Capacity Mechanisms For Power System Reliability

Why the traditional approach will fail to keep the lights on at least cost and can work at cross-purposes with carbon reduction goals.

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October 2013

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Acknowledgements

This paper draws upon a large body of work developed and/or commissioned by the Regulatory Assistance Project (RAP) to explore the topic of capacity payment mechanisms and related reliability issues, particularly in the European context. As lead author, RAP Associate Sarah Keay-Bright tapped this collective body of work and obtained valuable input from members of the RAP European team in preparing this synthesis paper. Special acknowledgement goes to RAP analysts and authors Meg Gottstein, Mike Hogan and Philip Baker, and to John Gerhard and Camille Kadoch for research and editing assistance. RAP is continually expanding its work in this area, which can be viewed and downloaded at www.raponline.org.

Executive Summary

- European governments are looking now at reforming or introducing what are sometimes referred to as "capacity mechanisms." "Traditional" approaches to capacity mechanism/market design may extend the life of high carbon, inflexible assets. This is a threat not only to decarbonisation goals but also to ensuring the reliability of the electricity system with a high percentage of renewable energy sources (RES) at least cost. On the other hand, capacity mechanisms can be designed both to enable power sector decarbonisation and to address system reliability challenges at least cost.

- In Europe, Member States (MS) are considering a range of capacity mechanisms, all of which are based on a very traditional approach to the question of "resource adequacy." [1] Experience from elsewhere in the world, such as from the United States, shows that capacity payments have entrenched the position of the existing mix of capacity resources regardless of its fitness for the purposes of a rapidly changing energy resource mix.

- The design of "traditional" capacity mechanisms is based on the purchase of a fixed quantity of capacity sufficient to meet highest total system demand ("peak demand") plus a reserve margin. Such capacity mechanisms generally reward all resources the same, as long as they fulfil their commitment to be available when called upon, irrespective of operational characteristics. In the future, systems with a high share of variable RES will need firm, dispatchable[2] capacity with flexible capabilities to be able to meet "net demand" (i.e., the demand for electricity that cannot be met by variable RES) at least cost.

- The increase in power production from variable RES and flat energy demand means that currently there is overcapacity across much of Europe. As a result, wholesale electricity prices have been below average. The carbon price also has been low. Some gas-fired generation has been mothballed because it is no longer economic to operate. But gas-fired plants can be quite flexible, thus the system is losing flexibility precisely at a time when such flexibility (and much more) will be needed to efficiently integrate renewables. Instead, older high carbon, inflexible assets appear to be earning enough money to continue to operate.

- Given the projected increase in RES, much of which is likely to be variable wind and solar, and given the long lifetime of most power plant investments, it is necessary to ensure right now that investment signals are sufficient to attract or support the right type (not just the right quantity) of capacity that is flexible enough to integrate variable RES at least cost.

- A checklist at the end of this paper sets out factors that should be taken into account when policy-makers assess capacity needs. A proposal also sets out how capacity mechanisms, if they already exist or are to be introduced, can be (re)designed to ensure investment in capacity with the right capabilities needed by the system. Alternatively, to achieve the same end, rules for existing balancing/ancillary services markets could be adapted. These proposals are designed to ensure that inflexible power plants (or those that are not flexible enough) will have very little, if any, opportunity to earn capacity market revenues.

[1] "Generation adequacy" is often used in discussion of the need for or design of capacity mechanisms. This paper uses the term "resource adequacy" as it encompasses a broader range of energy resources (including generation, demand response, demand reduction and energy efficiency) that can be used to provide capacity.
[2] "Firm" refers to the volume of MWs that the system operator can rely on being available to provide energy to the system at any moment in time, including generation or reduction of demand for energy. "Dispatchable" refers to the ability to increase or decrease electricity output on command, i.e., the resource is controllable.

1 Introduction[3]

In industrialised societies, power system reliability is considered to be a "public good," and this requires that customers' collective demand for electricity is met when they turn on their appliances and electric heating or cooling systems, subject to a socially acceptable standard for involuntary service interruption e.g. "black outs." Some regulators therefore set reliability standards. For example, in the US, the reliability standard requires reliable supply 99.7% of the time.[4] In some European countries, a Loss of Load Expectation (LOLE) reliability standard is used. This standard is defined as the average number of hours for which the load is expected to exceed the available capacity in a typical year.[5] The LOLE standard therefore sets a maximum time limit in a year during which load loss may occur. For example, the LOLE is three hours per year in France and four hours per year in the Netherlands. [6]

Reliable supply requires that energy demand and energy supply be precisely matched in real-time. Thus, there is a corollary need for the system to have enough quantity of "capacity" (physical capability to produce electricity, measured in a quantity of Watts) to meet the maximum expected demand ("peak"). "Capacity mechanisms"[7] have been employed in many liberalised market regions to ensure that the system does have sufficient capacity for this purpose. However, the reliability challenges of the power system are changing with a growing share of variable renewable energy sources (RES), requiring that the capabilities of this physical quantity of capacity also need to change.

"Traditional" capacity mechanisms focus only on what we refer to as "plain vanilla" capacity, ensuring that there are enough firm, dispatchable[8] energy resources[9] available to meet peak demand during a relatively limited number of hours in the year, irrespective of their operating capabilities in other hours. These traditional mechanisms are not designed to elicit the operation of or investment in capacity with the flexible capabilities that will be required with increasing frequency, and at multiple times of the day or year, as the share of variable[10] RES in the power mix increases.

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[3] A full list of abbreviations and terms used in this paper is presented in Appendix 1.
[4] North American Electric Reliability Council (NERC), Glossary of Terms Used in Reliability Standards, April 20, 2009 et http://www.nerc.com/docs/standards/rs/Glossary_2009April20.pdf
[5] DECC, "Annex C: Reliability Standard Methodology", July 2013. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223653/emr_consultation_annex_c.pdf
[6] Ibid.
[7] The term "capacity mechanisms" as used in this paper broadly encompasses a wide range of mechanisms that make payments for the availability of capacity, in place or being proposed, including a "strategic reserve".
[8] "Dispatchable" refers to the ability to increase or decrease electricity output on command, i.e., the resource is controllable. "Firm" refers to the volume of MWs that the system operator can rely on being available to provide energy to the system at any moment in time, including generation or reduction of demand for energy (through demand-side resources).
[9] The term "energy resources" relates to resources which can be used by the system operator to ensure electricity supply and demand meet and include energy generation, demand response, demand reduction, and storage.
[10] "Variable" as used in this paper refers to any source of electricity production where the availability to produce electricity is largely beyond the direct control of operators. It can be simply variable – changing

Capacity payment approaches that continue to reward resources that are not flexible enough will cause the system to be increasingly expensive in reliably meeting net demand and may even put the reliability of the system at greater risk. Moreover, experience shows that such approaches will breathe new life into high-carbon resources that can work at direct cross-purposes with carbon reduction goals.

The purpose of this paper is to:

- explain how the traditional approach to capacity mechanism design will fail to ensure reliability at least cost in a high variable RES future and can work at cross-purposes with carbon reduction goals; and
- set out the principles that should underpin new approaches that will ensure continued operation of and new investment in adequate capacity with the *right capabilities* needed to integrate higher shares of variable RES in the future at least cost.

2 What is a reliable power system?

The electricity system needs to be balanced in real-time, such that energy supply precisely matches energy demand with frequency and voltage remaining within regulated parameters (50 Hz frequency in Europe). The electricity system has a unique "serve all or none" nature. If the system fails to meet just one customer's power needs, then all customers on the same electric circuit also will be left sitting in the dark.

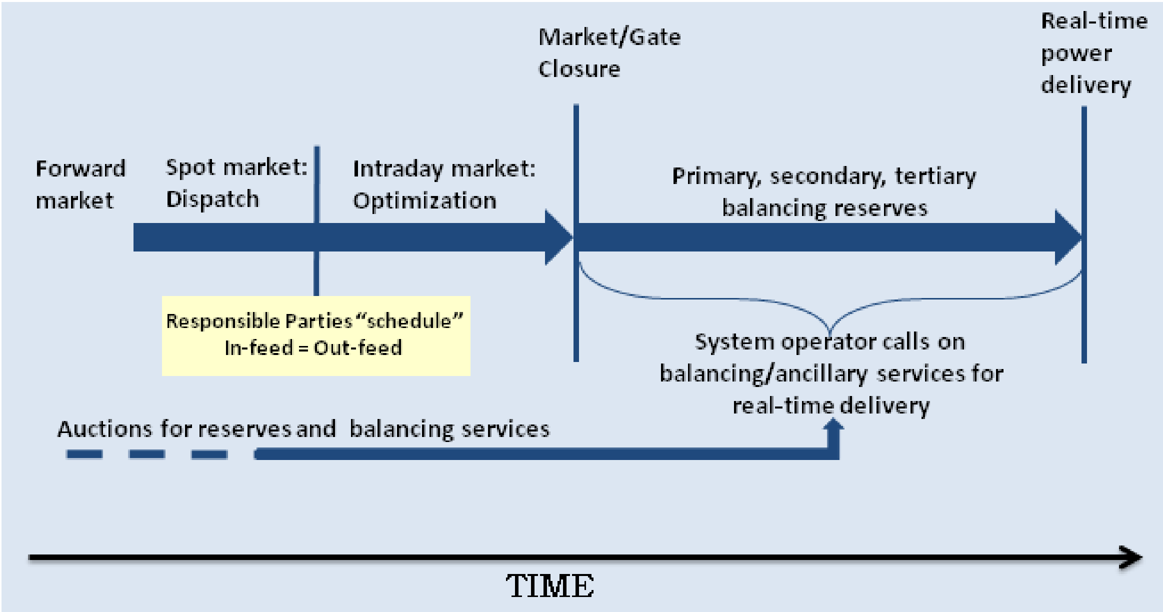
Figure 1 below illustrates common features of how energy is contracted in advance of real-time in European power markets[11]: months or even years ahead through the forward (bilateral) energy markets and closer to real time through the day ahead and intraday energy markets. As Figure 1 also shows, the system operator requires that market participants supply day-ahead schedules of power in- and out-feeds (and those day-ahead schedules must balance), but the real-time in- and out-feeds will of course always differ at least to some extent from these day-ahead scheduled amounts. To maintain system reliability, the system operator therefore contracts for balancing and ancillary services (e.g., primary, secondary, and tertiary reserves) to ensure that energy supply actually matches energy demand in real-time and to manage any unplanned events, such as unscheduled power plant outages. These services are purchased in day- and week-ahead auctions (sometimes even farther in advance) and called upon by the system operator very close to real time (i.e., after "gate closure," the point at which trading is closed and the system operator takes control). These purchases occur *irrespective* of whether there is (also) a capacity market/payment mechanism in

availability independently of changes in demand e.g., tidal energy – or variable and uncertain – variable and, in relevant timeframes, unpredictable e.g., wind. Some people refer to such resources as "intermittent."

