Competition in Markets for Ancillary Services? The Implications of Rising Distributed Generation

Michael G. Pollitt[a] *and Karim L. Anaya*[b]

ABSTRACT

Ancillary services are electricity products which include balancing energy, frequency regulation, voltage support, constraint management and reserves. Traditionally they have been procured by system operators from large conventional power plants, as by-products of the production of energy. This paper discusses the use of markets to procure ancillary services in the face of potentially higher demand for them, caused by rising amounts of intermittent renewable generation. We discuss: the nature of markets for ancillary services; what we really mean by ancillary services; how they are impacted by the rise of distributed generation; how they are currently procured; how they relate to the rest of the electricity system; the current state of evidence on ancillary services markets; whether these markets ever be as competitive as conventional wholesale energy markets, and offer some conclusions.

Keywords: Ancillary services, Balancing energy, Frequency regulation, Reactive power, Constraint management, Reserves

https://doi.org/10.5547/01956574.41.SI1.mpol

1. INTRODUCTION

Ancillary services are electricity products relating to wholesale electricity other than those traded through traditional wholesale electrical energy markets.[1] Roughly, they can be characterised as covering balancing energy, frequency regulation, voltage support, constraint management and reserves. They are related to power quality. These products[2] have traditionally been supplied to system operators at fixed or negotiated prices usually related to the opportunity cost of them being provided by traditional fossil fuel and conventional hydro generators. Over time some of these products have been available from more formal markets in some jurisdictions (e.g. for balancing energy and frequency regulation, for congestion and for reserves in markets such as PJM or Great Britain(GB)).

Rising amounts of intermittent distributed generation (wind and solar) on the electricity network creates the potential need for more ancillary services relative to total electrical energy sup-

1. System operators operate different kinds of markets such as for energy, capacity and other ancillary services. Among them, the spot energy market (by which we mean energy traded up to point at which ancillary services markets are made use of) is the one with the largest share in wholesale electricity costs.
2. The number of products, sub products and their respective names may differ across different jurisdictions.

a Corresponding author. Energy Policy Research Group, Judge Business School, University of Cambridge. E-mail: m.pollitt@jbs.cam.ac.uk.
b Energy Policy Research Group, Judge Business School, University of Cambridge. E-mail: k.anaya@jbs.cam.ac.uk.

The Energy Journal, Vol. 41, SI1. This is an open access article under the terms of the Creative Commons Attribution License (CC-BY), which permits use, distribution and reproduction in any medium, provided the original work is properly cited. All rights reserved.

plied: greater fluctuation in system frequency, more potential for high volts export constrained areas, more local network congestion (because generation is more distributed) and higher reserve requirements.[3] At the same time, distributed energy resources (DERs) can provide more ancillary services, both by distributed generation itself being incentivised to mitigate its impacts on the system or via new technologies (such as batteries or active demand management).

The focus of this paper is to introduce a discussion on whether markets for ancillary services, usually run by system operators,[4] can ever be as competitive as wholesale energy markets(?). Energy markets—where these have been allowed to develop—are in general characterised by increasingly deep market arrangements which make it difficult for them to be excessively monopolised in the absence of significant market power relating to incumbent generators. Good examples of these wide area markets are across PJM in the US, the increasingly integrated markets in Europe or the National Electricity Market (NEM) in Australia.

In what follows we introduce: the nature of markets for ancillary services; what we really mean by ancillary services; how they are impacted by the rise of distributed generation; how they are currently procured; how they relate to the rest of the electricity system; the current state of evidence on ancillary services markets; whether these markets ever be as competitive as conventional wholesale energy markets, and offer some conclusions.

2. MARKETS FOR ANCILLARY SERVICES?

Many discussions of ancillary services start with the physics of electrical energy (see for example, Kirchen and Strbac, 2019, p.141ff and Creti and Fontini, 2019, p.185ff) and how this gives rise to the unique products that make up the sorts of ancillary services that we see system operators procuring. We will come back to this, but it is instructive, for the purpose of this paper to start somewhere else.

The focus of this paper is on markets and where they are appropriate, so let us start with focussing on these. The most relevant economic paper in this context is Coase (1937) on *The Theory of the Firm*. This paper focuses the discussion of production efficiency on the question of the appropriate use of in-house production vs external production mediated via a market. The decision of a firm to go to the market to procure inputs to its production is a choice. Coase makes clear that intra-firm production is an alternative. What matters is which alternative has the lower transactions costs, where these reflect the costs of assuring quality of supply. Williamson (1975) formally suggested that the decision to produce in-house is a decision which trades off the production cost advantages of outsourcing in terms of increased scale with the transaction costs disadvantages of having to assure the external quality of bought-in inputs. Richardson (1972) pointed out that outsourcing itself can be closer to in-house production if it takes the form of an exclusive long-term contract or closer a pure decentralised market if inputs are acquired via spot market trading.

Ancillary services have historically been supplied by a combination of generator assets, network assets and demand response. In traditional vertically integrated utilities, ancillary services were mostly produced within the firm via a combination of own generation and appropriately con-

3. For instance in June 2017, Great Britain's National Grid published a document aimed at addressing the anticipated need for significantly more ancillary services over the period out to 2023 (National Grid, 2017a) in the face of sharply rising shares of intermittent renewable energy on the GB system.

4. There are some exceptions depending on the type of ancillary services. For instance, in Australia, the main Australian independent system operator (AEMO) has acted as a procurer of last-resort since 2012. Transmission operators have the primary responsibility to meet reactive power needs in the NEM (Anaya and Pollitt, 2020).

Open Access Article

figured network assets.[5] Indeed in much of the world this traditional vertical integration between generation and transmission remains in place (77 out of 172 countries).[6] However, liberalisation has led to the vertical unbundling of generation (and retail) from networks which in turn has meant new contracting arrangements between generators and system operators for the provision of ancillary services from generators. System operators responsible for "securing the system" mostly remain integrated with transmission owners (Chawla and Pollitt, 2013), with independent system operators (ISOs) operating a minority of the world's electricity networks. These system operators face a direct choice between in house investments in network assets and/or contracting with generators, demand and other third parties on a short or long term basis to provide services. ISOs, with no capacity for any hard asset investments, can still decide on the term-structure of the contracts that they enter into to provide ancillary services. Interestingly, technological developments—such as declines in the cost of battery storage—provide more choices (and in-house possibilities) for system operators to rely less on traditional providers—large generators—of ancillary services.

The point that Coase highlights is that ancillary services are something that transmission system operators could produce in-house without the use of the market, or could contract for long term with exclusive contracts or indeed procure via "spot" markets. When we discuss markets for ancillary services we need to bear in mind that "spot" markets are not always desirable or efficient ways of procuring inputs, even though over time there would seem to be a tendency to make more use of them in other areas of economic procurement (there has been a general trend to market based outsourcing among large companies).[7]

A key insight of Coase is that the capitalist firm makes the decision on how much outsourcing to do and how much to keep within its own internal planning system. As such one of the key efficiency drivers of the capitalist system is that it should arrive at a more optimal privately determined mix of planning and markets. An important implication of this for ancillary services markets is the extent to which the choice of particular types of markets (or the use of an external market at all) is actually globally efficient or one mandated by the regulator/central government.

In general, market outsourcing works well when the product being outsourced is well defined and separable from in-house activities, there is sufficient demand to justify the fixed costs of market participation and the product is capable of being provided by many cost-efficient/innovative suppliers who can compete directly with each other. While this is clearly true of wholesale electrical energy markets, it is likely to be less true of many ancillary services. In-house production/long-term contracting works well in conditions of uncertainty about how much to procure and/or how the costs of different quality features trade off with each other. In-house production/long-term contracting can also be a good way to manage external suppliers who would otherwise exercise market power. Indeed, in-house intra-firm production/long-term contracting is a form of private regulation (as well as planning).

Ancillary services, as we shall see, are often poorly defined as products, associated with significant uncertainties about how much to procure and may be subject to significant market power within the limited local area that they are needed (especially for voltage support and constraint management). These are traditional reasons why they have been supplied in-house or via longer-term contracts rather than via spot markets. None of the recent textbooks we looked at on electricity markets cite Coase's (1937) paper (though it is mentioned in Joskow and Schmalensee, 1983).

5. See Hirst and Kirby (1998) who discuss how ancillary services traditionally supplied by utilities on a regulated cost basis could be competitive in the future.
6. See Anaya and Pollitt (2019).
7. See for example Dahiya et al. (2015).

3. WHAT DO WE MEAN BY ANCILLARY SERVICES AND ARE THEY UNIQUE TO ELECTRICITY?

Various academics offer helpful perspectives on the nature of ancillary services.

Stoft (2002) discusses ancillary services in the US under 6 headings: real power balancing, voltage stability, transmission security, economic dispatch, financial transaction enforcement and black start. He then lists four real power balancing services: regulation of frequency, energy imbalance, spinning operating reserve and supplemental operating reserve. Stoft's lists are all the activities of the system operator.

Kirschen and Strbac (2019) helpfully emphasise that ancillary services "were given this name because they are auxiliary to the main commodity, i.e. electrical energy" (p.206). For them, the distinctive feature of the system operator (SO) is their responsibility to ensure the reliability of the system in real time. They point out that "ancillary services" are synonymous with "reliability resources" required by the system operator to do their job.

Creti and Fontini (2019) define ancillary services as "balancing services and reserves, as well as voltage control and system restoration services" (p.65). They point out that the first two can be provided competitively while the "latter two are provided by devices that are under the control of the SO or by a few types of plants" (p.65). However a key point about all ancillary services is that they only have one buyer in near real time and that is the SO.

Turning to different electricity systems the terminology around ancillary services becomes more diverse and it is difficult to map ancillary services products onto each other.[8] We discuss PJM in the US, Great Britain (GB) and the NEM in Australia in what follows as three examples of electricity markets with different (but transparent and easy to follow) ancillary services procurement arrangements. PJM is typical of arrangements in the US, while the GB is (currently) typical of arrangements within the European single electricity market.

Economic dispatch (following Stoft's list above) may be an objective of a US independent system operator/regional transmission organisation (ISO/RTO) like PJM, but it is a natural characteristic of any system where generators are clearly incentivised to profit maximise as they will make their least cost plant available. Most ISOs/RTOs have adopted centralised wholesale markets based on a security constrained bid-based economic dispatch model (Joskow, 2019). In Great Britain, under self-dispatch where power plants inform the system operator if they want to run, the system operator does not need to ensure economic dispatch of all power plants, the profit motive does that. Financial transaction enforcement (what is called "settlement" in Great Britain) is important but it need not be done by the system operator—it could be done by a third party.

PJM currently defines "ancillary services markets" as being only about frequency regulation, reserves and black start on its website.[9] A longer list of ancillary services (including reactive power among others) is provided in the State of Market Report for PJM prepared by Monitoring Analytics. Only regulation and reserves (synchronised and supplemental) are provided through market mechanisms, the others, such as voltage control,[10] are provided on a cost basis. Real time energy balancing is handled by the real time energy market which calculates clearing prices every

8. For an early attempt to compare the diversity of ancillary services definitions and arrangements, see Raineri et al. (2006). For a discussion of early arrangements in Nordic countries, see Kristiansen (2007).

