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Capacity markets and energy-only markets – a survey of recent developments

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What this paper is about

Ever since wholesale electricity markets were established in the 1990s, there has been debate about the relative merits of the 'energy-only market' (EOM) design and the alternative 'capacity market' (CM) design. The essential point of difference is that a CM imposes a compulsory contracting obligation on parties who purchase electricity in the spot market. Under this mechanism, a central party forecasts future demand and requires wholesale buyers to hold sufficient forward contracts to meet their net share of projected demand (see Chapter 3 for a fuller description of the structure of the two models).

Debate about the merits of the approaches has intensified in recent years – particularly as nations accelerate their efforts to reduce greenhouse gas emissions. The debate has produced a burgeoning list of reports and developments including:

- ISO New England and PJM made substantial changes to their CMs after 2015 to improve operational performance (see section 4.5)
- The European Union competition authority conducted an inquiry into capacity mechanisms in 2016 because of concerns about their potential effect on competition (see section 5.3)
- Eastern Australia considered in 2016-17 whether to adopt a CM but chose to modify its EOM (see section 4.3.3)
- Britain suspended its capacity mechanism in 2018, after the European Court found it potentially breached competition rules. The scheme was reinstated in 2019 (see section 4.2.3)
- A United States Federal Energy Regulatory Commissioner expressed serious doubts in 2019 about the effectiveness of current CMs (see section 5.4)
- Singapore is planning to replace its EOM with a CM from 2022 (see section 4.3.5)
- Alberta decided in 2014 to replace its EOM with a CM from 2021, and then abandoned that decision in July 2019 (see section 4.3.2).

In this report, we compare the performance of the two models – drawing on recent international experience and literature.

CMs and EOMs have different strengths in relation to reliability

CMs provide a high level of assurance that sufficient generation and demand-side response (DR) will be *built.* This is because CMs create explicit commitments to invest in supply or DR capability. CMs can also include tests to ensure that parties' commitments are backed by 'steel in the ground'. Having said that, many EOMs (e.g. New Zealand, Nord Pool, Singapore) have performed well in ensuring sufficient capacity is *built*. So, the real difference between CMs and EOMs is the level of ex ante assurance they provide. CMs provide a higher degree of ex ante assurance about the level of *built* capacity because that factor is under the direct influence of the regulator/market operator.

Turning to operational issues, CMs do not provide assurance that resources which have been *built* will actually be *available* when required. Indeed, experience to date suggests that EOMs will almost certainly perform better than CMs on this front, because EOM spot prices create stronger signals to make all supply and DR resources available during periods of scarcity.

Given that the two designs have different strengths with regard to reliability, the overall assessment of the two designs on this front is not clear-cut. Policy makers need to carefully consider which issue is likely to be most important – obtaining ex ante assurance about the level of *built* capacity, or ensuring that resources which have been built will be *available* when required. In the case of New Zealand, the latter issue appears to have been the more critical one - given the energy-constrained nature of our electricity system.

CMs tend to raise costs for consumers

Costs to consumers are expected to be higher under CMs than EOMs. The key reasons are:

- CMs are prone to over procurement. Key decisions must be made by a central party who will face lop-sided incentives. They will typically err on the side of caution because any failure in the form of power cuts will be visible, whereas the costs of over-building are harder to see.
- CMs create weaker incentives to select the most cost-effective mix of supply and DR options. This is because the central party will significantly influence the resource mix, but doesn't directly face the cost of its decisions. For example, the central party would need to decide what proportion of each wind generators' nameplate capacity will qualify as firm capacity. In truth, the answer depends on factors such as a generator's location and the extent to which wind patterns in that area are correlated with wind patterns elsewhere. But the central party may prefer a simple 'one-size-fits-all' rule because of the complexities of a more detailed assessment. That in turn would encourage parties to invest in a resource mix that reflects the CM's rules, rather than the mix that genuinely provides the firm capacity at least cost.
- CMs are less able to facilitate and reward innovation – the most important source of cost savings in the long-run – because of the higher level of centralised decision-making and prescription.

Market power

Some commentators argue that CMs insulate purchasers from the exercise of market power in the spot market because all purchasers are heavily contracted. However, other commentators argue that CMs exacerbate market power in the contracts market. In our view, neither model has an overwhelming advantage on the competition front, and both require careful design to minimise the scope for the exploitation of market power.

Durability

In theory, CMs should be more durable than EOMs because they do not rely on spot prices being able to reach very high levels in a scarcity event. However, because of poor operational performance during past scarcity events, leading CMs are moving toward penalty regimes which mimic scarcity prices under an EOM. So, the difference in durability from this source may lessen over time.

More generally, where CMs have been adopted, they are under almost constant change by the central decision maker – with some modifications being very significant. Furthermore, experience suggests CMs are more exposed than EOMs to legal or regulatory challenges due to the greater centralisation of decision-making and considerable administrative discretion conferred on the central party.

What should New Zealand do?

Neither EOMs nor CMs are perfect. Both have strengths and weaknesses – and experience is still being accumulated on their relative performance. Based on the international experience with EOMs and CMs to date, we suggest the following actions.

Keep an eye ahead

New Zealand should keep an eye ahead for any sign of potential or emerging problems. Identifying concerns at an earlier stage provides more time for careful examination to determine if problems are real or perceived (see below). If concerns are borne out, early identification also gives more time for proper diagnosis of causes, and identification of solutions.

New Zealand already has tools to facilitate monitoring of the forward outlook for supply and demand. These should be actively employed – focussing particularly on the supply margin and any indications that investment signals are not working as expected, such as contract prices which are persistently above new supply costs or stalled investment plans.

Identify whether any reliability concerns are due to investment adequacy

Electricity systems can exhibit reliability concerns for a wide variety of reasons. This is true of systems with EOM and CM designs. Indeed, reliability concerns were around long before electricity markets were created in the 1990s.

If reliability concerns do emerge, it is important to identify the real source of those concerns, as reliability concerns may be unrelated to investment adequacy and the choice of market design.

This was the case with reliability concerns which emerged in the aftermath of the state-wide power cuts in South Australia. Those stemmed from tripping of wind generators following a power system disturbance. Adopting a CM would not have addressed those concerns because they revolved around technical standards. Correctly diagnosing the concern is crucial to avoid solutions that are unnecessary, or worse, counterproductive.

Improve EOM design where feasible

If investment adequacy concerns do emerge, it would be important to understand whether they can be addressed without complete redesign of the electricity market. For example, adequacy concerns may be due to aspects of an EOM design that unintentionally cause problems – such as insufficient opportunity for DR to influence prices or poor price formation in scarcity situations. 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."[1] The European Commission made this statement because it was concerned that CMs could distort competition, risk jeopardising decarbonisation objectives and push up the price of electricity for consumers. [2]

Concerns may also arise for reasons that are temporary in nature and not directly related to the wholesale market design per se. This was the case with Germany which faced increased supply uncertainty due to the accelerated phase-out of nuclear power. After considering a wide range of options, Germany chose to retain an EOM design, but placed some generation in a temporary strategic reserve to facilitate the transition as nuclear plants phase out.

[1] European Commission (2016), *Final Report of the Sector Inquiry on Capacity Mechanisms*, p.7

[2] Ibid, p.1.

Understand the risks and costs of CMs relative to EOMs

Both EOMs and CMs have costs and risks and there is no perfect option. If serious consideration is ever given to adopting a CM for New Zealand, it would be important to draw on the latest international experience to understand the likely costs and risks. In this context, it is striking how much has changed among EOM and CM jurisdictions in the last five years. Whereas CMs were previously thought to provide greater assurance on reliability than EOMs (albeit at a cost to consumers), that assessment is now open to question. More generally, policy makers worldwide are assessing how to adapt electricity market arrangements to facilitate the transition toward net zero carbon. One key question in this context is whether a rising proportion of intermittent generation will cause unacceptably high levels of spot price volatility, or whether participants will adapt via contracting and/or use of physical options such as batteries. Other countries are likely to strike these challenges before New Zealand, because our relatively large and flexible hydro generation base provides a cushion to ease the transition. This means that New Zealand should be able to benefit from the design experiences of other countries – and not repeat their mistakes.

Having said that, there are some critical issues where international experience is not very useful – simply because our issues are distinct such as exposure to drought risk (see chapter 6). New Zealand would need to develop its own assessment of costs and risks in relation to these issues.

2 Introduction

2.1 What this paper is about

Ever since wholesale electricity markets were established in the 1990s, there has been debate about the relative merits of the 'energy-only market' (EOM) design and the alternative 'capacity market' (CM) model.

EOMs and CMs
We use the term "energy only market" to refer to electricity markets in which the only assured revenue source for suppliers is spot market payments. We use the term "capacity market" to refer to the spectrum of mechanisms which create a regulated revenue stream that is distinct from spot market payments. These mechanisms include formal capacity markets, strategic reserves, and the firm energy market in Colombia. We use the term CM because it is commonly used in the literature to describe this family of mechanisms. See Chapter 3 for more information on the two alternative designs.

Proponents of EOMs argue they have lower costs for consumers and, if structured properly, can ensure reliable supply.[3] Supporters of CMs argue EOMs are prone to under-investment, and this must be corrected by adding a regulated market for capacity.[4]

Debate has intensified in recent years – particularly as nations accelerate their efforts to reduce greenhouse gas emissions. The debate has produced a burgeoning list of reports and developments including:

- ISO New England and PJM made substantial changes to their CMs after 2015 to improve operational performance (see section 4.5)
- The European Union competition authority conducted an inquiry into capacity mechanisms in 2016 because of concerns about their potential effect on competition (see section 5.3)
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- Alberta decided in 2014 to replace its EOM with a CM from 2021, and then abandoned that decision in July 2019 (see section 4.3.2).

This paper compares the two models – drawing on recent international experience and literature.

[3] For example, see Hogan, W. (2005) *On an "Energy Only" Electricity Market Design for Resource Adequacy*; Hogan, W. (2013). *Electricity Scarcity Pricing Through Operating Reserves*.

[4] For example, see Cramton, P. and Stoft, S. (2006). *The Convergence of Market Designs for Adequate Generating Capacity*; Cramton, P. *et al*. (2013). *Capacity Market Fundamentals*.

2.2 Structure of report

This report is structured as follows:

- Chapter 3 describes the key features of EOMs and CMs – focussing particularly on the latter as these are less familiar to readers in this part of the world
- Chapter 4 discusses the relative performance of EOMs and CMs in ensuring reliable power supply to consumers
- Chapter 5 discusses the relative performance of EOMs and CMs in relation to costs
- Chapter 6 outlines some issues specific to New Zealand that would need to be considered if a CM were to be adopted
- Chapter 7 sets out this report's overall conclusions.

3 Energy-only markets and capacity markets – what the heck are they?

This chapter describes what we mean by 'energy-only market' (EOM) and 'capacity market' (CM). This description focuses on the nuts and bolts of the two models and does not delve into their theoretical underpinnings.[5]

Readers already familiar with EOMs and CMs can skip to the next chapters, which discuss the relative merits of the two approaches.

3.1 Energy-only markets

New Zealand has utilised the EOM model since its wholesale electricity market was established in 1996. Other jurisdictions that use an EOM model include Alberta in Canada, states in eastern Australia, Denmark, Norway, Singapore, and Texas.

In jurisdictions with an EOM design, a generator's only assured revenue source is from electricity sales into the spot market.[6] In practice, generators may also earn revenue from forward contracts.[7] Indeed, these typically account for the majority of revenue received by generators. However, the volume of contract revenue is dependent on the risk preferences of buyers and sellers of contracts, and there is no regulatory requirement for consumers to enter into forward contracts with the EOM model.

Spot prices in EOMs

In any electricity system, there will be a small fraction of the total resource capability that is only needed very rarely - such as to respond to extreme demand peaks or provide cover during multiple power station outages. In the EOM design, when such 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.

In practice, 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. Accordingly, in the EOM model, it is critical that spot prices can reach the value of lost load[8] during genuine scarcity situations.