[11] The physical balancing described is not the same as the financial trading that occurs on a power exchange. Power exchanges clear financial transactions to buy or sell energy between individual market actors. System operators, however, handle the fundamental physical balancing requirement through ancillary and balancing services auctions as well as through prescriptive regulations (system interconnection codes).

place. In other words, even "energy-only"[12] markets require that the system operator secure in advance the capacity to deploy such services to address reliability challenges in real-time.

Figure 1 - Market and Reliability/Security of Supply[13]



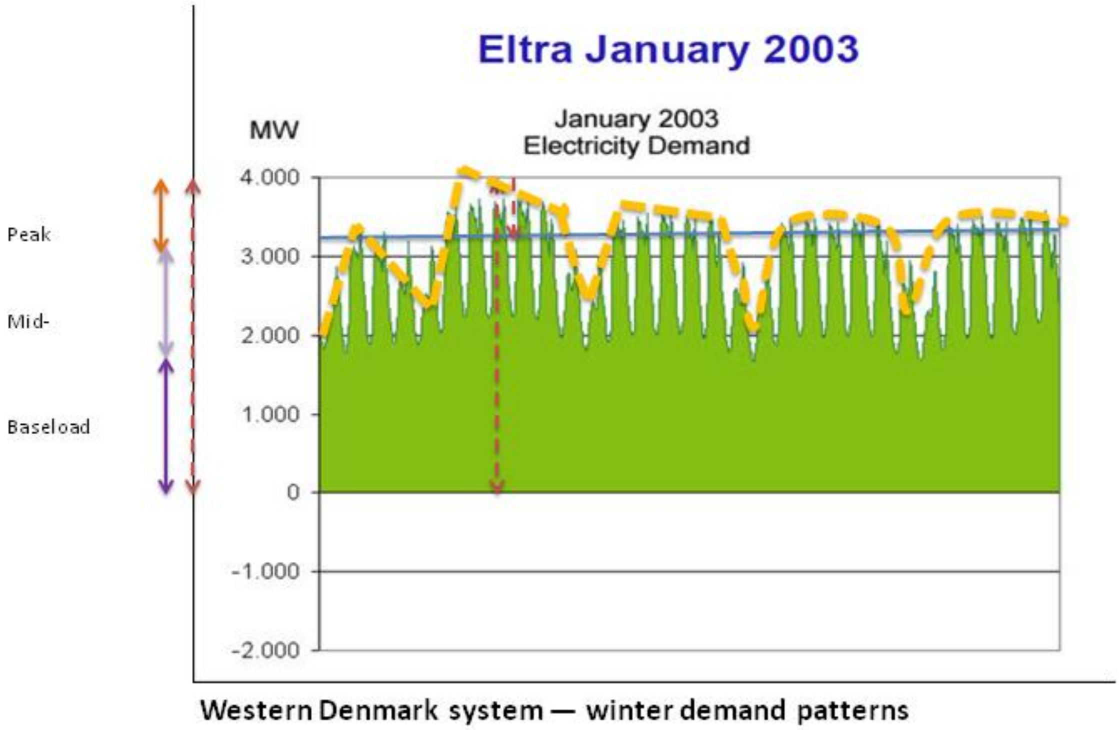
We address in the next section why there are discussions in Europe over the need for "something else" (e.g., capacity mechanisms) to augment what the system operator already does to ensure reliability. But in order to understand why the need to pay for "capacity" is the theme of these discussions, one has to understand how capacity fits into the *traditional* reliability challenge for a power system. That is, a system dominated by conventional, centralised thermal generation. Even before (and also since) market liberalisation, that traditional reliability challenge has been one-dimensional: to ensure that current and future total (peak) system demand has a correspondingly sufficient level of *firm capacity* "stacked" up to meet it, with a comfortable margin.

As illustrated in Figure 2 below, this stack consists of three categories of power plants corresponding to the traditional make-up of total demand on the system. Demand that needs to be met on a 24/7 basis is referred to as "baseload," and the technologies that have traditionally been used to meet some or all of this load (due to their operating characteristics/costs) are nuclear and coal-fired plants. Hence, they are typically referred to as "baseload" plants. Next, the typical total demand profile illustrated below requires resources that can operate a large number of hours during the year but, unlike baseload plants, can also "follow load" up and down in response to price/dispatch signals. These are referred to as "mid-merit" (or sometimes "intermediate load") plants. They typically are comprised of combined cycle gas turbines (CCGTs) and more flexible steam plants. In addition, there are short periods during the year when total demand is at its highest (peak demand), and the system therefore requires power plants that can run economically for only a few hours and then turn off for most of the year. These "peakers" typically are oil-fired steam plants, open-cycle gas turbines (OCGT), or diesel engines. The legacy portfolio of capacity resources is the result of

[12] An "energy-only market" denotes an electricity market without a capacity mechanism.
[13] Created by Andreas Jahn, RAP Associate.

decades of planning and investment, stretching back before liberalisation, based on this traditional profile of required capabilities. As long as the energy market is eliciting a sufficient stack of firm capacity (in MW) from these conventional, dispatchable power plants on the system to meet current and (projected) peak demand, then the system operator of a conventional fleet can be reasonably assured of being able to match peak demand and access the required quantity of balancing/ancillary services. Hence, historically, ensuring reliability has been relatively straightforward as long as this adequate quantity of firm resources is available (or expected to be available) to the system.

Figure 2 - The Reliability Challenge: Do you have enough firm capacity (# of MWs) to cover the few hours of highest (peak) demand?[14]



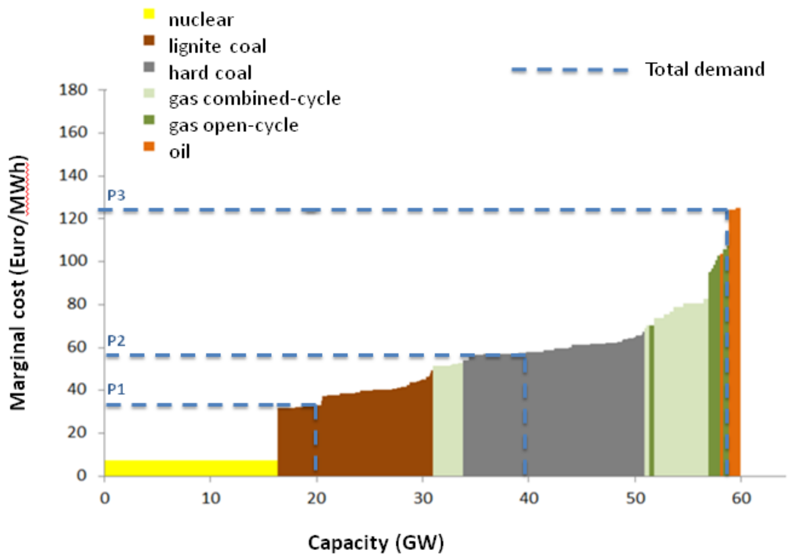
3 Why have capacity mechanisms been used in the past (and what are they, really)?

So why would a market composed of energy-market exchange trading and ancillary services give rise to adding “capacity markets” to this formula, shortly after market liberalisation? The reality is that the process of liberalisation, that is, transforming the system from domination by one or few state-owned or state-regulated vertically integrated utilities to a well-functioning, competitive market that can produce the investment and operational signals anticipated in economic theory, takes more time and is difficult to achieve in actual practice.

[14] Bach, 2005.

In a liberalised market, electricity prices are no longer set by regulators on the basis of approved costs and an approved rate of return on investment; they are determined by the market. The market operator stacks up the competitive bids to supply energy, starting with the cheapest first, until the total supply stack meets demand for that moment in time. The stacking of price bids from cheapest to most expensive is the “merit order” and very often (though not always – see Box 1 below) tracks the underlying variable cost (per kWh) of the bidding resources. Such a cost-based merit order is illustrated in Figure 3 for a typical thermal-based system.

Figure 3 - The Merit Order of Liberalised Energy Markets[15]



As in any commodity market the most expensive bid to “clear the market” (i.e., to find a willing buyer) sets the “clearing price,” and this price is paid to all suppliers of energy needed to meet demand for that particular interval. The plant submitting the most expensive bid to be accepted is called the “marginal plant” (i.e. lignite coal for P1, hard coal for P2, and oil for P3). In this example, when system demand was 20 GW, the clearing price was P1, and this was paid to nuclear units and some lignite coal units. When system demand doubled to 40 GW, the clearing price increased to P2, and this price was paid to all nuclear, lignite coal, combined-cycle gas, and some hard coal units. Capacity earns “inframarginal rent” when the clearing price is higher than its variable costs. For example, when system demand is 20GW, lignite coal is the marginal unit, but when demand increases to 40GW and hard coal sets the clearing price, it earns inframarginal rent of P2 minus P1. Box 1 explains the concept of scarcity pricing and the rationale for and impact of capacity markets (based on Baker, P. & Gottstein, M., 2013 (Section III)).

[15] Adapted, with permission, from original slide in German by Thomas Duveau, WWF Berlin.

Box 1: Energy-only markets and the role of capacity markets

"Energy-only" markets – that is, electricity markets without a capacity mechanism – rely on wholesale electricity prices[16] to reward capacity through inframarginal rents. The difference that can be earned in time between clearing prices and their variable operating costs is assumed to be sufficient to cover the investment and other fixed costs of that plant and so support economic viability.

