New Zealand Battery Portfolio delivery options - Capacity markets study

May 2023

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1. Introduction

Purpose

The purpose of this paper is to outline the range of Capacity Market (CM) delivery options available to provide New Zealand with sufficient reserve energy capacity to address the dry year problem. The research findings outlined in this paper will inform decisions concerning progress towards initiation of a New Zealand Battery Detailed Business Case. Specifically, this paper outlines how a market-based approach could be structured to deliver on the Portfolio option (see section 2 below for further information on the Portfolio option).

In achieving the above, this paper is looking at the effectiveness of, and conditions required to implement, a reserve capacity market[1] (a type of capacity market that is targeted to cover only generation or demand response assets that provide firm electricity in times of scarcity) as an addition to New Zealand's current electricity market structure. This paper is not focussed on whether an energy only market (EOM) or CM[2] (which provides for general generation adequacy) is a more appropriate overall electricity market structure for New Zealand[3].

Methodology

This paper defines key terms, outlines findings from a literature review undertaken on international examples of reserve capacity markets, and then sets out how an RCM might be applied in a New Zealand context.

Specifically, the literature review outlines the range of different CM types used in other jurisdictions, how each work to solve energy reliability problems in these jurisdictions, and the success / issues in doing so.

2. Definitions

Energy-only market (EOM)

In EOMs consumers pay electricity generators for the electricity they deliver[4]. The price paid for this electricity is determined by standard supply and demand dynamics via a wholesale spot market. Alongside the revenue generated from electricity sales in the spot market, in some EOMs (including New Zealand), generators also derive income from the sale of forward contracts directly to consumers. These contracts are used by both buyers and sellers to hedge against volatile spot prices by fixing their electricity price for a specified period[5]. Although there is no requirement for consumers to purchase forward contracts under the EOM model, these sales typically contribute a significant amount of generator's revenues. In New Zealand, retail customers and smaller businesses are typically on fixed priced contracts sold via electricity retailers and it's estimated that ~30% of total generator revenue in New Zealand is derived from forward contracts[6].

EOM's rely on spot and forward prices (which both reflect expectations of future electricity demand, supply, and generation costs) as the investment signal to build additional generation. See section 4 for a more detailed description of this relationship.

Capacity market (CM)

This term is used in this paper to refer to a market structure where all generators receive a payment for making electricity capacity available to consumers. This payment is distinct from, or in addition to, payments from consumers for electricity delivered. By making this availability payment, CMs work to

[1] See definition of Reserve Capacity Market in section 2 for more detail

[2] See definition of Capacity Market in section 2 for more detail

[3] A market-wide CM has not been considered as it is intended to develop generation to meet predictable load growth and not to address infrequent electricity shortage required for a dry year solution. Whether a CM or EOM is more appropriate for New Zealand was directly considered by the Electricity Authority Market Development Advisory Group.

[4] *Strategic Reserves versus Market-wide Capacity Mechanisms,* Holmberg and Tangeras, 2021.

[5] https://www.ea.govt.nz/news/eye-on-electricity/the-forward-electricity-market-explained/

[6] *Capacity markets and energy-only markets – a survey of recent developments,* Concept Consulting, February 2020. *Hedge Market Development – Issues and Options: technical paper*, Electricity Commission, 18 July 2006, p30. On average, 29.3% of total annual generation were covered by hedge contracts.

create a stable revenue stream for generators that is not directly tied to the volume of electricity sales made. This reduces generation investment risk for CM participants which improves overall system generation adequacy.[7] Where a jurisdiction utilises a CM under this definition it can no longer be said to be an 'energy-only' market.

Reserve capacity market (RCM)

An RCM is a targeted CM that provides generators with upfront payments to hold peaking generation capacity supported by appropriate fuel stocks or flows aside from the market. This reserve capacity is called on to meet increases in demand (or a reduction in available electricity generation) in pre-specified situations.[8] Reserves can include excess energy generation capacity, battery-like storage and dispatch systems, and demand response (DR) programmes. Reserve capacity may also be able to operate in the market at other times when it is not required to be held in reserve.

Like standard CMs, by providing a capacity payment to generators to hold a specific level of available generation in reserve, RCMs help reduce generation investment risk for developers and avoid revenue adequacy problems that can lead to the mothballing of existing reserve generation capacity.

Strategic Reserve

A Strategic Reserve is similar to an RCM in that they both hold generation aside from normal market operations to ensure its availability in predefined scarcity events. However, a strategic reserve typically refers to a directly contracted, or government / system operator (SO) owned set of assets whereas, an RCM is a market structure used to incentivise the market to deliver and hold distributed reserve capacity assets. The Whirinaki diesel generator was an example of a strategic reserve. These types of strategic reserve mechanisms are not considered in this report but could be considered as an implementation option for direct Government investment or contracting delivery mechanisms for a portfolio solution.

Demand response (DR)

DR refers to a reduction in electricity demand from consumers in response to changes in the supply or cost of electricity. DR is typically provided by large industrial and commercial electricity users. However, distributed energy resource management systems and smart technology are increasingly allowing residential users to provide these services through aggregation[9].

DR can involve actions from consumers such as reducing energy consumption during periods of high demand or shifting energy usage to times of the day when prices are lower. In this way, DR is a critical tool for balancing the supply and demand of electricity and can help reduce the need for new power generation infrastructure.

New Zealand's dry year problem

Dry year events are periods of weeks or months of lower-than-average water inflows into New Zealand's hydro lakes that significantly reduce the ability of these lakes to generate electricity[10]. Given New Zealand's heavy reliance on hydro generation, these dry periods create a large deficit in electricity supply and place significant pressure on the electricity system. Currently this gap in electricity supply is filled using fossil fuel-based generation with past 'dry years' typically resulting in high electricity prices and above average use of fossil fuels (and associated emissions).

Dry year events are dependent on weather patterns, and each is different. This makes them uncertain and difficult to predict. However, looking at historical data, the size of New Zealand's dry year problem is substantial – with shortfalls in electricity generation ranging between 3 – 5 terawatt hours (TWh) over a period of several months (around 10% of total annual electricity needs). As New Zealand transitions towards a low carbon economy, alternative renewable solutions to manage dry years will be needed to replace reserve fossil fuel generation or New Zealand may face significant electricity shortage risk.

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[7] CMs can also provide payment mechanism to compensate consumers for demand response.

[8] *Capacity markets and energy-only markets – a survey of recent developments,* Concept Consulting, February 2020

[9] *Notes on the NZ Electricity Market*, Poletti, 2023

[10] Dry periods typically occur in winter when electricity demand is high and hydro-power catchments sometimes don't receive enough rainfall or snowmelt.

Portfolio option

This describes a portfolio of energy storage and generation technologies, identified in the NZ Battery Indicative Business Case (IBC), that may, when combined, be able to address the dry year problem in a renewable way[11].

The portfolio option as identified in the IBC includes the following technology options:

- Flexible geothermal,
- Biomass and
- Hydrogen.

In the IBC, the portfolio option was used as a reference option. WSP's initial concept designs indicated it is a technically credible but unoptimized portfolio made up, in roughly equal parts, of the above three technologies. A portfolio option as imagined in the IBC is unlikely to be replicated in practice but provided a solution of sufficient size to be a genuine comparison for other dry year solutions considered.

The IBC briefly touched on three different ways that the portfolio option might be delivered and the high-level implications of these delivery models. These models are direct government ownership and operation of reserve capacity assets, government contracts for reserve capacity services, or creation of a capacity market. This paper is intended to outline, in greater detail, how a CM based delivery option might work to address the dry year problem in practice.

