual consumption level, which needs to be estimated as part of a negawatt scheme. With a financial product, the selling entity will only be able to "match" the cashflows due under the contract if they actually reduce consumption by the specified contract MWs.

Benefits and costs

4.46 MDAG's modelling has also highlighted that shape-related products will be in high demand in a 100% RE world, and these products will need sources of liquidity. The benefits of shape-related products are considered in the MDAG options paper. If products are designed with DSF in mind, industrial DSF providers could provide liquidity.

4.47 In turn, developing a hedge product that suits energy-limited DSF provides large consumers a way to fund these up-front investments. This in turn increases efficient decisions regarding enabling DSF.

4.48 The cost of this option, over and above consultation and industry work to design the product, will depend on how the product is operationalised. Making it available in OTC markets only will be relatively low cost. Listing on an exchange would have much higher costs.

49 This is not the only reason. Others include the lack of need for an intermediary to be a retailer with a purchase obligation, and the sheer infrequency of the vents which actually require interruption.

50 We acknowledge that an intermediary could aggregate a range of individual short-duration cap products, or simply the underlying DSF product, and back a more orthodox American/European cap product.

Timing and Priority

4.49 We afford this option high priority, due to the fact that many large industrial consumers are – today – making decisions to implement large electricity consuming devices, which could be used for DSF. The aggregate consumption of these devices will likely be significant.

4.50 However, the design exercise should be approach carefully, and industry involvement – both potential buyers and sellers of the product - is critical. This includes the design of the product as well as whether it is exchange listed or only traded OTC.

Issue: Large consumers do not have a way to smooth volatile revenues from DSF	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Investigate and encourage the design of shape related products that could allow industrial DSF providers to be sellers	High (supports contract options)	~1-2 years	Yes

C5 – Provide significant funding for pilots/trials to kick-start dynamic tariff use

Description

4.51 In summary, our preferred 'nudge' option is a well-funded trial, as outlined below, focused on testing novel types of arrangements between retailers, other intermediaries and customers for the deployment of DSF with a view to solving common information, knowledge and market integration gaps. Key learnings and outcomes of this trial will be published to increase the market's development and usage of DSF.

4.52 The level of funding should be commensurate with the potential benefits to New Zealand. We note the AUD36M ARENA demand response programme, which led to 200MW of demand response, as a comparator.

4.53 The trial could be complemented with **Option C2** and, if required, **Option C3** as described above, to accelerate DSF provider's readiness to participate in such a trial.

Rationale

4.54 Much of the future's promise of DSF uptake relates to a beneficial coincidence of technological developments – sensors, algorithms and communications – which relieves the end user from many of the burdens associated with historical demand response, primarily through automation, and the ability to assign that automation to a third party. The recent move to real-time pricing, and the imminent implementation of dispatch notification also help reduce cost and risk of providing DSF. Further, MDAG's modelling points to a future of higher wholesale price volatility, which increases the rewards to DSF.

4.55 This does not, however, mean that efficient levels of DSF will therefore immediately materialise, for three reasons:

(a) Today, DSF markets are still somewhat in a state of infancy. Existing intermediaries will have varying degrees of organisational inertia to overcome relating to DSF systems and capabilities.

(b) Further, as discussed earlier, vertically integrated generator-retailers have dampened incentives to utilise DSF.

(c) Finally, Options C4, C8, C11, C13 and C14 all point to information, knowledge and market integration gaps relating to DSF that exist today.

4.56 These factors create uncertainty about the success of DSF development (particularly in the mind of intermediaries, but also large consumers) that is likely to slow the development of DSF and DSF markets[51]. Flex Forum cite the 10-year journey of the UK:

> "Developing the capability, practices and processes cannot occur overnight. Electricity distributors in the United Kingdom have made considerable progress since announcing a flexibility commitment in December 2018, going from 116MW of flexibility contracted in 2018 to 1.6GW contracted in the first half of 2021. However, the UK's journey to use flexibility began in 2011."[52]

4.57 However, consumers are making significant investments in electrified equipment that could provide DSF today (electric vehicles, electrode boilers, HVAC equipment). This provides a present-day opportunity to embed flexibility in these investments at the most efficient point: when the investment is made.

4.58 In order to ensure that DSF develops efficiently, we believe structured "learning by doing" trials can help solve the information, knowledge and market integration problems that are common to all market participants (i.e., problem (c) above). Solutions to these common problems require a degree of coordination amongst a number of agents in the DSF "market", via trialling, before both suppliers and users of DSF can be more confident in making long-term procurement decisions.

4.59 We are in agreement with the Flex Forum that:

> "In the short term, coordinated and collaborative learning-by-doing will provide experience and insights into the capability, practices and processes required to maximise the value of flexibility. The experience from learning-by-doing will inform [implementation of] the capability, practices and processes, including changes to regulatory settings. A critical aspect of learning-by-doing is a supportive research and development system which unlocks resources and funding to enable and encourage collaborative efforts to answer both specific and systemic concerns."[53]

4.60 As Newbery (2018) notes, this "learning-by-doing" creates "otherwise unremunerated spill-over benefits"[54], which creates a prima facie case for support beyond what the market will provide initially. However, we agree with the IEA's assessment that such support should be "limited to kick-starting nascent demand response markets, because of its complexity and risk of undue subsidisation"[55]. We would add that it could also add new participants to existing (but embryonic) demand response markets. Some submitters to MDAG's Issues Paper[56] highlighted the "de-risking" effect of support to emerging DSF markets, although expressed similar caution to the IEA regarding the time-limited nature of such support.

51 As well as Flex Forum's reference to the UK, we believe there is a close analogy to the development of hedge markets in New Zealand. Despite significant research on hedge products and markets in the 1990s, much of it in the NZ context, meaningful and liquid hedge markets did not emerge until 2010/11 (following the establishment of exchange traded futures).

52 Flex Forum (2022) "Flexibility Plan 1.0", p8.

53 Ibid, p13. We also note that IPAG made similar recommendations in their Review of the Transpower Demand Response Programme, 12 July, 2021.

54 Newbery (2018), "Evaluating the case for supporting renewable electricity".

55 IEA (2016), "Re-powering markets: Market design and regulation during the transition to low-carbon power solutions".

56 Meridian, Electric Kiwi & Haast.

4.61 We believe that financial support for initial trialling and piloting (as opposed to long-term subsidisation of the service) can strike an appropriate balance of stimulating development and momentum whilst managing the risk of undue subsidisation. That said, funding needs to be sufficiently stable to ensure that the learning benefits are actually created; furthermore, the funding needs to allow for the learnings to be made available to the wider market so that they aren't captured only by those that participated in the trial.

4.62 Trial design needs to be considered carefully to ensure the outcomes improve the availability and uptake of DSF. The primary purpose of the trial is to give participants the chance to test 'novel' tariff types that are not yet mainstream in New Zealand – for example, exploring "semi-stable" tariffs where control over a portion of a consumer's load is assigned to an intermediary in exchange for an agreement regarding service levels and benefit sharing. Further, it could explore how DSF covered by the trial is best communicated to the system operator, and coordinated with EDBs. The point is to focus on DSF problems that are not yet fully solved, and/or finding new evidence regarding the potential consumer appetite to provide DSF.

4.63 We have not looked at the design of the trial in any detail, but suggest consideration be given to:

(a) Recruitment of customers for the trial being the responsibility of the participants

(b) What costs are funded by the trial (e.g., customer recruitment, reporting, back office systems etc)

(c) The period of the trial – e.g., run over a sufficiently long period to ensure that a range of wholesale conditions are encountered

(d) How information and forecasts are provided to the System Operator

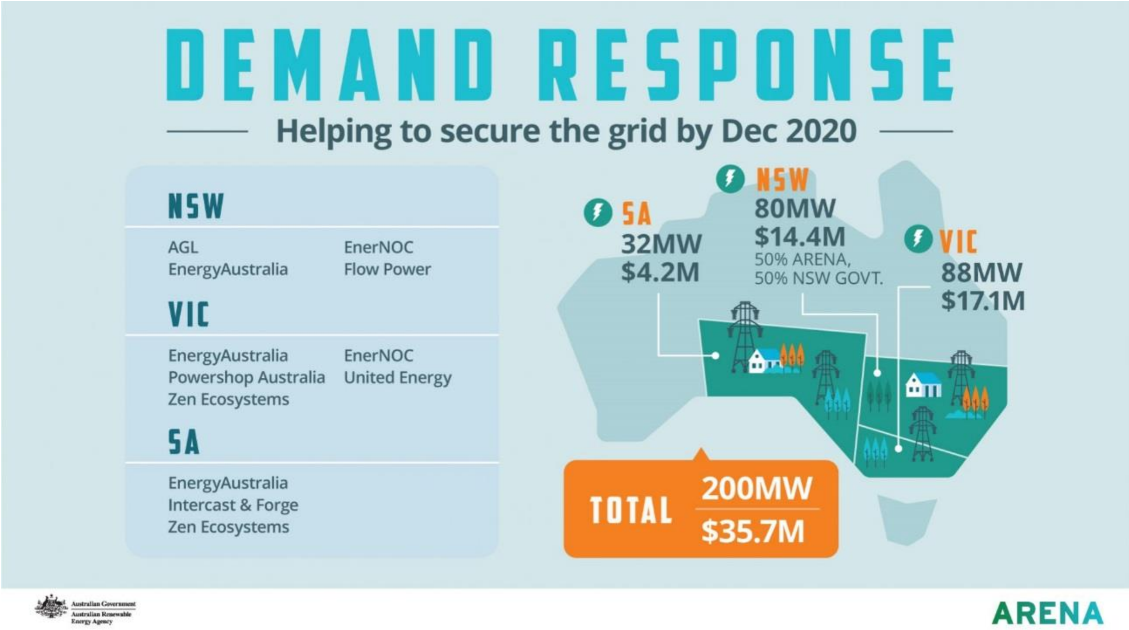
(e) Whether a target level of sustainable DSF should be set for the trial as a whole.

(f) Preference for novel tariffs (i.e., simple TOU tariffs should not be eligible), and optimise DSF across network tariffs and wholesale signals

4.64 A publicly funded trial should result in trial results and learnings in a final report that is available to all current and prospective DSF market participants.

International examples

4.65 There are myriad overseas examples of funding demand-side measures. We believe ARENA's demand response trials – in partnership with the Australian Energy Market Operator – are a good example of a targeted, outcome-focused approach. ARENA committed $36M to a 2017 tender which aimed to procure 100MW of response, but achieved double that amount (by 2020), with co-funding from industry of over $40M.



4.66 While much can be learned from the overseas work (some of which is published) and applied to the NZ context, we see potential benefits to NZ from dedicated innovation and trialling funding which can be matched to NZ's market design (e.g., nodal pricing), "energy culture" of consumers, and where NZ institutions and regulatory frameworks (EDBs, retailers, regulators) are in their maturity. We note that both the work of UK Power Networks, and the trials funded by ARENA, had direct involvement of the national system operators (GBESO and AEMO), and both sets of work foresaw value streams from both wholesale[57] and network users. Any innovation funding provided in NZ should have as a basic requirement that this "whole-of-system" approach to identification of value and costs is central to the trials.

Benefits and costs

4.67 The benefit of a trial is that innovative DSF tariffs are developed quicker, and in a way that suits New Zealand's customer preferences and meets the challenge of integrating wholesale DSF into the wider New Zealand ecosystem of demand response, ancillary services and market dispatch. This could have a profound impact on the options available to consumers to enable DSF.

4.68 Like the international examples above, we see the trial as being co-funded, meaning that there are public costs and private costs to the trial participants. The private costs should be net beneficial (as a result of tendering for the trial). The public costs would have to be outweighed by the national benefits of the trial.

4.69 We reinforce that we do see the contribution from public funds being significant (similar to the quantum in the ARENA trial above).

Timing and Priority

4.70 We see a well-funded trial as being integral to overcoming the historical inertia in consumer tariffs, hence afford it high priority. The design of the trial needs to be done well, which we expect could take over a year. Funding is likely to come from appropriation processes. Participants may then be selected via an RfP process. Hence the lead time to the commencement of the trial may be 2-3 years.

