



A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

Electricity is in ferment – an unusual state for an industry which has traditionally enjoyed the security of long-term assets, steadily growing demand, and stable revenues (which has, in short, long been the position of a typical utility). These secure foundations are now coming into question as the industry faces major technological, economic, and institutional change. Perhaps most visible are the developments in electricity generation – the growing penetration of intermittent renewable plants, driven both by technological advances and by the policy commitment to decarbonization. But significant shifts are also taking place elsewhere in the system with the rapid development of information and control technology, which is opening the way for new approaches to system management and more flexible demand. It is likely that we are only seeing the beginnings of these changes – they raise wider questions about the very nature of the industry's product and its relationship with its customers.

The technological developments have been accompanied by major policy and economic changes – falling electricity demand, greater use of on-site generation leading to lower network income, governments rather than markets driving investment in both renewable and fossil generation, and

so on. The institutional frameworks surrounding the industry are struggling to keep up. For two decades or so after 1990, governments across the world focused on liberalization and the extension of market forces; now there is a new emphasis on decarbonization, but governments have not yet worked out whether decarbonization and liberalization can go hand in hand or whether there is a fundamental conflict. Markets have also been slow to adapt to the new era – the industry has traditionally relied on marginal cost (kWh) pricing, although a large proportion of its costs have always been fixed (and some eminent economists like Ronald Coase have argued against the over-emphasis on marginal cost). With a growing penetration of zero marginal cost plants, the marginal cost approach looks increasingly outdated, whether at wholesale or retail level. Regulation too needs to respond to the changes – including the increasing decentralization of the system – under way. New coordination and control methods may be required to manage the rapid growth of intermittent generation, particularly wind. Indeed the whole basis of the industry's workings is coming into question: what ultimately are its products? How should it price them? What business models should the industry be developing? What are

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its resources and how do storage and demand response fit in?

These fundamental questions underlie many of the articles in this issue of the *Oxford Energy Forum*. One theme is the need to look at basic business models. *Rolando Fuentes* considers the impact of distributed energy resources (DER) such as solar panels, batteries, smart meters, and appliances, which are together acting as disruptive technologies. Using two examples of successful business models from the 'sharing economy' – UBER (taxi) and Airbnb (room letting) – the author identifies three big issues for the power sector: the reallocation of risk, the paradoxical role of price signals in situations of spare capacity, and the dynamics between regulation and business models. He argues that, contrary to the current situation in which electricity regulation dictates the business model of utilities, new business models can shape future regulation; by re-allocating risks, a new role can be created for incumbent utilities. Fuentes also proposes that electricity markets need to be re-designed to take into account the multidimensional nature of electricity and distinguish between separate services such as reliability (MW), energy (MWh), system savings (NWh), and environmental benefits (carbon dioxide emissions reductions).

Christoph Burger and *Jens Weinmann* also look at the implications of the growth in renewable generation for business models, particularly in Germany. Germany is in many ways affected by the issue more acutely than other countries, both because it has seen such a rapid increase in generation from wind and solar PV, and because in Germany little of this new generation is owned by the main utilities themselves. Those utilities are therefore facing a major erosion of their revenues and need to come up with imaginative responses – a difficult

task for companies used to more conservative ways of thinking. However, they are exploring new approaches, like outsourcing innovation and promoting co-investment and venture capital funds. But the long-term challenges posed by IT may be even more fundamental – challenges such as the Internet of Things, the sharing economy, and the use of blockchains to squeeze out intermediaries.

Integration of the new sources and system coordination are the focus of a number of articles. *Rahmat Poudineh* discusses the new requirements for grid management that result from the integration of renewable energy resources. In recent years supply side fluctuations, mainly related to wind and solar power, have presented a new form of uncertainty to the power system and added to the complexity of grid management. Power systems with a lot of renewables tend to experience short and steep ramps, such that the system operators need to bring on or shut down power plants more often than in the past, and within very short periods of time. He contends that as intermittency increases and the need for flexibility becomes critical, the system will require new models of grid management both at operational and institutional levels. In addition to traditional resource adequacy metrics we need new methodologies to quantify and assess the technically available operational flexibility of the power system. In addition, he argues, we need to ensure that electricity markets and regulations not only provide incentives for investment in flexible resources but also make efficient use of available resources.