Investment decisions are de-centralised in EOM

In an EOM, investment decisions in generation plant and demand-side response (DR) capability[9] are made by industry participants on a decentralised basis. A key factor affecting such decisions is the level of

[5] For readers interested in a more theoretical discussion of the models, a useful recent summary is contained in Bublitz A. *et al.* (2019), *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*, Energy Economics 80: 1059–1078.

[6] Strictly speaking, generators may also receive regulated revenue from sale of ancillary services, but these are a relatively small proportion of total revenues and are not considered further in this paper.

[7] These can take many forms, including sales to end-consumers (possibly via a retail-arm of a vertically integrated firm), bilaterally negotiated hedge contracts, and trading of hedge products on exchanges.

[8] The value of lost load (VoLL) is intended to reflect the cost that consumers incur when they suffer unexpected power cuts. It is typically a very large value – estimated at around $10k-$20k per MWh in New Zealand.

[9] This refers to demand which can be altered by consumers (or agents acting on their behalf) in response to changing system conditions.

spot and contract prices. If parties expect a tightening supply margin, price expectations will rise, providing an incentive for more investment, and vice versa.

While the level of investment in generation and DR resources reflects decentralised decisions by participants, it is nonetheless influenced by regulators and market rules. Key design issues include spot price formation rules when security is reduced (such as lowered instantaneous reserve cover), the level of any price caps or floors in the spot market, and prudential security arrangements, since these can affect risk management trade-offs for participants.

3.2 Capacity markets

Jurisdictions that operate a CM include south western Australia, Colombia, and the schemes covering parts of the United States (the Mid-West ISO, ISO New England, New York ISO, and PJM market areas). A fuller list is included in Appendix A.

Some researchers argue that EOMs provide insufficient revenue to assure timely and adequate investment in resources. They say EOMs have 'missing money' because very high spot prices will not be tolerated during scarcity conditions and/or are explicitly capped at levels well below the value of lost load. To address the missing money problem, proponents of CMs say that investment/retention decisions must be incentivised by capacity payments which are separate from spot market revenues.

CMs take a wide variety of forms, but they all specify an explicit target level of capacity, and place physical or financial obligations on generators and consumers intended to achieve this target. The following sections describe key aspects of CMs in a little more detail.

Target level of capacity adequacy is determined by a central party

The main objective of CMs is to provide greater assurance there will be enough physical capacity in place to meet future demand, even in extreme conditions. This means that "enough" must be defined and specified as a target. This is typically done by a central party (such as a regulator or market operator). For example, a CM could specify a target that there is always enough generation and DR capacity installed to cover projected peak grid demand plus a (say) 15 percent safety buffer.

The central party will need to prepare estimates of projected grid demand, as these ultimately drive individual parties' purchase obligations. The methodology used by the central party needs to account for factors such as weather uncertainty, levels of self-generation by consumers, voluntary demand response, changes in consumption patterns, population growth, etc. The central party will need to gather a significant volume of information to develop these projections (some of which is commercially sensitive such as commissioning/closure dates for major industrial power users). However, ultimately the central party will be making guesses, and the consequences in terms of reliability and costs will be borne by consumers.

Obligations on retailers and other wholesale market purchasers

Once the overall capacity target is defined, it will be translated into specific obligations for retailers and other wholesale market purchasers, such as large industrial consumers. These parties will have an obligation to hold capacity rights[10] to match their assessed share of the overall system demand in defined timeframes. These rights can be from self-supply (if they have generation), or via purchasing rights from other parties.

Where parties need to purchase capacity rights, CMs may allow bilateral purchases or use a central buyer (e.g. PJM). Some CMs have a hybrid, where any deficit in bilaterally acquired rights must be topped up via purchases from a central buyer (e.g. the scheme in Western Australia). In all cases, the ultimate source of capacity rights is generators and DR providers.

Obligations on generators and DR providers

To provide assurance that the capacity being procured is real, the volume of rights generators and DR providers can sell is typically restricted or 'qualified' on an ex ante basis, so that volumes cannot exceed a provider's assessed firm capability. This assessment is normally overseen or undertaken by a regulator, which prescribes rules covering issues such as the treatment of fuel availability for thermal plants, derating factors for plant reliability, derating factors for intermittent generation, definitions of plant retirement and commissioning etc. This issue is discussed further in section 4.4.

Registry to track capacity rights

CMs need to set up some form of central registry to record the number of qualifying capacity rights available for sale by each generator, the number of rights that must be acquired or held by 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.

Time horizon covered by capacity obligation

The obligation to purchase capacity rights will cover the current year at a minimum, and typically also extends for some future years as well. This provides more assurance that capacity will be installed when needed (noting the lead-time to build new generation is more than one year). Adopting a multi-year horizon provides a set of longer-term price signals, and may also provide generation and DR investors with greater revenue assurance.

However, the forward contracting obligation can pose challenges for parties whose demand is especially uncertain. For example, new entrant retailers or retailers losing market share can be penalised or advantaged, depending on specific rules adopted by the central party to allocate contract obligations among purchasers. Similarly, a large industrial user might face a contract purchase obligation some years into the future, despite uncertainty about its power demand in that year.

Commitment period

Sellers of capacity rights will be committed to provide capacity (and have rights to receive associated revenue) for a defined commitment period. This can vary from around a year to multiple years. Historically, CMs appear to have favoured one-year commitment periods. More recently, there seems to be a trend – at least for new generation – towards longer

[10] We use the term 'capacity rights' in this paper, noting that some CMs seek to ensure the availability of firm *energy* rather than *capacity*.

commitment periods under a fixed price with adjustments for inflation and a variety of conditions. For example:

- In PJM a single-year commitment period applies for capacity
- In ISO New England 1- or 5-year commitment periods apply for new capacity (generators have a choice) with capacity payments adjusted for inflation; there is a proposal to extend to 7 years
- In Great Britain, a 15-year commitment period applies for new capacity, 3 years for retrofits, and 1 year for existing generation.[11]

Setting prices for capacity rights

An auction process is typically used to determine the price of capacity rights. To reduce auction price volatility and mitigate market power, these typically use a 'demand curve' approach (effectively price-quantity bids). The curve is typically anchored around a point representing the optimal capacity level and the assessed cost of new supply. A downward slope is applied so the capacity price falls with additional supply offers. A price cap is also typically applied. For example, PJM caps the price at around 150 percent of the assessed cost of new capacity, and the price falls to zero once capacity reaches 107.5 percent of assessed requirements.

CMs may seek to directly set the clearing price, and use this to 'steer' the volume of capacity on the system (e.g. Western Australia's CM did this in the past) – noting this provides more control over capacity prices but does not guarantee that optimal capacity level will be installed.[12]

Collecting the money to pay capacity providers

Depending on the design, capacity providers will receive payments directly from wholesale purchasers (retailers and grid-connected large consumers) or from the central party. In the latter case, the central party will collect contract payments from wholesale purchasers, and use it to pay capacity providers. In both cases, retailers will need to factor in their capacity payment obligations when setting prices for end-use customers. And irrespective of the particular design, consumers will ultimately bear the cost of capacity payments.

Capacity rights can be expressed in physical or financial terms

Capacity rights can be expressed in physical terms (e.g. rights to consume a given level of MW for a defined period) or financial terms (e.g. a hedge contract that protects the buyer from spot prices above a pre-defined level). Expressing rights in financial terms is more flexible and requires less prescription, but there is still a significant monitoring and enforcement issue.

Strategic reserves – a special form of CM

CMs can be subdivided into market-wide and targeted approaches. Market-wide mechanisms provide financial support to all capacity in the market, whereas targeted mechanisms directly support only a subset of capacity. Often, this is capacity intended to be used as a last resort if specific conditions are met, e.g., a shortage of capacity in the spot market or prices settling above a certain level. The cost of maintaining (and possibly running) this capacity is typically recovered from consumers via

[11] Jenkin, T. Beiter, P. and Margolis, R. (2016). *Capacity payments in restructured markets under low and high penetration levels of renewable energy*. National Renewable Energy Laboratory, US Department of Energy.

[12] See European Commission, (2016). *Commission staff working document on the final report of the sector inquiry on capacity mechanisms: SWD(2016) 385 final*, available at https://ec.europa.eu/energy/sites/ener/files/documents/swd_2016_385_f1_other_staff_working_paper_en_v3_p1_870001.pdf.

some form of uplift payment. We refer to these as strategic reserve schemes (noting that individual jurisdictions may have other names for them).

New Zealand had a scheme of this sort between 2004 and 2010. Sweden has a strategic reserve scheme, Britain introduced one in 2014, and Germany launched a scheme in October 2019 to ease the transition as nuclear plant is decommissioned.[13]

One key issue with these schemes is that market participants may alter their private investment plans to take account of the presence of the strategic reserve – i.e. the aggregate system capacity may not increase with a strategic reserve. To counter this effect, policy makers may need to expand such schemes so that they become the principle revenue source for new capacity (as appears to be occurring in Great Britain) – in which case they become more like conventional CMs.

In principle, strategic reserve schemes could be designed so they don't undermine private investment incentives – however it is very difficult to achieve in practice. This was one of the reasons New Zealand discontinued its reserve energy scheme in 2010. As noted in the 2009 electricity market review, the "the reserve energy scheme had a number of perverse effects and probably did not improve overall security of supply. Concerns were that the scheme:

- Reduces incentives on market participants to manage their own risks (because the EC is expected to manage those risks as a last resort)
- Reduces the incentive for investment in peaker plants and for demand-side responses (because Whirinaki's fixed costs are recovered by a levy on all consumers)
- Incentivises lobbying to change the rules relating to reserve energy (e.g. on despatch of Whirinaki and to contract for additional reserve capacity), creating uncertainty."[14]

In the balance of this report, we focus mainly on conventional CMs – noting that some observations are also applicable to strategic reserve schemes.

Spot market continues to exist

Jurisdictions with a CM still have a spot market, and this provides signals to guide short-term decisions, such as those relating to plant commitment and/or scheduling of discretionary demand by consumers. Because resource providers receive capacity payments, they are less reliant on the spot market for revenue. As a result, spot prices are generally lower on average and less volatile than in an equivalent EOM.

[13] See https://europa.eu/rapid/press-release_IP-18-682_en.htm

[14] Cabinet Paper (2009), *Ministerial Review of the Electricity Market*.

4 Reliability of supply

This chapter discusses the performance of CMs and EOMs in relation to the reliability of supply.

4.1 What do we mean by reliability?

The terms 'security' and 'reliability' can have different meanings, depending on the author and context. In this report, we adopt the definitions below, as they generally align with international usage. We note that 'security' is the term more commonly used in New Zealand.

Reliability

Reliability refers to having adequate generation and DR capacity[15] to continuously meet consumers' demand for electricity. Reliability can be quantified as the proportion of total electricity demand that is satisfied (or curtailed).

A secure power system is a necessary, but not sufficient, condition for reliability.

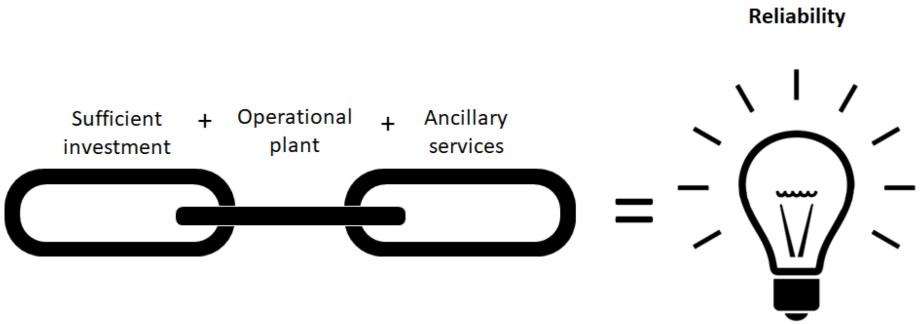
Security

Security refers to the ability of the power system to tolerate a disturbance (such as loss of a major generator or transmission circuit) and still maintain electricity supply to consumers. Security is achieved by operating the system in a stable state with instantaneous reserves available to counter unexpected events, and within the required bounds of technical parameters such as frequency, voltage, and fault current levels.