3. New Zealand's electricity market

New Zealand's electricity system is highly renewable with as much as ~82% of total electricity produced coming from renewable sources (of which hydro is the dominant source). [12] Unlike other countries, New Zealand's grid is not interconnected to any other grid and so all electricity consumed must be produced within New Zealand.[13]

Market structure

The NZ electricity market is managed by a centralised SO (a service provided by Transpower) that looks to match supply and demand in real time. A wholesale spot market facilitates the trading of electricity between market participants, while the SO is responsible for coordinating the physical transmission of electricity and ensuring that the system operates reliably and efficiently. The electricity market is regulated by the Electricity Authority (via the Industry Participation Code 2010[14])

The NZ market is a decentralised electricity market made up of the following five elements[15]:

1. **Wholesale electricity market** – this is an exchange (NZX) traded spot market that is priced based on electricity supply and demand at different nodes throughout the North and South Island[16].
2. **Electricity futures markets** – this is an exchange (ASX) traded market for electricity futures and options. Futures can also be traded off market between participants, however, these trades must be in line with the Industry Participation Code.

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[11] *NZ Battery Indicative Business Case,* Ministry of Business, Innovation, and Employment, 2022.

[12] Total installed electricity generation capacity of 9,345 MW, of which 58% is derived from hydropower with an additional 28.4% coming from other non-hydro renewables.
https://www.mbie.govt.nz/dmsdocument/23550-energy-in-new-zealand-2022-pdf
https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/ .

[13] Note, New Zealand imports fuels that are then used to generate electricity (e.g., coal).

[14] Electricity Industry Participation Code 2010 | Electricity Authority (ea.govt.nz)

[15] Prior to reform in the 1990's New Zealand's electricity industry was under centralised state ownership where the control of subsectors of generation and transmission were held by a government minister with the ability to set prices, determine investments of assets and production levels. *Decentralization and Re-Centralization of Electricity Industry Governance in New Zealand*¸ Richard Meade, Sept 2004.

[16] Alongside supply and demand, price is also determined with reference to the Short Run Marginal Cost (SRMC) of electricity supplied at that node.

3. **Ancillary services** – Ancillary services is an umbrella term used to describe five electricity market services directly contracted by the SO for a specified period to ensure grid stability / performance. These services are short term in nature (ancillary services can only be delivered for secs / mins to hours at most) and operate in a pre-specified set of circumstances. Ancillary services include:

    a. **Frequency keeping –** Frequency keeping services are required to manage short term supply and demand imbalances to ensure that the system frequency is maintained at or near 50 Hz.

    b. **Instantaneous reserve** – Instantaneous reserve is generating capacity, or interruptible load, available to operate automatically in the event of a sudden failure of a large generating plant or the HVDC link. This is distinct to general DR services.

    c. **Over-frequency reserve** – This describes disconnection of generators to reduce total system frequency in periods of a sudden surge in frequency (typically caused by a large reduction in industrial load).

    d. **Voltage support –** These are services that absorb or create reactive power to maintain a consistent system voltage.

    e. **Black start –** This service provides the grid with power to help other generators and the grid to restart after a black out scenario.

4. **Financial Transmission Rights (FTR) market** – the FTR market is designed to manage locational price risk created by differentials between nodal prices resulting from transmission losses, congestion and constraints.[17] In an electricity grid, electricity must be transmitted from where it is generated to where it is consumed through a network of transmission lines. During periods of high demand, this network can become congested, leading to higher cost differentials and locational marginal pricing.[18] The FTR market allows participants to hedge against congestion risk, enabling market participants to manage their exposure to the costs associated with transmission congestion.

DR / flexibility services – Although not a standalone element of the electricity market (DR is a part of both the ancillary services market and in the general spot market)[19]. DR is an increasingly important part of the electricity sector and a key area of development for the SO and is also beginning to be included in private offtake agreements between generators and consumers[20].

[17] https://www.ea.govt.nz/projects/all/ftr/

[18] Locational marginal pricing occurs due to heat losses or transmission constraints and such losses are included in the price at each location. This leads to price separation between the islands in New Zealand. https://www.ea.govt.nz/news/eye-on-electricity/new-zealands-geography-and-price-separation/

[19] Transpower commenced a DR programme in 2013, enabling electricity consumers (primarily commercial and industrial) to reduce their demand for a period of time to support supply-demand balancing in exchange for a payment upfront and/or at the time of loss?. This includes options for Economic Demand Response (providers bid to provide a requested reduction in demand) and Security Demand Response (providers make a guaranteed level of demand reduction available if called upon). Dif between Economic and Security options not clear. Both involve a request to reduce demand" Difference is the trigger? I can talk to this – essentially under Economic you agree a strike price but no obligation to drop if that price is called, but only paid of you do, under Security, as described. Economic works 'statistically' if you have so many participants that you can reliably estimate an expected aggregate response. Security approach more relevant here. In addition, large industrial users can also bid directly into the spot market, or negotiate directly with generators to provide demand side response at specific price points.

[20] *Meridian, NZAS sign 50 MW DR agreement,* Energy News, April 2023.

Transpower is developing a flexibility service management system 'flexpoint' to coordinate distributed energy resources and demand response to enhance grid stability and reduce peak load. https://www.transpower.co.nz/our-work/distributed-energy-resources/flexpoint

4. Issues with EOM design and the creation of sufficient reserve capacity:

In an EOM, investment decisions in generation plant and DR capacity are made in a decentralised way by industry participants. Decisions are made to maximise shareholder value and assessed using traditional corporate finance methodologies (e.g., investment is made where net revenues exceed a pre-defined return on investment threshold). Therefore, a key driver in this decision-making process is the level of expected revenue that generation assets, or DR, will derive from spot and forward contract prices[21].

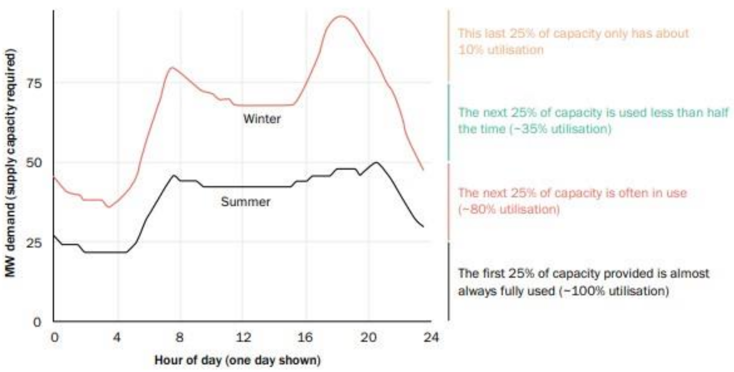
As mentioned in section 2, where market participants expect tightening electricity supply / a higher likelihood of electricity scarcity in future, electricity spot and forward contract prices rise to reflect this. This improves the economics of potential generation projects and in this way, higher electricity prices work to provide an investment incentive to maintain sufficient supply to meet expected future demand. In short, to develop additional generation, investors need to have confidence that future demand and prices will be sufficient to provide the return on investment required by the investor within a specified timeframe.

Inefficient price signals for infrequent events

For EOMs to operate effectively and efficiently, they would ideally have perfect competition, incremental rather than big-binary investment options, risk-neutral investors, and consumers that respond rationally to price changes. However, there are a range of factors observed in practice that dull price signals and reduce the effectiveness of an EOM to provide sufficient capacity to meet demand in more extreme scarcity events. These factors are outlined below and explained in greater detail in Appendix 1[22];

- **Missing money effect:** In any electricity system, there will be a small fraction of the total generation or DR capacity that is only needed very rarely – e.g., to respond to extreme demand peaks or provide cover during power station outages (such as in dry year events). In the EOM design, when last resort resources are operating, spot prices need to be at very high levels. This is because last resort resources may be entirely reliant on the revenue earned in those brief scarcity periods to cover fixed and variable costs as well as a commercial return on capital[23].