Rabindra Nepal and *Tooraj Jamsab* discuss the experience of market integration, renewable energy, and network regulation that has been built up by the Australian National Electricity Market (NEM). They provide an overview of the structure and

organization of the NEM and point out that, more than 14 years since the establishment of the NEM, wholesale electricity price differences persist across the Australian states. The main reason for this is the presence of network constraints across the regional interconnectors, which impedes the wholesale market integration process in the NEM. In addition, the authors argue that the lack of adequate interconnection prevents the development of new wind power in the resource-rich regions and leads to the curtailment of the existing capacity. The costs in terms of lost revenue to wind power plants as a result of curtailment are large and hamper meeting the national renewable energy targets. Therefore, the authors contend that the development of renewable energy and electricity market integration can be complementary policy objectives in the NEM as one of the largest interconnected energy-only markets in the world.

Richard Green and *Goran Strbac* explore ways of adapting European electricity markets for renewables. The authors argue that national renewable energy policies in the EU region are still uncoordinated, and the concentration of renewables in more favourable locations would bring important savings. Additionally, they argue that the existing linkages between day-ahead markets need to be supplemented with greater coordination on longer and shorter timescales. Short-term balancing costs could be reduced if system operators had access to balancing services and reserves in neighbouring systems. Cross-border trading of long-term contracts for energy would be facilitated by the use of Financial Transmission Rights (FTRs), which do not have the restrictions of capacity contracts. They also suggest that in order to facilitate balancing between countries, we may have to integrate



energy and reserve markets within each country – something that the American experience shows can be done. However, the political challenges involved in creating a good market design should not be underestimated.

Regulation and government policy also need to be addressed. *David Newbery* examines the logic, drawbacks, and possible resolutions of the EU Commission's proposed shift from feed-in tariffs (FiTs) to Premium FiTs (PFiTs), for future UK renewables support. The author reviews the history of UK renewables support and argues that an important advantage of quantity-based instruments like Renewable Obligation Certificates (ROCs) is that their cost is controllable. However, ROCs are exposed to volatile market prices and abundant renewables deployment can depress their prices. In contrast, a fixed FiT provides greater insurance but at the same time risks excessive demand and budgetary cost, if no cap is set on the total quantity procured. From the author's point of view, the question is how to combine the advantages of a PFiT with the risk-reducing properties of a FiT. Newbery argues that capacity contracts with suitable Power Purchase Agreements (PPAs) and contracts for ancillary and balancing services (with all contracts reflecting efficient market value) are the logical solution and should support the delivery of low-carbon electricity at least cost.

Ignacio Pérez-Arriaga and *Scott Burger* address the regulatory challenges related to the growing penetration of distributed energy resources (DER) such as: gas-fired distributed generation, solar PV, small- and medium-sized wind farms, electric vehicles, energy storage, and demand-side management. The fundamental question is what role should be played by DER, and what by conventional centralized energy resources. They

argue that current regulations are woefully inadequate to meet the incoming challenges and that what is needed is an in-depth review and corresponding modification to create an economically neutral playing field, enabling centralized and decentralized resources to compete and collaborate efficiently, while recognizing that they perform under very different conditions. This regulatory review should apply the fundamentals of microeconomics to power systems in order to do the following: reconsider the definition of 'essential electricity services'; examine how to compute prices so that economic efficiency is maximized; and understand what, if any, is the value that aggregation of DERs and any associated business models bring to the power system.