For flexible plant and most new plant investment to be economically viable in such a market, it has to be expected that as the combined supply of energy and reserves grows tight relative to demand the clearing price will begin to reflect the extra value to customers of ensuring uninterrupted service (known as "scarcity" or "shortage" value). In such situations, marginal prices can justifiably rise above the marginal production cost of the marginal plant, high enough for enough hours that even high marginal cost peaking plant can recover its fixed costs. Ideally, scarcity value is set by the willingness of customers to pay (often referred to as the Value of Lost Load, or "VoLL"). The actual VoLL has historically not revealed itself in practice because of significant demand-side "flaws."[17]

Allowing energy prices to increase to their full scarcity value[18] may not be acceptable either in regulatory or political terms. In many markets this has led to the introduction of price caps set below the VoLL (often well below the VoLL) or other features that undermine incentives to invest. Restoring this "missing money" that energy-only markets should provide via short-term scarcity pricing as an incentive for long-term investment is the primary purpose of capacity payment mechanisms. Capacity mechanisms are not necessarily designed to cover all of the fixed costs of generation. The degree of fixed cost coverage depends upon the corresponding design of the energy market.

Capacity mechanisms create a separate bidding platform where participants can compete for a revenue stream to be paid out regularly for a pre-determined period of time. These revenues are designed to be both more certain and more stable than the energy market revenues they are intended to replace. Payments are made to firm capacity committed to be available to the system operator (subject to penalties) if and when needed to meet demand in the future (a specified "forward year"). This payment is made in addition to the revenues the generator may earn in the energy market, but as illustrated in Figure 4 below, those prices are correspondingly lower due to the removal of scarcity value from the energy market (and payment of that value via the capacity auction). The generation supply curve in a competitive energy market, where a capacity market also exists, should now more closely reflect marginal costs – even when capacity is scarce. This assumes perfect competition and, in practice, mechanisms may be required to claw back capacity payments where energy prices are seen to unjustifiably exceed marginal costs due to market power as, for example, applied by ISO New England (USA).

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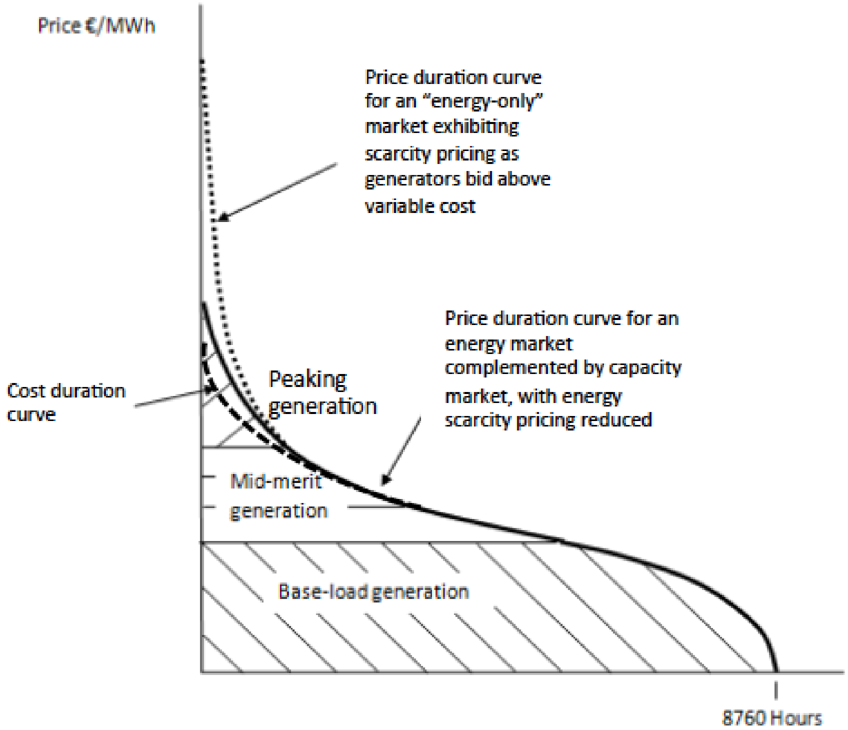
[16] Also referred to as "energy prices." "Wholesale electricity markets" are also referred to as "energy markets."
[17] See Smart Energy Demand Coalition, 2011 for a review of barriers to demand response throughout Europe.
[18] OFGEM recently commissioned a study by London Economics that estimated the average VoLL for residential/small commercial customers in GB to be a bit less than £17,000/MWh, which falls within the range of estimates available for VoLL in other industrialised markets.

Figure 4 Displacing/augmenting scarcity pricing through capacity payments[19]



Capacity mechanisms have been proposed in the past to ensure capacity is retained in the system or investment in new capacity is sufficiently forthcoming to meet projected demand. In the US, capacity mechanisms were introduced at a time when the US regulator (FERC) had recently introduced price caps in energy markets, generators were also struggling with high fuel prices for new natural gas-fired plants, and older less efficient plants were being retired (see Appendix 2 for more detail). In Sweden, after liberalisation, producers began to close fuel oil units previously used for back up, as they were no longer economic to run. Regulators were concerned about reliability so, in 2003, introduced a strategic reserve mechanism to attract investment in capacity that would provide the safety margin for ensuring reliability (i.e., payments were not given to capacity expected to deliver typical peak demand).

4 How are traditional capacity mechanisms designed?

Capacity mechanism design, structure, and implementation vary from region to region. All mechanisms have in common that they pay capacity providers for capacity to be available when needed. All capacity mechanisms that have existed to date, or that are currently proposed, are of the old "resource adequacy" paradigm, which is based on making sure there is enough firm capacity, of any type, available in the future to "stack up" and meet projected system peak demand with a targeted margin/reserve sized to meet a desired reliability standard. The same remuneration is paid to all firm capacity providers no matter what the nature or capability of the resource. Section 8 below illustrates the mechanics of a traditional capacity auction to highlight these common features.

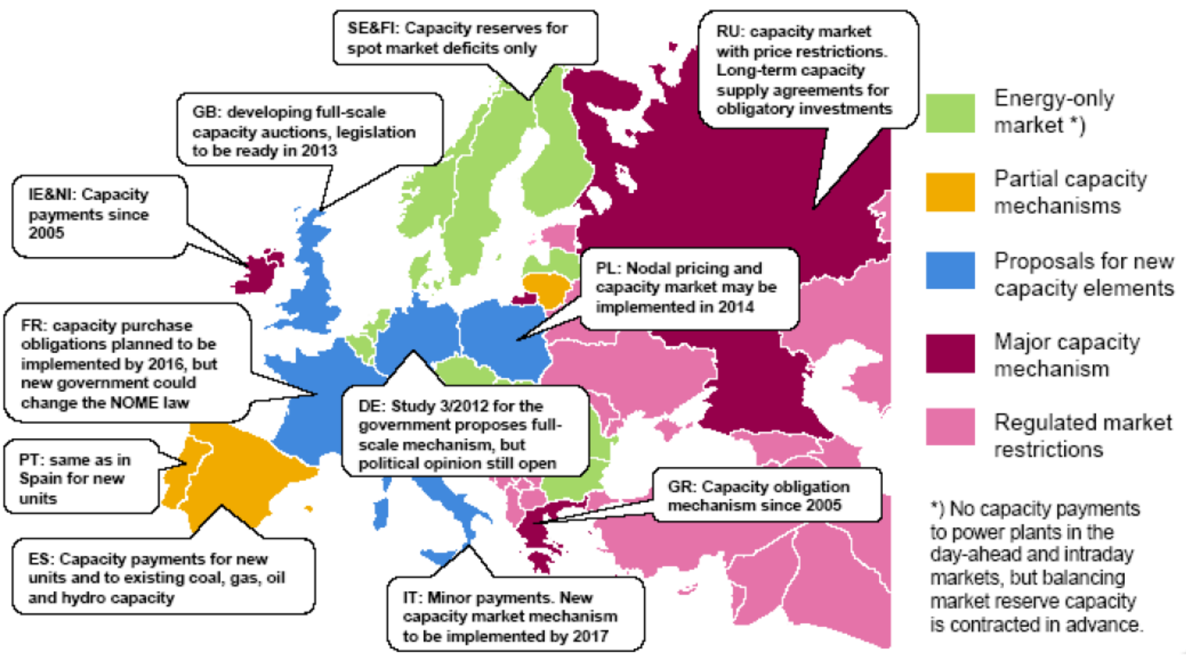
[19] Baker & Gottstein, 2013.

Since their inception, capacity mechanisms have been categorised according to the following key characteristics:

- Procurement can be centralised (system operator purchases capacity) or decentralised (retailers procure capacity pursuant to an obligation imposed by the system operator);
- The mechanism can be quantity or price based (system operator determines quantity and holds an auction to set the price; or the system operator determines the price and the market responds with a quantity available at that price); and
- Application of the mechanism can be targeted (applies to specific/limited capacity or capacity providers) or market wide (applies to all capacity providers).

The pros and cons of various designs will not be discussed here. The purpose of this paper is to explain why the traditional approach to resource adequacy, no matter what the design characteristics, is no longer fit for purpose. The map below provides an overview of the various capacity payment mechanisms currently in effect or proposed in Europe, effectively covering the full range of these traditional capacity mechanism designs.

Figure 5 Existing and planned capacity mechanisms in Europe.[20]



5 Why is the traditional approach no longer appropriate?

What is different now, compared with when traditional capacity mechanisms were first introduced, is that a 2050 decarbonisation trajectory is now being implemented in Europe. The EU Low Carbon Roadmap[21] sets out this trajectory for the power sector of reductions in CO_2 emissions of 54-68% by

[20] Belgian Regulatory Commission for Electricity and Gas, 2012.
[21] European Commission, 2012.