Figure 1 **Generation utilisation rates**



[21] There are a range of other factors that will impact specific generation development decisions e.g., location, generator's portfolio mix, WACC, risk appetite, corporate strategic objectives etc. As most of the major generators in NZ are also retailers (i.e., 'gentailers') the ability to manage wholesale price exposure through retail portfolio also informs investment decisions.

[22] The issues noted here apply to EOMs generally and are not specific to New Zealand. While not all issues identified are present in the New Zealand market, there is potential for these to manifest in the future, particularly as fossil fuel exits and no longer provides the scarcity and peaking cover it does today.

[23] Last resort resource providers may be able to sell contracts as an alternative to relying on spot revenues – but buyers are unlikely to purchase such contracts unless there is a real potential for spot prices to be very high at times.

The missing money phenomenon describes a situation where there is insufficient time at sufficiently high prices to cover all costs. This can be either from normal market operations or where artificial caps have been placed on spot prices by governments or SOs. The missing money phenomenon is less pronounced in New Zealand as real-time price caps implemented in the Code by the EA have been designed to be more representative of the true cost of unserved energy.

- **Barriers to entry:** Alongside price, investment in generation is also a function of other factors such as availability of land, resources, technology, capability, competition, access to capital and labour etc. Some technical options may be too expensive, too long-term or have too significant consenting or market power implications for the market to deliver. These factors create barriers to entry for new participants reducing the level of competition in the electricity market. This dulls the ability for the market as a whole to respond efficiently to price signals.
- **Misalignment of incentives:** In a decentralised EOM, generators are determining (based off pricing signals) how much generation plant is required. In general, private developers are risk neutral. i.e., because they are paid only for electricity delivered (and are not liable for the economic costs of electricity shortage in scarcity events), they are more likely to under build generation to just satisfy demand rather than overbuild to create slack or excess capacity in the market for low probability scarcity events. This is exacerbated by the inherent cashflow risk for generation which will only run infrequently (e.g., in scarcity events) which presents challenges for private investors to build this type of generation. In contrast, SOs and governments, are incentivised to avoid shortage and welfare loss. This means they are more likely to overbuild and pay for excess capacity in the system to maximise security of supply and avoid low probability outage events.
- **Market concentration:** In real-world electricity markets, a small number of producers often dominate the market, resulting in a duopoly or oligopoly, and invest strategically to extract maximum rents from consumers[24]. This acts a disincentive for incumbents to invest in additional generation capacity as it risks decreasing prices. In New Zealand, the electricity market is highly concentrated with four large vertically integrated generator-retailers (gentailers) providing over 80% of generation supply to the market[25].
- **Lack of demand side price elasticity:** In current wholesale electricity markets, large parts of electricity demand are inelastic from a short-term perspective, e.g., households often have a fixed rate for energy consumption and, thus, do not actively participate in the volatile wholesale market or react to reduce consumption even in the face of drastic prices changes. This can lead to inefficient electricity use in scarcity events reducing the efficacy of price signals in the overall market.
- **Merit order effect:** To minimise costs to consumers, electricity is generally dispatched to the grid in a “merit order” determined by the price at which generation is bid into the market which is a function of the short-run marginal cost of production (SRMC) (a function of operating costs) and the opportunity cost of storing that energy. Because wind and solar power have a low, or zero, SRMC (and limited or no ability to store electricity), the price at which they bid into the market is low and they are dispatched ahead of thermal generation plants (which typically have a higher bid price and SRMC as a result of fuel costs etc.). The rapid growth in renewables has pushed gas and coal-fired power plants down in this merit order, meaning many gas- and coal-fired generators (which typically have been used to provide regular peaking and back-up generation) produce far less power. This makes them less economic over time particularly as renewable generation makes up a larger proportion of total generation capacity. As a result, many thermal generation plants are being phased out of

[24] Schwenen, 2014
Grimm and Zöttl, 2013, Zöttl, 2010
Notes on the NZ Electricity Market, Poletti, 2023
[25] *Promoting competition in the wholesale electricity market in the transition toward 100% renewable electricity*, Electricity Authority, November 2022.

electricity markets reducing the grid's supply of flexible generation and progressively reducing security of supply in dry years.[26]

The above factors combine to both delay investment in generation until it is certain that demand will increase, and prices will be maintained, and limit the level of investment made in last resort generation.

5. International Case Studies of capacity markets

CMs can be configured in a range of different ways to fit the idiosyncrasies of a particular market. Common types of CMs internationally are:

- **Market-wide or targeted** – This describes whether the capacity payment is for all generators or just those providing quarantined reserve / last resort generation or DR capacity. For the purposes of this paper, only examples of targeted capacity markets have been considered.
- **Centralised or decentralised** – This describes whether capacity is purchased by a centralised SO or authority from the market (centralised), or by individual market participants from the market in response to regulation (decentralised).
- **Price based or volume based** – A volume-based mechanism refers to a market in which the total volume of generation capacity is predetermined by the SO, and the capacity price is determined in an auction for that specified volume (this could include additional nuance such as where and how the capacity must be delivered). A price-based mechanism describes a market where price is used as a tool to achieve / right size the amount of capacity procured[27]. The marginal pricing mechanism sets the highest accepted bid as a market price, which is paid to all accepted bids.[28]

The international literature review, undertaken as part of this report, considered a range of different CMs across the above CM spectrum in several different countries. See Table 1 below for an overview of the jurisdictions and CM types considered.[29] Appendix 1 contains a wider list of countries that use a CM within their electricity system.

Table 1 ***Overview table:***

Country	Market type	CM use	Procurement type	Category
Colombia	Targeted capacity payment	To cover longer term El Niño / severe drought events	Centralised	Price-based
Sweden	Targeted capacity payment	To provide energy security to cover peak winter demand	Centralised	Volume-based
PJM[30]	Market-wide capacity payment	Generalised generation adequacy	Centralised	Price-based
France	Targeted capacity payment	To provide energy security to cover peak winter demand	De-centralised / bi-lateral	Volume-based

Each jurisdiction's CM was then analysed against a set of criteria to determine how effective each method is (see below).

[26] https://ieefa.org/wp-content/uploads/2017/11/Spains-Capacity-Market-Energy-Security-or-Subsidy_December-2016.pdf
[27] *Strategic Reserves versus Market-wide Capacity Mechanisms,* Holmberg and Tangeras, 2021.
[28] *Strategic Reserves versus Market-wide Capacity Mechanisms,* Holmberg and Tangeras, 2021, p 16.
[29] Appendix 1 contains a comprehensive list of countries with targeted or general (market-wide) capacity markets.
[30] The PJM (In full) and Belgian capacity remuneration models were considered as part of the research for this report but were not included in the assessment process given they were not examples of targeted capacity mechanisms or were for a different purpose (PJM CM is a market-wide model while the Belgian CM is for the purpose of general capacity investment to cover nuclear phase out).

Analysis

Each of the above international examples were assessed (at a high-level) against a set of five criteria as follows:

1. **Reliable supply of electricity:** How well does each market structure ensure sufficient electricity supply is available in times of scarcity. Key factors for scoring include:
    - Testing regime – is there a mechanism to ensure capacity held can be delivered
    - Penalty regime – is there a mechanism to create an additional incentive to ensure that capacity is delivered as agreed
    - Historical performance – does the structure provide security of supply in practice
2. **Affordable / efficient supply of electricity:** How well does the market structure ensure that the amount of capacity built is right-sized and lowest cost. Key factors for scoring include:
    - Auction structure description (is it price or volume based?)
    - Centralised or decentralised (decentralised likely creates a more efficient build out as generators are risk averse in terms of generation build out but are less risk averse in terms of shortage – see discussion on misalignment objectives in section 4).
    - Secondary auctions – are there mechanisms for parties to rebalance obligations closer to the capacity delivery date to ensure the right parties are holding the right capacity obligations
3. **Fosters competition:** How well does the market structure ensure there is sufficient competition both at auction and in practice to ensure efficient price discovery? Key factors for scoring include:
    - Historical performance of how many parties take part in the auction
    - Who can participate?
    - Does it include current generation, new generation, and demand response?
    - Other auction rules that enhance or reduce competition e.g., technology agnostic
4. **Renewable supply of electricity:** Does the market / can the market be structured to incentivise renewable solutions?
5. **Complexity:** How complex is the scheme from a regulatory and SO standpoint?