9. See https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx. For some history on the evolution of ancillary service market design in PJM, see Isemonger (2009).

10. See https://pjm.com/~/media/about-pjm/newsroom/fact-sheets/reactive-power-fact-sheet.ashx

five minutes based on real time security constrained economic dispatch. Energy constraints within the transmission system are managed via nodal prices which are also calculated every five minutes.

The NEM has three categories of ancillary services (AEMO, 2015a): frequency control ancillary services (FCAS), network support & control ancillary services (NSCAS) and system restart ancillary services (SRAS). These cover frequency regulation, voltage control and black start. In addition NSCAS includes constraint management with respect to inter-connectors between regions (via a Network Loading Control Ancillary Service) and the provision of inertia (via a Transient and Oscillatory Stability Ancillary Service). The NEM operates a real time energy market with clearing prices every 5 minutes for each of its—5—provincial sub-markets.

National Grid (2017a) defined ancillary services in Great Britain under four basic product categories that the system operator (GB ESO) needed to procure: frequency regulation, voltage control, system security (including constraint management and black start) and reserves.[11] These are in addition to its use of the balancing market for real time energy and the operation of the longer term (1 year and 4 year ahead) capacity markets.[12] In 2016 there were around 30 products that the system operator might be procuring. This was in addition to a balancing energy market. This has since been rationalised to only 22 (and falling). For frequency, alone there were three products: primary, secondary and fast (PFR, SFR, FFR), corresponding to the speed at which providers could respond and the length of time for which they could hold their response quantity.

PJM, GB ESO and the NEM agree that ancillary services include frequency regulation and reserves. They disagree about whether "ancillary services" include voltage control or constraint management, though each of them do manage these. Balancing energy is procured via a "real time" market in each case and is not technically defined as an "ancillary service" in any of the markets, even though it is the system operator that requires a balancing energy service and is the one deciding how much quantity to take out of this market. The GB ESO, in line with system operators across Europe, bundles "balancing and ancillary services" and reports them together.

A key point is that the number of defined ancillary service products being procured by the system operator is a matter of history rather than purely a matter of the nature of the product. The product in many cases is not well defined. Some authors (e.g. Greve et al., 2018, who suggest trying to have one frequency response auction with bids evaluated against each other on the basis of willingness to pay for speed and quantity of response) have suggested rationalising the number of products down and trying to reduce the capacity for arbitrary product boundary categories. The GB system operator, National Grid ESO, has reported that it is working on the rationalisation, simplification and improvement on the current balancing services (National Grid, 2017b, 2018).

As we alluded to earlier it is fashionable—among electrical engineers—to suggest that the need for ancillary services is an unusual feature of electricity markets and arises from the peculiar physics of electricity (as embodied in Kirchoff's Laws and Ohm's Law). That physics involves: the need to balance supply and demand at all nodes in very close to real time; the presence of loop-flows which mean that power in meshed AC networks can flow down multiple pathways between the generator and the load; and that associated thermal, voltage and dynamic stability limits need to be observed in power transmission and distribution (see Leautier, 2019; Biggar and Hesamzadh, 2014, p.66).

11. This is in line with the European Network of Transmission System Operators (ENTSO-E) who define ancillary services to include black start, frequency response, fast reserve, reactive power and "various other services." See https://docstore.entsoe.eu/about-entso-e/market/balancing-and-ancillary-services-markets/Pages/default.aspx

12. ENTSO-E also combine and distinguish "balancing and ancillary services markets', op.cit.

It is important to state upfront that the need for firms producing a product to manage the unique chemistry or physics of the production and delivery process is not at all unusual. Nor is it particularly unusual that stability limits need to be observed and rates of change are important. Indeed, it is quite common that producer-distributor firms need to take actions which are unique to that industry (one thinks of the management of data packets, transportation of living tissue and aluminium production as being good examples of interesting physics and chemistry requiring adjustments to the production process), that does not make the economics of assuring quality and continuity of supply unusual. Furthermore, the actual physics of power networks is not that unusual: the public internet and transport networks share many similar characteristics. One of the great insights that drove power market reform was a scepticism (on the part of economists, such as Weiss (1975) and Joskow and Schmalensee (1983)) that the peculiar physics of electricity should prevent it being traded like other commodities.

Nor are the characteristics of service quality unique to electricity. Other network industries are not just concerned about delivering quantities of product, but care greatly about service quality which may be particular to them (and be very precisely defined). Thus financial transaction transmission networks (such as credit card systems) are interested in accuracy and speed which is every bit as significant as in electricity networks (Visa verifies a transaction in 3 secs globally). The public internet has to manage both data privacy issues and guard against data packet loss. Transport networks of various types (e.g. air transport) work to passenger safety standards which are similar to the standards for delivery of electricity (i.e. more than 99.995%[13]).

Similarly, it is also true that regulatory limits on the ability to vary real time prices is not unusual to electricity. Indeed, this is a common feature of all regulated industries, that governments and their regulatory agencies limit the use of price discrimination, especially by location, for final customers. More interestingly, it is a common feature of unregulated industries that private companies often engage in self-limitation of price variation because their customers prefer this (because it engenders trust), it simplifies marketing messages and reduces the likelihood of interference from regulators. Indeed, many platform markets go further and make their products free to whole classes of customer (across multiple geographies). Thus, exposing final customers to differential prices which reflect real time network conditions or local cost variance is in general not a feature of most markets—it is mostly left for network owners to manage those risks internally.

It is also common to say that the liberalised electricity industry has been restructured in a way—separating generation, networks and retail (and increasingly also system operation)—that gives rise to problems of coordination and requirements for market solutions which are unique to electricity. This is also not universally true: several other network industries have had forced separation of different stages of production (e.g. gas, telecoms) and many others have voluntarily separated stages of production (e.g. water, transport, financial services). Managing a transaction boundary is common to many industries and this does not require a unique set of market arrangements for the assurance of final product quality.

It is however true that certain aspects of outsourcing are forced in some electricity markets, when they could be more efficiently carried out in-house. Most industries simply carry excess capacity or curtail demand rather than use formal markets to match supply and demand and maintain quality in real time (though large firms do use smaller third parties to help them manage peak demand, e.g. logistics firms). Carrying excess capacity is a way to reduce the market power of third parties who may be only required occasionally and hence take opportunities for price gouging when

13. Regarding U.S. accident rate per 100,000 flight hours, see: https://www.faa.gov/news/fact_sheets/news_story.cfm?newsId=21274

they can. It is also true that the real-time impacts of failure to match electricity supply and demand can be more pervasive than in other sectors (though even this is not entirely clear as failures of payment and transport systems do have significant widespread effects in the short run).

4. WHY IS COMPETITION IN THE MARKET FOR ANCILLARY SERVICES RELATED TO THE RISE OF DISTRIBUTED GENERATION?

The rise of distributed generation is very real in some electricity markets under deep decarbonisation targets and/or where renewables are nearing grid-parity in cost. Distributed power production is expected to continue increasing significantly, with a forecast of around 110 GW by 2023 (with circa 55 GW in 2014) in Western/Eastern Europe and North America (VGB, 2018).[14] Most of these renewables are expected to be added to distribution networks. Much of these renewables will be in the form of solar and wind, which are intermittent and give rise to physical challenges which need to be managed. For instance, according to the Australian Renewable Energy Agency (ARENA),[15] more than 2m households in Australia (out of 8.3m)[16] have already installed rooftop solar systems. In the NEM, distributed energy resources (DERs)—which include solar, wind and batteries—are expected to increase from 4 GWs in 2016 to 18 GW by 2030,[17] in a system with peak demand in 2018–19 of 34 GW. By contrast in PJM, solar PV is forecast to grow from 5 GW in 2019 to 12 GW by 2034,[18] in a system with peak demand in 2018 of 166 GW. For the UK, there has already been a significant increase in distributed generation (DG): there was 33 GW of DG in 2018, more than twice the 2011 figure, representing almost 1/3 of total generation.[19]

Rising intermittent renewables, at least in theory, may increase the demand for ancillary services, as flexibility services are needed to support the absorption of renewables. Indeed, one study for Great Britain predicts that by 2030 the value of non-balancing market ancillary services will be 25% of the total value of the wholesale energy market, from 2% in 2015 (see for example Poyry and Imperial College, 2017, p.21, who suggest costs will rise from £0.6bn to c.£3.9bn). Evidence from the South Australia region of the NEM also suggests the importance of Frequency Control Ancillary Services (FCAS) may rise; as the table below notes FCAS averaged \$3.4m per annum 2012–2014, then increased to \$35m+ following the exit of the last coal plant in 2015.[20] We consider balancing, frequency regulation, voltage control, constraint management (which we take as the main system security product) and reserves in turn.

Wind and solar power are subject to difficult to predict intermittency and have daily loading patterns which can be extreme (with high ramp rates). This may increase the requirement for balancing energy, which is based on the difference between predicted supply and demand. It is important not to over-emphasise this because wind and solar forecasts are improving and intermittency is not the same unpredictability, especially in aggregate for whole electricity markets. The trend to more power being traded through balancing markets will be offset if intra-day trading through power exchanges becomes more prevalent. A spot market which operates near to real time and over

14. From Navigant Research report cited by VGB (2018, p. 10).
15. See: https://arena.gov.au/about/what-is-renewable-energy/solar-energy/
16. From 2016 Census. Figure refers to occupied private dwellings only, see: https://quickstats.censusdata.abs.gov.au/census_services/getproduct/census/2016/quickstat/036?opendocument
17. See AEMO (2019, p.16).
18. See https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/distributed-energy-resources.ashx
19. See DUKES (2019, p.96).
20. We note however that as a percentage of turnover, FCAS remains below 2% in the last two reported years. This has been due to the market response to rising FCAS prices.

Table 1: Frequency Control Ancillary Services (FCAS) costs in the NEM (South Australia region)

Year	FCAS Cont. ($m) [1]	FCAS Reg. ($m) [2]	Spot energy value ($m) [3]	Total FCAS / spot energy value [4]=[[1]+[2]]/[3]
2012	3.7	0.8	1,208.0	0.4%
2013	3.7	0.4	1,953.6	0.2%
2014	0.9	0.4	1,334.2	0.1%
2015	7.4	28.0	1,362.6	2.6%
2016	4.3	45.0	2,123.8	2.3%
2017	6.8	41.8	2,776.5	1.8%
2018	23.2	15.5	2,567.4	1.5%

Annual figures (nominal): Jan.–Dec., FCAS: Frequency Control AS, Reg: Regulation, Cont: Contingency. Source: AEMO (AS annual reports, aggregated prices and demand data—historical)

shorter time period windows (say 5 mins as in the NEM) will offset underlying rises in the demand for balancing energy. However, there is still much local variation—due to cloud cover or local wind patterns—which effects particular generation facilities at individual network nodes.

The presence of extremely variable wind and solar generators which are not synchronised to the system frequency may mean that the frequency varies more than in the past.[21] For instance, NEM system frequency (excluding the Tasmanian region) did show a significant decline in the percentage of the time it was operating inside the normal frequency range from February 2018 to February 2019. This followed several coal plant closures (5000MW+) and rising levels of variable renewable energy. This triggered an increase in AEMO (the system operator) demand for FCAS Regulation Services, from 130MW to 220MW+ in order to bring frequency back within the "Normal Operating Frequency Band" of 50Hz +/- 0.015Hz for > 99% of time. This change was implemented in March 2019.