It is important to recognise that a chain of elements must work together to achieve reliable supply – as illustrated in Figure 1. As we discuss below, most CMs focus principally on the first element in the chain – ensuring sufficient generation or DR investment. Historically, this has been the issue of greatest concern to those who doubt the efficacy of EOM incentives.

While CMs contain elements to incentivise real-time operation, these have typically received less attention and there has been a reliance on real-time markets (spot or balancing) to incentivise operating decisions.

Figure 1: The reliability chain



4.2 How have CMs performed in terms of reliability?

We have not been able to identify any comprehensive study that assesses the performance of CMs from a reliability standpoint (ignoring outages caused by transmission or distribution level issues). Having said that, many studies seem to accept that CMs have generally met their *capacity targets*. For example, a 2014 survey of experts in the United States found:

[15] We include battery storage within the definitions of generation and DR.

> "the experts generally contend that the capacity markets have achieved the goals of providing the required reserve margin [..] (54% agreed, 23% disagreed, and 23% had no opinion)".[16]

However, achieving the target *capacity* does not necessarily ensure *reliability*. As we noted above, reliability for consumers requires a chain of elements to work together.

CMs typically focus on making sure there is sufficient generation or DR capacity installed in a system to meet peak demand. Less attention has historically been directed at ensuring these resources are actually available to consumers in scarcity situations. As Wolak (2004) noted, this is analogous to ensuring there are enough bakeries, rather than enough bread.[17] Wolak went on to state:

> "even if a wholesale electricity market has a capacity market, there is no way to compel generation unit owners provide electricity if they would prefer to withhold this capacity to drive up the spot price of energy [sic]. Recall the "sick day" problem that occurred with generation units during the period December 2000 to May 2001 when many units were "declared" unavailable to operate."

Similarly, Bushnell (2017) stated:[18]

> "Providing missing money alone does not ensure the adequacy or reliable supply, only the adequacy of generation capacity with the potential to provide reliable supply. But reliability is not enhanced if the "adequate" capacity is not operating when it is needed."

The potential for sizeable gaps to arise between installed and operational capacity, even in more 'mature' CMs, has been highlighted with experience over the last decade.

4.2.1 ISO New England

ISO New England serves consumers in six states in north eastern United States. In 2003, the ISO adopted a new market design which included a capacity market. In 2008, ISO New England held its first auction under the new capacity market. A review of the arrangements in 2012 identified that many units were failing to deliver the full capacity specified in their forward capacity market supply offers. Average underperformance was quantified as 40% of the additional power required by the System Operator during contingencies.[19]

The System Operator attributed this significant underperformance to the fact that:

> "capacity resources rarely face financial consequences for failing to perform, and therefore have little incentive to make investments to ensure that they can reliably provide what the region needs when supply is scarce."[20]

Among the issues identified in the review were failures "to procure fuel, including natural gas-dependent resources during periods of limited gas

[16] Bhagwat, P. C. *et al.* (2016). *Expert survey on capacity markets in the US: Lessons for the EU*. Utilities Policy 38.
[17] Wolak, F. A. (2004). *What's wrong with capacity markets?* Stanford University.
[18] Bushnell, J. *et al*. (2017). *Capacity Markets at a crossroads*. UC Davis.

[19] Independent System Operator of New England (October 2012). *Forward Capacity Market Performance Incentives*.
[20] Federal Energy Regulatory Commission (May 2014). *Order on Tariff Filing and Instituting Section 206 Proceeding*. Docket no. ER14-1050-000-001.

supplies (particularly during the winter gas season), and the failure of resources to closely follow dispatch requests when needed to address contingencies".[21] The findings of the review prompted authorities to reassess arrangements (see below) – particularly those relating to operational incentives.

4.2.2 PJM

PJM is often considered to be a leader among markets with a CM. PJM serves over 65 million consumers. PJM's wholesale market was established on 1 January 1999.

In 2007, the market was redesigned to reflect incremental improvements and retail deregulation. The new design that became effective on 1 June 2007 included an annual capacity market, a forward market, locational capacity markets, scarcity pricing of capacity via a defined demand curve, clear links to the energy and ancillary services markets, incentives to provide energy reliability, and clear market power rules including a 'must offer' requirement. The redesign was regarded as a major improvement over the prior design.

In January 2014, the new design was tested when a polar vortex caused extremely low temperatures and record demand (141,846 MW) in the PJM region. During that weather event, PJM experienced an equivalent forced outage rate of 22%, far in excess of the 7% historical average. The capacity shortfall relative to obligations amounted to 40,200 MW. To manage this, system operators imposed voltage reductions of up to 5% but did not impose forced power cuts.[22]

While supply to consumers was not interrupted, the event was regarded a serious near miss and prompted authorities to reassess arrangements (see below) – particularly those relating to operational incentives.

4.2.3 Western Australia

A CM was introduced in 2005 and supply has been relatively reliable since that time.[23] Having said that, in June 2008 an explosion at a gas production facility cut the state's gas supply by around 35 percent.

In the week after the event, State Premier Carpenter warned he might need to invoke emergency powers and take control of the state's gas and electricity supplies, which could result in rolling stoppages, blackouts and brownouts.[24] As it turned out, reliable electricity supply was maintained by drawing on alternative thermal fuel sources (including emergency supplies of diesel) and voluntary conservation measures.

In January 2020, unplanned generation outages caused 98,000 customers to suffer blackouts, (around 7.5 percent of total connections). Power was restored to most customers within an hour.[25]

[21] Analysis Group (2013), *Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives*.
[22] PJM (August 2014), *Problem Statement on PJM Capacity Performance Definition*.
[23] We note the authorities in Western Australia selected a CM as the preferred design in part because the system is small and there is a high degree of supplier concentration. A CM was thought to be better able to address incumbent market power and uncertainties associated with large lumpy loads.
[24] Megalogenis, G. and Tasker, S-J., *WA gas crisis poses threat to economy,* The Australian, 12 June 2008.
[25] https://www.aemo.com.au/news/south-west-interconnect-system-power-event-10-january-2020

4.2.4 Great Britain

Britain introduced a capacity mechanism in 2014. This involves an auction process, where bidders (existing and new generation and DR) compete to supply capacity in forward years via an auction process – the first of which was held in December 2014. While Britain has not experienced any major reliability issues, the capacity mechanism itself has not worked as intended. One key problem area has been the incentive regime.

When the mechanism was designed, a penalty rate for non-delivery of 16,000 £/MWh was proposed. After negotiations with stakeholders, the penalty scheme was modified substantially and the charge was finally set at 1/24th of the respective auction clearing price, with a variety of caps on the penalties for CM contract holders. The reduced penalties meant that capacity prices were lower than expected in the first two auctions but according to some experts, it reduced the effectiveness of the performance incentive and undermined the integrity of the mechanism.[26]

In 2015, these researchers noted "if generators face little penalty for failing to deliver capacity, they may choose not to turn up in 2018"[27] (the first delivery period). This reasoning seems to have been confirmed by the indefinite delay in the construction of the 1.9-GW Trafford power plant, which was awarded capacity payments in 2014. Changes to the penalty regime were subsequently proposed to address the incentive issues.

In November 2018 the CM was suspended after the General Court of the European Union ruled that the European Commission had not effectively scrutinised the CM's competition implications. The ruling came after Tempus Energy challenged the UK Government arguing that the policy was anticompetitive.[28] In October 2019 the scheme was reinstated after the Commission confirmed that it complied with competition rules.[29]

4.2.5 Colombia

Most CMs are designed to meet a short period of scarcity (hours or days) caused by extremely high demand and/or multiple unexpected supplier outages. To our knowledge, the only CM which seeks to address reliability concerns over much longer periods (arising from hydro risk) is the scheme operating in Colombia. Like New Zealand, Colombia has a hydro-dominated system which is vulnerable in dry years. In such periods, reduced hydro generation must be offset by other actions, principally from higher thermal plant output.

In 2004, the regulator introduced a reliability mechanism in which suppliers sell firm energy obligations (Spanish initials = OEFs) via a centralised auction in exchange for fixed annual payments. These obligations are based on financial call option contracts with a high strike price and are backed by physical resources. When the spot market price exceeds the strike price, reliability providers are required to deliver the committed contribution and to return any positive difference between

[26] Gammons S. and Anstey G. (2014). *The UK Energy Market Investigation: A Desperate Search for Evidence of a Lack of Competition?* Competition Policy International, 15 April 2014.
[27] Ibid.

[28] https://theenergyst.com/tempus-wins-european-court-case-capacity-market-bias-towards-generation-dsr/
[29] https://www.gov.uk/government/publications/capacity-market-reinstatement-letters-from-beis-to-national-grid-eso-and-esc-october-2019

the spot price and the strike price to the contract buyer, receiving the option payment in exchange.

The regulator restricts the volume of OEFs that resource providers can sell. For hydropower plants, the allowable OEFs are calculated via an optimisation tool that assumes inflows will be at low levels. For thermal plants, OEFs are based on each plant's installed capacity, track record of forced outages and assessed fuel availability.

Colombia's scheme was tested by a drought in 2009/2010 and it did not work as expected. The regulator formed the view that hydro generators were not conserving water as intended and were instead generating to honour their overall bilateral sales commitments.[30] The regulator felt that if this pattern continued, it would result in very low reservoir levels at the beginning of the actual dry season. As a result, the regulator intervened, changing the dispatch rules to incentivise more thermal generation and reduced hydropower output.

Unexpected problems subsequently arose with some thermal plants due to fuel constraints. Despite holding firm gas supply contracts (necessary to be awarded OEFs), some thermal plants did not receive their contractually committed supplies. This was primarily due to unexpected pipeline capacity constraints. Some plants were capable of switching to liquid fuels, but the infrastructure for transporting liquid fuels had not been fully tested either, and supply problems arose in some cases. In total, of the 93 GWh per day of firm energy obligations contracted with thermal plants, 80 GWh per day were actually delivered.[31] Despite these setbacks, the Colombian electricity system managed to operate with no demand curtailment in the dry year.

After the event, performance during 2009/2010 attracted criticism from various quarters. The lower contribution from natural gas and liquid fuel-fired plants revealed flaws in the methodology for awarding OEFs – especially in relation to the treatment of fuel supply risk. Similarly, hydro generators argued the regulator's OEF methodology for hydro generation was flawed. They believed the regulator's intervention denied them an opportunity to demonstrate an ability to generate above the level of OEFs they had been assigned.

The experience in Colombia illustrates the difficulties in measuring 'firmness' over extended periods – when factors such as fuel supply chain integrity, transmission network resilience and weather pattern uncertainty become much more important. It also shows the challenge this raises for a regulator, who may struggle to obtain the information and expertise to calculate each resource's expected contribution in scarcity conditions.

The Colombian experience also highlights the importance of incentives for a regime to operate effectively. We understand Colombia's scheme did not provide explicit penalties for underperformance. As noted above, contrary to the regulator's expectations, hydropower plants continued to operate early in the dry year to meet their bilateral energy commitments, progressively draining their reservoirs. The Colombian Market Monitoring Committee concluded this was an indication that hydropower companies preferred the risk of future non-performance of their firm energy

[30] Comité de Seguimiento del Mercado Mayorista de Energia Eléctrica (July 2011). *Abastecimiento adecuado de gas natural: un tema sin resolver*. Report no. 60/2011.

[31] Ibid.

obligations over the immediate economic loss which they would have incurred had they reduced production and purchased power on the market to honour their bilateral contracts.[32]

An appropriate penalty regime may have altered the consequences of future non-compliance with OEF contracts, prompting hydropower companies to conserve more water to avoid potential charges in the future. Such an incentive might have also mitigated the fuel shortage-induced underperformance of thermal plants. The risk of paying a higher penalty might have encouraged thermal generators to sign fully firm fuel supply contracts, thereby motivating suppliers to reinforce the pipeline network, albeit also raising the overall cost of supply.

Despite some discussion of these issues in Colombia, we understand this type of approach has not been adopted, and the regulator CREG has institutionalised the interventionist approach applied in 2010 (i.e. it has retained some discretion over dispatch rules to limit hydro generation at times).[33]

As a recent World Bank (2019) review concluded, even though the Colombian regulator established a mechanism with the explicit goal of ensuring reliable supply, it has not achieved this goal.[34]

4.3 Are EOMs any better in relation to reliability outcomes?

As with CMs, we are not aware of any study that assesses the reliability performance of EOM in a comprehensive manner. Instead, we briefly review below the performance of the major EOMs in relation to reliability.