These criteria were developed based on the Electricity Authority's strategic mandate and the Investment Objectives from the NZ Battery IBC. How each case study performs against each of the criteria has been assessed, and a qualitive description provided along with a red, amber, green rating is provided in Table 2. The red, amber, green ratings have been defined as:

- Green: Performs well against the criteria – i.e., the scheme includes characteristics identified in the criteria.
- Amber: Some issues have been observed in meeting the criteria / the scheme does not appear to have some of the key characteristics identified in the criteria.
- Red: Performs poorly against the criteria.

Table 2 **Assessment of international capacity markets***:*

Country	Description	Reliable supply of electricity	Affordable / efficient supply of electricity	Fosters competition	Renewable	Complexity / application
Colombia **17.48 GW**[31] **Hydro** (80%) **EOM + RCM -**	Dynamic auctions are held four years ahead of time for firm energy obligations (OEF). The SO issues firm energy obligations and pays an auction-determined price per KW/hour of available installed generation capacity. Payment is made monthly during the awarded OEF period regardless of whether energy is delivered.	▪ **Testing regime** Firm energy is certified based on its expected performance and continually updated for historical performance in scarcity events. ▪ **Penalty regime** A covered call option for capacity agreed upon exposes the provider to spot prices in the instance of unavailability[32]. ▪ **Historical performance** In 2015 – 2016, an El Niño event led to historically low hydro-inflows. Despite plant outage, rationing of electricity was avoided and the firm energy market proved itself capable of operating under extreme stress. 2019 auctions secured OEFs for 1,398 MW of renewable energy.[33]	Auction uses a dynamic price-based mechanism with multiple-auction rounds to achieve lowest cost capacity. The auction starting price is based-off both 2x cost of new entrance (CONE) (estimated by the regulator) and previous auction outcomes. The SO is the end purchaser and does not have a profit-based incentive to achieve lowest possible cost. This may lead to higher prices than a decentralised market.	▪ **Who can participate?** Power generators, project developers, investors and commercial agents representing existing or new plant. ▪ **Does it include new generation or demand response?** Yes – auction prices begin at 2x CONE and include extended OEF commitments for new entrants.	There is no requirement on renewable generation or storage – typical capacity providers are fossil fuel based.	The Colombian RCM makes use of covered call options to ensure compliance / delivery of capacity. Multiple auction structures reduce cost but are more complex to run. Rebalancing auction mechanism also adds complexity but is necessary to ensure capacity is firm and sits with those best able to provide that capacity.

[31] *Scenario Analysis of an Electric Power System in Colombia Considering the El Niño Phenomenon and the Inclusion of Renewable Energies,* Restrepo-Trujillo et.al 2021.

[32] A covered call option describes an OEF holder selling the SO a right to buy a pre-specified amount of electricity at a pre-specified strike price but covering the risk of that option being called on by holding aside the same pre-specified amount of electricity. In this way, when the call option is exercised the OEF holder simply delivers the electricity held aside. Where they cannot deliver that electricity, they must satisfy the call option by buying electricity on the spot market. In times of scarcity, the spot price of electricity is to be significantly higher than the specified strike price defined in the call option – in this way the OEF holder is financially punished for not holding aside adequate capacity.

[33] https://renewablesnow.com/news/colombias-creg-calls-auction-for-firm-power-supply-in-2027-2028-814911/

Country	Description	Reliable supply of electricity	Affordable / efficient supply of electricity	Fosters competition	Renewable	Complexity / application
Sweden **43 GW**[34] **Hydro** (45%) **EOM + RCM**	Strategic reserve procured via an auction mechanism. Capacity auctions are held 6 months in advance of the winter period (Nov – March).	▪ **Historical performance** The reserve has been activated around ten times since 2009, most recently in December 2012 – however, it is not clear whether shortage was avoided as a result of the strategic reserve system or due to other factors (e.g., electricity imports).	The costs incurred by the strategic reserve during winter 2020/21 were 14,300 €/MW This is significantly higher than the real-time pricing cap / MWh outlined in the Code which places a range of $10,000 – $20,000 in scarcity events.	▪ **Does it include new generation or demand response?** DR can participate, however, there is a minimum size threshold of 10MW (this reduces realistic participation to large-scale industrial users only). Since 2017 all capacity acquired came from one bio-diesel plant. Further, the 2019 auction capacity was cancelled due to a lack of competition. ▪ **Other auction rules** 25% of reserve must be DR Availability clauses also reduce technology able to participate. The RCM is activated at the same price as the highest commercial bid in the spot market A risk of distortion arises as higher prices, which are needed to trigger additional investment, are capped as reserves are activated.	The market requires all capacity to be renewable. The only provider uses a biofuel fired plant.	This is a simplistic auction structure - however it is ineffective at receiving sufficient offers – this may lead to higher cost of delivery of this capacity.

[34] *Energy profile Sweden*, International Renewable Energy Agency.

Country	Description	Reliable supply of electricity	Affordable / efficient supply of electricity	Fosters competition	Renewable	Complexity / application
France **136.2 GW**[35] **Nuclear** (72%) **EOM + RCM**	The RCM places capacity obligations on Load Serving Entities (LSEs) that sell electricity to consumers. This obligation requires LSEs to hold sufficient capacity guarantees to cover their customers' consumption during peak demand periods. Capacity operators (generators and demand-side units) certify their capacity to the SO four years in advance of the delivery year. When certified they are provided with a capacity guarantee that can be sold to LSEs through over-the-counter trades or in organised market sessions. LSEs can then on-sell these guarantees between themselves.	▪ **Testing regime** Every certified capacity resource must be tested during peak winter days but no more than three times during the delivery year. ▪ **Penalty regime** Where capacity is not provided when called, LSEs are penalized based on the clearing price paid for the capacity guarantee (at auction) multiplied by the volume of the unfulfilled capacity. As LSEs directly contract with capacity providers, it is up to the specific contractual provisions between the two parties. ▪ **Historical performance** In 2016 LSEs procured 22.6GW of capacity guarantees traded / purchased.	Capacity required is calculated by the SO based on the forecast peak demand and available generation capacity.	▪ **Who can participate?** Market players, producers and consumers can all participate in the RCM. ▪ **Does it include new generation and demand response?** The RCM is technology agnostic but has a minimum 1MW size threshold for generation and DR units, including aggregated pools ▪ **Other auction rules** **Emissions:** No technical barriers that limit technologies (however, the RCM does not allow generation emitting more than 550 g CO_2/kWh to participate). The DR call for tenders also prohibits the participation of DR from fossil fuel generators. **Double dipping:** Capacity providers that participate in the Capacity Mechanism are not allowed to participate in the Energy Only Market (EOM) with the same capacity for the same period for which they have been awarded Capacity Guarantees.	The market requires all capacity to be renewable.	This market is supported by regulation to compel retailers to purchase capacity guarantees.

[35] RTE, Electricity Report 2020.

6. How could these findings be applied to the New Zealand context?

Based on analysis of the above international CMs, we have not identified any technical barriers to the operation of an RCM in the New Zealand context to maintain security of supply in dry years. Colombian and French markets have been able to procure significant reserve capacity to meet their peaking and shortage requirements (however, in Colombian markets this has not always been provided from renewable sources). When the total capacity achieved in these markets is prorated to the scale of New Zealand's electricity market, it suggests a capacity market could provide up to 2GW of reserve capacity (it is suggested that market testing would be required to determine the amount of generation capacity that would be achievable through an RCM in New Zealand).