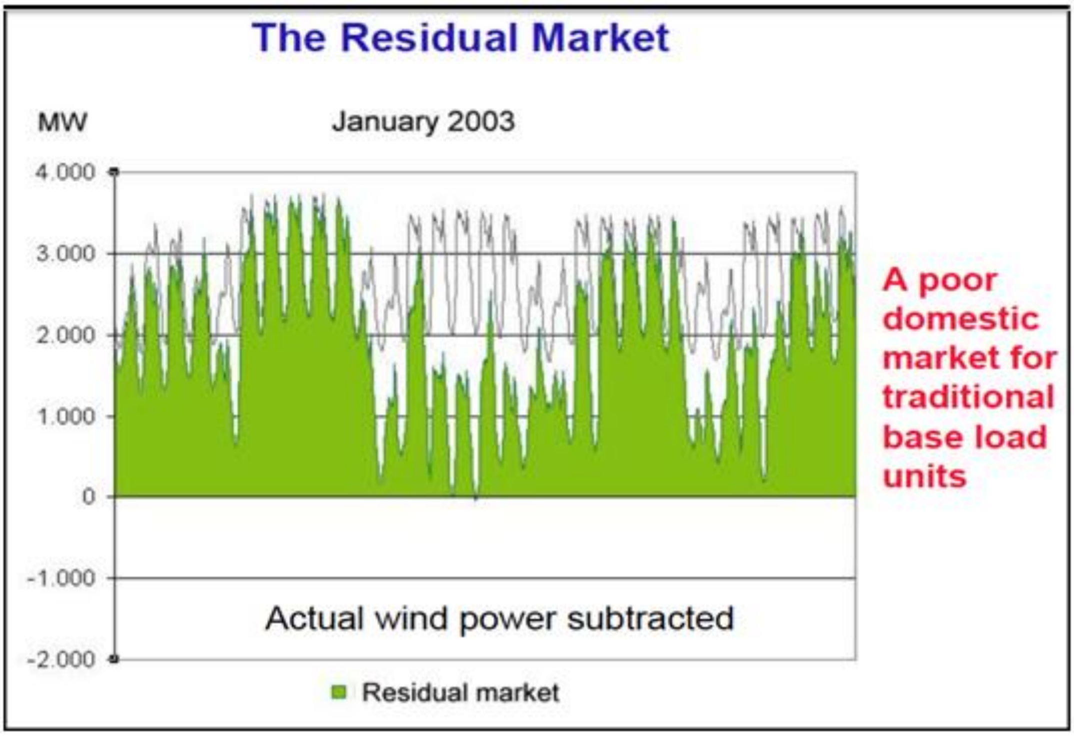
2030 and 93-99% by 2050 (relative to 1990). European legislation[22] is driving the penetration of renewable energy sources into the electricity system, and, in all EU Energy Roadmap scenarios,[23] RES would increase substantially, achieving a minimum of 55% in gross final energy consumption by 2050. Variable RES, largely wind and solar, are rapidly growing in many countries, accounting for a high proportion of new capacity in recent years.

Irrespective of what policies may be in place to support the investment costs of renewables (e.g., feed-in-tariffs), once the investment is made, their place in the "merit order" (see Figure 3) is dictated by their operating costs, which are near zero. Therefore, it is cost efficient to make the best use of such variable RES when they are available, including by increasing demand for energy at times, through demand response or storage. Equally, when wind and solar energy is not available, energy demand could be reduced instead of or in addition to dispatchable generation being increased, where the market decides the proportion of each. Increasingly, the system operator will need to match demand to supply and not just supply to demand, as has traditionally been the case.

Increasing shares of variable RES mean that *net energy demand* – that is, total demand minus the virtually 'free' energy available from renewable resources such as wind and solar – is becoming much more challenging to anticipate and serve over all timescales (see Figure 6). Wind and solar energy are variable, as is demand, but their variability is not always well correlated. At any moment the wind can slow or speed up or a cloud can pass in front of the sun, independently of changes in demand for electricity. In addition, situations can arise when energy demand and RES availability are travelling in opposite directions. Demand could be rising while variable RES is reducing, or variable RES could increase at times when demand is reducing, exacerbating the volatility in net demand. A high degree of flexibility within the portfolio of dispatchable resources is therefore called for - generation, demand response, or storage - that can increase or decrease rates of energy supply and demand at steep gradients (*ramping*[24]) and repeatedly over time (*cycling*[25]), in order to "flex" around the availability of variable RES and so meet both *net energy demand* and *resource adequacy targets* in the most cost-efficient manner possible.

[22] For further, more detailed information on pertinent European legislation, see http://ec.europa.eu/energy/renewables/targets_en.htm and http://www.res-legal.eu/.
[23] European Commission, 2013.
[24] Ramping is the capability of an energy resource (generation or demand) to change its power output or consumption. The 'ramp rate' is the speed of output/consumption change measured in MW per minute.
[25] Cycling is the act of turning an energy resource on/off repeatedly.

Figure 6 - The reliability challenge is rapidly shifting to having the right resources to follow frequent changes in “net demand.”[26]



Western Denmark system with ≈18% of energy from wind.
Note: This is much lower than future renewables targets.

As discussed above, capacity mechanisms are currently based on a single dimension (firm capacity in MWs) of the reliability challenge. Moreover, they are typically based on a conservatively high projection of the amount of firm capacity required to meet future peak demand. For the reasons set out above, going forward this projection needs to also reflect the Member State’s *net demand* taking into account estimates of variable RES penetration. Only then will it be possible to determine the flexible capabilities that will be needed in the future from firm, dispatchable capacity in order to reliably meet net demand with a growing mix of variable RES and at least cost. This is a crucial assessment to make considering the long lifetime of some energy assets.

6 What kind of capability is needed?

Growth in variable RES will affect the type and quantity of balancing/ancillary services required to ensure reliability of the electricity system. Studies indicate that it will not be the fastest services that will experience the greatest increase in demand with rising shares of variable RES (i.e., primary reserves or frequency response able to respond in seconds). Rather, the services that will be in

[26] Bach, 2005.

greater demand will be those that can respond within minutes to tens of minutes to hours and offering the following *capabilities*:[27]

- **Flexible, fast start-stop cycling capability:** The ability to shut down and re-start, or cycle, a resource multiple times within a reasonably short window of time and up to hundreds of times over the course of the year;
- **Regular, dispatchable ramping capability:** The ability to reduce a resource to a low level of stable operation and ramp it back up at a specified rate, not in a traditional operating reserve role (contingency conditions) but as a normal-course ramping capability; and
- **Ramping capability reserved now to be used in the future:** A slower type of secondary reserves with flexible ramping capability, a type of *ramping service,* which can address issues arising in the tens of minutes (e.g., due to forecasting error). Currently, ancillary services' capacities are usually set aside for a particular trade interval and deployed within that interval when pre-specified conditions are met. But with this ramping service, the ramping capability is set aside for later intervals in case a need for it materialises.

The three capabilities listed above are different in nature or degree from the capabilities of services that operators currently procure in balancing/ancillary services markets. These markets can indeed provide some flexibility (often a by-product of gas-fired plant) that is adequate for today's needs, but they would need to be adapted in order to attract the above-listed capabilities. Further, existing balancing/ancillary services markets are generally short term in nature with procurement of services just days or weeks ahead, whereas capacity mechanisms generally procure years ahead (e.g. three years in ISO New England or four years as proposed in Great Britain). To attract investment in capacity with adequate capability, either the services markets or capacity mechanism (where it exists or if one is to be introduced) should be reformed. This is discussed in detail in section 8.

Much existing conventional capacity (particularly coal and nuclear plant) has limited potential to provide the above-mentioned capabilities.[28] Most coal and nuclear plants were designed to provide efficient and steady baseload generation. Such plant was not designed to provide fast ramping times, short start up times, or efficient partial load operation. It is not impossible for many of these plants to provide these flexible services, but doing so will negatively affect operations, including maintenance schedules, efficiency, and operating lifetime. Many plants can be retrofitted with technologies to improve flexibility performance and to monitor the impact of cycling and ramping on physical wear of the plant but at relatively high cost (see Appendix 3 for further detail).

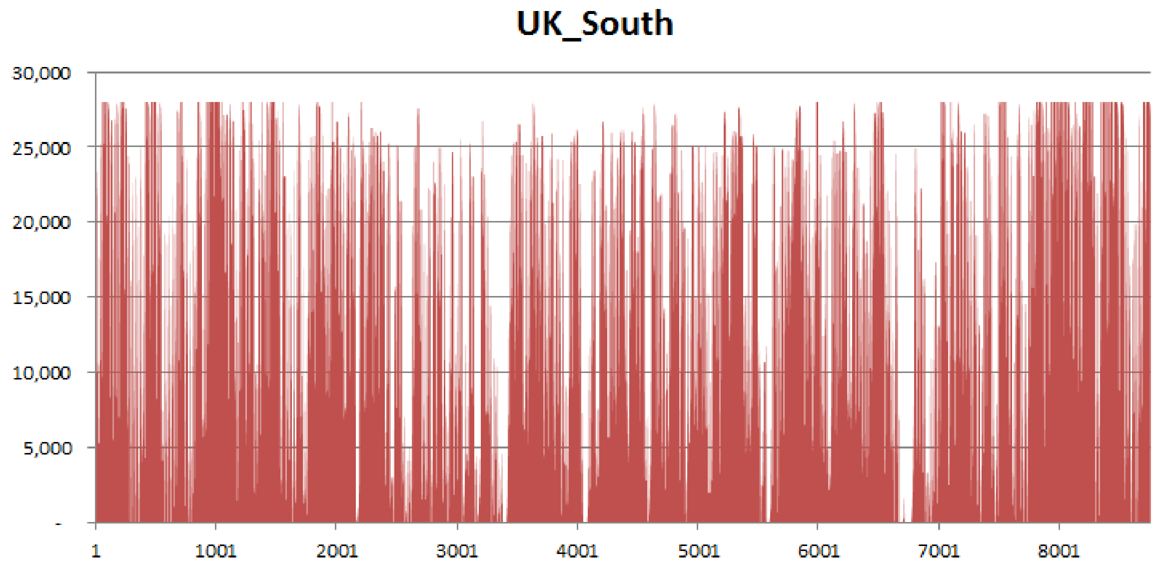
Having insufficient flexible capability within the available generation mix might lead system operators and regulators to resort to dealing with the balancing challenge (and increasing balancing costs) by curtailing renewables. It can also lead system operators to deal with the resource adequacy challenge by piling significant amounts of little-used surplus generation on top of existing, inflexible generation. This can be an extremely costly approach as suppliers must be paid to curtail under most market support mechanisms in place today. This is not to say that renewables should never be

[27] Hogan, 2012.
[28] MIT Energy Initiative, 2011.

curtailed—there are clearly instances where that is the most cost-effective thing to do. But resorting to RES curtailment beyond a certain percentage of available output (e.g., about 5% in many systems), instead of encouraging the orderly retirement of inflexible resources and increased investment in dispatchable resources with the right capabilities, leads to the systematic undermining of both decarbonisation and renewables targets--and is extremely costly to consumers.

Some existing generation resources (e.g., open-cycle gas turbines (OCGT) and some newer combined cycle gas plants (CCGT)) already possess useful operational flexibility, but they tend to be precisely those resources facing the greatest difficulties with revenues declining due to decreased operation with growth in new RES capacity. Many other existing plants (e.g., many older combined cycle gas turbines (CCGT)) could, with additional investment, offer greater operational flexibility. But as previously mentioned, existing balancing/ancillary services markets or capacity mechanisms where they exist are generally not well suited to drive such incremental investment. A recent simulation of the cycling expectations for the UK's mid-merit fleet (CCGT) indicates the need for such investment. The number of start-stops required of the mid-merit fleet increases from less than 50 per year for today's energy mix to over 260 start-stops by 2030 for an energy mix with 50% RES (including hydro and variable renewables), assuming a typical average load factor[29] of 58%.