4.3.1 New Zealand

New Zealand has operated an EOM design since the market was established in 1996. Although widespread forced load-shedding has never been required, public conservation campaigns were instituted to offset the effect of reduced hydro-generation during droughts in 2001, 2003 and 2008.

The frequent use of such measures led to changes in 2009 designed to reduce the perceived over-reliance on public conservation campaigns and improve reliability. Since those measures were adopted, no public conservation campaigns have been triggered. This is despite a severe drought in 2012 and droughts in 2017 and 2018.

More generally, New Zealand's capacity and energy margins have been actively monitored by the regulator or system operator for many years. Since that monitoring was introduced, the margin for the coming year has

[32] Comité de Seguimiento del Mercado Mayorista de Energia Eléctrica (October 2010). *Experiencias de la intervención del MEM bajo efecto del Niño 2009–10*. Report no. 53/2010.

[33] Comisión de Regulación de Energia y Gas (March 2014). *Resolución 26 de 2014, Por la cual se establece el Estatuto para Situaciones de Riesgo de Desabastecimiento en el Mercado Mayorista de Energia como parte del Reglamento de Operación*. Resolution from the Regulator.

[34] Rudnick, H. and Velásquez, C. (2019). *Learning from Developing Country Power Market Experiences - The Case of Colombia*, World Bank Group Energy and Extractives Global Practice March 2019: 52.

not dropped below the level assessed as being economically optimal. Indeed, at times it has been appreciably above that level.[35]

Having said that, New Zealand's supply margin increased appreciably for a period after 2009. This occurred as new generation investments committed earlier came on stream and demand was flat following the Global Financial Crisis. This makes it harder to determine whether performance since 2009 is due to the changes in market rules or the wider supply margin.

4.3.2 Alberta

Alberta has had an EOM design since its wholesale electricity market was formed in 1996. As far as we are aware, it operated reliably until July 2013, when there were forced power cuts as high demand coincided with outages at six generators.[36]

In 2016 the system operator launched a review because of growing concerns about the adequacy of investment incentives – particularly in the transition to much higher renewable generation sources. The system operator's review culminated in a 2017 provincial government decision to adopt a CM design from 2021.

Following an election in 2019, the incoming government reviewed the planned CM introduction. It concluded the EOM design was better able to address investment incentives than a CM and would have lower costs. In July 2019 the government decided to retain an EOM design.[37]

4.3.3 Eastern Australia

The eastern states of Australia have utilised an EOM design since inception of the so-called National Electricity Market (NEM) in the late 1990s. Until recently, the NEM has generally been regarded as performing well on the reliability front. However, in recent years there have been growing concerns about tightening capacity margins as older thermal plants retire. Concerns have also been expressed about the challenges associated with a rising share of generation from intermittent renewable sources.

In 2016, the NEM experienced widespread power outages when supply was cut to most consumers in the state of South Australia. The initial cause was a storm which knocked out some transmission towers and lines. Supply was then reduced further by the tripping of some wind generators which did not 'ride-through' the fault conditions when the transmission circuits were lost. The reduction in wind generation output then triggered a cascade failure in the South Australia region. Court cases are currently being pursued by the Australian Energy Regulator against the operators of the relevant wind farms alleging failure to perform in accordance with technical standards.

In response to this event and broader concerns about the potential for a messy decarbonisation transition, the NEM's market back-stop arrangement was recently modified. Until 30 June 2019, the NEM rules included a Reliability and Emergency Reserve Trader (RERT) mechanism. In essence, this mechanism allowed the market operator to procure last

[35] See https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment

[36] www.cbc.ca/news/canada/edmonton/alberta-hit-by-rolling-power-blackouts-1.1178711

[37] https://edmontonjournal.com/news/politics/conditions-have-changed-government-kills-planned-changes-to-albertas-electricity-market

resort resource (such as DR) if it believed that forced load shedding would otherwise be required in the near term (e.g. the coming summer). The RERT mechanism included cost recovery arrangements designed to avoid suppression of spot price signals, if the mechanism was triggered.

The RERT mechanism was augmented from 1 July 2019 with an additional Retailer Reliability Obligation (RRO) which looks beyond the near-term.[38] The RRO mechanism allows the regulator to trigger an obligation on retailers and other wholesale purchasers to hold qualifying contracts (or generation rights) for their share of projected peak demand, if the regulator (on advice from the market operator) identifies a reliability gap in the three year outlook. If a reliability gap still remains in the forecast with 15 months to run, the regulator (again on advice from the market operator) can trigger a tender to acquire resource to fill the gap (such as contracted DR) – similar to the pre-existing RERT mechanism. The cost of acquiring such resources is to be recovered from any retailers/purchasers with insufficient contracts/generation to cover their assessed peak demand, with costs per party capped at A$100 million.

The revised back-stop arrangement has some features which are CM-like. In particular, a requirement for purchasers to hold contracts or generation rights on a forward basis is a hallmark of CMs. However, it is important to note the requirement in the NEM does not apply unless the regulator (acting on advice) makes a specific RRO determination. If such a determination were to be made, it would apply only to specified regions and time periods. Thus, the default position in the NEM continues to be an EOM design with participants determining their contract positions, albeit in the knowledge that an RRO might be triggered at some point.

When the RRO was being developed, the possibility of introducing a full-blown capacity mechanism was also raised.[39] However, authorities chose to retain an EOM design with a stronger market backstop. More generally, there is a fairly broad view that better integrating emissions and electricity policy (at both the national and state levels) should be given more priority.[40]

Finally, there is a growing focus on the need to strengthen real-time incentives and the design of ancillary services markets. For example, the retirement of large synchronous units has introduced security challenges relating to inertia and system strength.[41] These are currently addressed by interventions by the market operator but are increasingly prompting discussion about longer-term solutions. These lines of thinking are well summarised in a 2018 study published by the Oxford Institute for Energy Studies, which argued that consideration should be given to extending the energy-only design to an 'energy + services' model, in which efficient price signals are created for the missing products necessary for operational security.[42] Strictly speaking, the NEM (and New Zealand for that matter) already operate an energy + services model, and this

[38] See www.energy.gov.au/sites/default/files/retailer_reliability_obligation_factsheet.pdf.

[39] For example, see: Wood, T. *et al.* (2017). *Next Generation: the long-term future of the National Electricity Market*. Grattan Institute.

[40] https://www.aemc.gov.au/news-centre/economists-corner/profiling-capacity-market-debate

[41] System strength is an umbrella term that reflects the ability of the power system to maintain stability after a disturbance. System strength is a highly localized issue and varies across parts of networks.

[42] Billimoria, F. and Poudineh, R. (2018). *Decarbonized market design: an insurance overlay on energy-only electricity markets*. Oxford Institute for Energy Studies.

proposal can be viewed as enhancing the range of ancillary services procured in parallel with energy.

4.3.4 Nord Pool

Nord Pool has operated an energy-only trading system for many years, covering Norway, Denmark, Sweden, Finland and part of northern Germany.[43] As far as we are aware, it has operated without any major capacity adequacy problems.

4.3.5 Singapore

Singapore's electricity market has utilised an EOM model since it was created in 2001. Singapore has experienced extremely high levels of reliability for most of this time. However, in September 2018, power cuts affected 147,000 consumers when two power stations tripped unexpectedly.[44] We note this event was not due to inadequate generation resources – Singapore's peak demand is around 7,000 MW and the island's installed capacity is approximately 13,500 MW.[45]

Notwithstanding the current supply margin, Singapore's authorities have become concerned about the outlook for future investment adequacy. This appears to stem from a combination of current low prices and the authorities' desire to maintain at least a 30 per cent reserve margin of non-intermittent plant above peak demand. While this appears to be viewed as politically necessary, it is likely to be well above an economic optimum or what an energy-only market would deliver over the longer-term.

In mid-2019, the regulator released a high-level straw proposal for a capacity market for Singapore. The proposed design would introduce a CM from 2022, with transitional arrangements to apply from 2020. Capacity would be procured over a four-year forward horizon, with resource providers selected via an auction mechanism. Resources would be subject to a qualification process to validate their availability in the delivery year, as well as the megawatt ("MW") value they may offer into the forward capacity market auction.

Each MW-year of capacity offer would require that MW of qualified capacity to be available, and to offer into the energy market, for a year, subject to penalties for failing to perform. The penalty rates would "be high enough to incentivise performance (but not so high as to impose undue costs that discourage participation)". Supplier offers into the spot market would be capped at short-run marginal cost for the supplier.[46]

The regulator released a second consultation paper for developing a forward capacity market and sought submissions by January 2020. It is currently considering those submissions.[47]

[43] We note Sweden has had a strategic reserve scheme since 2003, and Germany introduced one in 2019.
[44] See www.tnp.sg/news/singapore/worst-blackout-14-years-hits-147000-households-and-businesses
[45] www.energycouncil.com.au/analysis/singapore-some-familiar-issues-in-an-unfamiliar-context/
[46] See www.ema.gov.sg/cmsmedia/Consultation%20Paper%20-%20Developing%20a%20FCM%20to%20enhance%20the%20SWEM.pdf
[47] See www.ema.gov.sg/cmsmedia/Second%20Consultation%20Paper%20-%20Developing%20a%20FCM%20to%20Enhance%20the%20SWEM.pdf

4.3.6 Texas

Within the United States, Texas is the only state with an EOM design.

The market operator (ERCOT)[48] implemented widespread forced load shedding in 2011 when a polar vortex caused record low temperatures. This lifted demand and caused outages (e.g. from freezing pipes) at some generation plants.[49] In the subsequent polar vortex event in 2014, ERCOT (like PJM) experienced very high demand but did not need to implement load shedding.

More recently in August 2019 ERCOT declared an Energy Emergency Alert as reserve dropped below 2,300 MW.[50] This was the result of forced outages and unusually low wind production.

4.4 Operational incentives are important for EOMs and CMs

Experience with both EOMs and CMs has highlighted the importance of operational incentives – i.e. the incentives to make resources available and to utilise them in scarcity conditions.

4.4.1 Operational incentives should be robust with EOMs

In the case of EOMs, the prices generated in the spot market should (and typically do) provide very robust incentives to make resources available. Furthermore, the spot price signal is visible to all resource providers – both supply-side and demand-side and is unaffected by a participants' net contract position. As a result, during scarcity conditions, there will be very strong and uniform signals to all wholesale participants to increase supply and voluntarily reduce demand.

Having said that, an EOM's operational signals may be undermined by other aspects of an electricity market design, such as weak prudential arrangements or unduly low-price caps. In essence, EOMs will be less effective (and possibly fail) if participants can socialise the costs from poor decisions. A similar set of concerns applies in the banking sector, where regulators want to ensure banks cannot shift the cost of any poor decisions to other parties. In principle, such concerns can be addressed by measures such as robust prudential and stress-testing regimes.

4.4.2 Operational incentives with CMs have been mixed

Experience with operational incentives in CMs has been mixed. The record of ISO New England, PJM and Colombia all point to difficulty in ensuring resource providers will deliver their promised level of firm capacity. With CMs, this challenge arises because resource providers earn revenue from the sale of capacity rights, but it is inherently difficult to detect any non-performance because the full capacity obligation is rarely called upon.

In practice, two broad approaches have been used to deter non-performance in CMs:

1. Allowing resource providers to self-declare their level of firm capacity and applying stiff financial penalties for non-performance. In principle, these should reflect the economic cost

[48] Electricity Reliability Council of Texas.
[49] See https://rbnenergy.com/the-night-the-lights-almost-went-out-in-texas-polar-vortex-power-markets
[50] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081519-ercot-declares-another-energy-emergency-alert-prices-hit-9000-mwh

of non-performance (noting this can range up to the value of lost load in a scarcity event).