57 In the case of the ARENA DR trial, a specific component involved testing how the 10 selected projects could perform in AEMO's Reliability and Emergency Reserve Trader (RERT) arrangements, which are discussed further in Option C10. See ARENA (2019) *Demand Response RERT Trial Year 1 report*.

4.71 As discussed above, the trial itself should run for at least two years in order to obtain a reasonable sample of market conditions.

4.72 Hence, if this option was pursued in 2023, the outcomes of the trial may not be known until 2028/29. This is why we propose a high level of urgency of commencing the design process.

Issue: Development of new DSF-rewarding tariffs may be complex and risky, and this will slow development.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Design and fund a trial which de-risks the development of DSF-rewarding tariffs, and ensures they can be properly integrated into the market	High	~2-3years	Yes – trial will result in activation of DSF in scarcity

C6 – Use Customer Compensation Scheme to reward DSF – *not preferred*

Description

4.73 There are a range of options for how the CCS could be amended to encourage a better balance between incentives for demand response and incentives for prudent reservoir management. These could include:

4.74 Still requiring the retailer to make a total payment to customers in aggregate according to the default scheme, but allowing them flexibility in how they make that payment (e.g., by introducing a “beat your bill” incentive);

4.75 Allowing for a discounted default payment (per qualifying customer) if the retailer is providing additional CCS’s which reward demand reduction via an additional payment.

4.76 Converting the entire CCS design to be contingent on a customer’s demand response compared to some baseline - i.e., a “negawatt” scheme only triggered by a OCC.

4.77 Allowing for a discounted default payment (per qualifying customer) based on the number of customers the retailer has on tariffs which link retail prices to prevailing wholesale prices, even in a semi-stable way[58].

Rationale

4.78 In New Zealand, demand response has long been a feature of our management of low-inflow periods. Since the creation of the wholesale market in 1996, this has included:

(a) National conservation campaigns triggered by the Minister of Energy in 2001 and 2003.

(b) Media reporting of contingency planning regarding conservation in 2008 , including requests for consumers to be “prudent” with discretionary consumption (although no official campaign launched)

58 The Code already exempts the retailer from making default CCS payments to customers whose price under their existing retail contract is “*determined by reference to the final price at a GXP*” (9.21(2)). What we are suggesting here would further reduce the payment burden on the retailer based on the number of spot-linked customer tariffs they have active at any point in time. By “semi stable” we allow for tariffs that are not a direct pass-through of half-hourly wholesale prices, but rather have a monthly FPVV or TOU price structure that is indexed to prevailing spot prices (thus smoothing out any individual half-hourly shocks). It also needs to allow for situations where the customer’s payment is not necessarily linked to the wholesale price, but reflects the customer providing demand response in situations triggered by e.g., hydrology.

(c) Large commercial and industrial wholesale price-induced (or contracted) demand response in extended periods of high wholesale prices

(d) Retailer initiatives which saw e.g., incentives to reduce household consumption below some baseline (e.g., same month previous year).

4.79 Following the Ministerial Review of Electricity Market Performance in 2009, the Code was amended such that "official conservation campaigns" (OCCs) are now triggered by the system operator when hydro storage drops to a level defined by "hydro risk curves" that suggests there is a 10% risk of shortage that is forecast to persist for at least one week.

4.80 The Ministerial Review also required that "retailers make payments to consumers in the event of a conservation campaign or dry year power cuts." This in turn resulted in the "customer compensation scheme" (CCS) which requires retailers to make weekly payments to its qualifying customers for the duration of an official conservation campaign. Retailers must make a "default" CCS (rule 9.24) available to qualifying customers, where the retailer pays each customer a minimum amount determined by the Electricity Authority (currently $10.50 per week).

4.81 However, retailers may make available "additional" CCS's which the retailer may design. There is only limited guidance on how such schemes are designed, although the retailer must describe to the customer how it differs from the default. The customer must always have the option to select the default (regulated) scheme, and this choice cannot affect the underlying tariff the customer is on.

4.82 Neither an OCC nor CCS has ever been triggered under the Code.

4.83 A major source of criticism of the CCS is that it is in no way tied to actual savings made by an individual customer. This aspect of the design arguably reflects the intention of the CCS to act as an incentive for better reservoir management – either directly (by retailers who are vertically integrated with hydro generators with large reservoirs) or indirectly (via providing an incentive to hedge in such a way as good reservoir management is incentivised). Also, it is expected that in aggregate, customers will be voluntarily curtailing consumption as a result of the OCC.

4.84 However, we suggest that this intention, while worthy, may have the unintended consequence that it is hampering the development of demand-side response to NZ's major security of supply risk, and that a review is warranted.

4.85 Even if a retailer made available an alternative CCS (under 9.26-9.28) that attempted to incentivise actual demand response, a customer is comparing it with a scheme under which they receive a $10.50 per week payment for not responding at all. Not only does the alternative demand response scheme need to overcome the incentives of the FPVV tariff, it must also overcome the additional discount conferred by the CCS. We are not aware of how many retailers have designed, and can make available, additional CCS's to customers.

4.86 We acknowledge that paying for demand response under (a) – (c) above necessarily introduces the difficulties with baselining associated with any "negawatt" scheme (see Option C7). We note that only option (c) is a regulated negawatt scheme; options (a) and (b) would be designed by each individual retailer, thus requiring the retailer to absorb the risks inherent in baselining.

4.87 However, these difficulties do not exist with tariffs that simply index the retail price to current market conditions (option (d)). However, this option would potentially result in all customers of that retailer being paid less during an OCC that they would if they were with a competing retailer, which may result in customer switching.

International examples

4.88 Norway is largely alone internationally in providing an example of a hydro-dominated country that has exposed most consumers to varying prices (although not as volatile as New Zealand, until recently). However, it is important to understand Norway's energy cultural context – it is a wealthy country, and has enjoyed relatively low electricity prices (due to the dominance of hydro, coupled with interconnection with the rest of continental Europe) for a number of years.

4.89 That said, over 90% of Norwegian customers are on tariffs that are linked to wholesale prices; over 60% are effectively on "spot" tariffs. A key driver of this preference is the role of a "Consumer Council", which regularly updates and publishes estimated bill savings experienced by those on spot tariffs compared to FPVV. The Council recommends spot-related tariffs to customers, due to the fact they are expected to be cheaper than a FPVV contract.

4.90 As noted in the Issues Paper, Norwegian households on spot tariffs experienced a ~700% increase in prices over 2020-2021 due to a combination of low inflows into Norwegian hydro reservoirs combined with energy scarcity elsewhere in Europe. However, this has not seen any significant switching of customers to FPVV tariffs. We understand this is because of a widespread belief that FPVV will still, in the long-run, be more expensive than spot tariffs. We also note that FPVV tariffs appear to have relatively short contract terms.

Benefits and costs

4.91 The benefit of this option primarily relates to the reduction in the costs of generation in low inflow periods realised as a result of customers responding to alternative CCS tariffs by reducing demand (in addition to any demand reduction they would have provided with the default CCS).

4.92 The costs of this option would depend on which of the four methodologies above are chosen. As noted above, at least three of these are essentially negawatt mechanisms, that come with the attendant complexities and costs around baselining.

Timing and Priority

4.93 This option is not preferred.

4.94 At this stage, we believe there are a range of complexities with this option that need further consideration. As discussed under Option C7, we do not believe the complexity and likely cost associated with negawatt schemes is worthwhile until strong evidence emerges that the market is incapable of evolving tariffs which achieve the same outcome; these complexities exist for most of the variants of the CCS option considered here.

Issue: Customer Compensation Campaigns do not provide material incentives for customers to reduce consumption in low inflow periods.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Amend the CCS to include a requirement for retailers to reward customers for consumption reductions during Official Conservation Campaigns – **not preferred at this time**	Medium	~1-2years	Yes – in principle

C7 – Negawatt scheme for wholesale market – *not preferred*

Description

4.95 This option would see the wholesale market (via the clearing manager) make payments based on the wholesale price (aligned with what generators would be paid for wholesale generation) to particular qualifying consumers who reduce consumption, especially at peak times.

4.96 The quantity determined to be reduced would be assessed centrally as the difference between what the consumer would have consumed had the spot price not triggered a response (the “baseline”), and the customers actual metered quantity.

Rationale

4.97 The pursuit of equity between generation and consumption responses to wholesale prices is at the very heart of arguments in support of wholesale market nega-watt schemes, the basic thrust being that both provide the same service to security-constrained economic dispatch. Since the demand responding consumer generally faces the same dispatch requirements as a generator, it is argued it should be due the same compensation.

4.98 This is particularly acute when customers are on a tariff which does not reflect the real-time price (e.g., some form of FPVV/TOU tariff). Hence, in periods of acute wholesale scarcity, the savings they would make on their electricity purchase costs will be significantly less than the value of electricity in the wholesale market. Hence the underlying problem is that the customer is insulated from the wholesale price, and does not react according to the relativity of their willingness-to-pay (valuation of consumption) and the wholesale price.

International examples

4.99 Some international jurisdictions have schemes which make payments to consumers who invest in reducing consumption, especially at peak times. The concept of selling “nega-watts” was popularised in the 1980s by Amory Lovins (Rocky Mountain Institute) and has spawned a range of these schemes[59].

4.100 However, the achievement of payment equity, while an important design feature, is not the primary reason why regulators introduce nega-watt scheme. In fact, as will be shown below, only the Australian scheme pursues a generator-equivalent payment to responding customers in all conditions. Our impression of the reason why regulators introduce nega-watt schemes is frustration at the gap between the aspiration for greater demand side participation, and the lack of progress electricity retailers have made on incentivising demand response from their customers. As FERC noted in its Order 745A response:

59 We note these payments are often present in NZ (e.g., through EECA) and include payments for energy efficiency investments. Some pilots e.g., the Electricity Demand Reduction Pilot in the UK focused specifically on energy efficiency measured that reliably reduced peak demand, in order to determine the potential and efficacy of including demand response in the UK Capacity Market auctions. See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/828569/edr-final-evaluation-report__3_.pdf.

> "The existence of barriers helps to explain why payment of LMP as the market value of demand response services helps to produce just and reasonable wholesale energy prices. Paying LMP to demand resources will help address the lack of a direct connection between wholesale and retail prices and the lack of dynamic retail prices by providing those customers that can respond to price signals with the accurate market price signal for such response. Paying LMP, the marginal cost of energy, when demand response is a capable alternative to a generation resource, also will encourage more demand-side participation. ….These barriers create an inelastic demand curve in the wholesale energy market that results in higher wholesale prices than would be observed if the demand side of the market were fully developed. The Commission found that paying LMP when cost-effective may help remove these barriers to entry of potential demand response resources, and, thereby, help move prices closer to the levels that would result if all demand could respond to the marginal price of energy." [60]

4.101 FERC's statement above acknowledges that the scheme is intended to stimulate demand response, but it is a second-best option to a world where "all demand could respond to the marginal price of energy". This world likely appeared a long way off in 2011 when FERC made this comment, and indeed their own expert testimony noted the political infeasibility of all consumers being on dynamic prices, as well as the implications for metering in the mass-market segments. However, as discussed above, technology has moved a long way since then and we can contemplate where consumer response can be both automated and does not require the consumer to be directly exposed to wholesale prices.

4.102 In its most recent "Demand Response Strategy", PJM agreed that the goals of the nega-watt scheme can be realised through appropriate retail tariffs, and that the recent availability of such tariffs was a likely explanation for the low uptake:

> "DR participation as an economic resource in the wholesale energy market has been low, even with the payment of full [nega-watt] LMP. Many customers that typically might participate in the wholesale energy market can realize energy cost savings directly on their retail bills through more dynamic retail rate contracts. For those customers most willing to reduce load, there are few challenges to achieving energy cost savings on the demand side; many can find index-based contracts to realize electricity savings from load reductions."[61]

4.103 The AEMC acknowledged this likely transition in its draft determination on the Australian WDRM scheme, not only by excluding spot-exposed customers from participating in the scheme, but also clearly stating its expectation regarding the longevity of the scheme:

> "The growing number of consumers equipped to actively participate in the market will eventually lead to the market outgrowing the [WDRM] mechanism."[62]

4.104 It is clear that nega-watt schemes that exist today were introduced due to what was perceived as a market failure, and would presumably be removed if that was remedied. That said, we acknowledge the cynicism regarding the removal of supposedly "temporary" schemes. This raises the bar on determining whether one is required. Indeed, PJM implicitly acknowledged that there are challenges to transitioning out of a nega-watt scheme:

60 FERC (2011), Demand Response Compensation in Organized Wholesale Energy Markets: Order 745-A, Issued December 15, 2011, para 59, emphasis added.