David Harbord, *David Robinson*, and *Ivan Giraldo* illustrate how the energy regulatory regime in Colombia acts as a barrier to investment in wind power. The Colombian electricity system relies very heavily on hydro power. However, during El Niño (dry) weather periods, hydro-based generation falls significantly. Consequently, the regulatory system has been designed to finance the building of generation capacity that can substitute for hydro during dry periods. The regulator organizes auctions to select the plants that will be awarded long-term contracts to provide backup, and to determine the price for 'firm energy'. A critical issue has to do with how much firm energy is attributed to different technologies in the auctions. The authors argue that the current methodology underestimates the amount of firm energy available from wind power because it does not adequately reflect the evidence that wind generation is greater when it is most valuable, specifically during El Niño periods. Since secure long-term revenues are directly related to the amount of firm energy sold in the

auction, the regulations therefore act as a barrier to investment in wind power.

Electricity pricing and taxation are facing major new challenges. *Graham Weale* considers a significant policy consistency. On the one hand, governments see electricity as the main vector of decarbonization, via a greatly enhanced role for decarbonized electricity within energy supply. On the other hand, current taxation policy is hindering the process of electrification by loading more tax and surcharges on to electricity than on other energy sources – in Germany, taxes and surcharges on electricity for electric vehicles are actually higher than taxes on vehicle fuels. One result is that in many countries, electricity's market share is actually starting to decline. Weale considers various options for bringing energy taxation into line with overall energy and climate policy. Covering the costs of decarbonization from general taxation seems like a logical solution but it raises many political difficulties – the important thing is to recognize and address the problem.

Fereidoon Sioshansi looks at the implications of the changes under way in the power sector for the structure of electricity tariffs, focusing on the USA. Most consumers there pay on a volumetric (kWh) basis. This means that utilities lose income when consumers install on-site generation, such as rooftop solar PV, and as a result buy less from the grid. To make up for the loss of income, utilities may be forced to raise their tariffs – thus further encouraging investment in energy efficiency and on-site generation and leading to the so-called utility 'death spiral'. The process leads to a shift of costs from customers with solar generation to customers without, raising significant equity issues and pitting the two sets of customers against each other. Sioshansi considers various possible

solutions, such as three-part tariffs, increased fixed charges, time-of-use rates, and demand subscriptions, but concludes that ‘the battle is just beginning’.

David Robinson analyses the reasons why final electricity prices in the EU have risen so much faster than in the USA since 2008. This cannot be explained by different trends in costs related to wholesale generation, transmission and distribution networks, and retail services. Rather, it reflects the increase in the EU of a ‘government wedge’ in final electricity prices. This wedge includes taxes and levies related to the financing of decarbonization, and also support for domestic fuels (such as coal), subsidies for specific consumer groups, and other policy objectives. In short, final electricity prices in many EU countries no longer reflect the costs of supply, but rather the costs of meeting a variety of policy objectives. This has distributional consequences and hurts the competitiveness of many industrial and commercial consumers. Furthermore, it introduces economic distortions – which include an incentive for consumers to favour fossil fuels over electricity. He makes a number of policy recommendations, including the introduction of carbon taxes and

shifting some of the policy costs to the government budget.

Finally, two articles look at experience in China, which is facing challenges similar to those elsewhere in the world in relation to integrating the new resources, and is responding via a move to greater reliance on economic signals and market mechanisms.

Malcolm Keay, Xin Li, and David Robinson report on a study undertaken by the OIES, along with the Environmental Change Institute of Oxford University, on the potential for demand response in Shanghai. While interest in demand response is growing worldwide, examples from outside the OECD are often less familiar. Furthermore, the Chinese electricity system presents many special characteristics, in particular the widespread use of a form of administrative demand control to balance the system. Nonetheless, China is moving towards a greater reliance on economic instruments in electricity, as in other sectors, and the Shanghai study aimed to establish whether demand response could have a role there, as elsewhere. It showed that there is indeed potential for this approach, which could have both economic and environmental advantages, and the issues involved

are now being examined in more detail.