2. Assessing the maximum physical capacity of each provider and restricting their sales to this level. The capacity determination methodology needs to consider many detailed issues, such as the provider's access to firm fuel supply, level of plant reliability, adjustments for plant intermittency, degree of firm demand response etc. This is inherently difficult – especially where conditions are changing – such as when fuel supply conditions change. Penalties apply for any non-performance relative to assigned capacity, but these are normally well below the economic cost level.

As Batlle *et al*. point out, in theory resource providers are best qualified to estimate the expected capacity contribution from their facilities in scarcity conditions. And provided robust penalties apply (including financial performance guarantees), there should be no need for regulatory limits on the amounts of capacity that they sell.[51]

However, in practice most CMs make the regulator the arbiter of capacity, reflecting a mistrust of resource providers and the associated fear of power shortages. As one researcher noted "system planners and engineers have been uncomfortable with what they perceive as a reliance on purely financial, rather than physical, resource plans" with a strong preference for ensuring there is "steel in the ground".[52]

[51] Batlle, C., *et al.* (2015). *The System Adequacy Problem: Lessons Learned from the American Continent*. Capacity Mechanisms in the EU Energy Markets: Law, Policy, and Economics, London, UK: Oxford University Press.
[52] Bushnell, J. *et al.* (2017). *Capacity Markets at a Crossroads*. Berkeley, Energy Institute at Haas working paper.

4.5 Penalties for operational non-performance are being revisited in CMs

There has been a trend to refine the penalties for operational non-performance in CMs. This has arisen in response to recent experience (such as the polar vortex event in the United States) and to prepare for higher levels of intermittent generation – since these will create new types of reliability challenge.

Bublitz (2019) notes that refining the level of penalties requires careful balancing. Penalties should be high enough to ensure providers deliver on their commitments, but not so high that risks and costs for providers are unduly raised – since that will ultimately harm consumers.[53]

In ISO New England, the System Operator has established a higher penalty regime which is based on the assessed revenue requirement for a last resort supplier. The penalty rate is being progressively increased to US$5,455/MWh, which will apply from 2024 onwards.[54] We understand that this rate is based on the expected cost of a new entrant provider (based on CCGT technology), divided by the expected number of hours of scarcity conditions if the target reliability standard is met, adjusted by the expected performance during scarcity conditions (US$106,394/MW-year / (21.2 hours/year x 0.92) = $5,455/MWh).

From 1 June 2016, PJM began implementing new rules designed to better ensure resources will be available when called upon, especially in

[53] Bublitz A., *et al.* (2019). *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*. Energy Economics 80.
[54] Federal Energy Regulatory Commission (May 2014). *Order on Tariff Filing and Instituting Section 206 Proceeding*. Docket No. ER14-1050-000.

extreme weather conditions.[55] Under the new rules, resource providers assume greater financial risks if they do not meet their power supply obligations. The new rules are being progressively phased-in with full delivery from the capacity year 2020–21. We understand the penalty rate for scarcity conditions in PJM's revised regime is also based on the cost for a new entrant last resort provider.

An interesting aspect of the revised approaches being taken by PJM and ISO New England is that they have some strong parallels with energy-only markets. In EOMs, parties who sell firm capacity but fail to generate are exposed to the spot price. And in a scarcity situation, the spot price may reach the market price cap, which is typically set by reference to the revenue requirement for a last resort provider. Indeed, that is the approach taken in Australia, New Zealand[56] and Singapore. In effect, it appears that some aspects of CM designs (at least for PJM and ISO New England) are converging towards the features of an EOM.

Yet, it is important to note that penalties associated with a capacity contract can only mimic the spot price in inducing efficient behaviours. This is because a CM penalty will often need to be set in advance, rather than to reflect conditions at the time non-performance occurs. Furthermore, in a CM, penalties for non-performance will not be signalled to all resources, but only to those taking part in the capacity mechanism.

In this context, it is important to recall that providers only take on an obligation (and exposure to penalties) if their offer was accepted in a prior auction. There will typically be other physical resources not subject to any capacity obligation which could assist in an emergency. These can include resources such as stand-by generation on customers' premises, emergency DR capability, or additional capacity at power stations that were not cleared in previous capacity auctions.

Resource providers who are not obligated under the capacity mechanism may be able to assist in meeting demand, but will not receive a strong signal to do so because spot prices in a CM are typically set below the economic value of supply (unlike in an EOM).

Some commentators have gone further and suggested that improving the operational incentives of CMs will always be a second-best approach. For example, Professor Hogan stated:

> "everything channelled through the capacity market is indirect and convoluted. The process almost seems driven by a commitment not to fix the actual energy markets prices but rather to find ever new and ever more indirect pathways to reproduce the results of an efficient real-time market without actually implementing an efficient real-time market."[57]

4.6 Conclusion in relation to reliability

CMs provide a high level of assurance that sufficient generation and DR will be *built.* This is because CMs create explicit commitments to invest in supply capability. CMs can also include tests to ensure that parties' commitments are backed by 'steel in the ground'. Having said that, many

[55] PJM Interconnection (2018). *Strengthening Reliability: An Analysis of Capacity Performance*.

[56] New Zealand currently applies both a floor and a cap in scarcity situations involving widespread forced load shedding. In effect, the floor is based on the assessed costs for a new entrant last resort provider, and the cap is based on an estimate of the average value of lost load.

[57] Hogan, W. (2014). *Electricity Market Design and Efficient Pricing: Applications for New England and Beyond*. The Electricity Journal 27(7): 23–49.

EOMs (e.g. New Zealand, Nord Pool, Singapore) have performed well in ensuring sufficient capacity is *built*.

So, the real difference between CMs and EOMs is the level of ex ante assurance they provide. CMs provide a higher degree of assurance about the level of *built* capacity because that variable is under the direct influence of the regulator/market operator. However, the centralisation reduces the scope for testing of different views and increases dependence on a few decision-makers.

Turning to operational issues, CMs do not provide assurance that resources which have been *built* will actually be *available* when required. Indeed, experience to date suggests that EOMs will almost certainly perform better than CMs on this front, because EOM spot prices create stronger signals to make all resources available during periods of scarcity.

Given these factors, the overall assessment of the two designs on reliability is not clear-cut and depends in large part on what policy makers are most worried about – ex ante assurance about the level of *built* capacity, or that resources which have been built will be *available* when required.

5 Costs to consumers

This chapter considers the relative performance of EOMs and CMs in relation to costs.

5.1 CMs are prone to over-investment

CMs are prone to encouraging over-investment. The core reason is that CMs require a central party to make most of the key decisions – and it is very difficult to align the incentives of the central party with those of the consumers they represent.

One of the most important decisions is the overall reliability standard itself – which provides the anchor for the entire CM. Equally, if not more important, the central party will face a host of ongoing decisions to put the CM into operation, such as compiling demand projections, determining derating factors for generation, etc.[58]

One of the most important decisions is the level of voluntary demand response to assume during periods of tight supply, when spot prices will be higher. If the central party under-estimates the level of voluntary response, it will force some buyers to incur unnecessary costs for contracts that are not needed. Conversely, if it over-estimates the level of voluntary demand response in its projections, insufficient resources will be procured to meet the target capacity standard.

In making the big and small decisions, the central party will be aware that the cost of underinvestment will be very visible in the form of power cuts, whereas the cost of over-investment is difficult if not impossible to measure with certainty. Many researchers argue that this leads to skewed incentives and a strong tendency towards over-investment – to the detriment of consumer costs and efficiency.[59] International experience supports this view.

Western Australia

A review of the CM in Western Australia concluded the "primary problem with the mechanism was that it was leading to a significant over-procurement of capacity [..] with the level of excess capacity over the market requirement reaching 23 per cent by 2016-17 at an estimated cost of around $116 million."[60] This is an annual figure, and such costs were borne by the approximately 1.1 million households and businesses covered by that CM. Part of the cost arose from that CM's specific design, but it was also affected by the implementation challenges such mechanisms.

Figure 2 shows actual peak demand depicted by the dotted line at the bottom of the chart. The figure also shows various demand forecasts compiled in successive years, expressed on a 10% probability of exceedance (POE) basis.

[58] As noted in the previous chapter, it is also possible the CM will lift capacity without necessarily improving reliability.

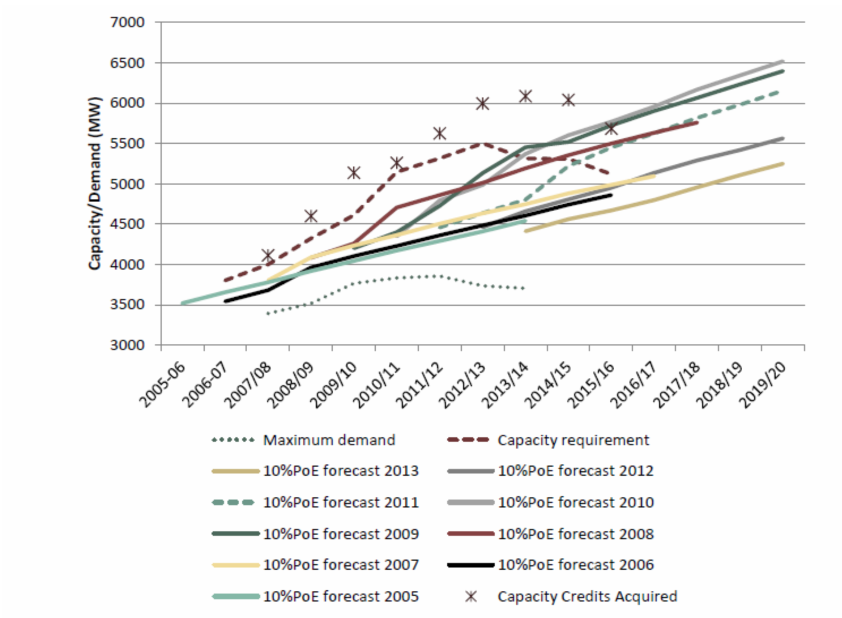
[59] See: Wood, T. *et al. Down to the wire: A sustainable electricity network for Australia* (Technical Supplement), Grattan Institute; Wood, T. and Blowers, D. (2017). *The Long Term Future of the National Electricity Market*, Grattan Institute; Grubb, M. and Newbery, D. (2015). *Security of supply, the role of interconnectors and option values: insights from the GB capacity auction*, Economics of Energy & Environmental Policy 4, 2: 65-82.

[60] Government of Western Australia, Department of Treasury, Public Utilities Office (February 2019). *Improving Reserve Capacity pricing signals – a recommended capacity pricing model Final Recommendations Report.*

The lines show that strong demand growth was expected for much of the period, driven by rising residential demand and rapid industrial expansion associated with the minerals boom prior to the global financial crisis (GFC). Conditions changed part way through the period, with strong uptake of roof-top solar panels (cutting residential demand) and the tapering off of industrial growth post-GFC. It took some time for these changes to become fully apparent, resulting in a widening gap between forecast and actual demand in the period after 2009. Subsequently, the gap narrowed as demand forecasts were scaled back significantly.

Because of the way the mechanism worked in Western Australia, there was substantial over-procurement of capacity. This was partly due to the forecasting challenges, but also because capacity prices were not closely linked to market need. As a result, in 2013/14 more than 6,000 MW of capacity was procured (and paid for), compared to peak demand of less than 3,750MW.

Figure 2: Historical demand forecasts compared to actual demand



Source: Electricity Market Review Discussion Paper, Electricity Market Review Steering Committee, Public Utilities Office, Western Australia, July 2014

As the review author's noted: "the weakness of the [CM] lies not in the forecasting ability of the [market operator], as this is likely to be no better or worse than other forecasting efforts undertaken over the same period, but in the use of a process so prone to error and over-estimation to determine such a large proportion of electricity costs. The costs of over-investment are not borne by the investors themselves, as they would be in the NEM and in most commodity markets, but by customers”.[61]

United States

Other sources cite over-investment as a common concern. For example, Wolak (2004) states “capacity payments encourage over-investment and new generation capacity mix that [is] more expensive [than] is necessary to meet an increase in annual electricity demand.”[62]

Bhagwat (2016) undertook a survey of experts in the United States and reported “the 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”.[63]

Even energy regulators have expressed concerns about over-investment with CMs. In April 2019, in a dissenting opinion, one of the United States Federal Energy Regulatory Commission’s (FERC) three commissioners stated:[64]

> “[Arrangements cause] PJM to procure too many resources at too high a price, with obvious detrimental consequences for consumers.”