61 PJM (2017), Demand Response Strategy, p3.

62 AEMC (2019), "Draft rule determination for National electricity amendment (wholesale demand response mechanism) rule 2019", para 16.

> "PJM recognizes that the transition from customers receiving both supply-side [ie nega-watt] payments and demand-side retail cost savings to receiving just demand-side retail cost savings will have obstacles to overcome. Nevertheless, this direction should be the long-term goal. If a customer desires to manage its energy cost, an appropriate retail rate/contract should be available to facilitate that capability."[63]

4.105 As far as we are aware, there has been no regulatory assessment of the availability of demand-response incentivising retail tariffs in New Zealand. Hence, even if NZ wanted to follow a similar path to FERC and the NEM, it appears that a first step is to ascertain whether retailers were making sufficient progress with the introduction of tariffs that would reward consumers for responding (or enabling and assigning the right to response) to wholesale market signals.

Primary components of negawatt design.

4.106 There are two primary components to a wholesale negawatt design:

(a) How, and under what conditions, a payment is made to a responding consumer

(b) How the "baseline" consumption is established, i.e., the counterfactual consumption had the consumer not responded.

Payment determination

4.107 We illustrate the basic mechanics (and variations) of these wholesale payments using the three main examples: Singapore (introduced in 2014), the US (introduced by FERC in 2011[64]) and Australia NEM's "Wholesale Demand Response Mechanism", introduced in late 2021:

(a) In the FERC scheme a reduction in demand that is dispatched by the system operator is paid the market clearing price for its reduction (in the same way a generator is), as long as a cost-benefit test being passed. The CBA requirement stems from the fact that the payment to the responding consumer(s) is spread across all wholesale purchasers; hence, if the response does not result in a reduction in wholesale price, all purchasers experience an increase in their consumption costs as a result of the scheme[65]. Hence the CBA requires that purchasers are no worse off as a condition of the market clearing price being paid to the responding load.

(b) Rather than paying the market clearing price, the original Singapore scheme[66] attempted to achieve the same outcome as the FERC CBA by setting the payment equal to the responding consumer to be equal to a third of the market benefit experienced by other purchasers. Hence if the price did not reduce, there would be no payment.

(c) The Australian WDRM avoided the issue of wider market benefits by forcing the responding customer's retailer to make wholesale settlement payments as though the response hadn't occurred – i.e., the retailer funded the entire (price multiplied by reduced quantity) payment to the responding customer.

63 PJM (2017), Demand Response Strategy, p4.

64 Wholesale nega-watt schemes are a requirement of FERC's standard market design following Order 745 in 2011. However, Texas does not have such a scheme, as it is not covered by FERC requirements.

65 Since wholesale payments remain the same is in the generation counterfactual, but total load has decreased as a result of the load reduction.

66 Singapore's scheme has been under review since 2020, due to very low participation and a range of issues identified with the design.

Baselining: the counterfactual

4.108 A key difference between paying a generator for wholesale energy, and paying a customer for wholesale response, is that the generator is paid the wholesale price for all of its metered output. Under a nega-watt scheme, the responding customer is only paid the wholesale price for the quantum of demand that it reduced from an unobservable counterfactual level representing the scenario where it had not responded. Nega-watt schemes estimate this level by using "baselining" methodologies, which attempt to use predictive algorithms based on previous demand to provide a reliable estimate of what the consumer's baseline consumption would have been, which can be compared with its metered consumption. FERC clearly stated that measurement and verification of the demand response are critical to the integrity and success of demand response programs. The difficulties with baselining were highlighted by the AEMC in their determination to establish the WDRM:

> "The wholesale demand response mechanism under the draft rule also relies on setting a baseline quantity against which the value of demand response would be calculated and paid. However, it is impossible to exactly know this counterfactual level of electricity consumption. If the baseline is set too high, consumers will pay more than they need to. If it is too low, then there won't be enough incentive to encourage demand response in the market. The draft rule seeks to minimise these consequences. Moving to a two-sided market in the long-run means that there would be no need to determine these artificial benchmarks."[67]

4.109 Given the "event" nature of the WDRM, we believe it would be difficult to game the scheme to achieve a greater payment than would otherwise be the case. However, except for customers that have very stable consumption profiles (which we suspect led the NEW to restrict access to only large customers), algorithms will inevitably have a bias.

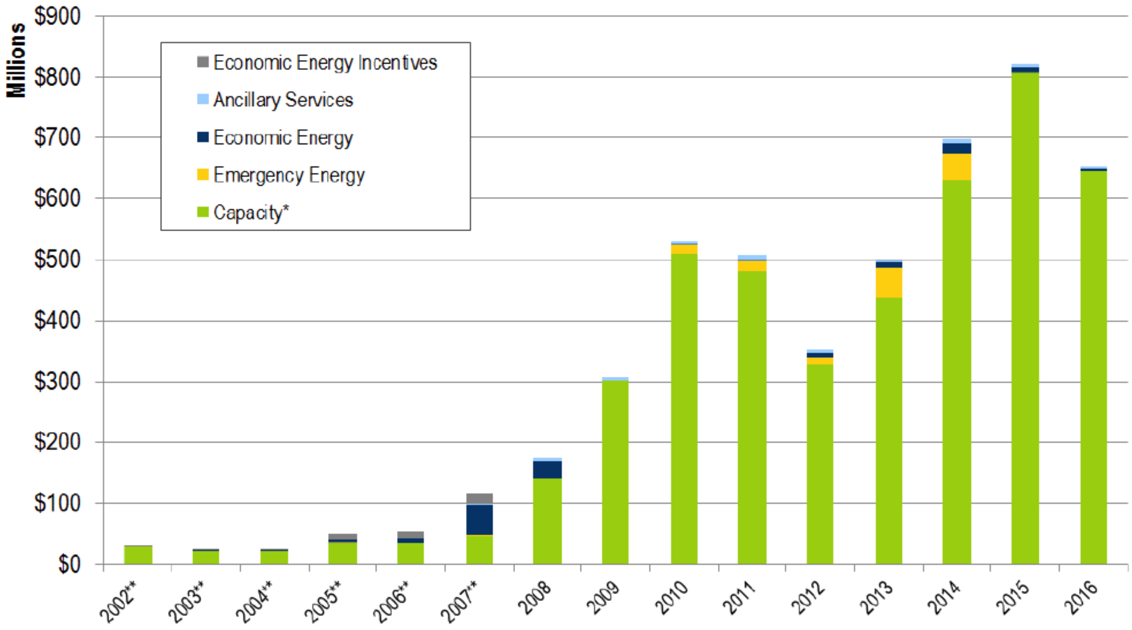
4.110 Appendix 3 compares the returns to the different DSF-rewarding tariffs, including the NEM's conception of the WDRM.

Performance of nega-watt schemes

4.111 As indicated above, the Singaporean and PJM schemes have experienced low uptake. In the case of PJM, it seems clear that the role of capacity remuneration mechanisms for demand response overwhelmingly dominate the incentives for demand response (Figure 1, where nega-watt payments are referred to as "economic energy"), and only require activation of response in a very small number of hours per year (much like ancillary services). Australia's scheme is less than a year old, and the report on its first year of operation is still some months away.

67 AEMC (2019), "Draft rule determination for National electricity amendment (wholesale demand response mechanism) rule 2019", para 20.

Figure 1 - Demand Response Revenue by year in the PJM market[68]



Reflections on nega-watt schemes

4.112 We make the following observations about negawatt schemes:

(a) While nega-watt schemes have been introduced in some liberalised electricity markets, performance has not been dazzling, although we await the outcomes of the first year of Australia's WDRM.

(b) Mechanically, the schemes do not have solid theoretical foundations, especially in respect of baselining, which is both methodologically difficult, and also presumes that the consumer had a property right over the level of demand they would have consumed had they not responded.

(c) There appears to be some degree of frustration amongst regulators who have introduced them, that the retail market should have solved this problem. Further, regulators appear to believe that a day will come when they will no longer be necessary.

(d) That said, it is clear that nega-watt schemes are a direct response to the wide gap between the expectations of demand response markets, and retailers' efforts to enable demand response.

(e) As far as we are aware, there has been no aggressive pursuit of retailers who aren't providing DSF-rewarding tariffs by the Electricity Authority. If we were to accept that nega-watt schemes are a way to stimulate demand response, it is not clear that we yet have a body of evidence that would suggest this is the correct method.

Benefits and costs

4.113 The benefit of negawatt schemes is the increase in industrial DSF that is used to respond to periods of high wholesale scarcity. As outlined above, this also comes with a benefit to the system in terms of supply side market power mitigation (noting that large consumers may also be able to exert market power through bids) and the political and social acceptance of high prices.

68 PJM (2017), Demand Response Strategy, p6.

4.114 Evidence from Singapore and PJM does not suggest the uptake would be significant, although the schemes exist in particular market contexts there. Monitoring the initial years of the WDRM in the NEM will be more insightful for New Zealand.

4.115 Our impressions of the international experience above is that the costs of designing and implementing negawatt schemes are significant. The international schemes have required extensive design, consultation[69] and changes to market dispatch, clearing and reconciliation rules and processes.

Timing and Priority

4.116 While negawatts are not a preferred option, we reiterate Option C1, which would at least begin the collection of data to determine whether or not New Zealand's retailers are progressing DSF tariffs faster than their Australian or American counterparts had. As far as we are aware, there has been no regulatory assessment of the availability of demand-response incentivising retail tariffs in New Zealand. Hence, even if NZ wanted to follow a similar path to FERC and the NEM, a first step is to ascertain whether retailers were making sufficient progress with the introduction of tariffs that would reward consumers for responding (or enabling and assigning the right to response) to wholesale market signals. Our recommendation that the Authority immediately commence monitoring tariff availability and uptake should be sufficient to build this evidence base.

Issue: Current tariffs and Code requirements provide insufficient incentives for large consumers to bid responsive demand into the wholesale market.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Introduce a mechanism into the wholesale market which pays large consumers for bid demand response at the wholesale price – **not preferred at this time**	Low/Unknown	>3 years	Unlikely due to timeframe for implementation

Enabling the wholesale market to realise the highest value uses of DSF.

C8 – FSR – improve DSF visibility and remove Code barriers

Description

4.117 The Authority will consider changes to the Code and dispatch processes to ensure that EDBs, retailers and flexibility traders provide the System Operator adequate information on their intended use of DSF, aggregated across wholesale and network uses at each GXP.

4.118 Further, existing technology specific barriers to entry for new technologies should be addressed as a priority to enable participation in existing energy and ancillary services markets.

Rationale

4.119 A number of submitters raised GXP aggregation of DSF as a potential issue. Most of these concerns related to the degree to which the System Operator will have visibility of varying demand.

69 Including legal challenge in the case of the US.

4.120 The history of system operation and security-constrained economic dispatch has seen a System Operator dispatching large generation plant to follow electricity demand. While demand hasn't been controllable, our patterns of demand have been largely predictable as a function of our behavioural patterns, weather and work hours. A future world of DSF will see more demand responding to system conditions (e.g., wholesale price or network congestion). With particular system conditions (high prices, or highly loaded networks) demand may deviate significantly from the traditional pattern.

4.121 While some of this response may be visible to the System Operator through dispatch notification a substantial amount could either be responding to wholesale signals but not notifying this to the System Operator, or not responding to wholesale signals at all (e.g., network congestion). As we highlighted in Batstone (2022), high wholesale prices may, in the future, be driven more by weather conditions than by system demand; hence network-based response may be activated at different times to wholesale-activated response.

4.122 This makes near-term load forecasting difficult, as forecasting algorithms only see the net result of the DSF decisions at the GXP and are unaware of what changes in load were a result of different types of flexibility being utilised (and therefore whether or not they can be expected to continue). Lack of understanding or awareness of device behaviour in network fault situations is also challenging.