Figure 7 – Expected operating profile of mid-merit CCGT in 2030.[30]



The deployment of smart grid and smart appliance technology - involving advanced instrumentation, communications, and control technologies - is opening up the possibility for demand to be price responsive and to participate in markets, including via third-party service providers referred to as demand response aggregators. Large pools of aggregated demand response, especially when

[29] Load factor is the amount of plant output relative to maximum output it could produce.
[30] Gottstein & Skillings, 2012. Source data compiled by RAP in consultation with KEMA for four representative centers of gravity reflected in the model runs for Power Perspectives 2030, European Climate Foundation. The full report is available at: http://www.roadmap2050.eu/attachments/files/PowerPerspectives2030_FullReport.pdf.

combined with thermal storage options, can provide the low-cost, bi-directional flexibility on the demand side that can be so valuable in integrating variable wind and solar energy.[31] A recent review of experience of demand response participation in US programs and markets (energy, ancillary services, and capacity) provides evidence that demand response can provide a reliable, dispatchable, and cost effective alternative to conventional generation.[32] Participation of the demand side in PJM's[33] capacity market auction for delivery in 2014/15 saved customers 10-20% in reliability costs region-wide and 30% in constrained power zones, culminating in total consumer savings of $1.2 billion.[34] At the same time, a review of demand response in European electricity markets reveals how market rules are preventing or limiting the participation of demand side resources and aggregators in markets.[35]

To ensure full participation of demand response resources in providing reliability services, qualification, measurement, and verification procedures should be appropriate and not unnecessarily constraining for large numbers of small, distributed providers. For example, high minimum bids exist across Europe, up to 50 MW in France.[36] By contrast, in the US-based PJM market, 1 MW was found to be too high and was subsequently reduced to 0.1 MW.[37] Aggregators should also be able to participate as balancing responsible parties and to substitute loads within their portfolio subject to reasonable constraints.

7 What type of capacity have capacity mechanisms procured in the past?

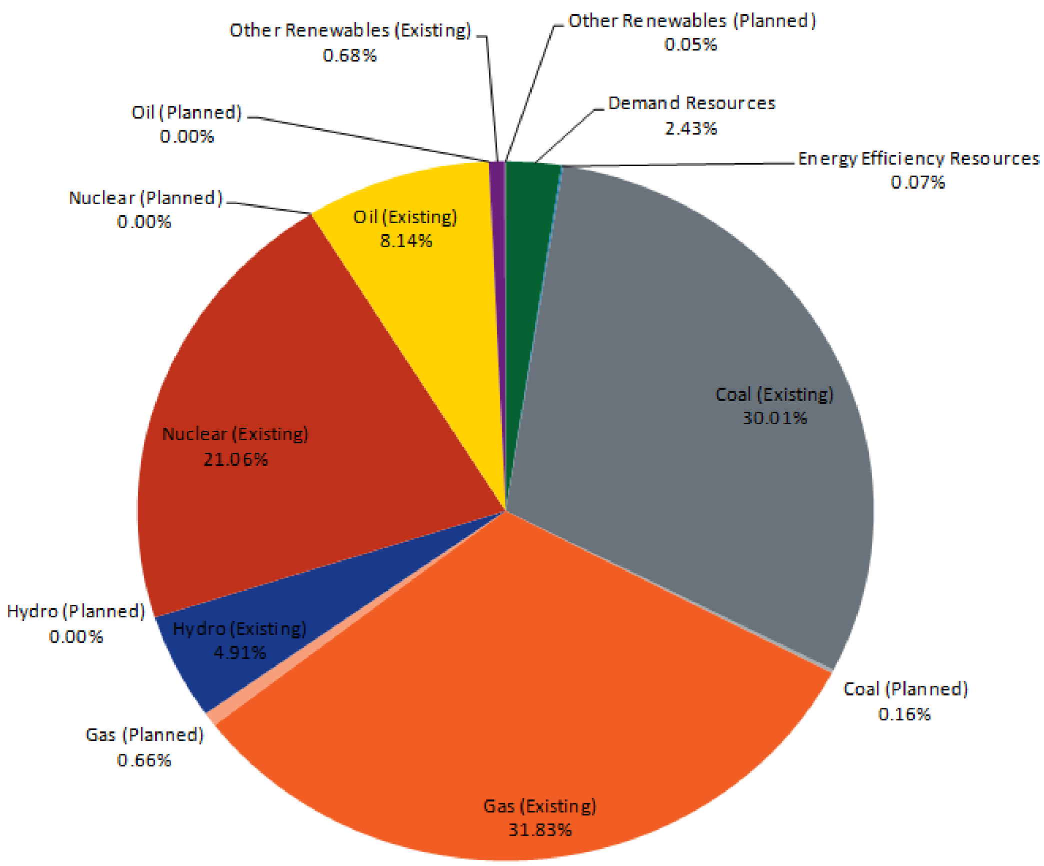
Not only do traditional approaches to capacity payments miss the mark on rewarding flexible capabilities, but evidence shows they also work at cross purposes with carbon reduction goals.

- A case study of the forward capacity markets in the US "followed the money" to examine what types of energy resources were receiving the capacity payments under that market design. The study found that the vast majority of the revenues went to existing high-emitting fossil-fuelled generators, many of which had some load following capabilities but most of which, relative to the requirements of the future illustrated above, would not be considered flexible enough.[38]

[31] For examples of how aggregators are providing demand response to programmes and markets see: Enbala (http://www.enbala.com/SOLUTIONS.php?sub=Grid_Balance) and Enernoc (http://www.enernoc.com/for-utilities/demand-response).
[32] Hurley et al., 2013.
[33] PJM (Pennsylvania-New Jersey-Maryland Interconnection) is the regional transmission organisation that coordinates the movement of wholesale electricity in all or parts of 13 US states and the District of Columbia.
[34] Gottstein & Skillings, 2012.
[35] Smart Energy Demand Coalition, 2011.
[36] Ibid.
[37] Hurley et al., 2013.
[38] Gottstein & Schwartz, 2010.

- An analysis of the recent UK proposals for a capacity mechanism concluded that the (traditional) approach being applied would be unlikely to address the system reliability challenge ahead (see Appendix 4).[39]
- Data collected by the independent market monitor for PJM, illustrated in Figure 8, showed that existing fossil-fuelled resources (gas, oil, and coal-fired) received 70% of the $42 billion in capacity payment revenues under the six auctions held by PJM prior to 2010. Nuclear, a highly inflexible energy resource, accounted for a further 21%. It is clear that very little of the revenue was awarded to new, flexible or environmentally sustainable capacity. All resources were rewarded the same rate per unit capacity.

Figure 8 - PJM capacity market auction revenues.[40]



($42 billion over six annual auctions prior to 2010 –
from 2007/2008 delivery year through the 2013/2014 delivery year)

[39] Gottstein & Skillings, 2012.
[40] Bowring, 2011.

The more enlightened traditional markets are permitting demand-side resources to participate in capacity market auctions. Indeed the PJM system operator has adjusted its auction rules to enable the participation of demand response and energy efficiency. Overall, however, capacity market design in most countries, including throughout Europe, continues to be developed for a primarily traditional, conventional power system. Design development lacks adequate consideration of the growing share of variable RES that the EU has committed to achieve and the flexible capabilities required of non-RES capacity to efficiently integrate that zero-carbon power into the system.

8 What might a capacity market design look like to address these shortcomings?

In capacity markets where auctions are held to arrive at a price for a defined volume of capacity irrespective of capability, the auction rules and forward[41] time period for the payments vary considerably. In general, however, the auction is based on an administratively set demand curve, based on a pre-defined installed capacity target, reserve margin target, and a price ceiling for capacity. Capacity providers submit bids, which when stacked up define the supply curve. The clearing price, paid to all cleared capacity providers, is determined at the point where the supply and demand curves intersect. This "single clearing price auction" is illustrated in Figure 9.

Figure 9 - Single Clearing Price Auction[42]

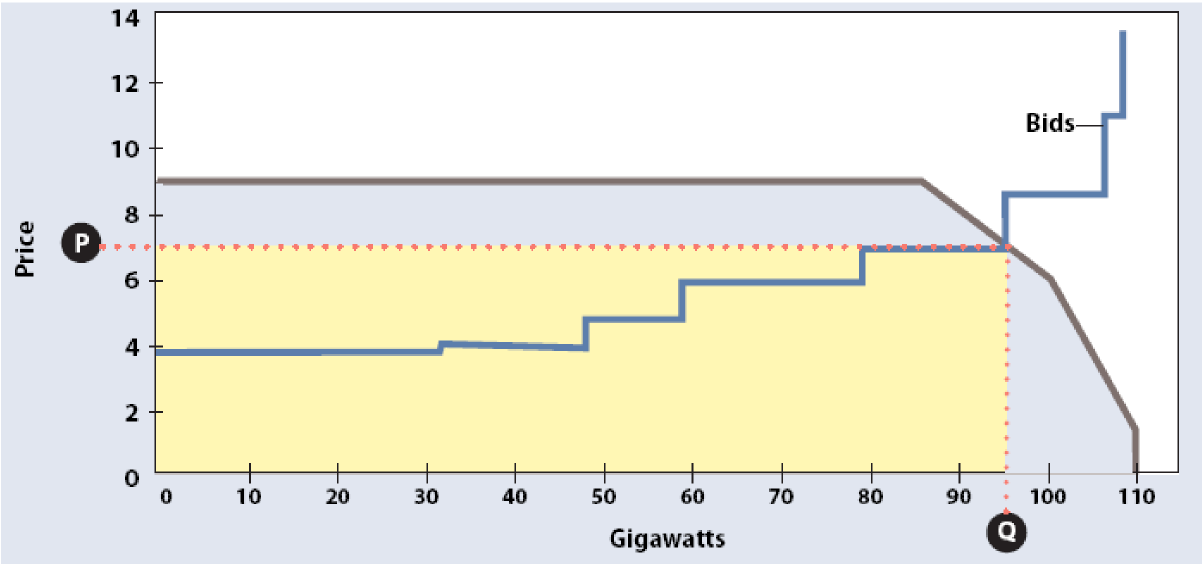


Figure 10 below illustrates what an apportioned, multi-tranche capacity mechanism would look like. Rather than a uniform clearing price paid to all capacity resources, three different values for resources are determined based on the capabilities of the various resources offered. Figure 10 is based on the same hypothetical system used for the typical traditional auction, illustrated in Figure

[41] The term "forward" is used to denote that the capacity payments relate to an "availability" requirement for a future time or "delivery year" which may be several years ahead.
[42] Hogan, 2012.