Fossil fuel generators connected to the system naturally adjust to maintain system frequency when loaded between their minimum and maximum stability limits. More accuracy in wind and solar forecasting can partly adjust for this and there is an issue of whether there will inevitably be more MWhs required for the maintenance of system frequency within required limits—more small variations around the target frequency can be partly offset by less large frequency variations arising from the loss of individual large fossil-fuel generating units. Synthetic inertia can be provided to replace the loss of the large rotating masses in conventional power stations which stabilise system frequency, but incentivising the provision of such inertia from, say, batteries is why system operators are looking more closely at markets for ancillary services.

Voltage must be maintained within minimum and maximum limits at all nodes. Voltage varies when too much power/too little power is injected relative to demand. This gives rise to the need for reactive power (MVars) to be either injected or withdrawn. Voltage can vary at every node and MVars do not travel far from where they are injected or withdrawn. So the adjustment of MVars is a local service (as opposed to the maintenance of system frequency which is system wide). Distributed generation gives rise to two new sources of MVar requirements. First, when distribution systems are operating with low demand but high generation, they export power and voltage rises. MVars need to be withdrawn. Second, when distribution wires are built for generation they can absorb MVars when not in use, hence MVars need to be injected (or the line can be isolated). Indeed, rising demand for MVars (to be withdrawn or injected) can be mitigated by better management of the existing distribution networks. Traditionally large scale fossil fuel generators have the capacity to supply/withdraw MVars at low cost and have been supplemented by reactive assets such as static

21. See, for instance, CCC (2019).

compensators. Falling traditional generation creates the need for replacement sources of MVars. Distributed generators and loads can be sources of MVars and be used to mitigate the increasing MVar requirements that rising distributed generators may create. Another option is optimising the operation of the distribution network assets to reduce MVar requirements (Strbac et al., 2018).

The intermittent nature of wind and solar power added to the distribution system exacerbates constraint management issues. This is because distribution systems are initially sized for loads and it is not likely to be optimal to re-size them for peak export of renewables, especially given that the peaks may be very peaky and coincident peaks from multiple generators interacting with local loads are rare. The willingness to pay for resizing for export is different than the willingness to pay for peak import. Load customers on distribution networks are willing to pay the value of lost load to avoid interruption. Generator customers on distribution networks are only likely to be willing to pay the market value of the electricity curtailed. This suggests a rising requirement for constraint management at the nodal level and hence a role for locational marginal prices to signal where best to locate generation and, increasingly, new loads (or storage).

Intermittent renewables suggest a need for increased (capacity) reserves, in the event of a deviation from the average level of output or due to expected daily or seasonal variation in wind and solar output. Reserve markets take many forms, the most important being markets for short term operating reserve (in Great Britain) or capacity markets.[22] Reserve markets involve paying capacity to be available at short notice rather than simply relying on short run market prices. A key question is whether intermittency, which is fairly predictable, can be best handled by short run energy prices, rather than via reserve markets? In the past reserve costs have consisted of simply paying the marginal cost of making existing fossil fuel plants (built for the energy market) available, rather than also compensating for the upfront capital cost of the reserve capacity (for capacity built for the reserve market). However in markets with declining demand and lots of existing fossil fuel generation capacity it is not immediately clear that higher quantities of reserves will give rise to high per MW prices for reserve capacity. Indeed, capacity market prices have been low in PJM and GB recently.

Overall, we would expect rising shares of intermittent renewables to increase the quantity of ancillary services demanded relative to the underlying total quantity of energy demand. However, it is important to point out that this is mitigated to some extent by better renewable generation forecasting and by increasing load flexibility (e.g. from the presence of electric vehicle loads). Furthermore, the ISO demand/requirement for frequency response (and other ancillary services) is small relative to total system (energy) demand.

It is quite another question as to whether rising demand for ancillary services means rising prices for ancillary services. This depends on the supply curve of ancillary services. Distributed generators can provide ancillary services as well as creating the demand for them. Thus, the net increase in demand (for new ancillary market players) is limited by this. It is also true that new providers of ancillary services, such as flexible loads and local storage can more easily provide the local ancillary services required for voltage and constraint management, than in the past. These technologies can provide ancillary services very competitively (with each other) and their costs are coming down significantly. At the same time, existing fossil fuel generators, faced with declining energy demand, can still compete strongly to provide them. This suggests that the estimate of £3.9bn in 2030 for Great Britain is already likely to be an overestimate (Poyry and Imperial College, 2017).

22. Capacity markets often cover the whole market and in that sense can hardly be thought of as “ancillary.”

5. HOW ARE ANCILLARY SERVICES PROCURED TODAY AND HOW MIGHT THEIR MARKETS DEVELOP?

Ancillary services are typically procured in three ways. First, via a mandatory response which is required as a condition of being connected to the network. This may or may not be compensated at a fixed price or at opportunity cost. Second, via a long-term bilateral contract (between the transmission system operator (TSO)/ distribution system operator (DSO) and the service provider) for a specific service at a specific location. Third, via a market based procurement mechanism on the basis of invited bids. These can involve regular auctions typically for one or six months ahead,[23] or indeed real-time co-optimised dispatch (as in Australia).

Taking each of the five main ancillary service products in turn, we can discuss the role of markets in their provision, drawing on the experience of GB, PJM and NEM.

In real energy balancing, this is very close to existing wholesale markets for electricity. Intra-day and formal balancing markets work in similar ways to day-ahead and longer term energy markets on the basis of price bids. Exposure to balancing markets is strongly disincentivised because if the market is long generation prices in the balancing markets will be low relative to longer duration markets for generators, while if the market is short retailers buying in the balancing markets will pay more than they would have done through longer duration markets. Hence both generators and retailers have incentives to minimise trading in balancing markets. The price series for the balancing market in GB shows that a generator receiving payment from the balancing market would on average have received significantly less than if they had sold day-ahead in the power exchange, similarly a retailer would have paid significantly more. In addition, the size of balancing markets is small at c.3% of total electrical energy consumed by final consumers in GB.

Markets for frequency response are common in advanced markets. They typically pay both an availability per MW and a utilisation payment per MWh. GB, PJM and NEM all have frequency response markets. In the case of GB there have been up to 4 frequency response (FR) products procured through market processes. Typically, these operate on a monthly basis for one month ahead. However, in many electricity systems frequency response is compensated per MWh of actual energy injected and generators are simply mandated to provide frequency response services. A comprehensive list of European countries with information about the type of payments (availability and/or utilisation) applicable to key ancillary services can be found at SEDC (2017).

Markets are used for reserves in the leading markets, though many electricity systems around the world still make use of fixed payments for capacity. Reserve markets can be for short term operating reserve, through to longer term capacity markets. What matters for real time operation of the system are the short run reserve markets. PJM defines different kinds of reserve products, listed in Table 1. The operating reserves design involves two types: Tier 1 and Tier 2 (for synchronised reserve). However, there are some inconsistencies in the current methodology in pricing and operational requirements (Hogan and Pope, 2019). PJM recently filed at FERC (its regulator) a proposal to consolidate Tier 1 and Tier 2 into one product (synchronised reserve) and adopt a more robust Operating Reserve Demand Curve (ORDC) market. The list of reserve and frequency response products procured in GB and Australia, is shown in Table 2.[24] The use of co-optimisation with wholesale energy markets is observed in the PJM and NEM markets (PJM, 2018: AEMO, 2015).

23. GB commenced trialling weekly auctions for frequency response in June 2019.

24. In GB, STOR and fast reserve are the most representative reserve products. For the full list visit: https://www.nationalgrideso.com/balancing-services/reserve-services

Open Access Article

Table 2: Comparison of different frequency response and reserve products procured in NEM, GB and PJM (selected products)

Description of AS/others	Australia (AEMO)	Great Britain (NGESO)	USA (PJM)
Frequency response	RegRaise RegLower	Firm frequency response (FFR) Enhanced frequency response (EFR) Mandatory frequency response (MFR)	Regulation
Reserves	Lower6sec,Raise6sec Lower60sec, Raise60sec Lower5min,Raise5min	Short Term Operating Reserve (STOR), Fast reserve	synchronised reserve (SR) non-synchronised reserve (NSR) supplemental reserve
Use of co-optimisation	Yes	No	Yes

Notes: There are three response speeds for FFR&MFR: primary (within 10sec sustained up to 20sec.), secondary (within 30sec sustained up to 30min), high (within 10sec sustained indefinitely). Two types of response speed for reserve: primary (within 10min): SR, NSR; secondary (within 30min).
In PJM two types of automated signals are generated for regulation: Reg. D (fast response), Reg. A (slow response).
Source: AEMO (2015), NGESO website (Balancing Services), PJM website (Ancillary Services)

Voltage control markets are underdeveloped (see Anaya and Pollitt, 2020).[25] Typically, reactive power must be provided locally and has been managed through mandatory requirements to provide it at fixed prices and a reliance on network owned reactive assets (such as shunt reactors). GB has been entirely procuring reactive power (RP) at fixed prices[26] (Obligatory Reactive Power Service - ORPS), with a parallel auction process (Enhanced Reactive Power Service - ERPS) having withered away to no useable offers. PJM compensates generators for RP capability based on American Electric Power (AEP) methodology and pays opportunity cost. NEM makes some use of a national RP market and participants may receive different kinds of payments depending on the operation mode (AEMO, 2017). More recently some jurisdictions have begun to experiment with local markets for reactive power. National Grid (the GB transmission system operator) and UKPN (the distribution system operator for the London area) are currently trialling the use of auctions to supply RP to four transmission-distribution boundary nodes in the south east of England near London. This trial aims to test the ability of DERs to supply RP via a weekly auction.[27]

PJM famously uses nodal pricing for constraint management[28] within its transmission system area.[29] These prices are calculated on the basis of the day-ahead bids/offers for every 5 minutes. They reflect the actual condition of the grid and network congestion. It is important to say that this is not a real-time auction, because the bids/offers are not adjusted in real time. By contrast in GB, constraints are managed by a mixture of contracts for constraint management and constraint payments whereby generators and loads are paid to adjust their positions to manage constraints. This is procured via tenders or bilateral contracts and the payments are determined in the balancing market (with suitable adjustments to the calculation of the balancing prices). These adjustments occur in a system where zonal annual charging for transmission gives a long run signal to generators and

25. Hogan (1993) suggests how competitive locational prices for reactive power could be calculated, though Kahn (1994) offers a critique of this based on the likely ability to exert local market power in reactive power markets.
26. Subject to some indexation.
27. For further details about the Power Potential trial see: https://www.nationalgrideso.com/innovation/projects/power-potential
28. Transmission constraints can be caused for different reasons (e.g. issues with thermal, voltage and stability operational limits).
29. A security constrained bid-based economic dispatch mechanism is used for simultaneously handling the management of transmission congestion and the scheduling of generation (Joskow, 2019).

loads. In Australia, congestion due to constraints on transmission networks is solved via the dispatch process in a zonal (regional) pricing model (AEMO, 2018).[30] There are five interconnected electrical regions, each one with a designated regional reference node,[31] where the regional reference price is set. An improvement of the methodology is currently under evaluation. A dynamic regional pricing approach is being evaluated by the Australian Energy Market Commission. In the case of congestion due to transmission constraints, pricing regions would be dynamically created (see AEMC, 2018b). In comparison with regional/zonal pricing, nodal pricing allows a more efficient dispatch that better reflects transmission system constraints (due to lower spatial granularity), however its implementation can be challenging (IRENA, 2019) and even in theory zonal pricing can be equally efficient (see Holmberg and Lazarczyk, 2015). Nodal pricing and zonal pricing with re-dispatching lead to different distributional outcomes which can favour zonal pricing (see van Blijswijk and de Vries, 2012). Kaleta (2016) considers the issue of which is fairer and raises fairness issues with both pricing approaches. Shifting from regional to nodal prices may also adversely affect liquidity in forward markets—at least in the short run.