4.123 We also acknowledge that the precise response from DSF may often be unpredictable, and not as reliable as issuing dispatch instructions to a large generating plant. Here, there are benefits to aggregation. Aggregation drives scale and diversity, which in turn allows an entity to become more confident in the nature of the aggregated response – even if that response is fundamentally probabilistic. Also, aggregators who handle both network-triggered and wholesale-triggered DSF are in an ideal position to indicate the expected collective behaviour of this DSF to the System Operator.

4.124 Essentially, these options are already included in the FSR Draft Roadmap, specifically the challenge of "Visibility and observability of DER" [70]. We have not considered in any depth the design, Code or market systems implications of these options, but note that the FSR project will address this issue. Specific activities under this include:

(a) Updating the Code to clarify DER obligations and operational requirements, and

(b) Update procedures and tools to include DER asset information.[71]

4.125 Submitters also asked that Code barriers to DSF participation in ancillary services be investigated and removed.

4.126 Again, the Future Security and Resilience (FSR) project has identified that there may be some existing barriers to the participation of DER in the ancillary services markets arising from "the regulatory framework, procurement mechanisms, tools and operational procedures would need to be updated to enable new technologies to participate in the energy market and ancillary services markets".

Issue: Material deployment of DSF not visible to System Operator in Dispatch Schedules	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**

70 FSR Phase 1 report November 2021, page 39.

71 Electricity Authority (2022). "Future security and resilience: Implementing activities for a secure and resilient low-emissions power system", August 2022.

Action: Accelerate "Visibility and observability of DER" workstream in FSR project	Unknown	2 years	Medium-High

C9 – FSR - accelerate new ancillary services for DSF uptake – *not preferred*

Description

4.127 The Authority's FSR workstream will be considering the potential for new ancillary services (synthetic inertia, very fast reserve) and is alive to the role that DSF could play in those. The project has established the likely timeframes by which the market will require these new services[72].

4.128 This option would see the FSR project accelerating the development of market procurement mechanisms for these new services, ahead of the need, in order to improve DSF uptake rates.

Rationale

4.129 In the phase 1 report on the Electricity Authority's Future Security and Resilience project, Transpower noted:

> "This opportunity has potential to provide more options to participate in the energy market (depending on the design and selection of future ancillary services) and to 'value stack' revenue opportunities for DER from existing and any new ancillary services….Further, the System Operator observes **there may be benefits to DER uptake rates, and consequently the services and benefits they can provide, if additional stackable revenue opportunities are available through new ancillary services which, while beneficial to power system operations, are implemented ahead of need. Instigating such a plan is a policy decision and can only be made by the Electricity Authority**."[73] (emphasis added)

4.130 Beyond the technical analysis, there is a market design element required for these new services – i.e., how they are procured and rewarded. Remuneration of the instantaneous reserve services in NZ is currently via an availability fee, rather than an event fee. As noted in Batstone (2022), this allows for a more stable set of cashflows than an event-only basis, especially since underfrequency events tend to occur 3-5 times per year. Hence the market design is integral to the degree to which these new services will accelerate DSF uptake.

International evidence

4.131 The analysis of ancillary services required by a very high renewables system is outside the scope of this paper, but we note there is a vibrant international focus on enabling distributed resources, including demand side response.

4.132 Market developments in other jurisdictions have also focused on allowing demand response (including via aggregators) into ancillary service markets. By way of example, in 2021, ERCOT added 100MW of data centres into a range of ancillary service markets. The data centres consist of hundreds of servers that can be turned on and off on demand, using fast-acting control systems to respond to primary frequency deviations, similar to the governors on a conventional thermal plant. The control systems give these data centres the ability to follow SCED basepoint and Load Frequency Control (LFC) instructions.

72 Ibid.

73 Transpower (2022), "Opportunities and challenges to the future security and resilience of the New Zealand power system: Final report", p51.

Benefits and costs

4.133 The benefit of this option is an increase in DSF resulting from earlier availability of revenue streams. It is not clear to us how this would be estimated: if the new ancillary products are introduced prior to the system actually needing them, the market value may be low, and hence the increase in "stacked value" may be minimal. This, in turn, depends on how the FSR project determines that the new services be procured.

4.134 There are a variety of important workstreams that need resourcing in the FSR roadmap, and presumably the earlier introduction of these products would result in delays to other FSR workstreams. The potential cost of these delays, or the increase in overall FSR resourcing to avoid them, would have to be carefully considered.

Timing and Priority

4.135 We agree that the efficient access of DSF to existing ancillary markets is a priority (per Option C8). We also agree that care should be taken in the design of future ancillary service markets so as not to inefficiently exclude DSF. However, we are not convinced that there are net benefits to accelerating the design of these products ahead of their need. We note the conclusion of Sapere's DER cost benefit analysis, which showed that the net benefits to DER (including demand side flexibility) to instantaneous reserves was absolutely dwarfed by those that could be realised through reduced or deferred investment in networks and supply-side generation and storage resources[74]. However, this analysis did not consider the value of DSF to ancillary services that may be developed in the future.

Issue: The value of DSF may increase in the future through provision of new ancillary services. However, these products have not been designed, and the markets do not yet exist.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: The Authority accelerate the introduction of new ancillary services to improve value stacking opportunities for DSF – **not preferred at this time**	Unknown	1-2 years	Depends on new services developed

C10 – Procurement process for high-scarcity DSF (RERT)

Description

4.136 The Electricity Authority introduce a formal procurement mechanism for last-resort response to grid emergencies. This would cover demand response including behind-the-meter generation that is not offered into the wholesale market (e.g., diesel generators or batteries).

Rationale

4.137 Currently, when the System Operator instructs EDBs to reduce demand, and load is forcibly curtailed, this is not paid for. This has long been a feature of the NZ power system.

74 Reeve, Stevenson and Comendant (2021), "Cost-benefit analysis of distributed energy resources in New Zealand".

4.138 In their submissions to the Issues Paper, Meridian and Transpower argued for payment to demand response in emergency situations. The Investigation into the Electricity Supply Interruptions of 9 August made a direct recommendation[75] that (effectively) the Code be amended to include a new "6 hour standby reserve" ancillary service which allows for both demand side response and backup generation, which could include hot water control, battery storage and "new demand side technologies such as electric vehicle (EV) charging and other discretionary load like cool stores and irrigation pumps. Demand aggregators are likely to have an increasing role to play."

4.139 As argued above, we believe one of the strongest arguments for an increase in demand response is that voluntary, commercial load reduction in place of forced curtailment would improve the durability of the market.

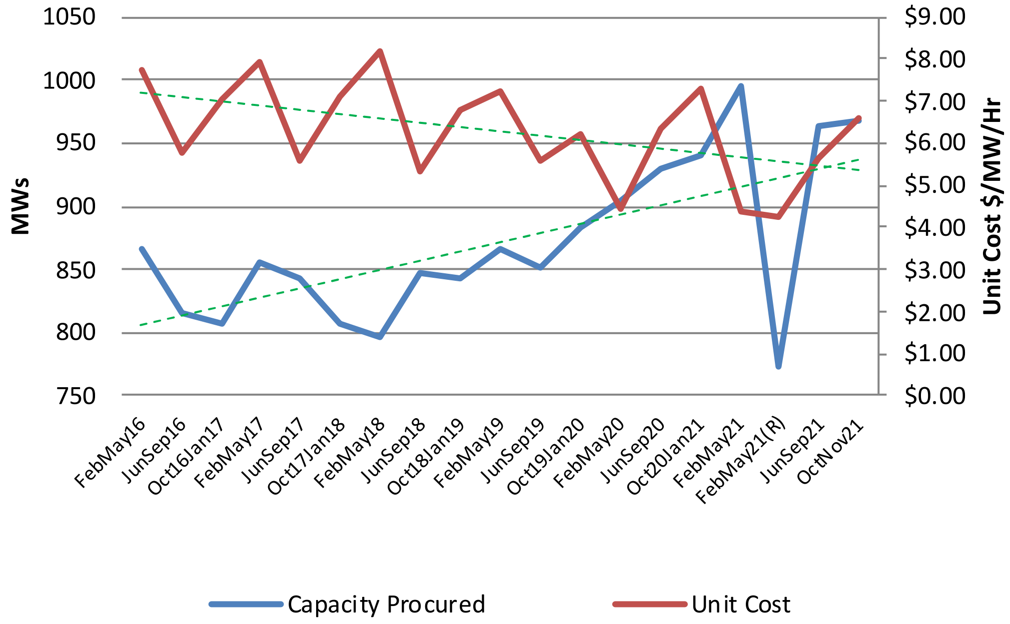
International examples

4.140 Around the world, there are a spectrum of options for last-resort emergency response, and we note two examples

4.141 In Texas, ERCOT's Emergency Response Service procures qualified loads and generation (e.g., standby diesel) to make themselves available for deployment in a grid emergency. Obviously, ERS providers must be loads and generation that would not otherwise be bid or offered into the wholesale market. ERCOT procures ERS four times per year, and each round calls for services that can be available to provide response during particular risk periods (e.g., weekday peaks), with response being called at 10-minute and 30-minute notice. The ERS providers are remunerated via a $50M fund established by the Public Utilities Commission of Texas and providers are paid an availability fee ($/MW per hour of availability). Figure 2 shows the downward trend of availability costs and upward trend in procured capacity since 2016. ERCOT note that the maximum annual spend limit of $50 million for ERS has been in place since 2007 and that this expenditure limit has not appeared to inhibit growth in the capacity offered or procured for the service. Rather, as the ERS service has grown in capacity offered and procured, the unit cost for the service has declined.

75 Investigation into the Electricity Supply Interruptions of 9 August, Section 5.3.

Figure 2 - Procured ERS Capacity versus Unit Cost, values are time and capacity weighted per each Standard Contract Term



4.142 We note that the ERS scheme was amended recently to include "weather sensitive loads" to facilitate the participation of air conditioning response during the summer periods under modified rules.

4.143 In Australia, the Reliability Emergency Reserve Trader (RERT) scheme serves a similar purpose, procuring resources that are not otherwise available to the wholesale market. However, the RERT procurement is somewhat different to the ERS described above, with potential providers of medium notice (7 days – 10 weeks) and short-notice (less than 7 days) being part of a panel which is called on only when reserve shortfalls are identified by the Market Operator (AEMO). Long notice providers (10 weeks – 12 months) do not have to be part of the panel, and are sought via a tender process. There is no payment for being on the panel; rather it serves as a mechanism by which technical and legal requirements to be agreed in advance, avoiding the need for such negotiations when the need is somewhat urgent. The mixture of availability, pre-activation and activation (event) fees are paid depends on the degree of notice. Availability payments are not made to the service providers to the short-notice reserves.

4.144 Both commercially reward providers of last-resort DSF, although neither scheme results in the DSF being formally bid into the dispatch process. Hence there is no price discovery role, as the resources contracted are, by design, not available to the wholesale market[76].

4.145 However, we believe this is a superior outcome than the status quo in New Zealand. Even without the price discovery role, though, the political durability of the wholesale market is improved, and the additional revenue to organisations able to provide the service may convince them to enter the wider DSF markets in particular times of the year[77].

76 This does not need to be the case, as long as the procurement approach sets bid prices and quantities in advance, to avoid the extreme exercise of market power. There would also have to be a requirement that these resources meet the same level of dispatch compliance required of generators (which presumably they have to as part of the ERS/RERT schemes described above).

77 Providers of DSF may have different appetites towards interruption at different times of the year. Having multiple ways and service levels through which such resources can be rewarded improves the ability to "value stack"; indeed, AEMO anticipates this is the case in the RERT scheme, allowing members of the RERT panel to contract their capacity with market participants and other parties, as long as AEMO is notified as such. See AEMO (2021) Final Reliability and Emergency Reserve Trader Guidelines available at https://aemo.com.au/.

Benefits and Costs

4.146 The benefit of this option is the aggregate value of:

(a) The reduction in involuntary demand curtailment (at an appropriate value of lost load), and

(b) the improvement in the social and political licence for the wholesale market arrangements resulting from a reduction in involuntary demand curtailment.