9. For the apportioned auction, net demand forecasts determine that the optimal apportionment of resources is at least 20 GW of flexible cycling resources (which could include energy storage services), at least 60 GW of highly dispatchable resources, with the balance up to 20 GW coming from firm resources of any type. This information is used to construct a different demand curve to the one used in Figure 9 using three different values[43] that reflect the maximum value to the system for the degree of flexibility provided.

Figure 10 - Multiple Clearing Price Auction[44]

Briefly, a typical 3-tranche model illustrated in Figure 10 conducts a sequential series of auctions:

- The first tranche (Q1) of MWs auctioned represents the most highly valued flexible capability needed to meet the net demand forecast, typically a resource that can operate like a peaker. Here, for example, demand response and gas turbine plant (as well as storage technologies) would be eligible to compete for this peaking (or peak shaving) capacity, and the high-value demand curve will yield a relatively high clearing price for this first auction (P1), but can go no higher than the maximum value to the system of this desired flexibility (12 in this example).
- The second tranche in this example represents the quantity (Q2) of the next most highly valued capability—those flexible mid-merit resources also required to reliably meet forecasted net demand. The prequalification for a resource to participate in this auction could require certain fast stop-start and ramping characteristics that resemble the operational requirements we see in Figure 7, for example. All prequalified resources on the supply or demand-side could compete for these payments, up to the quantity Q2, and the clearing price paid to winning bidders in this tranche is P2.

[43] The formal term for these "values" are Net CONEs (i.e., Cost Of New Entry).
[44] Hogan, 2012.

- Finally, the net demand curve may also indicate that some "plain vanilla" firm capacity has value to ensure that peak demand can be met reliably, that is, where the flexibility of that capacity is not important. This is illustrated by the "third" tranche that is basically an auction where all firm resources (demand- or supply-side) can compete for a relatively small quantity (Q3). The result will be a clearing price (P3) that is the lowest of the three--and could end up being close to zero—as there will be many eligible bidders driving the clearing price down. It is only in this final tranche that inflexible baseload power plants (e.g., coal, nuclear) could qualify to compete--albeit for a relatively small amount of capacity in the auction sequence. Moreover, this auction would also be open to all qualifying demand-side resources, which for the third tranche would include energy efficiency. [45] Experience demonstrates that when permitted to participate in capacity auctions, energy efficiency can compete very effectively against baseload plants to provide reliable, "plain vanilla" firm capacity to the system.

Further details with respect to how such an auction would be conducted can be found in Appendix A of Hogan, 2012.

9 What about carbon criteria or environmental criteria for capacity markets?

Given the existence of the EU2020 Climate & Energy Package and its current review for 2030, a capacity mechanism should not need to incorporate "carbon criteria" or "environmental criteria" unless it is rewarding high-carbon resources at a level that will jeopardise achievement of stated EU or Member State environmental/carbon objectives. The traditional capacity market, however, can end up doing this. Thus, further regulatory intervention may be required to ensure future investments are not at cross purposes with the decarbonisation trajectory (e.g., Emissions Trading Scheme (ETS) reform complemented with an Emissions Performance Standard (EPS) for CO_2). Though, this would not directly address the previously described reliability challenge.

For the case where a multi-tranche capacity mechanism would be implemented, then it would only be necessary to intervene generally in the market (e.g., with an EPS) if it was found that the auction outcomes were enabling continued investment in capacity at cross purposes with carbon/environmental goals.

[45] It is important to emphasise that, while energy efficiency's eligibility in this type of capability market may be restricted to the lowest value tranche because it lacks the ability to be dispatched relative to other demand-side resources (e.g., demand response), end-use efficiency is a foundational resource for the EU integrated market and decarbonisation policies overall, as is discussed in a number of RAP publications and presentations. See for example, Gottstein, 2012 and Cowart, 2011. For more on the experience with energy efficiency resources competing in capacity markets, see Gottstein & Schwartz, 2010. It is also important to remember that while enabling efficiency to participate in capacity markets is of significant benefit in controlling the cost of meeting resource adequacy and can be helpful in promoting cost-effective energy efficiency, the primary drivers for energy efficiency investment will continue to be programs and regulation given the barriers facing cost-effective efficiency investment in even well-designed electricity markets.

10 Why are capacity mechanisms being introduced across Europe right now?

Across Europe today, a number of capacity mechanisms are already in place or are about to be introduced. Concerns are similar as in the past, albeit in a context of rapid power system decarbonisation. The European power sector is part way through a major transformation that should eventually result in the emergence of an integrated, decarbonised electricity market. Renewable support policies have successfully introduced much new capacity in many countries, and this, along with flat energy demand has led to overcapacity and depressed wholesale electricity prices. This is explained in more detail in Box 2. Intervention through capacity mechanisms has generally arisen out of concerns that some existing generation is struggling to remain profitable, and/or the depressed prices are, rightly or wrongly, taken as evidence that there will be little incentive to invest in new plant (including peaking units) needed in a future where, for example, ageing plants are expected to be retired.

Box 2: Current market prices in Europe and resource adequacy[46]

Extract from RAP response to the European Commission consultation on "Generation Adequacy, Capacity Mechanisms and the Internal Energy Market in Electricity," Question 1: "Do you consider that the current market prices prevent investments in needed generation capacity?"

In nearly every region of Europe the problem facing the wholesale power market is that the system is oversupplied with generation capacity at the moment. What the current market prices are telling us is that disinvestment from generation capacity is needed. This is the result of the combination of flat demand (owing both to the economic downturn and to improvements in efficiency) and the policy-driven addition of low-carbon generating capacity (in some Member States, quite a lot of low-carbon generating capacity) to markets that were already fully served (and in some cases, e.g., Spain, already in surplus).

It is therefore no surprise that average wholesale power prices are quite low. This is sometimes called the "merit order effect," in which the addition of surplus must-run capacity into a fully supplied market results in a transitory depression in market prices. The effect is no doubt real, and the present value of the price reductions may well be significant, but it is certainly temporary. If and when the market is allowed to re-balance supply and demand (through some combination of retirement of surplus capacity and growth in demand) this aspect of the merit order effect will disappear.

It must also be emphasised that currently low wholesale market clearing prices are not a reflection of the marginal cost of production of variable renewables; contrary to a common misconception, marginal clearing prices in a properly functioning, fully competitive market reflect the value of the marginal kWh of electricity – this may or may not equal the marginal cost to produce that kWh, and in many scheduling periods it clearly does not nor should it.

Furthermore, renewables are virtually never the marginal resource on the system and therefore do not set marginal prices regardless of what their marginal production costs are. Current average low prices reflect the fact that there is too much capacity in the market and therefore the value of the

[46] Regulatory Assistance Project, 2013.

marginal kWh of electricity is very low, in some scheduling periods far below the marginal cost of production of the marginal generating unit.

The final point in response to this question is that while many regions of Europe are in a surplus capacity situation, it is possible that the existing portfolio of capacity is no longer a good fit for purpose given the evolving nature of the supply mix. That is, as more variable renewable production enters the market, the balance of the resource portfolio must either be more operationally flexible than has heretofore been necessary or demand must become more responsive to real-time conditions in the power system (preferably both). If the existing resource portfolio is not flexible enough to adapt to the increase in variable production it is likely that prices will be more volatile, and in fact that is the pattern we are seeing in the market at the moment. This volatility in prices has also been said to be preventing investment in needed generation capacity.

In the short run, it is low prices and volatility that will drive disinvestment from surplus generating capacity, and that in itself is not a bad thing. The problem will come if the resources that withdraw from the market are those more flexible resources the power system will need most going forward. That is the real challenge facing the wholesale market today – ensuring that the market properly reflects the value of those dispatchable capacity resources providing the system with the flexibility it needs to fully utilise low marginal cost resources,[47] while at the same time ensuring that the value of those resources unable or unwilling to adapt their operating profile as needed shifts downward in line with their actual value to the power system. What is needed, in other words, is not investment in capacity resources per se, but rather a realignment of investment based on those resource attributes of most value to the power system.

In Europe, some mid-merit gas plant has been observed leaving the system and additional plant is said to be under pressure. Gas plant, which constitutes the great majority of that mid-merit fleet, is not only more flexible but also generally less carbon intensive than coal plant. The allowance price under the Emissions Trading Scheme is not at a level that can compensate for the difference in wholesale gas and coal fuel costs, and the EU Industrial Emissions Directive, which could lead to the retirement of ageing unabated coal plant, has yet to take effect. It is important that the capacity that stays in the system or attracts new investment has the capabilities needed to integrate the projected rising share of variable RES in an efficient and cost-effective manner. This adds urgency to the need to ensure capacity mechanisms value not only the quantity but also the operational capabilities of firm capacity — for both existing and new resources.

A well designed capacity mechanism can ensure adequate investment in new capacity needed, providing a level playing field between technologies (both demand and supply side) such that energy resources with the right operational capabilities can be procured at least cost. At the same time, experience shows that capacity markets can also:

- have high transaction costs;
- be burdensome and resource-intensive for regulators with regular review/adjustment to achieve desired outcome;

[47] "Fully utilise" is used here to refer to the optimal trade-off between the cost of curtailing low-marginal-cost variable resources and the cost of avoiding such curtailment. Some level of economic curtailment of such resources should be expected.

- be difficult to terminate; and
- can bring about unintended consequences, including excess capacity, which are costly for consumers.

Moreover, capacity mechanisms designed and implemented at the Member State (MS) level risk conflicting with EU competition and state aid rules. They also risk working at cross purposes to European market integration policy. A recent paper explores whether capacity markets and market coupling can co-exist.[48] Differences in national capacity market design have the potential to create double payments for firm capacity and could lead to the inefficient virtual or physical migration of capacity across borders. It is possible to mitigate these effects through a more coordinated or regional approach to resource adequacy assessment. In the future, it could be possible to organise regionally-based auctions with firm capacity trading arrangements, in effect extending the concept of market coupling to include procurement of capacity as well as energy and balancing services.