Where fixed prices are still used to compensate ancillary services these prices were originally calculated to reflect the opportunity cost to a fossil generator of providing ancillary services rather than energy (if already running) or start-up costs (if they were not already running). The extent to which these prices (e.g. for reactive power) still reflect opportunity cost is questionable.

In terms of charging for ancillary services these were historically procured by the transmission system operator and charged out to final electricity customers as part of their transmission charges (this was the case under the CEGB in GB). However, over time ancillary services markets have developed and charging methodologies have become more sophisticated. For instance in GB, balancing services use of system (BSUoS) charges recover the cost of balancing the transmission system and are paid by generators and retailers.[32] Ancillary services may sometimes be procured by distribution companies and charged to their customers, within systems where distributed generation has become very significant.

The rise of distributed generation has put a new focus on the use of market mechanisms to procure ancillary services. This is partly because the case for market mechanisms becomes stronger in the face of rising uncertainty about where and when ancillary services will be required, but there are many potential providers. This is a good reason to make more use of markets, even if a given quantity and location of ancillary services, if known with certainty, could be procured more cheaply in-house or via a long-term contract.

The rise of distributed generation has also pushed distribution companies to consider market arrangements for procuring local ancillary services related to voltage service and constraint management. These could be in the form of using local markets for reactive power or extending locational marginal pricing to distribution system nodes. This is because the same trends that have given rise to distributed generation exist for storage and demand side management. Lower IT and metering costs mean that the average size of a provider of ancillary services can be reduced. However, it remains to be seen as to the extent to which distribution companies will make use of sophisticated mechanisms of procurement rather than resorting to fixed price contracts. A good example

30. This method can be seen as a simplified nodal pricing method. Zonal bidding for transmission is also observed in Denmark (2), Italy (6), Norway (5) and Sweden (4), IRENA (2019). Number of zones in parentheses.

31. Represented by a major demand and/or generation centre.

32. However, there is an ongoing consultation to remove the payment from GB generators in line with other European markets where generators do not pay the equivalent of BSUoS charges. See: https://www.nationalgrideso.com/document/141486/download

of divergence in this space is in GB where one distribution company in GB, WPD, decided to set a fixed price of £300 / MWh for constraint management (WPD, 2019), while another, UKPN, decided to only procure services via competitive tenders.

6. HOW DO ANCILLARY SERVICES MARKETS RELATE TO THE REST OF THE ELECTRICITY SUPPLY INDUSTRY?

Biggar and Hesamzadl (2014) helpfully characterise the electricity system as needing to undertake short run operational tasks, long run investment tasks and appropriate risk management activities to supply electricity. They also point out that the system should make efficient use of generation, available loads and the existing network, in both the short and long run, via efficient investment in generation, electricity consuming devices and the network.

Put like this the "optimisation" of the electricity system is extremely complicated and depends on overlapping timescales and the interaction of multiple decision makers. It involves combinations of planning and markets. Overlaid with all of this is: regulation of prices and pricing methodologies (which limit both average prices and price discrimination) and government industrial policy towards both electricity investments and electricity consumers. This may favour specific generation technologies (such as wind and solar), particular locations of loads and types of consumer energy equipment (such as smart meters). Two important economic principles need to be borne in mind: Coase on theory of the firm and the difficulty of specifying the role of the market prices vs internal planning; and the theory of second best (following Lipsey and Lancaster, 1956) where introducing more price differentiation in one part of the system is not guaranteed to improve overall system welfare, it may indeed worsen it.

There is a small but significant literature on the nature of "ancillary" markets and their particular features "as" markets. Reguant (2014) shows that ramping costs at generators explain much of the exaggerated market price fluctuations in real-time electricity markets. Ito and Reguant (2016) discuss how sequentially cleared markets, as exemplified by electricity markets in general, give rise to systematic gaming opportunities. Doraszelski et al. (2018) show that it took 3.5 years of bid experimentation before the market pricing in one new frequency response market in Great Britain became efficient. Gomes and Tirole (2018), in discussing the pricing of generic "ancillary goods" (e.g. delivery charges on internet purchases), make the point that often these are given away free and priced into the price of "basic products', in order to "optimally" promote sales. This further complicates the idea of a competitive market for "ancillary goods', because the way these are priced effects the total sales of the basic product. These studies together suggest that competitive price formation in thin markets for near real time ancillary services is difficult to both achieve and to monitor.

Markets for ancillary services sit within this complex picture and it is by no means clear that sharper short run price signals for one type of service within the system is an improvement over a more planned system, at the margin, which more carefully trades off overall system costs. For example, in the South Australia NEM region, falling levels of inertia were dealt with via a regulated solution, 3 Sync Condensers at a capital cost of $180m (perhaps $10m annual cost)—in a market which turns over $1bn per annum it is hard to imagine spot markets being worth establishing for this narrow system requirement. Indeed, the practice of co-optimisation per se which trades off more than one different market cost is not guaranteed in an n-th best world to be an improvement. Independence of different costs—which might allow market prices in one sub-area of the electricity system to not affect optimality of the system as a whole—helps but it is not pervasive in the electricity system.

A key challenge in markets for ancillary services is the trade-off between network solutions and market solutions. Building a bigger network reduces the demand for local ancillary services such as voltage support or constraint management. However, network solutions occur on a different time frame to ancillary services markets. They involve assets which might last 40 or more years and are funded under a different risk-management regime (at regulated rates of return).[33] Network solutions can be about thicker wires or about network assets (such as reactive compensators or grid connected batteries). Indeed, Kunz (2013) makes the point that the management of congestion can be focussed on either the network or on the market participants, but that the optimal pricing arrangements differ in either case. Uniform network service prices give stronger network management incentives, while differential nodal prices provide incentives to market participants.

Another challenge is time frame. Markets work well when there is a seamless connection between short run market prices and long run market prices, when long run contract prices exist which reflect the time series of short run prices. This can create financial instruments which allow investors in assets which play in short run markets to hedge their risk. This would seem to be important for ancillary services which are by their nature subject to highly volatile demand/supply and pricing in the short run. Some system operators have had to create specific markets which hedge this risk: such as those for financial transmission rights (to hedge against the use of nodal prices to manage short run constraints in the transmission system) and capacity markets to create long run markets (4 years+) for reserve capacity. One observation is that these long-run hedging markets are very patchy across ancillary services. They generally do not exist for frequency response, and not at all for voltage support.

Even in markets for electrical energy the existence of long run markets has been an issue. Such markets do not generally exist for power for more than 3 years, or if they do the product is rarely traded. Instead most generators have chosen to hedge longer-term by integrating with retailers directly—another Coasian solution to how to organise production efficiently in the presence of a lot of uncertainty about the future supply/demand balance and outturn prices. Thus, something like the classic Schweppian (Schweppe et al., 1988) insight that nodal prices can help manage short run network congestion (popularised to great effect by Hogan, 1992) must be put in context: it is only signalling one among many network characteristics and may not give rise to an overall efficiency improvement in the absence of the pricing of all other network characteristics. The fact is that only parts of the network are priced and only some network connected loads and generators are exposed to these prices. A system of constraint management that was more centralised could give rise to better long-run investment in constraint reduction and could easily be more globally efficient.

Rising distributed generation may exacerbate the global optimisation problem. It does this by giving rise to much greater fluctuations in the use of the network than in the past and hence the need to trade off different investments in load flexibility, generation and networks more carefully. With large transmission level generators and steady load growth the required investments are less subject to trade-offs, especially between longer run investments and short term ancillary service markets. Good examples would be the requirement to manage intermittency, which could either involve increasing market interconnection (over a wider area) or local solutions which could be on the demand or supply side (or even markets for "fast ramping" to deal with the Duck Curve issue arising from the rapid decline of solar generation in the evening). This suggests many more trade-offs across multiple overlapping scales and timeframes. The idea that "just" introducing a short-term local market is the solution to this problem is to limit and direct the solution in a particular and not-necessarily optimal way. One example of this is Papavasliou and Smeers (2017) who show how

33. In GB it is 45 years for new transmission operator (TO) assets, set by Ofgem under RIIO-T1 (Ofgem, 2012).

Open Access Article

the short run operating demand curve (ORDC) can co-optimise reserves and energy in near real time, but does not solve the long term problem of capacity adequacy.

7. WHAT IS THE EVIDENCE ON THE IMPACT OF RISING DISTRIBUTED GENERATION ON MARKETS FOR ANCILLARY SERVICES?

7.1 Cost, price and quantity impacts

In Europe the share of renewable energy in total electricity supply has risen from 15% to 30% in the last 10 years. It set to rise again to perhaps 55% in the next 10 years (see Chyong et al., 2019). In some countries the rise has been even larger. For instance in Denmark, Germany, Ireland, the UK and Australia (inter-alia) the share of renewables in electricity generation.[34] has risen sharply (with around 60.3%, 34.4%, 30.1%, 28.1% and 16% respectively by 2017). In PJM the share of renewables is still low. For instance by 2016, the share of PJM's installed capacity consisted of 33% coal, 33% of natural gas, 18% nuclear and only 6% renewables (including hydro).[35] Much of the new renewable capacity has been in distributed generation (especially in the UK and Germany) and a significant amount has been in non-dispatchable renewable generation (though biomass remains a significant share of the rise in renewables).

However the actual impact so far on the demand for ancillary services has been modest in most markets.[36]

In GB the growth of the cost of ancillary services has been modest at perhaps a rise of 25% over 5 years nominal terms (much less in real terms). This is not quite the full picture of the impact of renewable electricity. We have seen the introduction of a capacity market and there has been significant network reinforcement to support renewables, in particular, a large investment in interconnectors with other countries. It is observed that balancing costs (exc. transmission constraints) have increased by around 12% (annual figures) between 2013/14 and 2017/18, in real terms, see Figure 1.

In PJM, we observe that the annual average price of ancillary services has increased around 1% (annual compound average, real) for the period 1999 and 2018, see Figure 2. Reactive power ancillary service is getting more relevant than frequency regulation, especially in the last 5 years. In contrast with GB, PJM co-optimises regulation with synchronised reserves and energy in order to minimise the cost of the three products. AEMO also uses co-optimisation techniques.

In contrast with PJM and GB, in NEM ancillary service costs have increased materially, especially in 2017 and 2018. Looking at the figures it is noted that this increase in mainly driven by the upward trend in frequency control costs (FCAS contingency followed by FCAS regulation). Figure 3 depicts this trend.