4.147 The costs of the option would include:

(a) the design, consultation and implementation of the scheme, and

(b) The likely procurement costs of the last-resort demand response

Timing and Priority

4.148 As noted above, we recognise that the consideration of procuring standby DSF for grid emergency management purposes is an outcome of the August 9th review. We reinforce that this is an opportunity to use DSF to improve the political and social durability of the wholesale market arrangements, by prioritising the use of voluntary demand curtailment (on a procurement basis) over administrative load shedding (and associated scarcity prices).

4.149 If a vibrant DSF market emerges, and is signalled to the System Operator via bids, formal procurement of "last resort" demand response may not be net beneficial. Hence there is a degree of contingency between the monitoring of the DSF uptake (Option C1) and implementation of this option.

Issue: Last-resort DSF used in grid emergencies is not formally procured and paid for.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Introduce a formal procurement mechanism for demand response and behind-the-meter generation that can be available in grid emergencies	Medium-High	~2 years	Yes - Very High

C11 – Distribution pricing reflects network needs so wholesale market participants can optimise wholesale and network value streams

Description

4.150 This option asks the Authority to focus its monitoring of and guidance on distribution pricing on how network congestion is reflected, with a view to enabling intermediaries to optimise across wholesale and network values.

Rationale

4.151 Several submitters raised issues that could broadly be characterised as how distribution network and wholesale uses of DSF are coordinated and value-stacked.

4.152 In their submission, Orion note:

> "Spatial value drivers will incentivise optimal use of local network capacity, and depending on the time and location, may strengthen or conflict with signals from the wholesale electricity market. Therefore, **the interaction between these value streams must be better understood to maximise opportunities for flexibility while maintaining network reliability**. As wholesale market prices become more volatile, the impact of these signals on the operation of distributed resources must be coordinated between national and local network operators over operation and planning periods."[78]

4.153 As we have previously outlined, DSF should be able to compete on an equal footing with supply side investments, including capacity augmentation in transmission and distribution networks. The lowest cost way of delivering capacity and reliability should prevail.

4.154 For the transmission grid, the interaction and coordination between wholesale and network needs is addressed via the use of locational marginal pricing (LMP). This results in purchasers (retailers and direct connects) facing a dynamic price signal which communicates the value of energy at a locational level, accounting for local transmission capacity and the national balance of supply and demand.

4.155 These locational signals do not (dynamically or otherwise) reflect the needs in or conditions on the distribution network.

4.156 One way to coordinate wholesale and network signals in the distribution network would be to extend LMP beyond its current boundary (Transpower's grid). We discuss this, and potential variations, in Option C12.

4.157 The need to address a capacity issue in the distribution network can also be signalled by using network pricing structures that target the timing and location of capacity scarcity. These price structures would result in the costs of consumption being higher during those time periods which are driving the need for investment. This, in turn, provides an incentive for those with demand flexibility to reduce consumption.

4.158 We note that network price structures won't *guarantee* that sufficient DSF will be deployed to forestall investment; prices simply provide a signal that network capacity is scarce at that time and location. Further, network prices are currently changed (at most) annually, and within the year are static. Hence network prices are likely to be more useful to signal medium-long term network needs. For more short-term needs, formal contracting of DSF would provide a more "firm" response[79].

4.159 But, insofar as static network prices can signal spatial and temporal network needs over the medium-long-term, they provide incentives to change consumption patterns in a way that is helpful to the network. The remaining question is – can these signals then be "value stacked" with wholesale signals and, if so, who coordinates this?

4.160 As well as facing wholesale prices, retailers face these network prices[80]. Retailers are the point at which these different costs are united, so they are therefore rationally incentivised to minimise the aggregate level of network and wholesale purchase costs[81], thus providing a "coordinating" role. Retailers' decisions to utilise DSF, or incentivise consumers to utilise DSF (by passing through the network charges), should be based on the aggregate effect on these costs of changing demand.

78 Orion, 2022, Submission to MDAG 100% RE Issues paper, para 6(b).

79 That said, we explore in Option C12 the potential future options for dynamic network pricing such as those being developed and piloted through Ausgrid's Project Edith.

80 Distribution prices reflect transmission prices too, and these are not intended to signal any value of DSF.

81 To varying extents, based on whether they are part of a vertically integrated generator retailer or not.

4.161 Hence a substantial degree of "coordination" between network and wholesale-driven DSF would be achieved through retailers acting as the intermediary[82] **where network prices adequately reflect the value of DSF to meeting network needs.** Thus the degree to which networks can achieve these prices will influence the degree to which retailers can achieve "optimal" deployment of DSF (either themselves or via a flexibility trader). This is already a focus for the Authority in their practice notes for distribution pricing.[83]

4.162 The degree to which a customer or intermediary can optimise the combined network and wholesale value of DSF depends on whether the network tariffs are sufficiently granular (locationally) to reflect locational needs. We have not reviewed the practicality of achieving this relative to EDBs current network tariffs, noting this would be a "second best" option to LMP, since the network tariffs are static and the retailer (or customer, if pass-through was used) would not be responding dynamically to varying conditions on the network. There will also be situations where short-term network needs (e.g., planned outages, or emergency management) cannot be communicated by static network tariffs, and these situations need to be considered[84].

4.163 These concerns – while real - should not detract from the need for distributors to maximise the (pragmatic) level of signalling network needs through pricing. We agree with Orion that the interaction of wholesale and network value streams need to be better understood to maximise opportunities for flexibility while maintaining network reliability. This needs to be commensurate with distributors taking reasonable measures to reflect these value streams through their network pricing.

4.164 However, we acknowledge that there will likely be a gap between the signalling effect of these tariffs, and the dynamic, locational-specific needs of the network (without extending LMP into the distribution network, as discussed in option C12).

4.165 Finally, we observe that the drivers to use DSF to manage peak network loadings tend to align – in aggregate across the network - with the wholesale drivers to reduce demand. Today, wholesale prices are typically highest during times of peak demand (morning and evening peak). Under Real Time Pricing, if security standards are breached *at the GXP*, the wholesale price will reach scarcity levels – a very strong incentive for retailers to use demand management.

4.166 However, we note that this alignment of network and wholesale needs is not always the case. We highlighted in the issues paper that, in a high-renewables future, wholesale prices will become more correlated with the weather, and less correlated with load. Hence the two sets of incentives may not always overlap[85].

82 Or, as noted above, passing through both wholesale or network signals to the consumer.

83 Using price as a signalling mechanism (where needed) then (given the target revenue to recover) allocating residual costs in a least distortionary manner.

84 We note that the current Default Distributor Agreement establishes a hierarchy of needs, which prioritises emergency management over market needs, and allows retailers to access network-controlled DSF (primarily hot water control) subject to this hierarchy. Below we also outline how arrangements for emergency management (at the grid level) could evolve more to include formal procurement of DSF, which may lessen the pressure on networks needing to execute emergency management responsibilities.

85 This is particularly relevant with energy-limited DSF options - reflecting limited tolerance for service interruption (EV charging, thermal inertia in space and water heating systems) or simply storage limitations in electrochemical batteries – which needs to be "recharged" once the flexibility has been exhausted. One can imagine a scenario where a lack of wind and sun in the middle of the day may cause very high wholesale prices, to which energy-limited DSF responds. The duration of these prices could be such that the appetite for interruption is exhausted (either through draining the battery, or reaching the tolerance for service interruption) by the time the evening peak arises. Even if wind generation has returned to meet the wholesale needs of the evening peak, networks wishing to do load control over the evening peak for congestion management purposes will have access to much less locationally-relevant DSF. And the exact opposite could occur too. Either way, if a distributor has contracted for a specific time/location-bound service, this situation would be less likely to eventuate as the physical response can be planned for. The other relevant point here is that a distributor's "market" is much smaller – if several DERs behave differently to expected, it will make little difference at the GXP but can make a significant difference at the transformer.

International examples

4.167 In a large trial of EV charging tariffs, the UK Networks "Shift" project noted a similar challenge, raising the question as to what were the best pricing arrangements to solve the problem:

> "Whilst wholesale prices remain relatively benign, this means that the ToU [distribution] signal as tested could be sufficient to elicit the desired response. However, in future, wholesale prices are expected to become more volatile, including periods of negative prices. In this case, the wholesale price could be the determining factor in future smart charging optimisation algorithms, in which case ToU [distribution] tariffs may need to evolve… For example, as the capacity of solar and wind generation increases, we expect to see more instances of low or negative wholesale prices in the future, which may well result in EV charging being focused on those periods. DNOs will need to anticipate such events and determine whether the appropriate response is to attempt to counteract such price signals, or whether it is better from a 'whole system' perspective to reinforce the distribution network to ensure that renewable generation does not need to be curtailed."[86]

Benefits and costs

4.168 The primary benefit of this option is an improvement in the efficiency of DSF deployment across network and wholesale needs. *If* this results in better value-stacking, it may also bring to market more efficient DSF.

4.169 There may be increased costs for EDBs (pricing changes) and retailers as they develop systems to co-optimise across network prices and wholesale prices. However, we expect the former costs will be incurred as a result of the Authority's focus on distribution pricing and the incentives on distributors to meet network needs at lowest cost.

4.170 We have highlighted above that, if network prices do not provide an accurate valuation of DSF in certain situations, there could be an inefficient deployment of DSF (to wholesale uses) that deprives the network of DSF. And vice versa. This may have unintended consequences. We welcome comment from EDBs and market participants on situations where this may occur.

Timing and Priority

4.171 We acknowledge that one of the five current "focus areas" for the Authority in its distribution pricing workstream is that EDB distribution pricing roadmaps respond to future network congestion. The Authority has stated an expectation that "distributors will actively consider the impact of future congestion on their networks, and set out a time-limited plan for responding to that congestion in their roadmaps."[87] This focus area acknowledges the impact of widespread EV uptake and the electrification of process heat as drivers for this focus, and the Authority considers "separate load control tariffs to be an appropriate and cost-reflective way to approach mass EV charging and hot water heating, consistent with the distribution pricing principles."[88]

4.172 This option endorses this approach by the Authority, noting that static cost-reflective prices may need to be augmented with alternative pricing mechanisms to reflect shorter term network needs. However, until the analysis and resulting prices are in play, it is difficult to ascertain the "gap" in efficiency between that and an approach that approximates locational marginal pricing.

4.173 Our view is that any effort that pursues better integration between wholesale and network usage of DSF will reduce the chance that DSF is inefficiently prevented from providing value in either market.

86 UK Power Networks (2022), *Project Shift: Final Report*, May 2022, p38, 39.

87 Electricity Authority (2022), Open Letter to Distributors, Attachment, 19th September 2022.

88 Ibid.

Issue: Coordination and optimising the use of DSF across both network and wholesale markets is difficult due to dis-integrated procurement and pricing processes	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: The Authority continues to monitor EDBs development of pricing to reflect network congestion, allowing retailers to optimise across both value streams	High	2 years	Potentially

C12 – Investigate extending LMP into distribution networks

Description

4.174 In order to efficiently manage the dynamic needs of networks for DSF, the Authority considers extending the boundaries of locational marginal pricing (LMP) into the distribution network. This would mean that the current dispatch algorithm could reconcile energy and locational issues in deriving the least-cost approach to dispatch.

Rationale

4.175 On the high-voltage grid, the reconciliation of transmission network limitations and wholesale drivers is optimised and signalled through locational marginal pricing and accurate forecasts in the dispatch schedules. If there is a locational need for load management at a particular location on the transmission grid, this will be signalled through the forecast nodal price, as the market clearing engine (SPD) includes a model of the transmission network and resulting power flows[89]. Algorithms that are driving wholesale DSF will observe this nodal price and determine whether the DSF should be deployed for the afternoon (weather-driven) system peak price or the evening nodal-driven peak price (or some combination of the two). Offers of DSF, that are incorporated into the dispatch model, then provide a feedback loop to the market by revised forecast prices, communicating to the market any residual scarcity during the periods.