However, the needs of some of the capacity markets considered are more predictable than others e.g., French, and Swedish markets are looking to cover reoccurring electricity scarcity issues related to winter peaks whereas a New Zealand RCM and the Colombian RCM are both looking to solve a more unpredictable issue (dry years). This is important to note as it might impact the number and type of market participants and technologies that can realistically bid into the RCM as a solution. Further, this will also impact the way a New Zealand RCM would be called. For example, it would likely not be called on often but when it is it would be asked to provide significant energy on demand. This might be difficult for a renewable solution to cover (noting, Colombia currently uses fossil fuel based peaking technology as a key solution in their RCM cover this type of issue).

What type of RCM market rules would be required to cover New Zealand's dry year problem?

The following sections include an assessment of the most effective RCM type, and auction structure, for the New Zealand context. This is based on the idiosyncrasies of the New Zealand electricity market, New Zealand Battery project mandates around renewable generation, and the performance, and potential issues, of the international RCM examples in section 5.

Decentralised versus centralised market

In general, a centralised market structure may provide greater certainty that sufficient capacity is procured and that the capacity that is procured is firm (as the SO directly procures all capacity and is more risk averse with respect to shortage). However, a centralised market structure is also expected to cost more (in total, and per KW of capacity procured as the SO does not have an explicit profit motive, (unlike other market participants in a decentralised market structure).

Table 3 ***Benefits and risks of Decentralised vs Centralised auction structures***

CM type	Benefits	Risks
Decentralised	**Efficient risk transfer:** Decentralised obligations place the risk of non-supply on retailers rather than the SO. **Commodification:** Capacity guarantees can be securitised and easily traded between purchasers. This will help capacity holders dynamically balance their obligations in response to market conditions (e.g., as they gain or lose market share). **Simple mechanism:** Decentralisation places obligations on the market to contract with capacity providers. This simplifies the auction process from the	**Regulatory complexity:** New Zealand's electricity sector includes several large vertically integrated gentailers (these are entities that both generate electricity and sell that electricity on to consumers). Forcing retailers to hold capacity will likely require further separation to avoid entrenchment of already dominant market positions. **Competition:** Decentralising the auction process is unlikely to yield significant benefits given the depth of the New Zealand's market – i.e., large established gentailers will likely be favoured by retailing companies as they have

CM type	Benefits	Risks
	SO's perspective. However, exact definition of the type, length and availability requirements of any reserve capacity to be held is not simple. This will require a deeper understanding of the shape of dry year shortage. **Price:** Decentralisation increases the number of buyers for capacity (which could be bought and sold easily between parties). In a well-functioning market (with sufficient depth and several capacity providers). This helps improves competition and efficient price discovery. **Use of demand response:** Retailers may be better at making use of DR (given they hold a relationship with potential DR customers), which may reduce the need for physical capacity.[36]	established capability and plant to offer into the market. This may provide them with outsize bargaining power when compared to purchasers (as they will be one of the few providers who can reliably offer retailers capacity guarantees) - allowing them to be price setters during commercial negotiation. Decentralisation also may lead to vertically integrated gentailers favouring their own retailing arms when selling capacity guarantees. Moreover, vertically integrated retailers are also unlikely to look outside of their corporate structure for capacity guarantees. **Over capacity:** Over procurement of capacity is a function of any system that relies on a SO (a risk averse actor in the market) to determine the level of capacity that should be held aside. However, this over capacity issue is likely exacerbated in a decentralised auction process as synergies of an integrated market may be lost under decentralisation. The peak loads of different retailers generally do not coincide perfectly, meaning that the overall peak load is somewhat smaller than the sum of the peak loads of all retailers. Consequently, a decentralised capacity market could also result in higher overall capacity.[37]
Centralised	**Control:** A centralised system, where the SO determines and allocates capacity payments to bidders, provides the SO with direct control over the contractual terms by which that capacity is provided. **Competition:** Central control could incentivise new entrants as it could allow the SO to set more concessionary contractual obligations for new entrants. Where auction rules have sufficient lead in time and price, this may reduce barriers to entry for new participants into the electricity market.	**Over capacity:** Over procurement of capacity is a function of any system that relies on a SO (a risk averse actor in the market) to determine the level of capacity that should be held aside. **Risk transfer:** Centralised obligations leave the perceived risk of non-supply with the SO. A well-designed penalty regime is used to pass this risk on to RCM participants, however, given the obligations are procured by the SO there remains perceived risk that non-delivery of capacity is due to the SO. **Complex auction rules:** In a centralised system the SO runs an auction process to award / procure sufficient capacity obligations and payments. This can be complex (especially where a dynamic, multi-round auction process is required).

[36] Neuhoff et al., 2016
[37] Neuhoff et al., 2016.

Price-based auction structures vs volume-based structures

Given the SO determines the overall level of capacity procured in both a price-based and volume -based auction structure, there appears to be little difference in outcomes between the two. For example, in both, the SO must have a pre-determined volume of capacity required and either run an auction that uses price as the tool to achieve that volume (price-based) or explicitly target that volume in the market (volume-based).

A volume-based structure may give greater freedom for alternative procurement factors (e.g., whether the provider is a new entrant, or the type / technology of capacity procured) to help differentiate capacity providers (similar to a standard market tender process). However, it may also be less effective at price discovery than a price-based mechanism as consideration of other factors may lead to higher prices overall.

Other considerations

In addition to market type and auction structure, any RCM considered should also consider:

1. Shape of shortage: a New Zealand RCM will be designed to solve the dry year problem. In order to do so, and to ensure sufficient capacity with the right characteristics is procured (e.g., capacity solutions of sufficient scale are accepted), the SO will need to have a clear definition of the dry year problem in terms of frequency and depth of shortage.
2. Renewable generation build out: the mandate behind the NZ Battery project, under which this study was commissioned, requires that any NZ Battery solution must help support New Zealand on a pathway to 100% renewable energy generation. As a result, the way in which an RCM is designed should be cognisant of the impact it might have on renewable build out (see trigger rules).

Further, there are several auction rules that should also be considered to ensure an RCM structure is effective (an RCM should impose sufficient conditions to produce positive outcomes for New Zealand's electricity sector but not so many conditions that it reduces the number of entities offering capacity). Each are outlined below:

- **Double offer rules:** Currently, DR in New Zealand is contracted either directly into the spot market (large industrial users) or included as part of the instantaneous reserves programme run by the SO. Double offer rules will likely be required to ensure that DR offered in an RCM is not also offered into existing markets and being double counted.
- **Rebalancing auctions:** Rebalancing auctions would be required to allow capacity providers and load to readjust their obligations closer to the delivery period as they received improved information about total expected demand, progression of generation / capacity development etc.. Rebalancing auctions are mechanisms to ensure the right parties are holding the right capacity obligations and electricity can be delivered when needed.
- **Timeframe:** an RCM should have a sufficiently long timeframes both in terms of how far ahead capacity is sought for (horizon) and how long commitments are made fore (duration). To allow new entrants to bid in and develop capacity the horizon of the RCM should be sufficiently long to allow for the construction of a new asset (in New Zealand the average lead time for new renewable generation is ~2 – 7 years depending on scale and complexity.[38]). Further, the duration of the RCM payments should be sufficient to significantly reduce the commercial / revenue generation uncertainty over the life of the asset. However, consideration would need to be given to the price paid by the SO over the duration of the RCM and how to effectively underwrite the development of a new capacity asset without artificially locking in specific technologies over time.
- **Minimum size rules:** Minimum size thresholds (e.g., 1MW) would likely be required to avoid complexity (DR or small generator aggregators could be allowed to bid into the RCM but should require additional testing to ensure stated response is available).

[38] https://www.mbie.govt.nz/science-and-technology/energy-and-natural-resources/energy-and-natural-resources-reports/developing-renewable-energy-projects/. However, this can vary significantly depending on the size, scale, consenting conditions, and complexity of the project.