Germany

Germany has utilised the EOM model. It carried out a review in 2014/15 because of potential reliability concerns arising from its plans to aggressively move away from fossil fuel and nuclear-powered generation. The review considered a range of options including enhancements to the EOM model, strategic reserves and traditional CMs covering the procurement of all capacity.

A traditional capacity market design was rejected for three primary reasons: 1) sufficient levels of existing capacity, 2) a general perception that capacity markets distort the market, and 3) cost effectiveness.

In particular, the main research report for the review noted a “central capacity tendering mechanism with reliability contracts [..] and the focused capacity mechanism [..] bear the risks of considerable overcapacities. The latter is due to the fact that regulatory authority/administrations can be expected to aim at rather high capacity levels due to the high risk aversion.”[65]

The German government white paper rejected a capacity market. Instead, it proposed the energy-only market be enhanced, and that a temporary strategic capacity reserve be kept in place, particularly to ease the phase-out of nuclear plants. This reserve was subsequently approved by EU competition authorities as a transitional mechanism.[66]

5.2 CMs more likely to distort resource mix

Another concern with CMs is their potential to bias resource mix decisions (including DR) and raise supply costs. For example, Wolak (2004) stated capacity payments encourage a “generation capacity mix

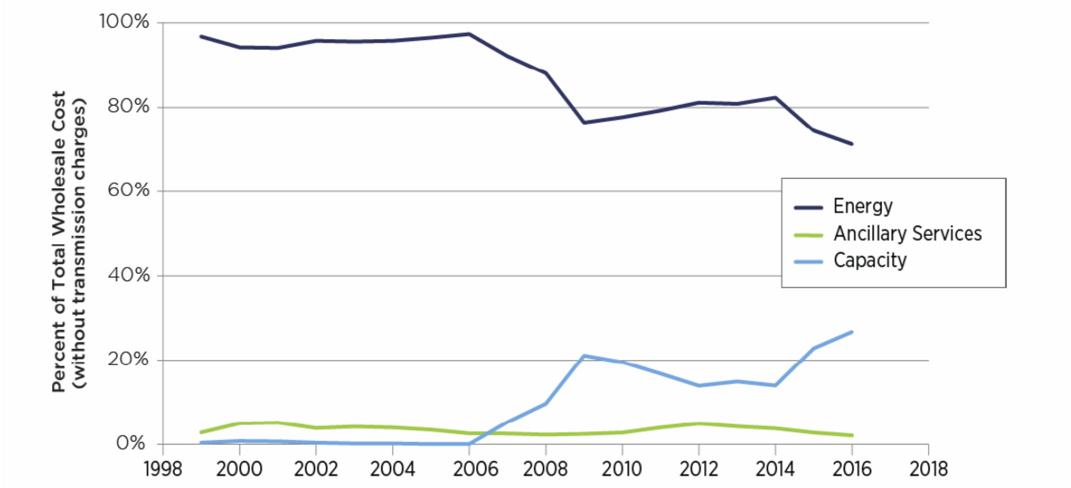
[61] Government of Western Australia, Department of Treasury, Public Utilities Office (2014). *Electricity Market Review Discussion Paper*.
[62] Wolak, F. (2004). *What’s Wrong With Capacity Markets?* Stanford University.
[63] Bhagwat, P. C. *et al.* (2016). *Expert survey on capacity markets in the US: Lessons for the EU*. Utilities Policy 38.
[64] Glick, R., United States of America Federal Energy Regulatory Commission, dissenting opinion on dockets ER19-105-001 and ER19-105-002, April 2019.
[65] Frontier Economics and Consentec (2014). *Impact Assessment of Capacity Mechanisms.* Report for Federal Ministry for the Economic Affairs and Energy.
[66] See https://europa.eu/rapid/press-release_IP-18-682_en.htm

that is more expensive than is necessary to meet an increase in annual electricity demand." Grubb and Newbery (2015) believed insufficient attention has been paid to the importance of capacity characteristics, and that this neglect biases decisions "towards over-procurement, which leads to a self-fulfilling prophecy that merchant generation investment can no longer be relied upon. Perversely, this exacerbates the missing money problem that capacity auctions were designed to address."

FERC Commissioner Richard Glick (2019) noted that by encouraging over-investment in capacity, PJM's CM reduces prices in the energy spot and ancillary services markets. He said this exacerbates the missing money issue, increasing reliance on CM revenues, and distorting the investment mix.[67]

PJM (2017) itself has also expressed concerns about the potential for distorted incentives. In filings to FERC, PJM noted a rising share of revenues coming from CM payments (shown in Figure 3), and commented that increasing reliance on these payments may unduly alter the resource mix.

Figure 3: Share of total wholesale electricity costs



Source: PJM (June 2017), *Energy Price Formation and Valuing Flexibility*.

A related issue is that where CMs adopt prescriptive approaches to determine firmness (rather than using spot prices as incentives), this can create unintended biases in favour of some resource types relative to others. For example, a CM will need to assign 'firmness factors' to wind generators – i.e. the volume of output that will be assumed to be firmly available in scarcity conditions. This will affect capacity payments that wind generators can receive, and may bias wind generation investment up or down, depending on the methodology used by the regulator.

Finally, a CM may bias the resource mix by treating resources in different ways based on their source, rather than any difference in inherent

[67] Glick, R., United States of America Federal Energy Regulatory Commission, dissenting opinion on dockets ER19-105-001 and ER19-105-002, April 2019.

performance. For example, under the British capacity mechanism, existing power plants can get contracts for one year, or three years, if they carry out upgrades. New power plants can get 15-year deals. And DR is only offered one-year contracts. This difference means the mechanism may not necessarily select the lowest cost option and was part of the basis of a successful legal challenge to block further auctions, discussed in section 5.4.

5.3 Competition and market power

Electricity is expensive to store, and most consumers are reluctant to voluntarily reduce their demand below planned levels. In combination, these factors mean spot prices are likely to reach very high levels if they are to send the appropriate economic signal during scarcity conditions. However, in such situations, it can be difficult to determine whether high prices are fully justified as suppliers can have more ability and incentive to raise spot prices (depending on their contract position). This means that EOMs need robust mechanisms to ensure there is competition in the spot and contracts markets (such as information disclosure rules and market-making arrangements).

One of the benefits often cited for CMs is that they mitigate suppliers' market power in scarcity conditions, because they reduce providers' reliance on spot market revenues and hence facilitate the adoption of lower price caps. Similarly, if a CM is structured as financial contracts which wholesale buyers must acquire, purchasers will be largely insulated from spot prices and caps can be set at high levels to maximise operational incentives.

While CMs can mitigate market power in relation to the spot market, they do not address all competition issues. International experience shows competition concerns often arise in the capacity market itself – on the seller or buyer side of the market. As noted by Brattle (advising the Singapore government on a possible CM) "market power is endemic to capacity markets (and to energy markets during tight supply conditions) because available supply typically exceeds demand by small margins, such that even medium-sized suppliers could withhold capacity profitably, unless required to offer competitively."[68]

Seller market power is also enhanced by the fact that most CMs compel buyers to hold a minimum level of capacity rights by prescribed dates – constraining some of the countervailing power buyers would otherwise have. Furthermore, the competitive dynamics in a CM auction can be difficult to predict at the time rules are being set, noting these may be finalised well before the auction to give prospective new bidders time to develop investment plans.

Concerns about market power are borne out by experience. For example, the recent World Bank (2019)[69] review of Colombia's CM noted that the mixed results of the scheme were due in part to "insufficient competition in auctions".

Similarly, the independent market monitor for ISO-New England stated:

[68] See www.ema.gov.sg/cmsmedia/Annex%20A%20-%20High-Level%20Design%20Straw%20Proposal%20v1.pdf

[69] Rudnick H. and Velásquez, C. (2019). *Learning from Developing Country Power Market Experiences The Case of Colombia*. World Bank Group Energy and Extractives Global Practice: 52.

> "when new suppliers are pivotal (must clear in order for ISO-NE to satisfy its capacity requirements) … they have strong incentives to raise their offers and increase the capacity prices. Likewise, the report shows that existing suppliers that are pivotal have strong incentives to retire units that would otherwise be economic in order to increase capacity prices."[70]

The American Public Power Association has raised potential concerns about existing generators discouraging new entry to ensure higher energy prices while receiving capacity payments, noting that "owners of existing generation resources have a strong interest in the current regime, which prevents competition from new entrants and props up capacity prices."[71]

One of the most common ways to address market power has been to impose caps and/or floors on auction prices for capacity. As noted by Bublitz et al. (2018):

> "the upper price cap needs to be high enough to incentivize sufficient investments when the system is tight and typically equals a multiple of the Net CONE [cost of new entry]. The lower price cap is usually set equal to zero and marks the capacity level when the desired reserve margin is reached. However, sometimes, in order to avoid a total price collapse or prevent market manipulation from large purchasers of capacity, a higher price is set, e.g., 75% of the Net CONE. [..] when setting the upper and lower price limit".[72]

Indeed, some commentators are unconvinced that bidding rules in CMs can effectively address market power and believe more direct measures are required. For example, Wolak (2004) stated CMs are "extremely susceptible to the exercise of unilateral market power, which implies that regulatory intervention is often needed to set the price paid for capacity."

Finally, we note the European Commission, in its role as competition regulator, launched an inquiry into capacity mechanisms (aka CMs) in April 2015. The inquiry was prompted by increasing interest by some member states in CMs. The Commission noted that "public support to capacity providers risks creating competitive distortions in the electricity market … or prevent competitive new entrants from becoming active on the electricity market. This distorts competition, risks jeopardising decarbonisation objectives and pushes up the price for security of supply".[73]

It also noted that "capacity mechanisms should be open to all types of potential capacity providers and feature a competitive price-setting process to ensure that competition minimises the price paid for capacity. Competition between capacity providers should be as large as possible and special attention should be given to new entry. Capacity mechanisms should ensure incentives for reliability and be designed to coexist with

[70] Patton, D.B., et al. (2014). *2013 Assessment of the ISO New England Electricity Markets, External Market Monitor for ISO New England,* Potomac Economics.
[71] American Public Power Association, *RTO Capacity Markets and their Impacts on Consumers and Public Power,* APPA Fact Sheet, May 2015.
[72] Bublitz, A. *et al*. (2018). *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*. KIT Working Paper Series in Production and Energy 27.
[73] European Commission, *Final Report of the Sector Inquiry on Capacity Mechanisms*, November 2016.

electricity scarcity prices to avoid unacceptable trade distortions and avoid domestic overcapacity." [74]

5.4 Durability

Electricity generation assets have relatively long lives. Prospective investors are therefore naturally wary of market arrangements which do not appear durable. When CMs were introduced, this was rated as one of their superior attributes relative to the EOM design, because the latter require politicians and consumers to tolerate (at least the possibility of) very high spot prices at times.

Proponents of CMs argued the likelihood of political intervention would be appreciably lower than with EOMs, because 'spikes' in spot prices would not occur (or at least would be much lower). Indeed, some researchers in New Zealand have raised the possibility that growth in generation with zero (or very low) short run marginal costs will cause extended periods of very low spot prices, in turn raising the level of prices at other times.[75] This could make spot prices so volatile that it may pose an 'existential' challenge to the whole market design, and its governance arrangements.

They note that in theory, it might be argued there is little difference from suppliers collecting revenue during occasional price spikes, or the Government collecting it via capacity charges, as was done when New Zealand last had a 100 percent renewable power system, before 1958. But they note there may be very significant differences in the way those two regimes are perceived by risk-averse investors, the regulator, and by the general public.

While these observations have some weight, an increase in spot price volatility will presumably also elicit a market response. For example, an increasing gap in spot prices between 'windy' and 'calm' periods will likely encourage parties to identify opportunities for increased flexibility from other sources – to capture the value of price differences where it is economic. Storage technologies, such as batteries and pumped storage, will likely increasingly emerge to arbitrage these opportunities, which will reduce the price differences between peaks and troughs.