Zhang Xiliang and Xiong Weiming analyse the significant curtailment of wind power in China. Although China has become the largest wind power market in the world, in the first half of 2015 over 15 per cent of technically available wind power could not be connected to the grid and had to shut down. The reasons include uncoordinated planning between the grid and the wind generators, inflexible dispatch, and the lack of suitable policy incentives for stakeholders, notably the grid operator and the coal power generators. The government has introduced a number of policy reforms, but the curtailment problem remains serious. In May 2015, the State Council released *Document 9*, which could be the basis for deeper reforms of the power sector. It emphasizes the role of market mechanisms, especially in generation and retail segments, and also stresses the importance of integrating renewable energy in order to facilitate decarbonization, improve air quality, and mitigate climate change. The authors conclude that the best way to solve the problem of curtailment of wind power is to introduce market mechanisms, such as a spot market, as well as policy incentives for key stakeholders.





Future business models for power markets: what can we learn from the ‘sharing economy’?

Rolando Fuentes

Innovations in distributed energy resources (DER) – like solar panels and batteries, information technologies, smart meters and appliances – have the potential to rock the fundamentals of the electricity sector. It now seems likely that a significant proportion of future end-use electricity consumption could be supplied and managed by relatively small-scale, distributed resources, opening up attractive alternatives to traditional utilities for customers. This shift could reduce reliance on the central grid, which could ultimately change the way electricity is purchased, transported, and consumed. Boundaries between transmission–distribution and distribution–commercialization and generation may become blurred, as these activities would occur in the same place: the household. However, the system would become more complex, since households are geographically dispersed.

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‘...A SIGNIFICANT PROPORTION OF FUTURE END-USE ELECTRICITY CONSUMPTION COULD BE SUPPLIED AND MANAGED BY RELATIVELY SMALL-SCALE, DISTRIBUTED RESOURCES...’

The arrival of these innovations is leading utilities around the world to re-evaluate their business models, and regulators are considering electricity market reforms. However, trying to fix the system with marginal or incremental amendments will not be sufficient to cope with all these changes. In this article we explore experiences gathered from other industries that have faced technological disruptions recently, together with lessons they have learned which might guide future business models in the power sector.

Value proposition

There are at least three reasons to revisit business models.

- 1 These technological disruptions make it more evident that electricity is a multi-dimensional commodity, the attributes of which at times may be difficult to price. For example, bound up with the energy service itself are: efforts to reduce emissions, reliability services, and risks. Also, the non-consumption of power has a value to the system. A key question for future business models then is how to monetize these values.
- 2 This eruption of innovative new technologies is taking place in a sector that has sunk costs and where investments are already in place. Hence the power sector cannot start afresh.
- 3 There is a place for both utilities and new entrants in the industry, albeit with different roles.

The prevailing business model for electricity utilities is a cost-plus structure in which the utilities pass their costs, plus a return on their capital investment, to customers at a variable rate (USD/kWh). The objective is to operate in a cost-minimization fashion and the model sustains itself with further capital investments, sales growth, and sustainable prices. This has led to the development of a business model where adding new capacity is the bread and butter of utilities’ revenues. But should we still impose this framework on utilities in the future, given massive investment requirements and lower sales?

There is a legacy in the power sector and the impact of the adoption of these technologies could go either way, with a positive or a negative impact. Uncoordinated introduction of DER

could increase system risks and transfer costs to other customers, in the absence of an organized market. However, so long as these newer technologies operate in a coordinated way with the other power sector resources, they can provide value to customers and to the overall system. Also, the value delivered by distributed technologies together would be greater than the sum of the values delivered by individual components.

These facts lead us to posit different roles for incumbent utilities and for new entrants. A utility offers not only energy to its customers but also spare generation capacity, ramping flexibility, operating reserves, spare distribution capacity, and ancillary services. But customers do not *value* all these items in themselves, since they don’t see them or think about them. Rather they value the services that depend on them – for example, reliability – from their power provider.