- **Renewable / low emissions requirements:** New Zealand's emissions reduction targets should be considered if developing an RCM. Renewability could be a requirement for participation in the RCM, or emissions pricing could be used to provide incentives for renewable solutions. If renewability was a requirement, consideration would need to be given to the inclusion of renewable generation forms that create emissions (e.g., geothermal) and how emissions intensity will be certified.
- **Technology threshold:** A technology agnostic rule as the default would help improve competition. However, technology maturity and the achievability of new capacity would need to be evaluated.
- **Testing regime:** A regular testing regime should be implemented to ensure that capacity is available to be called upon (at sufficient levels) when needed.
- **Penalty regime:** A penalty regime should be sufficiently onerous to ensure compliance and delivery of obligations agreed, but not so onerous it disincentivises generators from bidding into auctions. A covered call option may be solution to incentivise providers to deliver on obligations as it gives them 'skin in the game' without being so significant providers cannot pay the penalty.
- **Availability requirements:** An availability requirement is particularly important for DR to ensure there is sufficient capacity available often enough to cover dry year shortage events (which can be ongoing for several months).
- **Trigger rules:** A set of rules that clearly outline when reserve capacity is drawn on, and how it might interact with the spot market, is important to ensure the RCM operates only when needed and doesn't create perverse incentives and outcomes in the wider EOM spot market. This is an important consideration as market interaction and the creation of unintended incentives were a significant reason behind the scrapping of the Whirinaki reserve energy scheme[39].

7. Next steps

This study is a starting point to better understand how / whether capacity markets could be used as a tool to deliver a decentralised additive portfolio of generation, storage, and DR sufficient to address dry year risk. There are a range of additional pieces of work that would help improve the accuracy and useability of this report. These include:

- Development of a clear definition of the probability weighted shape of shortage (including duration, depth, frequency). This would help determine the types of suitable technologies and availability rules required to ensure capacity procured is firm and of sufficient scale (capacity and energy).
- Develop a straw person CM approach and test it in the application of this definition to at least the technology options we have been considering: (geothermal, biomass, DR, pumped hydro)
- Further consideration of the future of New Zealand's electricity system and the SO's direction of travel with respect to the inclusion of DR programmes and flexibility markets. This is important as depending on the structure of these markets they could influence the degree of scarcity an RCM would need to address, and the role demand response could play in either or both if they were to co-exist.

[39] Whirinaki plant to be sold | Beehive.govt.nz

APPENDIX 1: EOM market and capacity investment

Missing money / market - In any electricity system, there will be a small fraction of the total generation or DR capacity that is only needed very rarely to respond to extreme demand peaks or provide cover during power station outages (such as in dry year events). In the EOM design, when last resort resources are operating, spot prices need to be able to rise to very high levels. This is because last resort resources may be entirely reliant on the revenue earned in those brief periods to cover their standing and operating costs[40]. Accordingly, in the EOM model, it is critical that spot prices can reach the true value of lost load during genuine scarcity situations.

In 2013, the scarcity pricing Code amendment attempted to address this missing money phenomenon by introducing a $10,000/MWh price floor and $20,000/MWh price cap to the spot market when an electricity supply emergency causes forced power cuts.[41] The price floor is supposed to be equivalent to the level of price required to cover the costs of last-resort generation while the price cap is an upper estimate of the value of forgone consumption during emergency load shedding.

However, even if earnings from price spikes are sufficient to cover fixed and capital costs, investors may not be willing to bear the associated cashflow risks related to frequency of payments and are unable to allocate them effectively through futures and contract markets. In this case, the problem is referred to as missing market instead of missing money[42].

Barriers to entry: Electricity generation investments are typically large binary investments made by participants based on supply and demand assumptions that feed into standard corporate finance decision-making. However, they are also a function of other factors such as availability of land, resources, technology, capability, competition, barriers to entry, access to capital and labour etc. In addition, generation investment is not instantaneous, additional generation takes time to build and principles of economies of scale also apply – often additional generation capacity is built in blocks rather than as standalone assets that meet marginal demand. This can dull the connection between price and investment and mean that prices can fluctuate significantly over the short to medium term, as the market moves between states of relative overbuild to scarcity of supply.

Lack of demand side price elasticity: Large parts of electricity demand are inelastic from a short-term perspective, e.g., households have a fixed rate for energy consumption in combination with a base rate tariff and, thus, do not actively participate in the volatile wholesale market or show any reaction even to drastic prices changes.[43] Therefore, in times of scarcity the marginal costs of dispatchable generation sets the market price until demand can no longer be met by the existing generation capacity. For this reason, the price signal between reliable supply and generation adequacy is weak.

[40] last resort resource providers may be able to sell contracts as an alternative to relying on spot revenues – but buyers are unlikely to purchase such contracts unless there is a real potential for spot prices to be very high at times.

[41] https://www.ea.govt.nz/assets/dms-assets/11/11824Scarcity-Pricing-Overview.pdf

[42] *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*, Bublitz et.al, 2019.

[43] *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*, Bublitz et.al, 2019.

APPENDIX 2: International case studies

Colombia

Energy market characteristics:
80% of Columbia's total electricity generation is derived from hydroelectric sources (~66% of total installed capacity[44]) with limited storage capacity. Like New Zealand, because Colombia's electricity generation is hydro dominant, in times of prolonged drought conditions they face significant security of supply issues. To ensure generation adequacy in dry periods Colombia utilises a firm energy RCM. [45]

How the RCM works:
Colombia's RCM works by paying generators a reliability charge in return for Firm Energy Obligations (OEFs) - awarded by a regulator via a regulated auction process. Under this mechanism, generators are compensated for the availability of their installed generation capacity with a fixed amount per kW, paid monthly during the awarded OEF period, regardless of whether any energy is delivered.[46]

Auction rules:
The RCM has two auction processes:

Primary Auction:
- OEFs are awarded through a dynamic price-based auction designed to identify least cost providers 4 years ahead of when the capacity is expected to be required. The auction works by offering suppliers a price / kW to provide OEFs with each applicant responding with their willingness to supply at that price.
- Where too much capacity is offered, the price is lowered, and the auction is rerun. Suppliers cannot increase their offered capacity between each successive round. The price starts at a high price (twice the Cost of New Entry (CONE)) and progressively reduces. CONE is estimated by the regulator and is adjusted for new auctions based on previous competitive auction results.[47]

Secondary auction process:
- This is a reconfiguration auction that is held for each commitment year that has not yet occurred but for which firm energy has already been procured in an earlier primary auction.[48]
- These reconfiguration auctions allow suppliers, and load, to balance their positions in light of improved information. For example, a project may proceed faster or slower than anticipated, and load growth may be faster or slower than expected. In addition, a monthly auction is held during the commitment year to provide a further opportunity to balance positions.

Who can participate?
Power generators, project developers, investors, and commercial agents representing existing or new plant are invited to participate in the firm energy auctions. However, promoters of generation projects that are not constructed yet need to demonstrate that they have a grid connection in place and that their power plant can be commissioned on time to provide firm energy during the OEF period. [49]

The commitment period for existing resources is one year. The commitment period for new resources is between one and twenty years. New resources select their preferred commitment length during the auction qualification (the firm energy price is adjusted for inflation during the commitment period).