Looking behind the figures in more detail we find that the quantity of ancillary services being procured has been rising, but that prices have been moderating (i.e. in line with competitive responses, including from battery storage).

A clear picture that emerges, so far, is that the implications of rising amounts of renewable generation for ancillary services is modest. This is not to say that better use could not be made of

34. Sources Eurostat database and DEE (2018).

35. See: https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

36. There is more potential for increase in isolated markets with very strong renewables growth. Ireland has experienced a growth in constraint management costs, with a large growth in wind generation, see Di Cosmo (2018).

ancillary services markets: maybe there has been too much network investment and not enough competitive procurement.

7.2 Analysis of markets for ancillary services

There has been relatively little literature on the analysis of markets for ancillary services. Most of the current literature is focused on technical issues around the integration of intermittent resources and their ability to provide ancillary services (including those from distributed generation such as solar PV, wind). Anaya and Pollitt (2020) provide further details about specific technical studies related to ancillary services.

There are a small number of surveys of ancillary services markets. For instance, Rebours et al. (2007) evaluate the economic features of eight system operators in their procurement of frequency and voltage control ancillary services. They identify the different methods for procuring those services and identify common features among the different jurisdictions, observing a lack of competition for some of them such as voltage control. Zhou et al. (2016) perform a survey of ancillary services (with a focus on frequency regulation and reserves only) in the ISOs/RTOs from the US. They find common trends among system operators and identify that frequency regulation are the ancillary markets with the highest price followed by spinning and non-spinning reserves. They identify PJM as the largest market for frequency regulation (by revenue and capacity) and for spinning reserves (by capacity). Banshwar et al. (2018) discusses the ancillary service markets in the US and BRIC countries (Brazil, Russia, India and China). They explore the main issues that each of these markets is facing in order to improve competition (i.e. weak legal systems, poor ancillary service market design, and other non-energy related factors). They find that India and China are at the developing and exploratory stages, respectively.

There are relatively few analyses of ancillary service market prices (as ancillary services, rather than the earlier examples of market behaviour more generally). Some of these are simulations and some are analyses of actual data. Skytte (1999) offers an early econometric study of frequency regulation prices in Nord Pool to show that these are more exaggerated than energy prices. Jamalzadeh et al. (2008) show how co-optimisation of ancillary services and energy in California should result in significant improvements in efficiency. Zhang (2009) found that the transmission congestion contract market in New York was inefficient with risk averse bidders under paying for the rights to congested transmission capacity over the period 2000–04. Mount and Ju (2014) question this result using later data, finding no evidence of under-pricing in mid-2006. Wang et al. (2011) analyse reserve and frequency regulation prices in Ontario, New York and ERCOT (Texas) over the period 2005 to 2009 and compare them to the price of energy in the respective markets. They find that the ancillary market prices exhibit much more volatility *and* lower predictability than the underlying energy prices to which they are linked. Paine et al. (2014) show that the exact design of ancillary services markets significantly effects the revenue of market participants. The same pumped storage hydro facility in the New England ISO area earns one eighth the frequency response revenue that it would earn in the MISO area. Rammerstorfer and Wagner (2009) analysed the 2006 reform of the minute reserve market in Germany combining the four separate markets that previously existed. They find that market efficiency did improve. Flinkerbusch and Heuterkes (2010) simulated the counterfactual and estimated the initial impact of the reform to be a 17% reduction in balancing costs. Haucap et al. (2014) estimated that the reform more than halved the costs of reserves procured through the market. Furtwangler and Weber (2019) show that when CHP plants entered spot energy and reserve markets in Germany prices of both fell. Gianfreda et al. (2016) shows how rising

Figure 1: Trend of balancing costs in GB (exc. Transmission constraints)

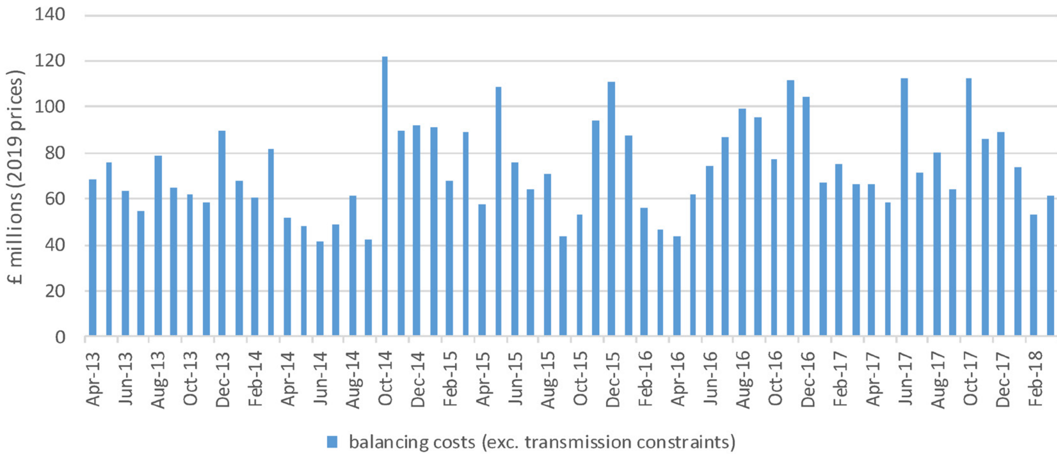


Figure 2: Ancillary services average cost per component in PJM (USD)

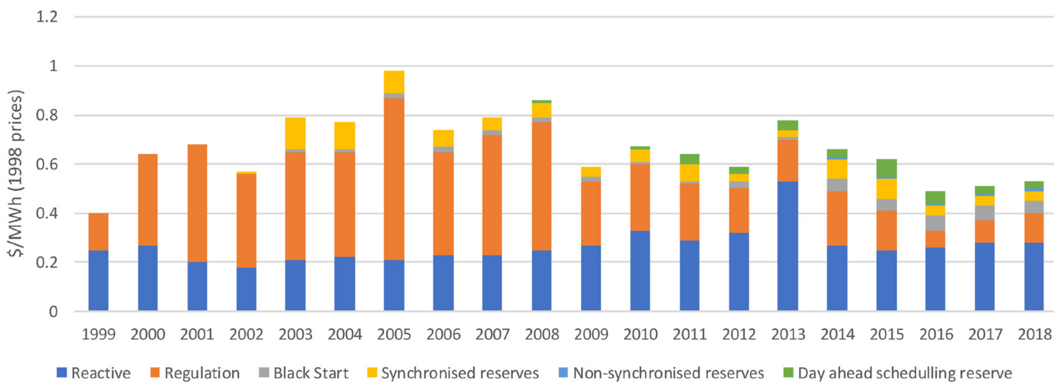
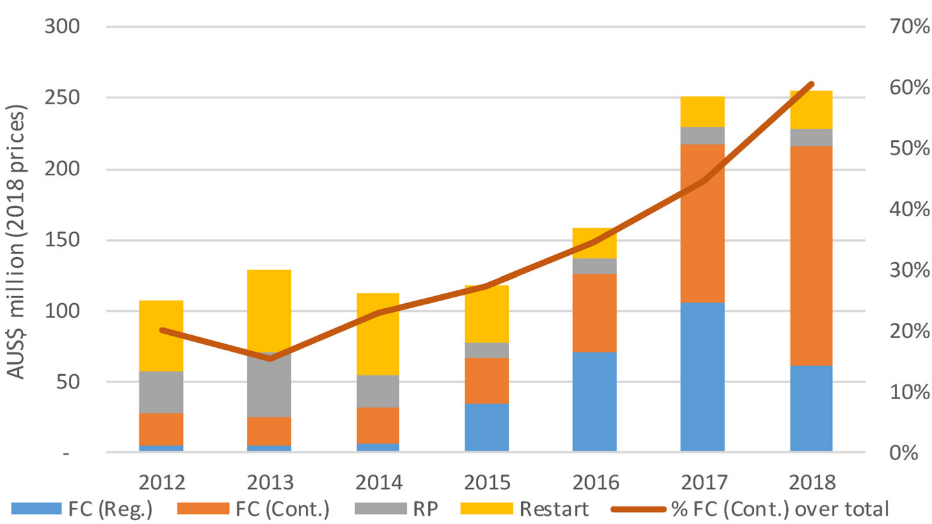


Figure 3: Ancillary services costs per component in the NEM



amounts of renewable electricity supply (RES) in Italy is increasing the market power of fossil fuel generators in the balancing market.

The picture that emerges from these empirical studies is that: they focus on a small number of markets; they do point to significant effects due to changes in market design rules particularly (with respect to who can participate); and that prices are relatively volatile and more difficult to predict than energy prices. There would also appear to be plenty of scope for additional academic work on the likely future profitability of market provided ancillary services investments under different market designs, given the emerging evidence on actual market prices and quantities.

7.3 Innovation

Several studies discuss the scope for significant improvements in the efficiency of ancillary services markets.

Metaxoglou and Smith (2007) look at day ahead and hour ahead reserve markets in California to show that shifting reserve procurement closer to real time would reduce total costs. They suggest that system operator was prevented from doing this to the optimal extent by the current market design. Van der Veen and De Vries (2009) discuss a number of improvements to Dutch Balancing market which aim to reduce demand for balancing services and increase participation in the face of rising microgeneration. Just (2011) discusses how the shortening of reserve market trading periods in Germany would improve efficiency and reduce both reserve prices and spot energy prices. This is because closer to real time procurement of reserves improves dispatch decisions (as also discussed in Just and Weber, 2008).

Doorman and van der Veen (2013) discuss how a common set of rules for balancing markets across Europe could be developed. Mauritzen (2015) points out how poorly designed subsidy regimes for renewable electricity supply (RES) increase balancing costs using Danish data, implying that better integration of RES into the market in the future, could reduce balancing costs. Kunz and Zerrahn (2016) show that congestion management costs in central Europe (Austria, Czech Republic, Germany, Poland, and Slovakia) would fall by over 75% under coordination. Van den Bergh et al. (2017) show that cross-border reserve sharing in Central Western Europe (Belgium, Luxembourg, France, Germany and the Netherlands) could reduce total reserve costs by one third. Baldursson et al. (2018) show that further sharing of reserves between 6 countries in Europe (Belgium, France, Germany, the Netherlands, Portugal and Spain) would reduce annual reserve costs between them by 500 m Euros p.a.