Airbnb and UBER

It has been suggested that solar photovoltaic (PV) panels, batteries, and smart grids can essentially transform the power markets into a series of nested markets, connected through different platforms as if they were multiple-sided markets. According to an IDEI (Institut D’Economie Industrielle) working paper of 2004 – ‘Two-Sided Markets: An Overview’ by Jean-Charles Rochet and Jean Tirole – a multiple-sided market is a meeting place for a number of agents that interact through an intermediary or platform. Markets of this sort, such as credit card companies and stock exchanges, have become prevalent in today’s economy. Google Search, Amazon, Facebook, UBER, and Airbnb are just a few of the more prominent examples. In these types

of markets, according to the EPRG (Energy Policy Research Group) working paper 'Platform Markets and Energy Services' of 2013 by Claire Weiller and Michael Pollitt, an intermediary captures the value of the interaction between user groups, and network externalities may lead to one of them being charged a non cost-reflective price.

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'THE VALUE PROPOSITION OF THE SHARING ECONOMY BRINGS TOGETHER OPERATORS WITH UNDERUSED ASSETS...'

The UBER (taxi) and Airbnb (room letting) business models – two successful companies of the 'sharing economy', as it has come to be known – may help us understand the future business models of the power generation sector. We can draw three lessons from the sharing economy experience. The first is that risk is re-allocated across the market, the second is the paradox between spare capacity and price signal, and the third relates to the dynamics between regulations and business models.

The value proposition of the sharing economy brings together operators with underused assets and others that may wish to hire or rent, in a timely manner, with low transaction costs since their information is more transparent due to the use of an internet platform. The businesses of the sharing economy set out to optimize the use of resources by making more frequent use of excess capacity in goods and services. According to an *Economist* article ('The Rise of the Sharing Economy') in March 2013, other terms that have been coined in the media for this sector are the 'collaborative economy', the 'asset-light lifestyle', or the 'access economy'.

Risk-reallocation

One of the key elements of the UBER or Airbnb business models is the need to deal with the uncertainty buyers and

sellers have in sharing and trading with people they have never met. Thus, as a side effect, insurance companies have gained from this model as more people demand their service. Borrowing this idea, an incumbent utility could act as the insurer of the rest of the power sector. As more renewable energy is installed and operated, this would mean two things: a growing share of generation would be at zero marginal cost, and utilities could end up with unused capacity for long periods of time. Paradoxically, that would make traditional capacity more important system-wide, as the incumbent would be the operator of last resort to keep the lights on. Consequently, the benefit of maintaining the grid's operability with the costliest energy source would outweigh the cost of the absence of electricity.

If utilities are to use their infrastructure as insurance, they will need to change the way they charge customers. A health insurance company's business model, for example, is based on healthy people financing treatments for ill people. The way forward for the utility could be to charge a fixed price, like an option value, for back-up. This would compensate for the long periods of zero marginal cost generation that could undermine the energy service their installed capacity provides, but not the reliability component provided by the same capacity. Utilities could offer memberships, or stream services like the internet television network Netflix, where customers pay a fixed amount. Or energy providers could offer contracts of service for electricity 'on demand', which would be more expensive, or 'as available', based on solar or other intermittent renewable generation (according to the chapter 'Electricity markets and pricing for the distributed generation era' by Malcolm Keay, John Rhys, and David Robinson in Fereidoon P. Sioshanshi's 2014 book *Distributed Generation and its Implications for the Utility Industry*).

This option would detach power prices from the time variable. The alternative

would run contrary to the recent tendency to have more real-time decisions with smart metering, as it would decrease the number of transactions and increase the time period during which they take place. Counterintuitively, this option would increase the time lags of transactions by charging fixed prices for coverage in longer periods. However, fixed prices have been met with significant resistance from energy efficiency and DER advocates, because customers would no longer have the incentive to adopt the new technologies and thus save money.