To avoid conflict with EU competition, state aid, and market integration rules, the Commission will shortly issue guidelines for MS intending to implement resource adequacy (capacity) mechanisms. These guidelines will likely also set out requirements for resource adequacy assessments and the design of mechanisms. Such guidance should, as a minimum, encourage MS to incorporate into capacity need assessments the projections for variable RES within the MS and neighbouring MS with analysis of how this affects net load and the capability of capacity resources required. The guidance should also encourage MS to consider all cost-effective measures that could help ensure system reliability, for example, aggressively incorporating capacity-equivalent demand side resources into the market for capacity. Such measures would reduce the cost of a capacity mechanism to consumers in the short term and reduce the need for capacity-based interventions in the longer term.

11 But first things first: Are there better, cheaper ways to enhance system flexibility?

The urgency to “flexibilise” the power system is not the same for each Member State right now, but it will become increasingly so for all with the growth in variable RES required to meet the EU 2050 decarbonisation targets. The new reliability challenge is to develop a market design that attracts the needed investment in those flexible resources required to reliably operate the system around the availability of energy from variable RES, at least cost to consumers and the economy. With an increasingly integrated European market, this is no longer a Member State’s internal market challenge but, rather, requires a regional perspective. Implementation of the Internal Energy Market will contribute to addressing the reliability challenge as balancing areas expand through balancing market coupling and increased interconnection. The accuracy of variable RES forecasts also continues to improve and will likely continue to do so, and these improved forecasting capabilities will, among other things, improve the ability to forecast net demand and reduce reserve requirements.

[48] Baker & Gottstein, 2013.

While at some point new, flexible resources will need to be added to the system, addressing the current situation with a focus on investing in new resources - rather than tapping the full flexibility potential of existing system resources, including demand response - will likely add unnecessary costs. A key challenge is to cost-effectively resolve the mismatch between the capabilities of the existing thermal generating portfolio and the operational demands driven by the needs of the evolving supply mix. Tapping the potential of demand response is a critical component of the solution.

The following are valuable and low cost measures that can help meet the operational needs of the system:[49]

- aggregation of larger balancing areas;
- increased interconnectivity with neighbouring markets;
- transmission investment to mitigate internal congestion;
- shorter scheduling intervals;
- improved, centralised weather-forecasting and better operationalization of forecasts; and
- demand enabled to be (and fairly rewarded for being) more responsive to uncontrollable changes in supply.

An alternative to capacity mechanisms - particularly where investment in more firm capacity is not needed but where investment is needed to improve the capability of existing capacity - could involve adaptation of the existing ancillary/balancing services markets currently used by European system operators today. RAP has proposed that the existing reserves /ancillary services markets could be adapted through establishment of an "enhanced forward services market."[50] This follows a similar approach to the tranched capacity mechanism design described earlier in section 8.

The enhanced forward services market approach essentially evolves the short-term services markets by adding new products or services (ramping, cycling) as necessary, enabling full participation of the demand side, and by introducing longer term investment timescales for revenue payments through forward auctions. These markets could then drive investment in improved capabilities from existing resources rather than merely compensating existing resources for the direct incremental cost of providing such services (which is generally the case now, if they are compensated at all).

While an enhanced forward services market approach can offer an alternative to a capacity market in replacing missing money in the energy market, a national approach to adapting services markets has the potential to create similar impacts on the internal electricity market as for a capacity market (e.g. double payments; migration of virtual or physical capacity[51]). As explained earlier, this can be remedied with a more coordinated or regional approach. One advantage of an enhanced forward services market approach over a capacity mechanism is, however, that rules could be fairly easily adjusted to reflect improvements in the operation of energy-only markets, which is a key objective for the European internal energy market.

[49] Hogan, 2012.
[50] Hogan, 2012.
[51] Regulatory Assistance Project, 2013.

The Californian system operator (CAISO) is proposing to evolve its services markets along the lines of the enhanced forward services market model, incorporating the three capabilities mentioned earlier in section 6. Services would be procured through five-year forward auctions.[52]

12 Capacity Mechanisms: A checklist for need, alternatives, and design.

1. *Capacity (resource adequacy) need assessments; what quantity and capabilities are needed?:*
   - Has a detailed assessment been carried out which incorporates a "higher case" long-term projection for variable renewables, the impact on net demand and therefore:
     a. the quantity of capacity; and
     b. how flexible the firm, dispatchable energy resources of the system will need to be to ensure reliability?
   - Does the capacity need assessment (for quantity and capabilities) also take into account:
     - potential of the demand side;
     - interconnection between Member States;
     - aggregation of balancing areas and cross-border trading;
     - ENTSO-E resource adequacy assessments on a regional level;
     - other low cost measures to cost-effectively meet operational needs of the system e.g. transmission investment to mitigate internal congestion; more accurate weather forecasting; shorter scheduling intervals.
2. *If, having taken into account all of the above considerations, the need to invest in a greater quantity of firm capacity is not urgent, can investment in the flexibility of existing resources be driven by adapting the services markets?:*
   - Adapt existing short-term ancillary service/balancing markets by adding new products or services (ramping, cycling) as necessary, enabling full participation of the demand side and by introducing longer term investment timescales for revenue payments through forward auctions.
3. *If a capacity mechanism exists or is to be introduced, is it fit for the purpose of delivering reliability at least cost?*

The requirements listed below are based on a screening checklist set out in the recent publication, *Beyond Capacity Markets – Delivering Capability Resources to Europe's Decarbonised Power System*.[53] RAP has applied this checklist to screen the capacity market design put forth in 2011 as part of Great Britain's electricity market reform package[54] (see Appendix 4 for a summary).

A positive response to each of the following questions suggests the proposed market design is robust, while negative responses to any of the questions should raise significant concerns. Does the mechanism:

a. Seek to deliver the range of capabilities that the system will actually need to meet *net demand* with an increasing proportion of renewables?

[52] Xu & Tretheway, 2012.
[53] Gottstein & Skillings, 2012.
[54] Department for Energy and Climate Change, 2011.

b. Maximise the potential for existing resources (generation, demand and storage) to deliver the necessary capabilities before resorting to incentivising more expensive new resources?
c. Seek to secure comparable services from all potential resources, in particular, the demand side? Are the eligibility criteria for the demand side and for distributed or aggregated resources fair and reasonable, on an equal footing to centralised conventional generation?
d. Ensure that resources that cannot provide the necessary range of capabilities (e.g., inflexible generation) are put at an appropriate competitive disadvantage to those resources that do provide the capabilities?
e. Charge the costs of reliability services in a way that avoids creating earnings risks that are difficult to manage for renewable generators? To the extent that these risks are increased, does the proposal address how the potential adverse impact on the deployment of renewables can be addressed in other ways?
f. Deliver reliability in a manner that promotes future cost reductions and innovation in the provision of flexible capabilities and avoids foreclosing the market to future providers?
g. Create a potentially scalable design, including the future integration of neighbouring balancing areas and the sharing of capability resources? Consider potential effects on market coupling and available mitigating measures?
h. Recognise the carbon content of resources procured to provide the range of capabilities?

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14 APPENDIX 1:

Acronyms:

CCGT	Combined Cycle Gas Turbine
CO_2	Carbon Dioxide
ENTSO-E	European Network of Transmission System Operators for Electricity
FERC	Federal Energy Regulatory Commission
kW	Kilowatt (power/capacity)
kWh	Kilowatt-hour (energy)
LOLE	Loss of Load Expectation
MS	Member State
MW	Megawatt (power/capacity)
MWh	Megawatt-hour (energy)
OCGT	Open Cycle Gas Turbine
PJM	Pennsylvania-New Jersey-Maryland Interconnection
RES	Renewable Energy Sources

Definitions:

Ancillary services: Services that help the system operate continuously within required parameters (e.g., frequency and voltage range), including the ability to recover energy balance after significant unplanned changes in supply and demand.

Balancing services: Purchases and sales of energy made by the system operator close to real time that are necessary to correct current or expected imbalances between supply and demand for each trading period.

Baseload, mid-merit, peak-load generation: Operation mode of a generating plant based on a combination of technical and commercial factors (e.g., how economically the plant can run at different load factors). Operation that occurs all or most hours is referred to as 'baseload,' only for short periods to meet system peak is known as 'peak,' and operation falling between baseload and peak is referred to as 'mid-merit.'

Capability resources: Products and services that need to be delivered to a decarbonised power system in order to maintain system reliability over both the short- and long- term. Includes capabilities that require investment in the right mix of generation, demand-side resources, storage and grid resources to deliver flexibility and other attributes necessary to cost-efficiently balance systems where there is an increasing proportion of renewable power.

Capacity mechanisms/markets: Encompasses the range of capacity payment mechanisms designed to remunerate market participants for committing a volume of firm capacity to generate power or reduce demand by an equivalent amount during hours of system peak demand.

Clearing price: The most expensive bid cleared to meet demand for a certain time interval sets the “clearing price,” and this price is paid to all suppliers of energy needed to meet demand for that particular interval.

Cycling: The act of turning an energy resource on/off repeatedly.

Demand Response: A broad term to describe actions to adjust electricity use in response to incentives or changes in prices.

Demand-side resources: The full range of customer-based resources (end-use energy efficiency, demand-response and customer-sited generation) that reduce energy needs at various times of the day and year—across some or many hours.

Dispatchable: Refers to the ability to increase or decrease electricity output, i.e., the resource is controllable.

Energy resources: Resources that can be used by the system operator to ensure energy supply and demand meet, including generation, demand response, demand reduction and energy storage.

Firm capacity: The volume of megawatts guaranteed to be available to provide or reduce energy to the system at any moment in time.

Inframarginal rent: Inframarginal rent is earned in the wholesale electricity market when the clearing price is higher than the bid price of the energy provided to meet demand.

Load factor: A measure of the output of a power plant compared to the maximum output it could produce.

Load-following: A load following energy resource adjusts its power output/consumption throughout the day based on changes in demand, following the load curve. Load following plants often stop generating at night when demand for electricity is at its lowest.

Marginal cost: The change in total cost that would result if output were to increase by a measurable unit.

Marginal plant: The plant submitting the most expensive (cleared) bid to meet system demand is called the “marginal plant”.

Net demand: Total energy demand minus the available ‘free’ renewable energy from resources such as wind and solar. Net demand also excludes that part of gross demand effectively served by production from other non-dispatchable resources, such as combined heat and power plants that cannot change their power output in response to the demands of the power system.