There would appear to be significant innovations taking place around ancillary services and a lot of promise arising from new technologies that can help with better energy forecasting (of consumption and generation), involving artificial intelligence (AI) and associated machine and deep learning. A key starting point being that the current algorithms for estimating ancillary service requirements tend to be static and very conservative, leading to over-procurement.[37] More dynamic methods of estimation are already being implemented in some markets (e.g. for operating reserve in Belgium[38]). Different electric utilities (e.g. Duke Energy, Southern California Edison, First Energy) are already using AI in order to solve business challenges (including customer engagement applications and forecasting).[39] Han and Papavasiliou (2015) note that dynamic topological control of networks—which would be facilitated by AI—could yield almost the same amount of savings in

37. For an analytical discussion see Hermans et al. (2018).
38. See De Vos et al. (2018).
39. See: https://utilityanalytics.com/2018/05/road-mapping-for-artificial-intelligence-are-utilities-already-there/

congestion costs as nodal pricing. Better modelling will reduce the need for ramping resources (see Moarefdoost et al., 2016). Moving to shorter trading periods might also reduce costs (as it has done for energy see Märkle-Huß et al., 2018) and is predicted to reduce balancing costs (see Pape, 2018). The addition of more distributed energy resources (i.e. distributed generation units and EVs) within the electricity system and the opportunity to trade flexibility services (i.e. balancing services) from them, would add more complexity to the electricity network. This could be reflected by the trading of new products, new market participants (i.e. aggregated DERs including storage), the demand for better forecasting, the availability of more data to manage and process and further coordination between parties[40] etc. Blockchain is among the technologies that can help to improve short run operation in the presence of smaller intermittent generators by shortening the small scale transaction validation time. However, some limitations need to be taken into consideration, especially for real time transactions (DENA, 2019). All these developments are being driven by rising distributed generation. Increased DERs can be a source of ancillary services. For instance, wind turbines can be adapted to produce ancillary services if required (see Hirth and Muller, 2016).

There are currently several initiatives (in the form of projects, start-ups etc.) that are using DERs in the provision of different ancillary services and their number is rising. Many of them use one or a combination of the technologies noted previously. Kufeoglu et al. (2019) identify a list of 40 energy-related start-ups in order to explore their business models. They consider key business model dimensions (value proposition, value creation, value revenue). They find that around 35% of them report having utility partners and many of them use blockchain technology. Having these kinds of partnerships may increase the chance of better financial support (in fact, many of them have received customer based funds) and reduces regulatory obstacles (the use of a *regulatory sandbox* is also observed here, especially in the UK). The prospects for some technologies' participation in ancillary services remains questionable (e.g. the potential for EVs to provide reliable reserve: see Jargstorf and Wickert, 2013). Some remain optimistic of high returns from ancillary services for residential air conditioners/heat pumps (see for example, Mathieu et al. (2015) and Hao et al. (2015)). The prospects for low cost batteries in providing frequency response seem strong (see Yu and Foggo, 2017). While others, such as Cappers et al. (2013) for the US, note that while removing barriers to demand side participation in ancillary services markets would help, uncertain revenue expectations may reduce the expected profitability of these prospective participants.

Based on this, it is expected that the procurement of ancillary services from DERs could increase over time. The Open Networks project of the Energy Networks Association in the UK suggested that 270 MW of flexibility services (mainly related to local constraint management) were procured by distribution companies in 2017 rising to 800 MW+ in 2018 (ENA, 2019).

7.4 Who will run future markets for ancillary services?

A major question going forward is who will be responsible for future ancillary services markets and the division of responsibility between the transmission level system operator (TSO) and the distribution system operator (DSO). In Europe there is a further question of the division of responsibilities between national system operators and pan-European system operators.

Energy balancing, frequency regulation and the provision of reserves are best conducted at the transmission system level. In Europe, there is scope for having pan-European or regional mar-

40. There are ongoing initiatives in the UK (ENA, 2018) and in Australia (ENA- AEMO, 2018) that are exploring the future interactions between DSOs and TSOs in order to trade flexibility services from DERs in the most efficient way.

kets for these within the framework of the European single market for electricity (see Pollitt, 2019) which is largely complete for day-ahead wholesale energy.

For voltage support and constraint management provision will increasingly need to take place within distribution systems and be driven by the rise of distributed generation (see for example Schermeyer et al., 2018). At the very least markets will need to be organised at this level. It is another matter whether they should be run by the existing transmission system operator as an extension of their existing markets or whether they should be a new service provided by the distribution system operator or whether an independent entity would be the most suitable for this role. See CERRE (2019) for the discussion of a set of proposals about the future role of ISO/TSO for procuring flexibility services from DER.

The fundamental issue here is what is the value of extending the role of the ISO/TSO versus extending the role of the DSO? This is a Coasian question and depends on the relative efficiency of different types of firms in different jurisdictions. In many systems DSOs are small and lacking in market management experience (see Kufeoglu et al., 2018), while TSOs are the source of expertise in running formal ancillary services markets. The voltage boundary between TSOs and DSOs is a historic accident and does not reflect what might be optimal for system operation: indeed, that is one of the reasons for the move towards ISOs, which can reflect better the mathematical optimisation of the system without worrying about the underlying ownership of the network assets. On the other hand, DSOs have relationships with their customers directly connected to the distribution system and can work with them to physically facilitate their participation in ancillary services markets.

A reasonably sized DSO can be sophisticated enough to run off the shelf ancillary services procurement software.[41] There is no doubt that some unusually large distribution companies such as Enedis—the national distributor business of EdF—in France or ENEL Distribution in Italy could. However, one might expect that medium sized private distribution companies such as ConEd in New York, UKPN in London and Ausgrid in Sydney could run local markets for ancillary services at the same time as their transmission level counterparts NYISO, National Grid Electricity System Operator or AEMO who run market wide balancing, frequency regulation and reserves markets. Indeed, there would be some regulatory benefit to setting these larger DSOs up in competition to their transmission level counterparts as procurers of ancillary services.

However, the eventual division of responsibilities is an open question given the nature of economies of scale and scope in running markets and the linkages between markets (the co-optimisation question). Having markets coordinated centrally has some cost advantages in terms of driving IT costs down, though it potentially reduces innovation and increases IT risks. It also might be preferred by market participants who may themselves want to participate in several markets simultaneously. Indeed, one solution for a storage facility is to sign one long term contract with the system operator and let the system operator decide how to operate the facility and for what service in real time (something which was possible under the DRAM procurement scheme in California - see Anaya and Pollitt, 2020). The alternative of leaving individual DERs to optimise their own bids across multiple markets being conducted at multiple scales is challenging for the DERs.

One new possibility afforded by local procurement of ancillary services by DSOs is the ability to co-optimise between regulated network investments and DER ancillary service solutions. Assuming that the regulatory regime rewards this (as it intends to under RIIO in Great Britain and REV in New York), this should allow the DSO to offer a contract to a DER to provide constraint

41. It is notable that in New York State (under its REV initiative) and in Great Britain mid-sized DSOs (of the order 2 million customers) are running "markets" for ancillary services. See https://nyrevconnect.com/non-wires-alternatives/ and ENA (2019).

management or voltage support in lieu of upgrading its network. This might wholly or partially finance the DER.

8. WILL ANCILLARY SERVICES MARKETS EVER BE AS COMPETITIVE AS WHOLESALE ENERGY MARKETS?

In considering the prospects for ancillary services markets, it is interesting to ask will they ever be as competitive as wholesale electrical energy markets?

The simple answer would seem to be no. This is important because we should be careful to suggest that we need to rely on them more in the future.

There are a number of elements to this.

First, ancillary services markets are largely constructs of the system operator. This means they are subject to a certain degree of arbitrariness (in defining maximum allowed speed of response or minimum size participation criteria[42]) and a lack of transparency around the price formation process. It is difficult to construct a price and quantity series for national ancillary services markets and some prices are subject to confidentiality (e.g. constraint payments to generators under negotiated contracts in GB). While one can find information on total costs of ancillary services for GB it is more difficult to see how they were arrived at—the division of payments through the balancing mechanism for balancing and non-balancing services is decided internally. National Grid have begun to rationalise their markets and this has led to some products being removed suggesting that unlike energy markets there is a risk that DERs relying on certain types of payments in the future are subject to the fundamental risk that their offered service might simply not be procured in the future. A particular feature of ancillary services markets which involve multiple system operators across different regulatory jurisdictions is the incentive to shift costs between jurisdictions (e.g. by pushing congestion to the border, which has been a problem in Europe).[43]

Second, unlike markets for energy, ancillary services markets are not usually two-sided (i.e. a market where both supply and demand are competitively determined). Thus prices do not arise as the interaction of modellable supply and demand. Those who create the demand for ancillary services are not those who pay for it when it comes to frequency regulation, voltage support, constraint management (even in PJM most loads are not exposed to nodal prices) and reserves. This introduces the further arbitrariness that these services can often be over-procured by the system operator or subject to bargaining back by network companies whose own incentives to build network or invest in other regulated assets (such as reactive assets) may impact on the quantity of ancillary services demanded. The capacity market is a classic example of this where there have both been cases of over-procurement of capacity (in the early years of the GB market) and bargaining back by US state regulators approving new plants to reduce capacity payments or the GB system operator uprating interconnectors (in recent years) to reduce capacity market prices.

Third, in line with the above payments for ancillary services are not focussed back on those who cause the need for them. Even where the markets are one-sided, focussing payments back on the causers of the demand for ancillary services could improve efficiency. Instead most ancillary services costs are socialised across all transmission connected demand (in PJM) or a mixture of all

42. For instance, larger minimum threshold sizes (in MWs) can inhibit the participation of smaller consumers/generators, especially in those jurisdictions where aggregators are not allowed (or are limited) to participate in the wholesale market if they don't have an agreement with suppliers. In Europe, France and Switzerland are among the first countries in establishing a framework for the participation of independent aggregators and their role in markets (SEDC, 2017).

43. See for example Willems (2002) and Bjørndal and Jörnsten (2007).

transmission connected consumption/generation (in the NEM and GB). In the NEM one frequency regulation product (Regulation FCAS) is charged out on the basis of a "causer pays" principle (see AEMO, 2015b). Kim et al. (2017) discuss cost causality contracts for ancillary services between the distribution system operator (DSO) and the TSO, where the DSO would pay the TSO for ancillary service requirements imposed outside its network, but in return the TSO would offer a partial insurance contract. The reason causer pays is difficult is precisely because of the disproportionate payment risk that a full causer pays methodology imposes on individual market participants, whereby individual generators/loads could be liable for a disproportionate share of the entire market's ancillary services cost depending on the market conditions. Indeed better TSO/DSO coordination may serve to reduce ancillary service costs (see Hadush and Meeus, 2018).

Fourth, markets for ancillary services will be risky for investors, raising the cost of capital and encouraging a particular sort of DER response (i.e. ones with low capital cost). These investments will compete poorly with network owned assets (the in-house solution) and network solutions in terms of value for money for customers. For instance, it is perfectly possible that in the medium-run a centrally contracted fleet of distributed batteries could provide the vast majority of the required ancillary services a under long term contract at much lower cost than a set of real-time ancillary services markets (let alone the current collection of ancillary services procurement methods observed in most markets).

Over time, each of these limitations could be partially addressed for some ancillary service products. The prospects for different ancillary service markets may be divergent. Markets for frequency response and reserves are well developed already in multiple jurisdictions. However competitive constraint management and voltage control markets are highly challenging due to their local nature. Rising amounts of distributed generation both raise demand for ancillary services and provide competitive sources of ancillary service provision, however some of the core issues which limit the competitiveness of short-term non-energy ancillary service markets[44] will remain.

9. SOME CONCLUSIONS

Ancillary service markets are currently small relative to markets for day-ahead and longer term wholesale energy. The rise of intermittent renewable energy would seem to increase the quantities of ancillary services required, however this is not quite the same as meaning that the value of ancillary services will become significantly larger in the future than it is now. Better wind and solar forecasting, combined with sharper real time energy price signals will offset the need for more frequency regulation, voltage support, constraint management and reserves. The presence of electric vehicles also offers significantly more potential for managing the electricity system relative to now and could provide a cheap source of ancillary services in the same way that fossil fuel power plants have done traditionally.