There are two caveats. First, as is often the case, the starting point matters. For example, people are willing to pay for health insurance to *increase* their coverage, whereas customers of the power sector start with near 100 per cent coverage already. In complete energy autonomy they would need to get used to paying for a service that they are accustomed to receiving and taking for granted, alternatively, they would need to demonstrate their willingness to accept occasional service disruptions. Second, contracts for stream services like Netflix are feasible since there is no rivalry in consumption in their stream service. Electricity is a rival good in consumption, but it can still be argued that not all of the utility's customers will need back-up at the same time, just as not all people claim on their health insurance or cash-in their bank accounts at the same time.

Spare versus scarce

There is a paradox in the sharing economy model. The traded asset is usually idle capacity – for example, Airbnb's asset is unused rooms in people's houses – whereas economic theory focuses on how prices send scarcity signals. The question is: what are the spare, and what are the scarce, assets in the new electricity sector structure? It may be that the abundant asset will be PV solar panels. One of the concerns is that PV ends up completely



flooding the electric power system with uncontrolled amounts of zero variable cost energy. The scarce resource is more difficult to work out. However, bearing in mind the nature of the new technology, the distribution sector, the multidimensional characteristics of products and services in the power markets, and the network effects, we foresee the following:

- Average cost per kW will be lower. A recent multidisciplinary MIT study ('The Future of Solar Energy', 2015) shows that a large penetration of solar PV displaces the plants with the most expensive variable costs and increases the cycling requirements of thermal plants.
- The role of energy aggregator will be more widely seen. If generation is intermittent, dispersed, and uncertain, what business ideas can ameliorate these undesirable characteristics? The answer lies in the creation of a relatively new player in the market: the aggregator. The aggregator's function would be to coordinate the loads from dispersed sources, thus smoothing out the underlying intermittency. These new players are already emerging in California.
- Indirect services will be central to the new electricity markets. Electricity has multidimensional attributes. The most straightforward is the quantity of energy delivered at specific times and locations. But we can also consider the purpose for which the electricity is used. For example: charging a battery, running a fridge, watching TV, end-use, cooling, and heating. And we should consider its reliability – the probability that supply would be available. Firms can sell reliability (MW), energy (MWh),

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'THE AGGREGATOR'S FUNCTION WOULD BE TO COORDINATE THE LOADS FROM DISPERSED SOURCES, THUS SMOOTHING OUT THE UNDERLYING INTERMITTENCY.'

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system savings (NWh), or environmental benefits (carbon dioxide emissions reductions).

- Managing demand profile is key for the new marketplace: the distribution. One of the main determinants of distribution operations is demand profile. How can business solutions, to some extent, help to manipulate demand profiles so that non-consumption and demand response become valuable?

A key issue would be how to price these services, as most of them are externalities – positive and negative. There are a couple of alternatives:

- Regulation that imposes values, products, and transaction guidelines. Such regulation would establish the rules of the markets, while the markets themselves would then decide the efficient level of provision.
- A *Coasian* approach where governments assign property rights, for example over the reliability aspect of the system, and permit actors to trade between themselves.

Regulatory dynamics

Utilities' business models have largely been dictated by their regulatory model. It is true that the rate-of-return regulation in some countries has made the utility business model an infrastructure one. But in other regulated industries where technological innovation has changed the landscape, regulation has proved to have been lagging behind the impetus of the industry. One of the most notable cases where regulation has been forced to adapt to these technologies is in the taxi services industry, with the advent of UBER.

In such a case, the dominant strategy for a new entrant – UBER, or Airbnb, for example – is to quickly grab market share to lock in their platform. This would force regulators to accommodate these new business practices as the standard regulation. For example, regulators have taken a hands-off approach with regard to risks for new taxi services and have

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'WILL PENETRATION OF DISTRIBUTED ENERGY RESOURCES OCCUR IN AN ORDERLY MANNER ALLOWING REGULATORS TO ACCOMMODATE THEM?'