Furthermore, because of poor operational performance during past scarcity events, some leading CMs are moving toward penalty regimes which mimic scarcity prices under an EOM (as discussed in section 4.4). If this trend continues, any difference in durability arising from a risk of political backlash over high prices/penalties during scarcity periods may diminish.

More generally, looking at experience over the last decade, the expected durability advantage of CMs is far from clear. As noted in section 4.2.5, Colombia's CM did not work as intended and has been subject to significant and ongoing intervention by the regulator since its introduction.

The CM adopted in Western Australia has also undergone significant and ongoing changes – prompted in large part by concerns that it imposed

[74] Ibid.

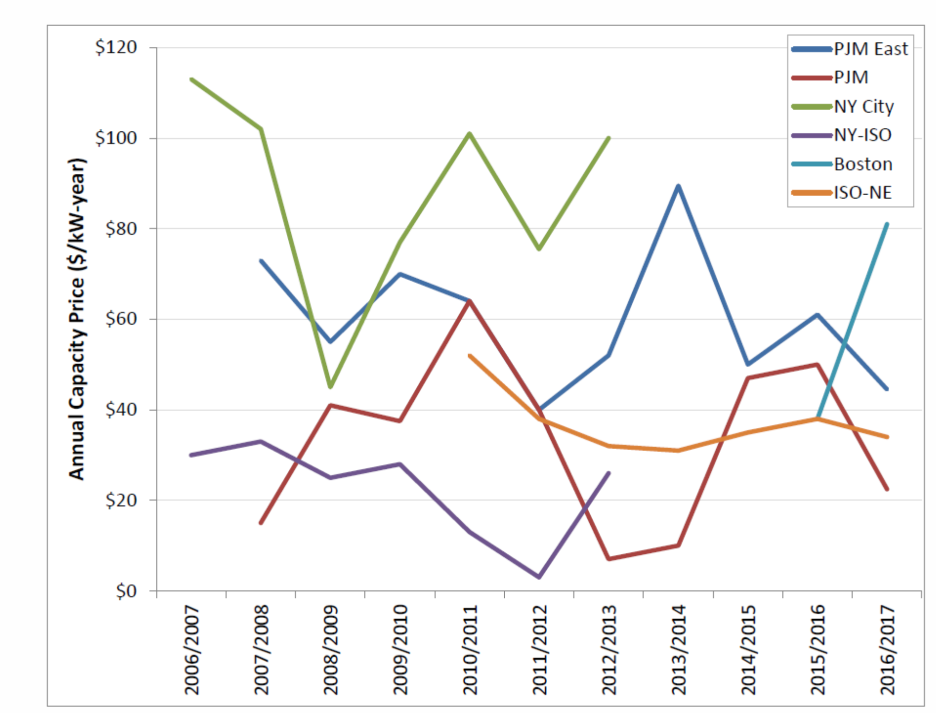
[75] See Philpott, A., *et al.* (2019). *The New Zealand Electricity Market: challenges of a renewable energy system*. Electric Power Optimization Centre.

excessive costs on consumers and did not sufficiently incentivise an efficient resource mix.[76]

In relation to the United States, capacity prices have been volatile ever since auctions commenced in the mid-2000s. As shown in Figure 4, annual prices have varied by more than five-fold in some jurisdictions and there has been even greater volatility at the sub-regional level (not shown on the chart, but around ten-fold in one case).

Some of the volatility is due to market fundamentals, such as load growth, fuels prices etc. and cannot be attributed to lack of stability from policy makers. However, 'non-market' factors have also played an important role according to researchers.[77] These include "ongoing rule changes implemented in capacity markets (e.g., changes to the VRR[78] demand curves ..[and] "administrative patterns"—such as load forecasts, CONE estimates".[79]

Figure 4: Capacity prices for CMs in the United States (auctions between 2006 to 2013)



Source: Federal Energy Regulatory Commission (2013). *Centralized Capacity Market Design Elements*. Staff report no. AD13-7-000

[76] Government of Western Australia, Department of Treasury, Public Utilities Office (February 2019). *Improving Reserve Capacity Pricing Signals - a Recommended Model.*

[77] Spees, K., *et al (2013). Capacity Markets: Lessons Learned from the First Decade.* Economics of Energy & Environmental Policy.

[78] Variable resource requirement (VRR) refers to a mechanism where the price cap in a capacity auction varies with the current system margin. If the system is tight, a higher cap applies, and vice versa.

[79] Jenkin, T. *et al.* (2016). *Capacity Payments in Restructured Markets under Low and High Penetration Levels of Renewable Energy*. National Renewable Energy Laboratory, US Department of Energy.

In April 2018, PJM sought approval to further amend its capacity auction rules to address increasing volumes of generation receiving subsidies from state governments or other bodies. For example, Illinois and New Jersey provide subsidies to some nuclear power plants to incentivise zero emission generation. Some participants saw these arrangements as distorting competition, and convinced PJM to proposal a rule change to address the effect on competition. In June 2018, FERC commissioners in a 3-2 decision declined to approve the change proposed by PJM. As a result, PJM was unable to run the capacity auction scheduled for August 2019, and it remains unclear how or when this issue will be resolved. Speaking about the issue in February 2019, Commissioner Richard Glick (a former energy company executive) said:

> In some regions, capacity constructs are encouraging "substantial amounts of excess capacity beyond the level most people think is reasonable"
>
> "Then we see people proposing to change that to actually increase the price so we can actually have more capacity .. and to me that's not good for consumers and arguably is not just and reasonable"
>
> "It's incredibly complex .. and we constantly get proposed changes .. I just worry that we're making it a lot more complicated than it is and not necessarily producing the results"
>
> "We need to figure out a new approach to capacity markets if we're going to have them."[80]

[80] See www.utilitydive.com/news/glick-calls-for-new-approach-to-capacity-markets-in-wide-ranging-naruc-ta/548337/

A similar dynamic has recently unfolded in Great Britain. Although the European Commission authorised Britain's capacity mechanism in 2014, that authorisation was overturned by a European court decision in late-2018 when the mechanism was found to selectively favour some forms of generation, and therefore distort competition. Further auctions and capacity payments under the pre-existing mechanism were put on-hold for almost a year. In October 2019, the mechanism was reinstated following a detailed further investigation by the European competition authorities.[81]

5.5 Innovation

Arguably, innovation is the greatest source of efficiency in the long run. Hence, electricity market arrangements should provide incentives to encourage and reward innovation. This is an area where the EOM design is generally considered to outperform CMs. In large part, this stems from the less prescriptive nature of EOM arrangements relative to CMs.

An example is the concept of firmness. This has a temporal dimension: sometimes firmness is needed for hours, sometimes for days, and sometimes for weeks or months. Often, the type of resource most suitable for the provision of short-term firmness is different to that suited to longer-term firmness.

In a CM, the regulator must define the concept of firmness. For example, the regulator will specify the period of sustained operation that a DR provider or generator must operate to avoid penalty – in terms of hours, days or weeks etc. This period will effectively set the firmness 'standard' applying to all capacity procured under the CM and narrow the focus of

[81] See https://europa.eu/rapid/press-release_IP-19-6152_en.htm

innovation toward the regulator's view of needs – rather than the full spectrum of requirements in the system.

More generally, technological development has increased the difficulty in reaching broad consensus over what reliability requirements and metrics should be. Legitimate differences in opinion over the reliability value of demand response, intermittent renewable energy and dispatchable generation will arise. As resources become more diverse, the challenge of forecasting their value for reliability months and years in advance greatly increases.[82] Indeed, some researchers go so far as to argue that CMs place the 'initiative' for innovation in the hands of the regulator.[83]

By contrast, in an EOM design, spot prices can reflect the value of firmness in each different timeframe.[84] The 'broadcast' incentives provided by spot prices in an EOM design are likely to be especially important for mobilising distributed resources – such as charging (and potentially discharging) of electric vehicle batteries. By contrast, the greater standardisation and centralisation of decision-making required with CMs is likely to be less supportive of innovation.

This theoretical advantage is illustrated by recent experience in Australia's EOM. Innovation is occurring to facilitate the entry of intermittent renewable generation. One generator (ERM) is offering to sell two hedge products which help to 'firm' the output from solar generators. The first product provides greater certainty about the value of electricity produced during daylight hours, for periods that broadly match the production profile of single-axis tracking solar generators. The second product addresses the largely predictable need to cover the absence of generation from the approach of sunset to sunrise. ERM anticipates these products will allow solar generators to sell flat, round-the-clock swaps, therefore leaving themselves exposed to spot prices for only the few hours that their solar generation does not correlate with the firming products.[85]

Likewise, wind firming products have been developed by AGL, and provide compensation when wind generation is less than the forecasted average wind generation. The pay-out is based on the difference between a strike price agreed at inception and the spot price. The rationale for this product is to allow wind generators to firm up their generation volumes. The product is currently based on total wind generation in a particular state. This means individual wind farms will have basis risk when their wind patterns are uncorrelated to the state as a whole. However, it is possible that this product could evolve to offer more specific hedges to wind generators. While these products are in their early stages, they provide examples of the innovations facilitated by an EOM design.

5.6 Conclusion in relation to costs

Costs to consumers are expected to be higher under CMs than EOMs. The key reasons are:

- CMs are prone to creating substantial excess supply capability. Key decisions must be made by a central party who will face lop-sided incentives. They will typically err on the side of caution

[82] Bushnell, J. (2017). *Capacity Markets at a Crossroads*

[83] Auer, H. and Haas, R. (2016). *On integrating large shares of variable renewables into the electricity system*. Energy 115, 1592–1601

[84] Unless the time interval is shorter than the length of the spot market trading period.

[85] See: www.energycouncil.com.au/analysis/firming-renewables-the-market-delivers/

because any failure in the form of power cuts will be visible, whereas the costs of over-building are harder to see.

- CMs are more likely to create a distorted resource mix between generation types and DR because of the prescriptive rules required to measure firm capacity. CMs are also more susceptible to lobbying by special interests seeking preferred treatment for their particular options.
- CMs are less able to facilitate and reward innovation – the most important source of cost savings in the long-run – because of the higher level of centralised decision-making and prescription.
- CMs appear no more durable that EOMs – as the greater centralisation of decision-making and considerable administrative discretion encourages continued lobbying by special interests.

6 New Zealand specific issues

If a CM were to be considered for New Zealand, there would be some specific issues to address, as outlined below.

6.1 Joint capacity and energy adequacy issues

Most CMs in operation in the world today are designed to address capacity adequacy. However, New Zealand faces both capacity and energy adequacy risks.[86] As far as we are aware, the only CM designed to address energy adequacy is that operating in Colombia. It is unclear how effectively that scheme addresses capacity risk. As discussed in section 4.2.3, Colombia's scheme has yielded mixed results in addressing energy adequacy issues and cannot be regarded as a stable and effective model.

Any CM design for New Zealand would need to consider how to determine the firm energy capability of generation and DR providers over multiple timeframes – to ensure providers do not oversell their capability. Determining the volume of firm energy capability would be a major challenge – as it has proven to be in Colombia. Moreover, a CM would need a mechanism to frequently (more than annually) reassess the firm capability of providers – because it can be affected by starting storage levels, outages, thermal fuel supply etc.

In addition, New Zealand faces capacity risks (at least in the North Island), so the CM would need to determine both firm capacity and energy capability for resource providers. The answers are likely to differ for some plant (e.g. 100% of a hydro generator's nameplate capability could be assessed as firm capacity, but its firm energy capability might be assessed as, say, 50%).

Likewise, consumers (or their agents) would need to have purchase obligations that specify both capacity and energy requirements. For example, some consumers might be able to reduce demand for a short period (reducing their capacity cover requirements) but be unable to sustain such reductions (meaning they need 'full' energy cover).

These types of factors mean the CM monitoring system would need to track both capacity and energy rights for all market participants. The monitoring system would likely need to be very prescriptive, to ensure that all demand sources have procured adequate capacity and energy rights, and that suppliers have not over-sold their physical ability to deliver such rights.