The overall optimisation of the electricity system involves the interaction of ancillary services, wholesale energy and networks and is not solely dependent on the nature of the market for ancillary services. Ancillary services trade off with wholesale energy and network operation and investment in ways that may mean that co-optimisation or internalisation is preferable to a stand-alone spot ancillary services market. The Coasian question of the optimal allocation of activity between in house and market transactions requires relatively more attention than the Schweppian question of how to increase optimal decentralised price signals.

44. Here balancing energy is excluded.

Ancillary services markets are limited by the overarching role of the system operator, whose monopoly purchaser position acts to create investment risk relative to wholesale energy markets.

Regulators need to carefully evaluate changes to ancillary services procurement, given the split incentives which exist for them to be acquired in a system optimal manner. The question of whether they are best acquired in the future by the transmission level system operator or the distribution system operator is an open one for voltage support and constraint management.

There is, however, considerable scope for innovation in the provision of ancillary services and the targeting payment for them. At this stage, there remains much room for experimentation globally as shares of distributed generation rise on the electricity system.

ACKNOWLEDGMENTS

The authors acknowledge the very helpful comments of four anonymous referees. They are also grateful for helpful discussions with colleagues at National Grid and UKPN. All remaining errors are their own. They acknowledge funding from the EPRG and earlier financial support from the EPSRC Business, Economics, Planning and Policy for Energy Storage in Low-Carbon Futures project (Grant number: EP/L014386/1). EPSRC research data statement: there is no additional data beyond that reported in the paper.

REFERENCES

AEMO (2015a). *Guide to Ancillary Services in the National Electricity Market*. Australian Energy Market Operator, April 2015.

AEMO (2015b). *Settlements Guide to Ancillary Services Payment and Recovery.* Australian Energy Market Operator, 1 July 2015.

AEMO (2017). *Network Support and Control Ancillary Services Agreement*. *Generic Proforma.* Australian Energy Market Operator, Dec. 2017.

AEMO (2018). *AEMO observations: Operational and market challenges to reliability and security in the NEM*. Australian Energy Market Operator, March 2018.

AEMO (2019). *Technical Integration of Distributed Energy Resources: Improving DER capabilities to benefit consumers and the power system. A report and consultation paper*, Australian Energy Market Operator, April 2019.

AEMO—ENA (2018). *Open Energy Networks. Consultation Response. Australian* Energy Market Operator and Energy Networks Australia, December 2018.

AEMC (2018). *Coordination of Generation and Transmission Investment. Final Report,* Australian Energy Market Commission, December 2018.

Anaya, K.L. and M.G. Pollitt (2020). "Reactive power procurement: A review of current trends." *Applied Energy* 270:114939. https://doi.org/10.1016/j.apenergy.2020.114939.

Baldursson, F.M., E. Lazarczyk, M. Ovaere, and S. Proost (2018). "Cross-Border Exchange and Sharing of Generation Reserve Capacity." *The Energy Journal* 39(4): 57–84. https://doi.org/10.5547/01956574.39.4.fbal.

Banshwar, A., N.K. Sharma, Y.R. Sood, and R. Shrivastava (2018). "An international experience of technical and economic aspects of ancillary services in deregulated power industry: Lessons for emerging BRIC electricity markets." *Renewable and Sustainable Energy Reviews* 90: 774–801. https://doi.org/10.1016/j.rser.2018.03.085.

Biggar, D.R. and M.R. Hesamzadah (2014). *The Economics of Electricity Markets*, Wiley. https://doi.org/10.1002/9781118775745.

Bjørndal, M. and K. Jörnsten (2007). "Benefits from coordinating congestion management: The Nordic power market." *Energy Policy* 35(3): 1978–1991. https://doi.org/10.1016/j.enpol.2006.06.014.

Cappers, P., J. MacDonald, C. Goldman, and O. Ma (2013). "An assessment of market and policy barriers for demand response providing ancillary services in U.S. electricity markets." *Energy Policy* 62: 1031–1039. https://doi.org/10.1016/j.enpol.2013.08.003.

CCC (2019). *Net Zero—Technical Annex: Integrating variable renewables into the UK electricity system*, London: Committee on Climate Change.

CERRE (2019). *Smart Consumers in the Internet of Energy: Flexibility Markets and Services from DER*. Final Report, November 2019.

Chyong, K., M. Pollitt, and R. Cruise (2019). *Can wholesale electricity prices support "subsidy-free" generation investment in Europe?* EPRG Working Paper No.1919.

Coase, R.H. (1937). "The Theory of the Firm." *Economica* 4(16): 386–405. https://doi.org/10.1111/j.1468-0335.1937.tb00002.x.

Creti, A. and F. Fontini (2019). *Economics of Electricity: Markets, Competition and Rules,* Cambridge: Cambridge University Press. https://doi.org/10.1017/9781316884614.

DEE (2018). Australian Energy Update 2018, August 2018, Australian Government Department of the Environment and Energy: Canberra.

DENA (2019). Dena Multi-Stakeholder Study. Blockchain in the integrated energy transition. Study findings. German Energy Agency, February 2019.

De Vos, K., N. Stevens, O. Devolder, A. Papavasiliou, B. Hebb, and J. Matthys-Donnadieu (2019)."Dynamic dimensioning approach for operating reserves: Proof of concept in Belgium." *Energy Policy* 124: 272–285. https://doi.org/10.1016/j.enpol.2018.09.031.

Di Cosmo, V. and L.M. Valeri (2018). "Wind, storage, interconnection and the cost of electricity generation." *Energy Economics* 69: 1–18. https://doi.org/10.1016/j.eneco.2017.11.003.

Doorman, G.L. and R. van der Veen (2013). "An analysis of design options for markets for cross-border balancing of electricity." *Utilities Policy* 27(C): 39–48. https://doi.org/10.1016/j.jup.2013.09.004.

Doraszelski, U., G. Lewis, and A. Pakes (2018). "Just Starting Out: Learning and Equilibrium in a New Market." *American Economic Review* 108(3): 565–615. https://doi.org/10.1257/aer.20160177.

DUKES (2019). *Digest of United Kingdom Energy Statistics 2019*, London: Department for Business, Energy & Industrial Strategy.

ENA (2018). Open Networks Future Worlds. Developing change options to facilitate energy decarbonisation, digitisation and decentralisation. Energy Networks Association.

ENA (2019). Open Networks Project 2018 Review. Energy Networks Association.

Flinkerbusch, K. and M. Heuterkes (2010). "Cost reduction potentials in the German market for balancing power." *Energy Policy*, 38 (8): 4712–4718. https://doi.org/10.1016/j.enpol.2010.04.038.

Furtwängler, C. and C. Weber (2019). "Spot and reserve market equilibria and the influence of new reserve market participants." *Energy Economics* 81: 408–421. https://doi.org/10.1016/j.eneco.2019.03.023.

Gianfreda, A., L. Parisio, and M. Pelagatti (2016). "The Impact of RES in the Italian Day-Ahead and Balancing Markets." *The Energy Journal* 37(SI2): 161–184. https://doi.org/10.5547/01956574.37.SI2.agia.

Gomes, R. and J. Tirole (2018). "Missed sales and the pricing of ancillary goods." *Quarterly Journal of Economics* 133 (4): 2097–2169. https://doi.org/10.1093/qje/qjy016.

Greve, T., F. Teng, M. Pollitt, and G. Strbac (2018). "A system operator's utility function for the frequency response market." *Applied Energy* 231(1 December): 562–569. https://doi.org/10.1016/j.apenergy.2018.09.088.

Hadush, S.Y. and L. Meeus (2018). "DSO-TSO cooperation issues and solutions for distribution grid congestion management." *Energy Policy* 120: 610–621. https://doi.org/10.1016/j.enpol.2018.05.065.

Han, J. and A. Papavasiliou (2015). "Congestion management through topological corrections: A case study of Central Western Europe." *Energy Policy* 86: 470–482. https://doi.org/10.1016/j.enpol.2015.07.031.

Hao, H., B.M. Sanandaji, K. Poolla, and T.L. Vincent (2015). "Potentials and economics of residential thermal loads providing regulation reserve." *Energy Policy* 79 (April): 115–126. https://doi.org/10.1016/j.enpol.2015.01.013.

Haucap, J., U. Heimeshoff, and D. Jovanovic (2014). "Competition in Germany's Minute Reserve Power Market: An Econometric Analysis." *The Energy Journal* 35 (2): 137–156. https://doi.org/10.5547/01956574.35.2.7.

Hermans, M., K. Bruninx, S. Vitiello, A. Spisto, and E. Delarue (2018). "Analysis on the interaction between short-term operating reserves and adequacy." *Energy Policy* 121: 112–123. https://doi.org/10.1016/j.enpol.2018.06.012.

Hirst, E. and B. Kirby (1998). "Simulating the Operation of Markets for Bulk-Power Ancillary Services." *The Energy Journal* 19 (3): 49–68. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol19-No3-3.

Hirth, L. and S. Müller (2016). "System-friendly wind power: How advanced wind turbine design can increase the economic value of electricity generated through wind power." *Energy Economics* 56: 51–63. https://doi.org/10.1016/j.eneco.2016.02.016.

Hogan, W. and S. Pope (2019). PJM Reserve Markets: Operating Reserve Demand Curve Enhancements, March 2019.

Hogan, W.W. (1993). “Markets in Real Electric Networks Require Reactive Prices.” *The Energy Journal* 14(3): 171–200. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol14-No3-8.

Hogan, W. W. (1992). “Contract networks for electric power transmission.” *Journal of Regulatory Economics* 4(3). 211– 242. https://doi.org/10.1007/BF00133621.

Holmberg, P. and E. Lazarczyk (2015). “Comparison of Congestion Management Techniques: Nodal, Zonal and Discriminatory Pricing.” *The Energy Journal* 36(2): 145–166. https://doi.org/10.5547/01956574.36.2.7.

IRENA (2019). Increasing Space Granularity in Electricity Markets. Innovation Landscape Brief. International Renewable Agency.

Isemonger, A.G. (2009). “The evolving design of RTO ancillary service markets.” *Energy Policy* 37 (1): 150–157. https://doi.org/10.1016/j.enpol.2008.06.033.

Ito, K. and M. Reguant, M. (2016). “Sequential Markets, Market Power and Arbitrage.” *American Economic Review* 106 (7): 1921–1957. https://doi.org/10.1257/aer.20141529.

Jamalzadeh, R., M.M. Ardehali, and M. Rashidinejad (2008). “Development of modified rational buyer auction for procurement of ancillary services utilizing participation matrix.” *Energy Policy* 36 (2): 900–909. https://doi.org/10.1016/j.enpol.2007.11.010.

Jargstorf, J. and M. Wickert (2013). “Offer of secondary reserve with a pool of electric vehicles on the German market.” *Energy Policy* 62(November): 185–195. https://doi.org/10.1016/j.enpol.2013.06.088.

Joskow, P.L. and R. Schmalensee (1983). *Markets for Power: An analysis of electric utility deregulation*, Cambridge MA: MIT Press.

Joskow, P.L. (2019). Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience. MIT Center for Energy and Environmental Policy Research, CEEPR WP 2019-001, January 2019. https://doi.org/10.1093/oxrep/grz001.