4.176 The reason that conflict potentially arises between wholesale DSF and distribution network DSF (or more broadly DER) is that the locational scarcity signal implied by congestion in a distribution network is not signalled to the market model, and therefore cannot be optimised (and least cost dispatch achieved) from a whole-of-system perspective. There is no model of the distribution network built into SPD, let alone locationally-relevant prices produced. If it were, the revised version of SPD would determine how DSF (and any other form of distributed energy[90]) would be optimally deployed to manage system energy needs and locational (network) scarcity, based on offers. The resulting locational prices would provide the incentives for purchase-exposed intermediaries (e.g., retailers) to procure and bid DSF into the wholesale market.

89 Although this is a linear (direct current) approximation of power flows across the grid. The degree of approximation is adequate for the high voltage grid, but, as discussed further below, this approximation becomes problematic when modelling power flows (and thus locational prices) deeper in the distribution grid.

90 We note that the same issue arises with relatively large competing generation sources that are connected to the distribution grid, rather than directly to a GXP. While these generation sources will likely offer into the wholesale market, and both could be cleared, how any network limitation (on transporting their combined output from site to the nearest GXP) is managed is beyond the purview of the System Operator and SPD, as it is determined by the EDBs congestion management policy. Presumably the net result of this capacity allocation is determined in advance and signalled to the System Operator via the quantities offered by each generator to the wholesale market.

4.177 The Authority has undertaken previous work on extending LMP beyond the GXP boundary[91], which provides a starting point for discussion. The authors concluded that:

(a) Locational marginal pricing could probably be extended into sub-transmission assets with relatively little impact on the current market dispatch algorithms, processes etc.

(b) However, deeper into the distribution network, power flows across lower voltage distribution lines tend to be limited by voltage drop. Hence it is unlikely that the DC approximation of the electrical system embedded in SPD would provide a reliable basis on which to calculate distribution-level LMPs.

(c) This work also highlighted the critical interconnection between LMP in the distribution network and the evolution of Distribution System Operators.

International examples

4.178 UK Power Networks in their “FutureSmart” vision traversed similar ground, noting:

> “The price signals created by nodal pricing allows for network constraints to be resolved through the market since participants are incentivised to adjust their positions where constraints exist. However, there is still an ongoing role for the GBSO and DSO to manage the overall system in real time, ensuring that the market delivers the constraint management is it designed to do, and resolving network constraints that occur below the voltage level of nodal pricing.”[92] .

4.179 UK Power Networks FutureSmart vision also considered how the evolution from nascent local flexibility markets may evolve through time to tighter integration with the national system operation activities:

> “Over time, as DER penetration increases, these local flexibility platforms could merge into a broader DSO flexibility platform, which might interface with the GBSO’s Balancing Mechanisms and potentially the flexibility platforms of neighbouring DSOs.”[93]

4.180 We note though that other jurisdictions are developing “dynamic operating envelopes” (DOEs) as a solution to ensuring wholesale DSF (and more generally DER) is consistent with a dynamic assessment of distribution network capacity. DOEs are a “principled allocation of hosting capacity”[94] in that they “represent the technical limits within which customers can import or export electricity…[varying] import and export limits over time and location based on the available capacity of the local network or power system as a whole”[95].

4.181 We have not reviewed this in any detail, but observe that the DOEs are potentially analogous to the way security constraints are dynamically varied in the NZ market model[96] . that said, noting our concern above that LMP may simply be impractical at some medium or lower voltages, DOEs are likely to be a part of how flexible resources are deployed on the distribution network.

91 Batstone, Reeve, and Stevenson (2018), *An exploration of locational marginal pricing at the distribution level in the New Zealand context*, available at https://www.ea.govt.nz/assets/dms-assets/24/24663An-exploration-of-locational-marginal-pricing-at-a-distribution-level-in-the-NZ-context.PDF.

92 UK Power Networks (2017), *FutureSmart: Consultation Report*, p17.

93 Ibid., p18.

94 See ARENA: https://arena.gov.au/knowledge-bank/on-the-calculation-and-use-of-dynamic-operating-envelopes/.

95 https://arena.gov.au/assets/2021/09/doe-workshop-summary.pdf.

96 Also known as simultaneous feasibility testing.

4.182 The development of DOEs appears to be focused on a dynamic representation of network constraints[97], rather than the production of dynamic locational marginal prices to guide investment. However, as the penetration of DER increases in the network, a distribution system operator (invariably via an algorithm) will need to determine how to allocate scarce capacity amongst competing DER within each envelope. If this algorithm is seeking least cost dispatch, it will have to ration based on some indication of relative "cost" of the devices (and their relative impact on the "envelope").

4.183 We are not aware of any DOE implementations that are considering the role of cost. If it were to do that, it would be feasible to produce market clearing prices from the optimisation of the DOE[98].

Benefits and Costs

4.184 Extending LMP into the distribution network would be that the wholesale price would efficiently signal the combined network and wholesale value of energy at that point in the network. DSF that can be activated at that network location can then be efficiently deployed. From a first principles perspective, the level of efficiency would, in many cases, be higher than that based on static network tariffs.

4.185 However, we cannot tell at this point how far into the distribution network LMP can practically go, while still being able to guarantee optimal market clearing prices. This may limit the extent to which (D)LMP materially improves efficiency.

4.186 The costs of making this change would be significant, but haven't been explored. There would be significant changes to software market systems and retailer & EDB tariffs. As highlighted above, in all likelihood, a change to the boundaries of LMP would be considered alongside the potential establishment of distribution system operators, which would be a significant undertaking in itself.

4.187 It may be that pursuing DOEs is a lower cost (or more net beneficial) pathway towards dynamic management of the distribution network, as it offers two clear steps – firstly to provide a dynamic assessment of capacity, and later how that capacity is allocated amongst users based on relative costs and benefits. However, we have not done this comparison in any detail.

Timing and Priority

4.188 The previous work noted above was not definitive in its conclusions about implementation complexities, but offered a number of potential actions through which this could be investigated collaboratively with industry (especially networks and retailers). However, we believe this investigation – which is a fundamental change to LMP, and potentially introduces a new role for distribution system operators – would be a significant undertaking.

4.189 To some extent, further development of this option would depend on the Authority's confidence that the majority of network issues can be signalled through static cost-reflective tariffs, rather than via dynamic LMP signals.

Issue: Static cost reflective tariffs may not provide the most efficient signal of dynamic network needs for flexibility, undervaluing the role that DSF can provide.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**

97 In Australia, they are primarily being used to liberate solar export that is currently constrained by static export limits.

98 For the OR geeks out there, the distribution LMP would just be the shadow price on the DOE constraints. But a shadow price relies on a valuation of the resource (i.e., it needs a specification of costs).

Action: The Authority extend LMP into the distribution network, as far as practical.	Unknown	4+ years	Unlikely due to implementation timeframes

Increasing consumer and intermediary awareness of current or future DSF value

C13 – Provide info to help large users with upcoming DSF investment decisions

Description

4.190 An appropriate sector organisation disseminates information (such as detailed data on future spot price behaviour) which allows large energy consumers to model the benefits available from the wholesale market (and potentially networks) if they enable or enhance DSF capability in their asset decision making.

Rationale

4.191 In its submission, EA Networks noted in respect of the owners of 1,460MW of identified fossil fuel boilers in the South Island:

> "…many are planning to significantly decarbonise in the next 10 years, but few are thinking about the future shape of electricity prices. In particular, the fact that as we increase the proportion of uncontrollable renewables, prices will be much more volatile. This means heating systems that can be interrupted will be cheaper to supply. Not only will the customer have cheaper electricity, but wider system costs will be lower as well…..Unfortunately, when we talk to these customers about such investments, they really show us the business case or information that prices will be more volatile going forward. In addition, their advisors, in the form of consulting engineers have no concept of the increasing volatility of future wholesale prices and therefore the value of the new electric systems being flexible."[99]

4.192 EA Networks highlighted a significant information gap, that, if filled, could provide valuable information to organisations who are designing and installing large electricity-consuming devices imminently. This information could support the business case for larger hot water storage, standby boiler systems (to be used in dry years) and other forms of DSF that can be embedded at the time of installation.

4.193 This highlights that, despite MDAG's analysis illuminating opportunities for DSF that may exist in 10-15 years time, investment decisions are being made today that may either limit, or provide the opportunity, for those value streams to be captured.

4.194 The industrial case studies described in the accompanying slide pack, 'DSF Case Studies', are the first step in filling this information gap. They focus specifically on a stylised industrial setting, and quantify the potential benefits. However, as with all stylised examples, there are a number of practicalities which could not be included in the analysis, as these will be specific to each industrial setting. EA Network's recommendation was that detailed price scenarios be made available to organisations and consultancies who are developing business cases for these investments, so that they can tailor how this data is used to establish the net benefits of enhancing DSF capability.

99 EA Networks (2022), Submission to MDAG on Price Discovery under 100% Renewables, 17 March 2022; page 2-3.

4.195 While the Authority could provide this information, we also note that EECA plays a significant role in the decarbonisation of industrial heat, through its disbursement of the Government Investment in Decarbonising Industry (GIDI) fund, it's Energy Transition Accelerator and Regional Energy Transition Accelerator programs, and its wider advice to large energy consumers. The role of information provision in this respect should be discussed between the Authority and EECA.

Benefits and Costs

4.196 The benefit of providing better information about future prices, and thus the value of DSF, is that large customers will make better decisions about whether to enable DSF, as well as sizing the amount of DSF (e.g., hot water storage capacity).

4.197 We do not believe the costs of this option are significant. EECA, for example, already provide information to large energy consumers considering decarbonisation, and are working closely with these consumers through their Regional Energy Transition Accelerator programme. It would be a relatively small cost to produce the data required (given MDAG's modelling has been completed) – depending on the future scenarios consumers want to consider.

4.198 There would be possibilities for further developments, e.g., web-based tools for people to calculate the value of particular types of DSF, based on the MDAG scenarios. These would lead to additional costs that would have to be considered.

Timing and Priority

4.199 We see this option as highly valuable, and should be afforded significant priority – as noted earlier, a number of industrial consumers are considering or implementing electrification decisions imminently. A significant portion of the data and information has been completed as part of MDAG's work, and just needs to be reformatted to be appropriate to the large energy consumer audience.

Issue: Large consumers contemplating electrification of process heat do not have sufficient information to quantify the future value of DSF.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: The Authority, EECA or IPENZ provide relevant information (e.g., MDAG's 100% RE wholesale price scenarios) to large consumers.	High	1 year	Yes, for decisions being made imminently

C14 – Provide info to help domestic customers with DSF decisions

Description

4.200 Powerswitch enables customers to directly compare their expected bill under a traditional FPVV contract versus one which contains incentives to exercise DSF. This should ultimately include the ability to upload the consumer's consumption data to Powerswitch as part of the comparison.

4.201 There could also be a role for the new Consumer Advocacy Council to provide advice to consumers regarding the costs and benefits of DSF-rewarding tariffs.

Rationale

4.202 The benefits of transparency around DSF tariffs goes beyond regulatory analyses to a better consumer understanding of the various options and their potential benefits.