Obligations:
- The firm energy product is a financial call option backed by a physical resource certified as capable of producing firm energy during a dry period. The financial call option hedges load from high energy prices during periods of scarcity. Because generators sell the call option, where prices rise above the specified strike price, they are effectively paying the SO and

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[44] https://www.researchgate.net/publication/221177668_Colombia_Firm_Energy_Market
[45] Firm energy is used in this market to describe the amount of energy that can be produced with 100% certainty during a dry period.
[46] https://www.cliffordchance.com/briefings/2019/02/colombia_cargo_porconfiabilidad2019auctio.html#:~:text=The%20Reliability%20Charge%20(Cargo%20por,the%20'El%20Ni%C3%B1o'%20phenomenon
[47] https://www.researchgate.net/publication/221177668_Colombia_Firm_Energy_Market
[48] https://www.researchgate.net/publication/221177668_Colombia_Firm_Energy_Market
[49] https://renewablesnow.com/news/colombias-creg-calls-auction-for-firm-power-supply-in-2027-2028-814911/

hedging them from high prices. The supplier's generating units and fuel provide a physical hedge to limit the risk of them selling the call option.

- Suppliers that supply more than their share during scarcity periods are rewarded and those that supply less are penalized. In each case, the marginal incentive comes from the energy spot price.
- A supplier's certification of firm energy depends on its estimated ability to supply firm energy in a dry period. This estimate depends at least in part on historical performance, and this provides an additional incentive.[50]
- In the firm energy market, the existing resources cannot impact the firm energy price. Since load is hedged from high spot prices, the market can still rely on high prices to balance supply and demand during dry periods, rather than rationing.[51]

Other notes:

- A supplier's obligation in any day is equal to its share of firm energy. The obligation is distributed over the day based on the hourly dispatch. Tying a unit's obligation to its hourly dispatch during scarcity events reduces market power and improves the performance of the spot energy market.

Historical performance:

- In 2008 and 2011, two firm energy auctions guaranteed 3,996 MW in new projects under the OEF mechanism.
- In 2015 – 2016, an El Nino event led to historically low hydro-inflows. This event coincided with a declaration by a significant thermal generator that it was unable to honour its firm energy obligations and the unscheduled shutdown of several hydro and other plants for more than a month. Despite these events, rationing of electricity was avoided and the firm energy market proved itself capable of operating under extreme stress.[52]

[50] https://www.researchgate.net/publication/221177668_Colombia_Firm_Energy_Market
[51] https://www.researchgate.net/publication/221177668_Colombia_Firm_Energy_Market
[52] Circular069-2016 Anexo1.pdf (creg.gov.co)

Sweden

Energy market characteristics:

Sweden's total generation in 2020 was 130.2 TWh (made up of: 45% hydropower, 17% wind power and 1% solar power.

Sweden's electricity market includes a strategic RCM alongside a wholesale energy market and ancillary and balancing services markets[53]. Sweden also has the ability to import electricity directly from neighbouring countries) .[54] The strategic RCM (operated by Svenska Kraftnät) provides ~562MW (total capped amount requested = 750 MW) of capacity and is intended to ensure that enough capacity is available in winter periods.

History:

The Strategic RCM was first adopted as a temporary measure in 2003 to provide ~2 GW of generation capacity with an original expiry date in 2008. Since then the total reserve maintained has been significantly scaled back but the programme has been extended out until 2025.

Despite having the ability to draw electricity from other countries, Sweden has always been able to satisfy electricity demand in winters through its installed capacity and strategic reserves (with imports only required rarely in peak conditions) [55]. As a result, rolling blackouts have not occurred in Sweden since the deregulation of the market and Sweden has been a net exporter of electricity since 2017. [56]

How the RCM works:

- The RCM is funded with consumer levies collected through electricity bills and is active only during the winter period from November to March.
- At present, the reserve only comprises a single biofuel fired generation plant (as previous participants retired their generation plant).

Auction Rules:

- The reserve is procured through separate public tenders for generation and DR units held six months before the winter period.[57]
- Auction rules state minimum 25% of the reserve should be assigned to demand response.
- The capacity procured in the strategic reserve also cannot participate in any other market during the winter period. [58]
- There is a minimum size (10 MW) for DR offers.

Who can participate and obligations:

- Demand-side units must make capacity available for 2 hours with a recovery period of 6 hours and provide their response within a maximum of 30 minutes.[59] These availability requirements and minimum participation sizes implicitly favour conventional generation and big industrial consumers. However, even big industrial users have found capacity commitment rules difficult to meet.
- All reserve capacity is required to be available 95% of the time during the winter period, or the capacity payment is reduced. For DR providers, this means that they must commit to using more electricity than the sold capacity 95% of the time.
- As of 2016 the entire reserve must now consist of renewable generation capacity[60].

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[53] The national automatic Frequency Restoration Reserve Capacity market was introduced since 2022, creating a new market design.
[54] https://energimyndigheten.a-w2m.se/Home.mvc?ResourceId=208766
[55] https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/Nordic/2022/Nordic_and_Baltic_Sea_Winter_Power_Balance_2022-2023_report.pdf
https://www.ifn.se/media/byddy5yr/wp1387.pdf
[57] https://smarten.eu/wp-content/uploads/2022/01/the_smarten_map_2021_DIGITAL_final.pdf
[58] https://smarten.eu/wp-content/uploads/2022/01/the_smarten_map_2021_DIGITAL_final.pdf. Demand response has previously been allowed to leave the reserve temporarily and be active on the spot market – however in these circumstances they did not receive any capacity payment.

[59] https://smarten.eu/wp-content/uploads/2022/01/the_smarten_map_2021_DIGITAL_final.pdf
[60] Proposition 2015/16:117

Historical Performance:

- The reserve has been activated around ten times since 2009, most recently in December 2012.

- **Lack of competition:**
  - o The last successful tender for generation was in 2017, resulting in a four-year contract for the period 2017–21, with the option of extending until 2025. In recent years, all capacity has been procured from one specific plant, Karlshamnverket, since the competing Mälarenergi and Stenungsund power plants have been closed.
  - o In 2019, TSO tendered for a further 188 MW of generation capacity, to reach the cap of 750 MW, but the tender was cancelled due to lack of competition.

- **High costs:** The costs incurred by the strategic reserve during winter 2020 / 21 were 14,300 €/MW. The current RCM costs ~2-3% of the market price for electricity.[61]
- **Price distortion:** SR is activated at the same price as the highest commercial bid in the spot market. A risk of distortion arises as higher prices, which are needed to trigger additional investment are capped as reserves are activated.

[61] copenhagen-economics-2016-market-design-for-a-reliable-swedish-electricity-system.pdf (copenhageneconomics.com) The cost is indicated as around 100 million SEK per year in this 2021 report.

France

Energy market characteristics:

The French electricity market is an EOM that includes a wholesale real-time spot and a futures market, a capacity guarantee mechanism, and an ancillary services market. Total generation is 450.8 TWh with generation being predominately sourced from nuclear plants (~72%) followed by renewables (~18%) and fossil fuels (~10%).[62]

Short-term prices in France are volatile as there is no large-scale storage of electricity, and the supply-demand balance is influenced by cold weather (which increases electricity demand).[63]

France guarantees electricity adequacy in peak demand periods / periods of scarcity through a both a targeted capacity mechanism Garanties de Capacités (that includes a DR tender) and an emergency interruptible load programme. This system is designed to both incentivise a modification of consumption behaviour during peak periods and ensure sufficient remuneration for peak capacity that is only running for a few hours per year.

How the RCM works:

- The RCM was implemented in April 2015 and became effective during 2016-2017[64].
- The RCM works by placing capacity obligations on Load Serving Entities (LSEs) – entities that sell electricity to consumers. This obligation requires LSEs to hold sufficient capacity guarantees to cover their customers' consumption during peak demand periods.
- Capacity operators (generators and demand-side units) certify their capacity to the SO four years in advance of the delivery year. When certified they are provided with a capacity guarantee that can be sold to LSEs through over-the-counter trades or in organised market sessions. LSEs can then on sell these guarantees between them. Exchange volumes and prices (€/certificate) are published on the EPEX SPOT website.
- The "appel d'offres effacements", is a programme to allow DR units to take part in the RCM. DR is procured through yearly tenders. DR operators may choose to certify their capacity (and receive sellable capacity guarantees) up to one year in advance.
- The required capacity is determined by the French regulator based on the forecasted peak demand and available generation capacity. The capacity obligations are expressed as a percentage of the expected peak demand and represent the minimum level of capacity that LSEs must hold to cover their customers' consumption during peak demand periods.