The CM could be less prescriptive if it used economic penalties to deter under-procurement by purchasers and over-selling by providers. However, to be effective, this would need to mimic the spot price in an EOM – which begs the question of whether a CM would be preferable.

6.2 Locational issues

CMs effectively impose a contract obligation on demand-side parties (or agents), requiring them to hold purchase rights to match their assessed load. To be effective, the rights also need to match their location. In some CMs, there is a single price zone (e.g. Western Australia) so this is straightforward. Where jurisdictions have locational price differences, purchasers need to hold the requisite rights at each location. However, as

[86] By 'energy adequacy', we mean having sufficient supply or DR capability to address a reduction in supply that is sustained over weeks or months.

far as we are aware, all jurisdictions with operating CMs have either a single locational price or zonal pricing for load (e.g. PJM). We are not aware of any CM jurisdictions that have full nodal pricing for purchasers.

However, New Zealand operates with full nodal pricing for both generation and demand. This introduces a significant complexity in the task of assessing and monitoring adequacy because judgments need to be made about the extent to which purchase contracts at location Y are acceptable to cover load at location Z. The rules that the regulator adopts in this area would have important financial consequences for both suppliers and purchasers.

6.3 Market size

The small size of the New Zealand market increases the level of concern about market power in relation to both buyers and sellers of rights, and these are heightened further when regional constraints are accounted for.

A related issue is the relative lumpiness of some risks in the New Zealand system. It is possible that the total number of firm rights offered by generators will be below the 'after diversity' supply capability of the system as a whole. This situation could arise if individual generation owners, concerned about the potential penalty for non-performance, reduce their capacity offers to the total nameplate capacity of their portfolio, less their largest single unit. Viewed from the individual generation owner's perspective, this may be rational. However, if all owners do it, that could remove an appreciable portion of supply from the capacity market – even though the likelihood of all those units being physically unavailable at the same time is vanishingly small. In theory, this issue could be addressed by co-insurance arrangements between suppliers, but it is unclear how practical that would be.

These types of issues would likely reinforce the need to consider price floors or caps on firm rights – which in turn might constrain the effectiveness of the CM from an adequacy perspective.

6.4 Transitional issues

Introducing a capacity mechanism in New Zealand would entail a major redesign. It would not just be a simple add-on – especially given the need to address energy and capacity adequacy issues. New Zealand participants have geared their businesses around an EOM design. For example, suppliers and purchasers have entered into bilateral hedge contracts – some of them for relatively long terms. It would be important to try to accommodate these prior commitments if there was any move away from an EOM. This would be possible if the CM design allowed purchasers to contract bilaterally – and there is no obvious reason to preclude such contracts. Indeed, allowing bilateral contracting is relatively common among CMs overseas and provides more flexibility for participants.

Assuming bilateral contracts was to be allowed, it would be necessary to determine how each existing contract is to be 'counted' in terms of creating firm capacity and energy rights. It would be very important to have a clear methodology in this area. Purchasers would obtain credits from any qualifying contracts, and that would reduce their net obligation to buy further contracts. Conversely, for parties who have sold qualifying contracts, it would reduce their headroom to make further such contract sales. It is also possible that parties to existing bilateral contracts would make amendments to their terms, so that they better conform with the requirements of a CM.

More generally, adoption of a CM would likely require some years to fully implement – based on experience in other markets. In the meantime, resource providers could delay or shelve investment plans until the design of a CM is finalised. For this reason, there is a risk that moving to a CM could degrade reliability initially, unless careful thought is given to transitional issues.

7 Conclusion

This chapter summarises our overall observations. It also makes some suggestions for future consideration if concerns emerge about resource adequacy.

7.1 CMs and EOMs have different strengths in relation to reliability

CMs provide a high level of assurance that sufficient generation and DR will be *built.* This is because CMs create explicit commitments to invest in supply capability. CMs can also include tests to ensure that parties' commitments are backed by 'steel in the ground'. Having said that, many EOMs (e.g. New Zealand, Nord Pool, Singapore) have performed well in ensuring sufficient capacity is *built*. So, the real difference between CMs and EOMs is the level of ex ante assurance they provide. CMs provide a higher degree of assurance about the level of *built* capacity because that variable is under the direct influence of the regulator/market operator.

Turning to operational issues, CMs do not provide assurance that resources which have been *built* will actually be *available* when required. Indeed, experience to date suggests that EOMs will almost certainly perform better than CMs on this front, because EOM spot prices create stronger signals to make all resources available during periods of scarcity.

Given these factors, the overall assessment of the two designs on reliability is not clear-cut and depends in large part on what policy makers are most worried about – ex ante assurance about the level of *built* capacity, or that resources which have been built will be *available* when required.

7.2 CMs tend to increase costs to consumers

Costs to consumers are expected to be higher under CMs than EOMs. The key reasons are:

- CMs are prone to creating substantial excess supply capability. Key decisions must be made by a central party who will face lop-sided incentives. They will typically err on the side of caution because any failure in the form of power cuts will be visible, whereas the costs of over-building are harder to see.
- CMs are more likely to create a distorted resource mix between generation types and DR because of the prescriptive rules required to measure firm capacity. CMs are also more susceptible to lobbying by special interests, seeking preferred treatment for their particular options.
- CMs are less able to facilitate and reward innovation – the most important source of cost savings in the long-run – because of the higher level of centralised decision-making and prescription.

7.3 Market power

CMs and EOMs are both susceptible to competition issues. Both require careful design to minimise the scope for the exploitation of market power.

7.4 Durability

In theory, CMs should be more durable than EOMs because they do not rely on spot prices being able to reach very high levels in a scarcity event. However, because of poor operational performance during past scarcity events, leading CMs are moving toward penalty regimes which mimic scarcity prices under an EOM. So, the difference in durability from this source may lessen over time.

More generally, where CMs have been adopted, they are under almost constant change – with some modifications being very significant. Furthermore, experience suggests CMs are more exposed to legal or regulatory challenges due to the greater centralisation of decision-making and considerable administrative discretion conferred on the central party.

7.5 What should New Zealand do?

Neither EOMs nor CMs are perfect. Both have strengths and weaknesses – and experience is still being accumulated on their relative performance. Based on the international experience with EOMs and CMs to date, we suggest the following actions.

7.5.1 Keep an eye ahead

New Zealand should keep an eye ahead for any sign of potential or emerging problems. Identifying concerns at an earlier stage provides more time for careful examination to determine if problems are real or perceived (see below). If concerns are borne out, early identification also gives more time for proper diagnosis of causes, and identification of solutions.

New Zealand already has tools to facilitate monitoring of the forward outlook for supply and demand. These should be actively employed – focussing particularly on the supply margin and any indications that investment signals are not working as expected. This includes factors such as whether contract prices are persistently at levels above the cost of new supply, and/or whether there are blockages to new investment.

7.5.2 Identify whether any reliability concerns are due to investment adequacy

Electricity systems can exhibit reliability concerns for a wide variety of reasons. This is true of systems with EOM and CM designs. Indeed, reliability concerns were around long before electricity markets were created in the 1990s.

If reliability concerns do emerge, it is important to identify the real source of those concerns. For example, reliability concerns may be unrelated to investment adequacy and the choice of market design.

This was the case with reliability concerns which emerged in the aftermath of the state-wide power cuts in South Australia. Those stemmed from tripping of wind generators following a power system disturbance. Adopting a CM would not have addressed these concerns because they revolved around technical standards. Correctly diagnosing the concern is crucial to avoid solutions that are unnecessary, or worse, counterproductive.

7.5.3 Improve EOM design where feasible

If investment adequacy concerns do emerge, it would be important to understand whether they can be addressed without complete redesign of the electricity market. For example, adequacy concerns may be due to aspects of an EOM design that unintentionally cause problems – such as insufficient opportunity for DR to influence prices or poor price formation in scarcity situations. 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."[87]

Concerns may also arise for reasons that are temporary in nature and not directly related to the wholesale market design per se. This was the case with Germany which faced increased supply uncertainty due to the accelerated phase-out of nuclear power. After considering a wide range of options, Germany chose to retain an EOM design, but placed some generation in a temporary strategic reserve to facilitate the transition as nuclear plants phase out.

7.5.4 Understand the risks and costs of CMs relative to EOMs

Both EOMs and CMs have costs and risks – and there is no perfect option. If CMs are seriously explored in depth, it would be important to understand the likely costs and risks.

Drawing on international experience would be very important in this regard. Indeed, in the global transition toward net zero carbon, other countries are likely to strike challenges before New Zealand because we have the advantage of a large and relatively flexible hydro generation base to ease our transition. This means that New Zealand should be able to benefit from the design experiences of other countries – and not repeat their mistakes. In this context, it is striking how much has changed among EOM and CM jurisdictions in the last five years.

Having said that, there are some critical issues where international experience is not very useful – simply because our issues are distinct such as exposure to drought risk (see chapter 6). New Zealand would need to develop its own assessment of costs and risks in relation to these issues.

[87] European Commission, *Final Report of the Sector Inquiry on Capacity Mechanisms*, November 2016

Appendix A. Overview of CMs

Overview of implemented CRMs around the world. Sources: Bhagwat et al. (2016b), Byers et al. (2018), Cejie (2015), Chow and Brant (2018), Deutscher Bundestag (2016), EirGrid plc and SONI Limited (2017), European Commission (2014, 2016a,b,c, 2017a,b), Government of Western Australia (2017), Hancher et al. (2015), Harbord (2016), Midcontinent Independent System Operator, Inc. (2019), New York Independent System Operator (2018), Patrian (2017), PJM (2018), Roques et al. (2017), Single Electricity Market Committee (2016), Southwest Power Pool, I. (2018a,b), Svenska Kraftnät (2016).

Type	Market area	Administrator		Eligible technologies				Status[1]	
		TSO/ISO	RA	TPP	VRES	DSM	IC		
Strategic reserve	Belgium	x	x	x		x		Active	(2014)
	Germany	x	x	x		x		Planned[2]	(2018)
	Sweden	x		x		x		Active	(2003)
Central buyer	Colombia		x	x	x			Active	(2006)
	Ireland[3]	x	x	x	x	x	x	Planned	(2017)
	Italy[3]	x	x	x		x	x	Planned	(2018)
	Poland[4]	x	x	x	x	x	x	Planned	(2018)
	UK	x	x	x	x	x	x	Active	(2014)
	US – ISO-NE	x		x	x	x	x	Active	(1998)
	US – MISO	x		x	x	x	x	Active	(2009)
	US – NYISO	x		x	x	x	x	Active	(1999)
	US – PJM	x		x	x	x	x	Active	(2007)
De-central obligation	Australia – SWIS	x	x	x	x	x		Active	(2005)
	France	x		x	x	x	x	Active	(2015)
	US – CAISO	x	x	x	x	x	x	Active	(2006)
	US – SPP	x		x	x	x	x	Active	(2018)
Targeted capacity payment	Spain[5]	x		x				Active	(2007)

Abbreviations: CAISO—California ISO, DSM—demand side management, IC—interconnector, ISO—independent system operator, ISO-NE—ISO New England, MISO—Midcontinent ISO, NYISO—New York ISO, PJM—Pennsylvania-New Jersey-Maryland Interconnection, RA—regulatory authority, SPP—Southwest power pool, SWIS—South West interconnected system, TPP—thermal power plant, TSO—transmission system operator, VRES—variable renewable energy sources

[1] Year of (planned) implementation in parentheses. The year refers to the respective mechanism currently in place, however, other mechanism may have been used before.

[2] In Germany, two separate mechanisms have been discussed that can be classified as a strategic reserve. In 2016, a security stand-by arrangement for lignite-fired power plants with a total capacity of 2.7 GW was introduced in order to attain national climate targets. Furthermore, an additional so-called capacity reserve is supposed to be active in winter of 2018/19 to ensure generation adequacy. However, as the European Commission still assesses whether the capacity reserve complies with EU state aid rules, it is unclear whether the planned schedule can be met.

[3] To date, targeted capacity payments are used.

[4] Currently, a strategic reserve is implemented.

[5] This refers to the now in place "availability service" mechanism. An additional mechanism named "investment incentive" was abolished in 2016.