Peak/off-peak: System peak demand is the highest instantaneous level of total energy demand on the power system over a given period of time (e.g., daily peak, seasonal peak, annual peak). Periods outside the peak are usually referred to as off-peak.

Ramping: The capability of an energy resource (generation or demand) to change its power output or consumption. The ‘ramp rate’ is the speed of output/consumption change measured in MW per minute.

Reliability: Ability to meet the electricity needs of customers connected to the system over various timescales even when unexpected equipment failures or other factors reduce the amount of available electricity. Consistent with current industry practice, ‘reliability’ can be broken down into two general categories—resource adequacy and system quality.

Reserve Margin: The amount of installed generating capacity exceeding forecasted peak load.

Reserves: See ancillary services.

Resource adequacy: Enough of the right kinds of resources to match demand and supply across time and geographic dimensions and deliver an acceptable level of reliability.

System quality: Short-term, reliable operation of the power system as it moves electricity from generating sources to retail customers, including the ability of the system to withstand unanticipated disturbances or imbalances in the system while maintaining required frequency and voltage levels. Balancing and ancillary services contribute to system quality.

Variable RES: Sources of renewable energy are “variable” if the availability to produce electricity is largely beyond the direct control of operators. It can be simply variable – changing availability independently of changes in demand, e.g., tidal energy – or variable and uncertain – variable and, in relevant timeframes, unpredictable e.g., wind. Some people refer to such resources as “intermittent.”

15 APPENDIX 2: How Forward Capacity Markets Evolved in the US[55]

To maintain reliable operations, electric systems must maintain sufficient capacity resources to meet peak load requirements plus a planning reserve margin (referred to as "resource adequacy" or the "planning reserves"). Under traditional utility regulation, resource adequacy is met by load-serving entities obtaining regulatory approval to hold a portfolio of resources, the costs of which (including a reasonable return on investment) are recovered from captive customers. In areas of the country that have restructured their electricity markets, many load-serving entities compete for retail customers with other suppliers, creating financial risk for long-term resource commitments, and in many cases have divested generation to new owners that compete for sales and thus have no guarantee of cost recovery. The capacity markets of the eastern RTOs/ISOs were implemented against this backdrop of restructuring in the retail electric markets of each region.

Early on, the eastern RTOs/ISOs, like the power pools that preceded them, employed rules requiring load-serving entities to maintain adequate capacity resources to meet the planning reserve margin, coupled with a deficiency charge assessed to members who failed to meet their capacity requirements. The original capacity market designs were voluntary balancing markets intended to provide transparent market-based mechanisms to assist load-serving entities in meeting their installed capacity obligations.

These market constructs generally procured capacity on a daily or monthly basis with a short lead time and relied on deficiency charges to set market prices. Over time, concerns grew that these early market-based capacity constructs were inadequate to ensure long-term resource adequacy. In response, centralized capacity markets were implemented by the eastern RTOs/ISOs to provide more lead time and certainty for investment in new capacity resources, including an adequate opportunity for all resources to recover both their variable and fixed costs over time.[56] The Federal Energy Regulatory Commission (FERC) provided each region with flexibility as to market design and did not require a "one size fits all" approach. However, the primary goal of each of these markets is the same: ensure resource adequacy at just and reasonable rates through a market-based mechanism that is not unduly discriminatory or preferential as to the procurement of resources.

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[55] Based on an extract from FERC, 2013.

[56] Ensuring an opportunity to recover both fixed and variable costs over time should avoid the so-called "missing money" problem.

16 APPENDIX 3: Capabilities data[57]

Flexible Operation of Thermal Power Plants: Key Findings

1. The most important requirements for the flexible operation of thermal generators are partial load efficiency, fast ramping capacity, and short startup times.
2. Coal plants can generally ramp their output at 1.5%–3.0% per minute. As ramp rates increase, expected maintenance costs also increase.
3. Current coal plants were not designed for flexible operation and will have mechanical, maintenance, and operational issues when pushed to operate flexibly. Generally, operators tend to run older coal plants flexibly because they are smaller capacity units (i.e., easier to ramp) and their capital costs have been fully recovered.
4. The role of coal-fired power plants is changing already due to lower natural gas prices and lower electricity demand. This trend towards lower capacity factor usage is expected to continue as higher levels of intermittent renewable generation resources are added to the electric power system.
5. It is technically possible to design coal-fired power plants for flexible generation, but it would require a substantial change in the overall design basis.
6. Natural gas-fired power plants provide the greatest generation flexibility to mitigate large-scale penetration of intermittent renewables with ramp rates of 8% per minute. New natural gas combined-cycle (NGCC) plants continue to improve their capabilities for responding to the intermittency of renewable generation.
7. The time required to start up an NGCC plant largely depends on the amount of time that the plant has been shut down. As the number of startups increases, the time between maintenance periods decreases, keeping units off-line for longer periods of time and increasing maintenance costs.
8. Relatively new nuclear reactors ramp asymmetrically: plants can down-ramp 20% of their total output within an hour, but they require six to eight hours to ramp up to full load.
9. Nuclear plant ramping operations are not fully automated. Operating a nuclear plant in a transient state requires manual manipulations that create additional opportunities for operator error.

Comparison of capabilities of different types of capacity[58]

Capacity type	Minimum load %	Spin ramp rate %/minute	Quick start ramp rate %/minute
Nuclear (1125MW)	50	5	5
Pulverised coal-fired (606MW)	40	2	-
Natural Gas Combined Cycle (580MW)	50	5	2.5
Gas Turbine (211MW)	50	8.33	22.2
Integrated Gasification Combined Cycle (590MW)	50	5	2.5
Battery Energy Storage (sodium sulphide, 7.2MW)	0	20%/second	20%/second
Pumped Storage Hydropower (500MW)	33	50	50
Compressed Air Storage	50	10	4

Note: Data is for 2010, except compressed air storage plant which is a projection for 2015.

[57] Key Findings from MIT, 2011.
[58] Black & Veatch, 2012.

Cycling of conventional technologies[59]

Text Box 2. Cycling Considerations

- Cycling increases failures and maintenance cost.
- Power plants of the future will need increased flexibility and increased efficiency; these qualities run counter to each other.
- Higher temperatures required for increased efficiency mean slower ramp rates and less ability to operate off-design. Similarly, environmental features such as bag houses, SCR, gas turbine NOx control, FGD, and carbon capture make it more difficult to operate at off-design conditions.
- Early less-efficient power plants without modern environmental emissions controls probably have more ability to cycle than newer more highly-tuned designs.
- Peak temperature and rate of change of temperature are key limitations for cycling. Water chemistry is an issue.
- The number of discrete pulverizers is a limitation for pulverized coal power plants and the number of modules in add-on systems that must be integrated to achieve environmental control is a limitation.

<u>The ramp rate for coal plants is not linear as it is a function of bringing pulverizers on line as load increases.</u> A 600-MW pulverized coal-fired unit (e.g., Powder River Basin) can have six pulverizers. Assuming an N+1 sparing philosophy, five pulverizers are required for full load so each pulverizer can provide fuel for about 20% of full load.

From minimum stable load at about 40% to full load, it is the judgment of Black & Veatch, based on actual experience in coal plant operations, that the ramp rate will be 5 MW/minute at high loads. This is about 1%/minute for a unit when at 500 MW.

<u>The ramp rate for a combined-cycle plant is a combination of combustion turbine ramp rate and steam turbine ramp rate.</u> The conventional warm start will take about 76 minutes from start initiation to full load on the combined cycle. The combined ramp rate from minute 62 to minute 76 is shown by GE to be about 5%/minute for a warm conventional start-up.

GE shows that the total duration of a "rapid response" combined-cycle start-up assuming a combustion turbine fast start is 54 minutes as compared to a conventional start duration of 76 minutes for a warm start. The ramp rate is shown by GE to be slower during a rapid start-up. The overall duration is shorter but the high load combined ramp rate is 2.5%.

After the unit has been online and up to temperature, we would expect the ramp rate to be 5%.

[59] Black & Veatch, 2012.

17 APPENDIX 4: Assessment of Capacity Market Proposal in Great Britain[60]

Check-list	Assessment of proposal
Procure range of capabilities?	No – the mechanism is designed to reward firm capacity only. The primary way to incentivise a range of capabilities is the price available through bidding into the balancing mechanism. However, the ability of investors to act on the basis of predictions of these short term signals is a matter of debate.
Maximise potential for existing resources?	Yes – the shorter term nature of the auction will tend to favor existing resources. This is important in the GB market since a large proportion of fossil plant will face closure decisions over the coming decade.
Demand side?	Possibly – although the success in attracting demand-side resources will depend on the extent to which the system operator is incentivised to ensure they participate. There is currently relatively little demand response provided on the GB system — around 1GW is contracted with the system operator and a similar amount is believed to be contracted by suppliers to reduce peak demand [21]
Less revenue for resources that do not provide range of operational capabilities?	No – earnings through the capacity mechanism will vary according to availability at times of system peak and not as a result of the range of capabilities offered.
Recognise carbon content?	No – this incentive is restricted to the carbon cost associated with energy sales for operational assets. In particular, the procurement of inflexible capacity may lead to significantly increased curtailment of renewable generation and the cost implications of this trade-off will not be taken into account.
Avoid adverse impact on renewable investments?	Possibly – details of cost recovery not yet defined. Capacity costs may be shared equally by suppliers on a pro-rata volume basis, in which case there will be no relative economic effects between technologies. However, the costs may be recovered through higher imbalance settlement prices which will tend to adversely affect renewable generators that are unable to control their output in operational timescales.
Promote innovation and avoid foreclosure?	No – there is no discussion of the need to adapt the mechanism as the market develops. It is, as yet, unclear whether the proposals are envisaged as an enduring change to the market rules or a temporary 'fix' to be implemented only during periods of capacity shortage. Also, it is not clear how the mechanism will attract major new investments if the short term auctions fail in this regard. The most likely approach is that investors will have the option of a 'commitment period' as in the US forward capacity markets -- however, this is not discussed in the current proposals.
Market integration and sharing balancing resources?	No – the way this mechanism might continue to deliver reliability as GB becomes increasingly interconnected with neighbouring markets is not apparent. In particular, the ways in which the mechanism can be designed to operate in line with market coupling principles and potentially larger balancing areas are not addressed.

[60] Gottstein & Skillings, 2012.