Auction rules

- Market players, producers and consumers can all participate in the RCM.[65] Currently, there are 13 independent aggregators who are actively participating.[66,67]
- The RCM is technology agnostic but has a minimum 1 MW size threshold for generation and DR units, including aggregated pools.
- The emergency interruptible load programme is focussed only on DR from highly energy-intensive industrial users (minimum size of 25 MW)[68].
- There are no technical barriers that explicitly limit certain technologies (however, the RCM does not allow for the participation of fossil fuel generation emitting more than 550 g

[62] https://www.iea.org/countries/france
[63] https://www.cre.fr/en/Electricity/Wholesale-electricity-market/wholesale-electricity-market
[64] https://www.nortonrosefulbright.com/en/knowledge/publications/db70dcf8/capacity-market-in-france
[65] https://www.services-rte.com/fr/decouvrez-nos-offres-de-services/participer-au-mecanisme-d-ajustement.html
[66] https://www.services-rte.com/files/live/sites/services-rte/files/pdf/RRRC/Liste%20AA%20RRRC.docx
[67] https://smarten.eu/wp-content/uploads/2022/12/the_smarten_map_2022_DIGITAL-2.pdf
[68] https://www.agora-energiewende.de/en/projects/comparing-capacity-market-designs-in-france-and-potentially-germany/#:~:text=France%20and%20Germany%2C%20the%20two,due%20to%20start%20in%202015. The interruptible load programme tenders a rolling reserve of 1.5 GW. The interruptible contracts have a maximum duration of two years for every technology and the procurement is done through calls for tenders. The interruptible load programme does not allow aggregation to meet the minimum MW threshold. The scheme requires fast responses (5 seconds for lot n°1 and 30 seconds for lot n°2) and long availability (e.g., in 2021, there was a requirement for there to be three 750 hour periods between 1 July 2021 to 31 December 2021 period available for lot n°1 and two 250 hour periods for lot n°2).

CO_2/kWh). The DR call for tenders also prohibits the participation of DR actions that involve fossil fuel generators.
- There are no availability requirements built into the mechanism, nor specific metering requirements.
- Every certified capacity resource must be tested during peak winter days but no more than three times during the delivery year.
- Capacity providers that participate in the RCM are not allowed to participate in the EOM with the same capacity for the same period for which they have been awarded capacity guarantees. However, plant can participate in both the EOM and capacity mechanisms at the same time. (Limitations also exist between the DR tender and the interruptible loads programme).
- Where capacity is not provided when called, LSEs are penalized based on the hourly spot price. As LSEs directly contract with capacity providers, it is up to the specific contractual provisions between the two parties.

Other:
- The RTE is looking to boost availability of capacity guarantees by easing regulatory constraints. These modifications include eliminating fees for upward rebalancing for delivery years.[69] These changes have driven up certified capacity levels for several technologies, particularly DR and cogeneration.[70]

Historical Performances:
- The market has been able to react favorably in times of scarcity. However, it is not clear whether this was due to the RCM or due to the French market's connection with other European countries.[71]
- The 2016 auction procured 22.6 GW of capacity guarantees traded / purchased[72].
- No evidence has been found to suggest the RCM negatively impacts supplier diversity.
- Prices of capacity guarantees reflect supply and demand with capacity prices increasing in 2020 in response to rising energy futures prices. This increase in price further encouraged capacity operators to increase available capacity during the winter of 2020.[73]

[69] https://bilan-electrique-2020.rte-france.com/market-mechanism-capacity-mechanism/?lang=en#1
[70] https://bilan-electrique-2020.rte-france.com/market-mechanism-capacity-mechanism/?lang=en#1
[71] https://bilan-electrique-2020.rte-france.com/market-mechanism-capacity-mechanism/?lang=en#1
[72] https://www.epexspot.com/en/news/epex-spot-successfully-launches-first-auction-french-capacity-market
[73] https://bilan-electrique-2020.rte-france.com/market-mechanism-capacity-mechanism/?lang=en#1

APPENDIX 3: Overview of CMs

Type	Market Area	Procurement Type		Category		Considered
		Centralised	*Decentralised*	*Price-based*	*Volume-based*	
Targeted / Strategic reserve	Belgium	x			x	Considered but discarded – The Belgian capacity remuneration model was considered as part of the research for this report but was not included in the assessment process given it is for the purpose of general capacity investment to cover nuclear phase out rather than extreme scarcity events.
	Germany	x			x	Not yet considered – to be targeted in a further iteration of this study.
	Sweden	x			x	Considered
	Colombia	x		x		Considered
	Spain					Considered but discarded – The Spanish capacity market has undergone significant change within the last 3 years with the phase out of a previous CM and the implementation of a new model in 2021. However, given its recent implementation there is not sufficient data to inform an assessment as part of this report.
	France		x		x	Considered
General CM	Ireland	x		x		The Ireland model is not considered as it is a market-wide capacity mechanism (aimed at general generation adequacy) that compensates all generators for generation capacity.[74]
	Italy	x		x		The Italian market is not considered as it is a market-wide capacity mechanism (aimed at general generation adequacy) that compensates all generators for generation capacity.[75]
	Poland	x		x	x	The Polish model is not considered as it is a market-wide capacity mechanism (aimed at general generation adequacy) that compensates all

[74] https://www.sem-o.com/markets/capacity-market-overview/
[75] https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc

						generators for generation capacity including, those foreign from neighbouring EU countries.[76]
	UK	x		x		The UK model is not considered as it is a market-wide capacity mechanism (aimed at general generation adequacy) that compensates all generators for generation capacity.
	US – ISO – NE	x		x		The ISO has a Forward Capacity Market, which is a long-term wholesale electricity market ensuring local and systemwide adequacy – as a result, it was not considered for this study.[77]
	US – MISO	x		x		The MISO maintains an annual capacity requirement on all load-serving entities (LSEs) based on the load forecast plus reserves. LSEs are required to specify to MISO what physical capacity are designed to meet the load forecast. [78] This could be considered for the next iteration of this study.
	US – NYISO	x		x		Not considered as the NYISO Installed Capacity market is a market-wide model designed to promote general resource adequacy by providing suppliers with means to recover a portion of their fixed capital costs and to offer a pricing signal for investment.[79]
	US – PJM	x		x		Considered but discarded – PJM remuneration model was considered as part of the research for this report but were not included in the assessment process given it is a market-wide CM model where all generators are compensated to improve overall generation adequacy.
	Australia – RERT programme	X		x		The RERT is not a comparable RCM as RERT panel members are compensated directly for electricity provided in a scarcity event (rather than via a capacity payment).
	US – CAISO		x		x	This paper did not consider CAISO as it does not have a capacity market and solves general adequacy problems through a mandatory resource adequacy

[76] https://energy.ec.europa.eu/system/files/2020-02/polish_implementation_plan_final_0.pdf
[77] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-the-fcm-and-its-auctions
[78] https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc
[79] https://www.cmegroup.com/education/articles-and-reports/introducing-the-nyiso-eletricity-capacity-market.html

						requirement to procure 115% of LSE's aggregate system load.[80]
	US – SPP		x	x		This paper did not consider SPP given no capacity market exists and the monopoly service providers in SPP are responsible for maintaining resource adequacy.[81] This could be considered for the next iteration of this study.

[80] https://sustainableferc.org/navigating-caiso/
[81] https://sustainableferc.org/rto-backgrounders/navigating-spp/#:~:text=SPP%20coordinates%20the%20dispatch%20of,changes%20from%20the%20expected%20demand.