Just, S. (2011). “Appropriate Contract Durations in the German Markets for On-Line Reserve Capacity.” *Journal of Regulatory Economics* 39 (2): 194–220. https://doi.org/10.1007/s11149-010-9141-0.

Just, S. and C. Weber (2008). “Pricing of reserves: Valuing system reserve capacity against spot prices in electricity markets.” *Energy Economics* 30 (6): 3198–3221. https://doi.org/10.1016/j.eneco.2008.05.004.

Kaleta, M. (2016). “A generalized class of locational pricing mechanisms for the electricity markets.” *Energy Economics*, in press.

Kahn, E. and R. Baldick (1994). “Reactive Power is a Cheap Constraint.” *The Energy Journal* 15(4): 191–201. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol15-No4-9.

Kirchen, D.S. and G. Strbac (2019). *Fundamentals of Power System Economics,* 2nd Edition, Wiley.

Kim, S-W, M. Pollitt, Y.G. Jin, J. Kim, and Y.T. Yoon (2017). *Contractual Framework for the Devolution of System Balancing Responsibility from Transmission System Operator to Distribution System Operators*, EPRG Working Paper No.1715.

Kristiansen, T. (2007). “The Nordic approach to market-based provision of ancillary services.” *Energy Policy* 35 (7): 3681–3700. https://doi.org/10.1016/j.enpol.2007.01.004.

Küfeoğlu, S., M. Pollitt, and K. Anaya (2018). *Electric Power Distribution in the World: Today and Tomorrow*, EPRG Working Paper, No.1826.

Küfeoğlu, S., G. Liu, K. Anaya, and M.G. Pollitt (2019). *Digitalisation and New Business Models in Energy Sector*, EPRG Working Paper No.1920.

Kunz, F. (2013). “Improving Congestion Management: How to Facilitate the Integration of Renewable Generation in Germany.” *The Energy Journal* 34(4): 55–78. https://doi.org/10.5547/01956574.34.4.4.

Kunz, F. and A. Zerrahn (2016). “Coordinating Cross-Country Congestion Management: Evidence from Central Europe.” *The Energy Journal* 37(SI3): 81–100. https://doi.org/10.5547/01956574.37.SI3.fkun.

Leautier, T.-O. (2019). *Imperfect Markets and Imperfect Regulation: An Introduction to the Microeconomics and Political Economy of Power Markets*, Cambridge MA: MIT Press.

Lipsey, R.G. and K. Lancaster (1956). “The General Theory of Second Best.” *The Review of Economic Studies* 24 (1): 11–32. https://doi.org/10.2307/2296233.

Märkle-Huß, J., S. Feuerriegel, and D. Neumann (2018). “Contract durations in the electricity market: Causal impact of 15min trading on the EPEX SPOT market.” *Energy Economics* 69: 367–378. https://doi.org/10.1016/j.eneco.2017.11.019.

Mathieu, J.L., M.E.H. Dyson, and D.S. Callaway (2015). “Resource and revenue potential of California residential load participation in ancillary services.” *Energy Policy* 80: 76–87. https://doi.org/10.1016/j.enpol.2015.01.033.

Mauritzen, J. (2015). “Now or Later? Trading Wind Power Closer to Real Time And How Poorly Designed Subsidies Lead to Higher Balancing Costs.” *The Energy Journal* 36(4): 149–164. https://doi.org/10.5547/01956574.36.4.jmau.

Metaxoglou, K. and A. Smith (2007). “Efficiency of the California Electricity Reserves Market.” *Journal of Applied Econometrics* 22 (6): 1127–44. https://doi.org/10.1002/jae.982.

Moarefdoost, M.M., A.J. Lamadrid, and L.F. Zuluaga (2016). "A robust model for the ramp-constrained economic dispatch problem with uncertain renewable energy." *Energy Economics* 56: 310–325. https://doi.org/10.1016/j.eneco.2015.12.019.

Monitoring Analytics (2019). *State of the Market Report for PJM Volume 2: Detailed Analysis. Monitoring Analytics, Independent Market Monitor for PJM*, March 2019.

Mount, T.D. and J. Ju (2014). "An econometric framework for evaluating the efficiency of a market for transmission congestion contracts." *Energy Economics* 46: 176–185. https://doi.org/10.1016/j.eneco.2014.09.014.

National Grid (2017a). *System Needs and Product Strategy*, June 2017, Warwick: National Grid.

National Grid (2017b). *Roadmap for Frequency Response and Reserve,* December 2017, Warwick: National Grid.

National Grid (2018). *Product Roadmap for Reactive Power*, May 2018, Warwick: National Grid.

Ofgem (2012). *RIIO-T1 Final Proposal for National Grid Electricity Transmission and National Grid Gas. Finance Supporting document.* Dec. 2012.

Paine, N., F.R. Homans, M. Pollak, J.M. Bielicki, and E.J. Wilson (2014). "Why market rules matter: Optimizing pumped hydroelectric storage when compensation rules differ." *Energy Economics* 46: 10–19. https://doi.org/10.1016/j.eneco.2014.08.017.

Papavasiliou, A. and Y. Smeers (2017). "Remuneration of Flexibility using Operating Reserve Demand Curves: A Case Study of Belgium." *The Energy Journal* 38(6): 105–135. https://doi.org/10.5547/01956574.38.6.apap.

Pape, C. (2018). "The impact of intraday markets on the market value of flexibility — Decomposing effects on profile and the imbalance costs." *Energy Economics* 76: 186–201. https://doi.org/10.1016/j.eneco.2018.10.004.

Pollitt, M. (2019). "The European Single Market in Electricity: An Economic Assessment." *Review of Industrial Organization* 55 (1): 63–87. https://doi.org/10.1007/s11151-019-09682-w.

Poyry and Imperial College (2017). *Roadmap for Flexibility Services 2030, A report to the Committee on Climate Change*, London: Poyry.

Raineri, R., S. Ríos, and D. Schiele (2006). "Technical and economic aspects of ancillary services markets in the electric power industry: an international comparison." *Energy Policy* 34 (13): 1540–1555. https://doi.org/10.1016/j.enpol.2004.11.015.

Rammerstorfer, M. and C. Wagner (2009). "Reforming minute reserve policy in Germany: A step towards efficient markets?." *Energy Policy* 37(9): 3513–3519. https://doi.org/10.1016/j.enpol.2009.03.056.

Rebours, Y.G., D.S. Kirshen, M. Trotignon, and S. Rossignol (2007). "A Survey of Frequency and Voltage Control Ancillary Services—Part II: Economic Features." *IEEE Trans. Power Syst.* 22(1): 358–366. https://doi.org/10.1109/TPWRS.2006.888965.

Reguant, M. (2014). "Complementary Bidding Mechanisms and Startup Costs in Electricity Markets." *Review of Economic Studies* 81(4): 1708–42. https://doi.org/10.1093/restud/rdu022.

Richardson, G.B. (1972). "The Organisation of Industry." *The Economic Journal* 82(327): 883–896. https://doi.org/10.2307/2230256.

Schermeyer, H., C. Vergara, and W. Fichtner (2018). "Renewable energy curtailment: A case study on today's and tomorrow's congestion management." *Energy Policy* 112: 427–436. https://doi.org/10.1016/j.enpol.2017.10.037.

Schweppe, F.C., M.C. Caramanis, R.D. Tabors, and R.E. Bohn (1988). *Spot Pricing of Electricity*. Springer. https://doi.org/10.1007/978-1-4613-1683-1.

SEDC (2017). *Explicit Demand Response in Europe. Mapping the Markets 2017*. April 2017, Brussels: Smart Energy Demand Coalition.

Skytte, K. (1999). "The regulating power market on the Nordic power exchange Nord Pool: an econometric analysis." *Energy Economics* 21 (4): 295–308. https://doi.org/10.1016/S0140-9883(99)00016-X.

Stoft, S. (2002). *Power System Economics: Designing Markets for Electricity*, Wiley-IEEE Press. https://doi.org/10.1109/9780470545584.

Strbac, G., D. Pudjianto, and P. Djapic (2018). *Market Framework for Distributed Energy Resources-based Network Services,* June 2018, Imperial College London.

van Blijswijk, M.J. and L.J. de Vries (2012). "Evaluating congestion management in the Dutch electricity transmission grid." *Energy Policy* 51: 916–926. https://doi.org/10.1016/j.enpol.2012.09.051.

Van den Bergh, K., K. Bruninx, and E. Delarue (2018). "Cross-border reserve markets: network constraints in cross-border reserve procurement." *Energy Policy* 113: 193–205. https://doi.org/10.1016/j.enpol.2017.10.053.

Van der Veen, R.A.C. and L.J. de Vries (2009). "The impact of microgeneration upon the Dutch balancing market." *Energy Policy* 37 (7): 2788–2797. https://doi.org/10.1016/j.enpol.2009.03.015.

VGB (2018). *Electricity Generation 2018–2019 Facts and Figures*, August 2018, Essen: VGB PowerTech e.V.

Wang, P., H. Zareipour, and W.D. Rosehart (2011). "Characteristics of the prices of operating reserves and regulation services in competitive electricity markets." *Energy Policy* 39 (6): 3210–3221. https://doi.org/10.1016/j.enpol.2011.03.008.

Weiss, L.W. (1975). “Antitrust in the Electric Power Industry.” in A.Phillips (ed.), *Promoting Competition in Regulated Markets*, Chapter 5, Washington, D.C., USA: Brookings Institution Press, pp.135–173.

Willems, B. (2002). “Modelling Cournot competition in an electricity market with transmission constraints.” *The Energy Journal* 23(3): 95–126. https://doi.org/10.5547/ISSN0195-6574-EJ-Vol23-No3-5.

Williamson, O.E. (1975). *Markets and Hierarchies*, New York: Free Press.

WPD (2019). *Emerging DNO Flexibility Opportunities—Flexible Power, Western Power Distribution*, February 2019.

Yu, N. and B. Foggo (2017). “Stochastic valuation of energy storage in wholesale power markets.” *Energy Economics* 64: 177–185. https://doi.org/10.1016/j.eneco.2017.03.010.

Zhang, N. (2009). “Market performance and bidders’ bidding behavior in the New York Transmission Congestion Contract market.” *Energy Economics* 31 (1): 61–68. https://doi.org/10.1016/j.eneco.2008.09.001.

Zhou, Z., T. Levin, and G. Conzelmann (2016). *Survey of U.S. Ancillary Services Markets. ANL/ESD-16/1.* Energy Systems Division, Argonne National Laboratory. https://doi.org/10.2172/1236451.

IAEE

International Association for
ENERGY ECONOMICS

The IAEE is pleased to announce that our leading publications exhibited strong performances in the latest 2019 Impact Factors as reported by Clarivate. The Energy Journal achieved an Impact Factor of 2.394 while Economics of Energy & Environmental Policy saw an increase to 3.217.

Both publications have earned SCIMago Journal Ratings in the top quartile for Economics and Econometrics publications.

IAEE wishes to congratulate and thank all those involved including authors, editors, peer-reviewers, the editorial boards of both publications, and to you, our readers and researchers, for your invaluable contributions in making 2019 a strong year. We count on your continued support and future submission of papers to these leading publications.