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chosen to include insurance clauses as part of their regulation. This was adapted from UBER's own business model. Other jurisdictions facing similar problems are likely to follow what the first mover regulators have done. This will then become the norm. Having a homogenous regulation framework helps new companies expand more rapidly across different cities or countries. A key element for the electricity generating industry is this chicken and egg question: will penetration of distributed energy resources occur in an orderly manner, allowing regulators to accommodate them? Or will new entrants and new business models in the end pre-empt future regulation?

Conclusion

Business models in the electricity sector have been under scrutiny. In this article we try to draw parallels from industries that partially resemble the power sector and that have faced recent technological disruptions.

The main points we can draw from those are:

- 1 technical disruptions will force regulations and business models to adapt;
- 2 business models can shape future regulation, as opposed to the position at present where regulation dictates the business models for utilities;
- 3 re-allocation of risks opens up the prospects of a new role for the incumbent utility; and
- 4 electricity has multi-dimensional attributes for which markets need to be designed.

This article is based on a forthcoming KAPSARC publication



How the ‘Big Beyond’ will change business models of utilities

Christoph Burger and Jens Weinmann

Challenges of energy incumbents

According to figures from the German environmental ministry, Germany increased its intake of renewable energies from 6 per cent in 2000 to 32.5 per cent in the first half of 2015. The country’s incentive system, based on fixed feed-in tariffs, motivated private individuals such as homeowners, farmers, and energy associations to participate in the market. In 2014, around half of all renewable energy installations were owned by citizens, rather than corporate entities, and more than 1.5 million producers of electricity participated in the market.

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‘IN 2014, AROUND HALF OF ALL RENEWABLE ENERGY INSTALLATIONS WERE OWNED BY CITIZENS, RATHER THAN CORPORATE ENTITIES...’

In contrast, the ‘Big 4’ energy incumbents operating in Germany – EnBW, E.ON, RWE, and Vattenfall – own less than 10 per cent of all renewables installations. One of the reasons why incumbents have not participated in the rush for renewable energies may be that their business model has traditionally been directed towards large-scale projects, rather than smaller, decentralized installations, given that the proportion of transaction costs involved in small-scale investments is typically higher than in larger projects.

Since the marginal costs of sun and wind power are practically zero, the priority feed in of renewable energies has induced a downward pressure on prices in the German wholesale market. Average peak load prices have decreased from around 60 EUR/kWh in 2011 to less than 35 EUR/kWh in 2014, according to the Fraunhofer Institute

for Solar Energy Systems (ISE). E.ON, the largest German electricity producer, posted a loss of EUR5.7 billion for the first nine months of 2015, while competitor RWE’s operating result decreased by 9 per cent. The erosion of revenues has led to a strategic shift being undertaken by E.ON and RWE. Both utilities intend to split their assets into two separate and independent entities, with the intention of reorganizing their activities and creating companies that are able to fit better into the changing marketplace.

Counter-strategies and new forms of innovation

Many European electric utilities that are exposed to similar developments have realized that their business model has to change if they want to survive in the competitive environment. They have to become more innovative and explore new business models to compensate for the loss of revenues in their traditional business units. In the past, research and development within utilities predominantly focused on incremental innovation, on the gradual improvement of processes and operations, rather than on disruptive business ideas. Utilities with a retail and distribution business have a particular advantage in the testing of new business models, because they are already physically present on the premises of their customers, via metering technology.