4.203 Currently, for residential consumers, it is difficult to quickly ascertain the difference that a DSF-rewarding tariff could make to their costs of consumption. The primary tariff-comparison service is Powerswitch, and it is not easy to directly compare specific tariff types (in the same way as in, e.g., Norway – see below):

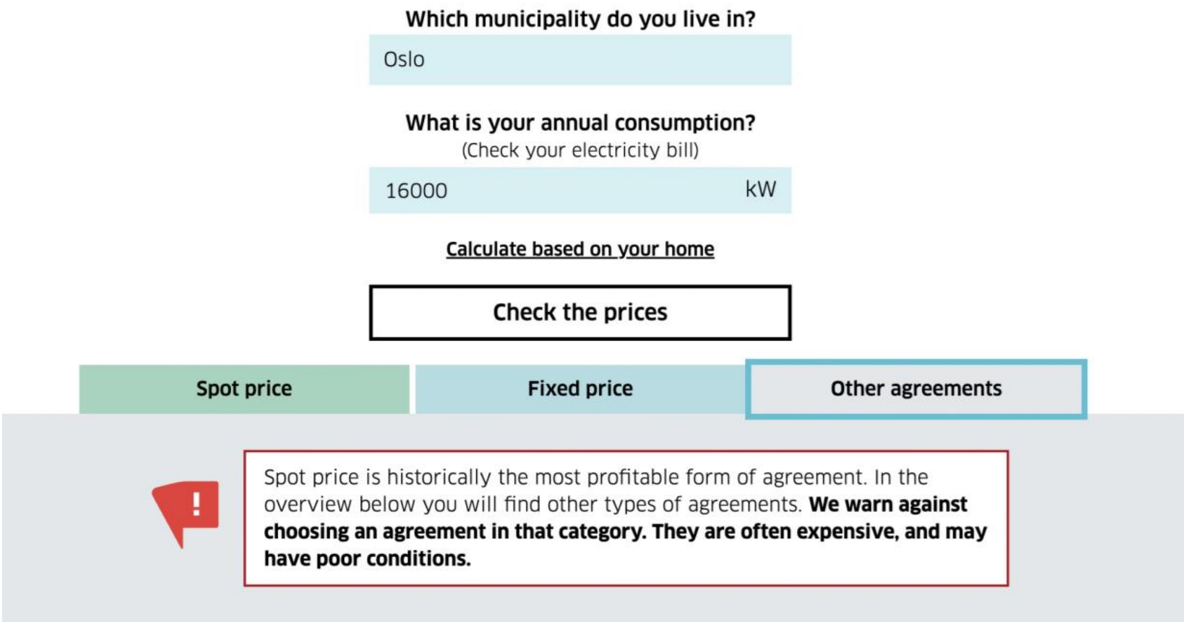
4.204 It is not possible to filter all tariffs to show only those that price consumption differently at different times of day. Ironically, these “spot price” tariffs can specifically be filtered out, but not isolated for comparison.

4.205 Even if it were possible to isolate spot-linked tariffs, to gain an accurate picture the customer would have to manually enter consumption at different times of day. There is no facility for Powerswitch to directly access smart metering data.

International examples

4.206 As highlighted above, one reason why Norway sustains such a high proportion of customers (including households) on spot-based tariffs is that there is a high degree of monitoring and reporting that compares the expected costs of fixed-price contracts versus dynamic tariffs. This is undertaken by the Norwegian Consumer Council, and includes strong recommendations from the Council about the best tariffs (Figure 3).

Figure 3 - screenshot from Norwegian Consumer Council tariff comparison website



Benefits and costs

4.207 The benefits of this option primarily relate to greater awareness of available DSF tariffs, and better decisions being made by domestic consumers about whether to move to a DSF-rewarding tariff.

4.208 The costs would primarily be amending the Powerswitch systems to be able to produce the functionality allowing consumers to efficiently search and compare tariff types. Functionality could be provided for consumers to explore shifting consumption.

4.209 Providing for the upload of customer smart metering data would be an additional cost.

Timing and Priority

4.210 We afford this option a high priority – our framework is based on consumer choice, and that consumers can access information on the costs and benefits of enabling DSF. We note that – even today – there are sufficient DSF-rewarding tariffs available in the market to warrant customers being able to obtain an independent validation of how much they would save.

4.211 We have not discussed with Powerswitch how difficult the above changes would be to the software underpinning Powerswitch.

Issue: Many domestic consumers may be unaware of what DSF-rewarding tariffs are available to them, and/or unable to quantify the potential benefits to them.	**Potential net benefit**	**Likely lead time to implement**	**Useful for transition**
Action: Powerswitch make it easier for consumers to find and evaluate/compare tariffs that reward DSF.	Medium-High	1-2 years	Depends on availability and uptake

5. Strengthening competition

D1 – Develop dashboard of competition indicators for flexibility segment of wholesale market

5.1 Policy makers and industry participants need indicators of competition to monitor trends and determine whether pro-competitive actions are required. In particular, new measures are needed to assess competition in the provision of flexibility services provided over a week or longer. For example, it will be important to track the availability of flexibility products that could be used to firm the output of intermittent generation sources.

Issue: It is hard to assess how competition for flexibility services is changing	Net benefit	Likely lead time to implement	Useful for transition
Action: Develop dashboard of competition indicators for flexibility segment of wholesale market	High/Medium	1 year	

D2 – Greater transparency of hedge info (esp non-base load) covering offers, bids + agreed prices

5.2 As noted in the ‘Improving the contract market’ section (see paragraphs 3 to 3.3) we see merit in enhancing the existing hedge contract disclosure regime.

5.3 As well as improving the information available to parties negotiating contracts, this should facilitate broader surveillance of the contract market. This includes the provision of information to assist in detecting any potential breaches of the Commerce Act[100] or the trading conduct provisions in the Code (see paragraphs 3.27 to 3.30).

Issue: Increase information available to participants to improve monitoring of contract market	Net benefit	Likely lead time to implement	Useful for transition
Action: Enhance hedge contract information disclosures	High/medium	1 year	Yes in principle

D3 – Develop flexibility access code (non-price elements)

5.4 As noted earlier, the shift to a renewables-based system will increase supplier market concentration for longer duration flexibility services, all other things being equal. This raises the potential for some suppliers to become a bottleneck, affecting competition in upstream and downstream markets.

5.5 A related concern is that even if such suppliers were operating competitively, it could be difficult to tell because much of the information to make the assessment is not transparent or even collected. Furthermore, parties who raise alleged competition problems could have unrealistic expectations or commercial incentives to talk up their concerns. In short, there is arguably a wider common interest in adopting a clearer framework for monitoring the interactions between parties with control of substantial flexibility resources and other participants.

100 In particular, the new test in section 36 prohibiting conduct which has purpose, or has or is likely to have the effect, of substantially lessening competition in a market or related market.

5.6 Similar concerns have arisen in the supermarket sector, focusing on the way the two major supermarkets interact with upstream grocery suppliers and downstream competitors. In response to these concerns a grocery code of conduct and wholesale access regime are being developed.[101] These arrangements are still being developed but it appears they will create more formal *processes* to govern the interactions between major supermarkets and their suppliers/competitors, rather than defining specific outcomes.

5.7 We think there is merit in adopting a similar framework for the provision of longer duration flexibility services. For brevity we have called this a 'flexibility access code'. In broad terms the access code would apply to nominated participants deemed to have significant market power in the provision of longer duration flexibility services. The access code would set out processes to be followed by these participants in the provision of flexibility contracts. While more detailed work would be required to determine the exact content of a code, it could cover matters such as:

(a) Definitions about what constitutes flexibility contracts.

(b) Requirements on relevant parties to specify the type of information they need from parties seeking flexibility contracts.

(c) Requirement on relevant parties to respond to requests within defined timeframes and in writing, and with reasons if a request is declined.

(d) Record keeping obligations on relevant parties.

5.8 Parties seeking flexibility products could include independent generators, wholesale buyers such as industrial consumers, and retailers.

5.9 An access code should make it easier for participants and regulators to detect any anti-competitive behaviour in the provision of flexibility products. For example, it should provide information to better identify whether products are being withheld from some parties or priced in an anti-competitive manner. It should also complement the internal transfer pricing arrangements that were recently introduced into the Code. This Code increases price transparency for flexibility products provided between the generation and retail arms of vertically integrated suppliers.[102]

5.10 Enforcement against any anti-competitive conduct in the provision of flexibility products would rely on the trading conduct provisions in the Electricity Industry Participation Code (see paragraphs 3.27 to 3.30) or the Commerce Act.

Issue: Help to ensure 'flexibility contracts' are available on reasonable terms, and that claims of anti-competitive behaviour can be properly investigated	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Introduce a flexibility access code	High	1-2 years	Yes in principle

101 See www.mbie.govt.nz/have-your-say/grocery-code-of-conduct/. This code focuses on the interface with upstream suppliers. The government is also considering wholesale access arrangements between the major supermarkets and downstream grocery retail competitors – see www.mbie.govt.nz/about/news/new-measures-to-increase-access-to-grocery-wholesale/.

102 See www.ea.govt.nz/development/work-programme/risk-management/internal-transfer-pricing-and-profitability/.

D4 – Extend trading conduct rules to hedge market

5.11 We see merit in extending the trading conduct rules to cover the contract market. We think this would have direct benefits in the contract market as well as wider indirect benefits. This is because the contract market has a strong influence on upstream competition for new investment and in the downstream retail market.

Issue: Help ensure contracts are available at competitive terms and prices	Net benefit	Likely lead time to implement	Useful for transition
Action: Extend the trading conduct rules to the hedge market	High/Medium	1 year	Yes in principle

D5 – Market-making for shaped contract products

5.12 As noted in the 'Ensuring effective risk management and efficient investment' section we see merit in introducing market-making for shaped contracts such as some form of cap or peak product.

5.13 From a competition perspective we think this would have direct benefits in the contract market. Furthermore, if shaped contract products were more readily available, that should reduce the scope for generators to exercise any substantial power they have in the spot market.

5.14 This is because participants would have greater means to use contracts to mitigate their exposure to spot prices. In addition, a more transparent forward price curve for shaped products should reduce generators' ability to exercise market power in the contract market. This is because the availability of such forward prices should make it easier for parties to make investment decisions in flexibility alternatives, such as storage devices or demand response capability.

Issue: Improve information available for monitoring of contract market and reduce scope for exercise of market power	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Introduce market-making for shaped contracts.	High	2-3 years	Yes in principle

D6 – Physical disaggregation of flexible generation base – *not preferred*

5.15 If conduct-based measures are judged to be ineffective, structural options would be required to address market power at its source. One approach would be further ownership disaggregation of physical generation assets, especially the break-up of generation bases that provide a large proportion of the system's flexible hydro generation. The desire for stronger competition was a driving motivation for the disaggregation of physical generation assets from ECNZ to form Contact in 1996, and the later three-way physical split of ECNZ in 1999.

5.16 Options for further physical disaggregation of generation assets were looked at in 2009.[103] One key challenge identified in that work was the potential for coordination inefficiencies to arise if management of closely related hydro stations on single river chains was split between multiple parties. That work ultimately led to the transfer of the Tekapo A and B stations from Meridian and Genesis.

103 The study was undertaken by the Electricity Technical Advisory Group, which reported to the Minister of Energy and Resources in 2009. Appendix 15 describes a range of options that were considered. See www.beehive.govt.nz/release/electricity-review-released.

5.17 As matters stand, there are few opportunities for further physical disaggregation of the hydro generation base without splitting ownership of closely related stations on river chains. Such splits could lead to coordination difficulties.[104] In this context, it is important to note that there would also be a need to disaggregate the rights to longer term storage in the main upstream reservoirs at the head of each chain.

5.18 The sole exception is a potential to split the ownership of the Manapouri and Waitaki hydro schemes[105] (currently both are held by Meridian). However, the Manapouri scheme has little longer-term flexibility and the competition benefits of such separation appears likely to be relatively modest based on the available information.

5.19 In addition, pursuing physical ownership changes would probably be quite disruptive and require significant implementation effort. For example there would be a need to address the effects on existing long-term contracts, resource consents, land agreements etc. It would also be important to consider how assets subject to transfer would be valued, and any associated impacts on investment confidence.

5.20 Given the potential costs and risks, a physical disaggregation of major hydro schemes is not a preferred option based on current information.

Issue: Some participants may have scope and incentives to abuse market power in provision of flexible supply	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Physically disaggregate some of the flexible generation base – **not preferred at this time**	Low relative to cost	2-3 years	

D7 – Virtual disaggregation of flexible generation base

5.21 If structural options are judged to be necessary, we think 'virtual' break-ups would be much better than divestment of physical assets. Virtual break-up options would use financial contracts designed to mimic the effect of physical disaggregation, but ownership and generation dispatch rights would remain unchanged. This means that there should not be any loss of coordination efficiencies on river chains.

5.22 An option in this domain would be to create more effective competition in flexible supply by allocating (by auction) a significant tranche of flexible contracts from the primary holders of flexible supply (Meridian and Mercury) among wholesale market participants.

5.23 Financial contracts can alter the incentives on parties with flexible generation. For example, a party that has an underlying incentive to withhold flexible generation from the market could have very different incentives if its contract position turns it into a net buyer in the spot market in the relevant time intervals. The design of contracts and their volumes would require detailed analysis. However analogous contracts have been applied or considered for other electricity systems with large volumes of flexible hydro generation such as those in Tasmania or the Pacific North-West of the United States.

104 The same type of challenge is the reason that some stations are combined into groups for dispatch purposes under the 'block dispatch' provisions of the Code.

105 Noting the Tekapo A and Tekapo B stations are held by Genesis and form part of the upper Waitaki scheme.

5.24 Having noted the preference for virtual over physical break-up approaches, it is important to note that implementing a virtual break-up would still be a significant undertaking and require substantial effort. There would be a need to consider the detail of the contracting mechanisms, the potential need for transitional arrangements, and how contracts were to be allocated and valued. Finally, it would be important to avoid any adverse effects on investment confidence.

5.25 However, given the foundational importance of competition to the success of the wholesale market, we need to be open to moving to virtual break (for example by an allocation of flexible contracts) if conduct measures prove to be not effective.

Issue: Some participants may have scope and incentives to abuse market power in provision of flexible supply	Potential net benefit	Likely lead time to implement	Useful for transition
Use longer term contracts to achieve a virtual disaggregation of flexible generation base (**Not** recommended at this time but preferred as a back-up option)	Potentially high	2-3 years	

D8 – Price caps applied in the electricity spot market – *not preferred*

5.26 Price caps on wholesale spot prices have been considered in the past and were rejected due to a high risk of adverse consequences. For example the Commerce Commission in 2009 stated:

> "A wholesale price cap may lead to undersupply of generation, unless other mechanisms such as generating-capacity obligations and capacity payments, are used. Yet those mechanisms do not necessarily remove all the detrimental effects of price caps."[106]

5.27 The Commission also referred to negative experience with spot price caps in California and quoted United States experts who said:

> "price caps on spot electricity transactions amounts to following a series of bad decisions with a worse one. While such price caps may temporarily ease the pain, they will make the patient sicker by the end of the day. Price caps on wholesale transactions will create short-term shortages, and discourage imports [from other states connected to California]. Price caps also reduce the incentives to invest in generating plants. A low price cap also discourages demand side participation in the mitigation of shortages through demand side management."[107]

5.28 We believe the earlier findings regarding the risks with price cap remain valid. Indeed, if anything, a shift to a renewables-based system will increase the risks with spot price caps. This is because stored energy sources (in batteries or stored water or other forms) will become the marginal source of supply more often. This will make it even more difficult to determine the true value of energy at each point in time, and hence determine an appropriate cap.

106 See Commerce Commission electricity investigation report; paragraph 659, 21 May 2009.

107 Commerce Commission electricity investigation report; quoting Shmuel Oren and Pablo T. Spiller; paragraph 659; Commerce Commission; 21 May 2009.

5.29 In summary, we do not believe price capping mechanisms should be explored further based on current information.

Issue: Some participants may have scope and incentives to abuse market power in provision of flexible supply	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Introduce caps on spot prices or offer prices – **not preferred at this time**	Low relative to costs	1-2 years	

6. Increasing public confidence

E1 – Structured information programme for wider stakeholders

6.1 Although the electricity system touches the daily lives of most New Zealanders, there is relatively limited understanding of how the system works among many key stakeholders. Equally importantly, there is little understanding of how the spot market and contract market help to ensure reliable supply at least cost to consumers.

6.2 By way of analogy, New Zealand floated its dollar in 1985 after many years with fixed or pegged exchange rates. The benefits of a flexible exchange rate are now widely accepted, but that was not the case at the time and an understanding of those benefits took some years to emerge. We expect a similar process needs to occur in relation to the electricity market.

6.3 To help build a wider and deeper understanding of these issues, a structured information programme should be developed to explain how the system and market work. This should be sponsored by regulatory bodies and a cross section of participants including generators, retailers, distributors and the grid operator. Ideally, the programme would include visits to a range of facilities including a system operations control room. Such a programme should be targeted at groups such as Members of Parliament, consumer advocates, senior officials, and key media.

Issue: Many key stakeholders are unfamiliar with how electricity system and market works	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Provide information programme on electricity system and market to key stakeholders	Medium	1 year	

E2 – Regular briefings for Ministers and officials on current and expected conditions

6.4 The Electricity Authority already provides regular briefings to the Minister of Energy and Resources. However, our understanding is that these largely focus on the forward work programme and any recent or upcoming events of special significance. As far as we know, there is not very much information provided on the near-term situation and outlook.

6.5 We think it would be useful to extend the scope of current briefings to provide more information on the outlook. This would include information on demand trends and projections, energy storage levels, investment trends, climate outlook and price implications. An example of a similar document is the Situation and Outlook for Primary Industries (SOPI) reports prepared each quarter by the Ministry of Primary Industries[108] (we note the SOPI reports are published and that could also be useful with an electricity sector equivalent).

6.6 The information would help to ensure Ministers and officials are well informed about current and expected conditions. Such information should also help to identify risks ahead of time, and ensure they are managed in an orderly way if they emerge.

Issue: Ministers and officials have relatively limited information on electricity system's current situation and outlook	Potential net benefit	Likely lead time to implement	Useful for transition

108 See www.mpi.govt.nz.

Action: Provide regular reports on electricity system current situation and outlook	Medium	1 year	

E3 – Increase inter-change with international experts

6.7 Electricity systems around the world are in the midst of a profound transition. We think there is much that industry stakeholders, regulators, and policy makers can learn from inter-change with international experts.

6.8 Certainly, that has been the experience of the MDAG members and secretariat for this project. The project has benefited from discussions with experts in Australia, Canada, Europe, Great Britain, Singapore, and the United States. These discussions helped to identify weaknesses and strengths in New Zealand's electricity system arrangements, many of which were not fully appreciated before the inter-changes took place.

6.9 With this factor in mind, we think there would be merit in finding ways to deepen the linkages to overseas experts. Possible avenues include:

(a) Hosting academics with expertise that is most relevant to New Zealand's challenges

(b) Initiating staff exchanges between the Electricity Authority and the Australian Energy Market Commission and the European Agency for the Cooperation of Energy Regulators

(c) Hosting an electricity sector conference. In this context we note there is a lot of interest in New Zealand given the already high level of renewable generation. This highlights the potential for two-way information flow.

Issue: New Zealand can learn much from overseas experience and knowledge	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Improve international linkages via visiting experts, secondments, hosting a conference or similar measures	Low-Medium	6 months	

E4 – Enhance monitoring with more autonomy

6.10 Active monitoring is a vital ingredient to building confidence in electricity markets. In particular, the complexity of electricity markets means it is very hard for most parties to figure out whether the market is performing as it should. Hence the role of monitoring is very important.

6.11 The Electricity Authority currently performs the monitoring function for the electricity market. There are two broad aspects to this work. First, it monitors compliance with the Code, and may initiate an enforcement action if it believes the Code has been breached.[109]

6.12 Second, it undertakes more generalised market monitoring. This work does not focus on alleged breaches per se, but instead may examine events and actions of participants that raise concerns. Market monitoring activities may result in suggestions for Code amendments, market facilitation measures, or in a finding that no further action is needed.[110]

109 See www.ea.govt.nz/code-and-compliance/compliance/compliance-monitoring/.

110 See www.ea.govt.nz/monitoring/market-performance-and-analysis/.

6.13 While the Authority's monitoring activities have stepped up in recent years,[111] we think there is a good case for further strengthening this function. Firstly, we suggest that the level of resources devoted to the function should be reviewed. If more resources were available, we expect this would allow more active monitoring and accelerate the investigation processes.[112]

6.14 Second, there is a case for making the monitoring function more independent from the rule-making function. This would mean that the monitor does not opine on the effectiveness of its own rules, and this should contribute to confidence in robustness of market monitoring.

6.15 The main argument against a separation of market monitoring from design activities is that there are synergies between these functions. In particular, many of the analytical resources needed for monitoring are also likely to be useful for formulating and testing modifications to market rules.

6.16 There is a continuum of options to create more independence between the monitoring and rule-making functions:

(a) At one end of the spectrum, an option would be to locate the functions in separate organisations. This approach is adopted in Australia[113] and parts of North America[114];

(b) Closer to that end of the spectrum, another option would be to amend the Electricity Industry Act 2010 to define the monitoring and enforcement as a function to be a carried out by a 'unit' within the Authority with its own charter. We consider this to be sub-optimal;

(c) Between the two ends of the spectrum, our preferred option (which does not require any legislative change) is for the Authority to establish a monitoring and enforcement 'unit' (within the Authority) with its own public budget (within the Authority's budget), its own web site presence and public performance reporting, and with published 'operating protocols' (prescribed by the Authority), which would set out how it is to operate and report, and its guiding principles (for example) neutrality, objectivity, an evidence-based approach, with the goal of ensuring compliance with the Code to achieve the statutory objectives.

(d) At the other end of the spectrum, there is the option of making no change to the public-facing aspects of the Authority's present approach, but behind-the-scenes the Authority would allocate more resources to its monitoring and enforcement functions.

6.17 On balance, we prefer the (c) above.

Issue: Monitoring of market is critical to ensure confidence	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Enhance monitoring and provide greater independence	Medium	1-2 years	

111 For example, in 2019 it has published quarterly performance reports.

112 For example, some reviews have taken over a year to complete. While the critical time constraining factors are not known, it seems likely the reviews could have been finished earlier if more resource was available.

113 The Australian Energy Market Commission designs the rules, and the Australian Energy Regulator monitors and enforces them. To reduce duplication of overheads, the Australian Energy Regulator is located within the Australian Competition and Consumer Commission. See www.aemc.gov.au/regulation/national-governance.

114 In these jurisdictions the market monitoring function is commonly contracted to an external party. See www.potomaceconomics.com/markets-monitored/ercot/ and www.albertamsa.ca/about-us/.

E5 – Periodic warrant of fitness review for independent regulatory agencies

6.18 The Electricity Authority is an independent Crown entity. This is the same status as the Commerce Commission and some other regulatory agencies. These bodies operate ‘arms-length’ from Ministers when fulfilling their statutorily independent functions.[115]

6.19 Many international studies argue that having independent regulators is important for industries that require long-term investments.[116] This is because these regulators act in a role akin to referees for such industries, regulating much of the interplay between consumers and suppliers. Having a referee that is insulated from day-to-day political forces helps to ensure that there will be consistent application of the governing legal frameworks over time. This in turn helps to provide the confidence for suppliers and consumers to make long term investments. Conversely, if industry participants thought decisions could become biased or unpredictable, that would ultimately harm consumers, as it could mean desirable investment is delayed or becomes more expensive.

6.20 We think it makes sense to retain the model of independent regulators model for the electricity industry. However, it is also important to ensure that Ministers (and the wider public) have confidence in the operation of independent regulators. On this front, one specific issue to bear in mind is that referees will often attract criticism from some participants, even if they are doing a great job. It is important to be able to weight the merit of criticisms but this can be challenging given the complexities of the issues in the electricity sector.

6.21 One possible way to address this is to provide for a periodic 'warrant of fitness' review of independent regulatory bodies.[117] A mechanism along these lines was recently introduced into the Reserve Bank Act. It requires the Bank to review and assess the formulation and implementation of monetary policy at least every 5 years. The power is broadly specified allowing reviews to cover strategic or operational issues, or both. The Bank must deliver a report on each review to the Minister of Finance which must then be published. We understand this provision was added to the Reserve Bank Act to strengthen confidence in the formulation and implementation of monetary policy.

6.22 We think a similar approach could be adopted for the regulation of the electricity sector. A further possible step would be to require that the electricity regulators commission external experts (possibly overseas based) to undertake such reviews, with secretariat support from the agencies. We understand that this is the approach taken with the central bank in Sweden. This approach should strengthen the credibility of the findings of periodic reviews.[118]

Issue: Ministers’ confidence in the independent regulator model is hampered by the difficulty in properly assessing its performance	Potential net benefit	Likely lead time to implement	Useful for transition
Action: Require regulators to commission periodic 'warrant of fitness' reviews to be undertaken by independent experts	Medium	1 year	

115 See https://www.publicservice.govt.nz/system/crown-entities/.

116 See www.oecd.org/gov/regulatory-policy/Culture-of-Independence-Eng-web.pdf.

117 See clause 131.

118 We note the equivalent provision for New Zealand’s central bank does not *require* the use of external reviewers, but the Reserve Bank could choose to adopt this path. We note also that the Minister may review the Bank’s operations and performance (clause 194), but we understand this power has never been used.