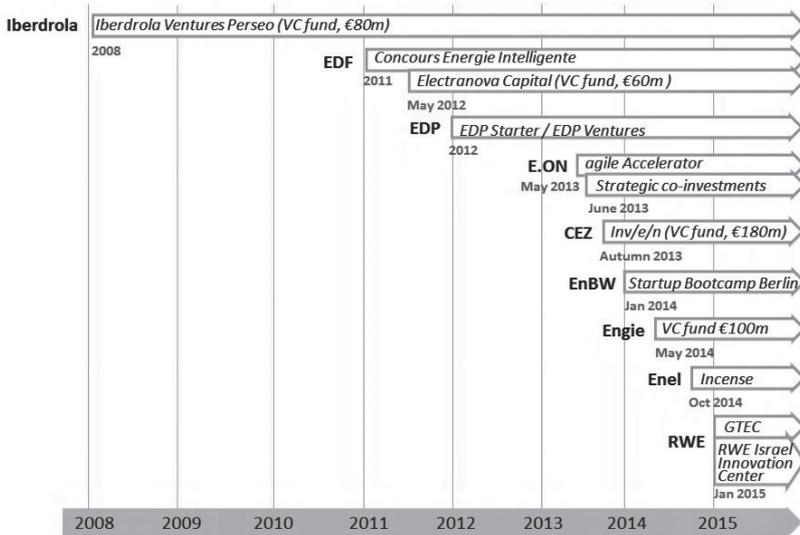
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‘MANY EUROPEAN ELECTRIC UTILITIES ... HAVE REALIZED THAT THEIR BUSINESS MODEL HAS TO CHANGE IF THEY WANT TO SURVIVE...’

However, utilities struggle to find people within their workforce that are

capable of developing genuinely new, customer-centric, digital business models. Hence, they follow a strategy that has proven successful in many other industries, as diverse as pharmaceuticals, logistics, or finance, over the last couple of years. They outsource innovation to young teams of entrepreneurs and the founders of new companies. The most common instruments of that process are venture capital (VC) funds, incubators, and accelerators. VC funds typically provide financial resources to a portfolio of small companies, but they do not interfere with the day-to-day operations of their ventures. By contrast, corporate incubators provide an environment (but not necessarily a physical location) where new ideas from inside or outside the company are nurtured, protected from the company’s other key performance indicators and standard corporate culture. Accelerators, the third common type of these new forms of innovation, are programmes of two to six months duration in which a team of mentors and coaches guides the founders of new companies through the process of developing a business plan and of finding investors to commercialize their ideas.

Hybrid forms of business model are also possible: E.ON, Germany’s largest utility, pursues a strategy of co-investments where (limited) involvement and early bonding between a business unit (which takes over some type of ‘ownership’) and the venture is desired.

As early as 2008, the Spanish energy utility Iberdrola began setting up a VC fund and through to 2015 most major European players followed – either establishing their own organizations or participating in collaborative efforts



Timeline of exemplary initiatives of selected European utilities in the field of 'diverse' innovation

Source: based on C. Burger, S. Pandit, and J. Weinmann (2015). *ESMT innovation index 2014 – electricity supply industry: The 'big beyond'*, ESMT Business Brief No. BB-15-01, (Figure 7).

with other companies. The diagram below shows a selection of initiatives undertaken by major European energy incumbents.

Three major challenges emerge with this type of diverse innovation:

- 1 The multitude of ideas implies that a large fraction of these start-ups and ventures will not succeed in the marketplace. A venture capital firm typically receives 2,000 business plans, evaluates 200, and invests in 20, of which roughly 2, or 10 per cent, outperform – a chance of 1:1,000 to identify a successful business model. The 'fail-fast' attitude is an inherent characteristic of the start-up ecosystem, but it requires a fundamental change in mentality of the top management of electricity utilities.
- 2 Integrating the ventures into existing organizational structures is most likely to succeed when done early. For example, German incumbent E.ON tries, very early in the process, to identify business units that will take 'ownership' of idea and start-up.
- 3 Will the new ventures yield sufficient revenues soon enough to

compensate for losses in other units, thus ensuring corporate survival? The US company IBM is a prime example of a company that can reinvent itself, but many other incumbents from other industries have disappeared. Polaroid, Kodak, and DEC are just some examples.

Not all seems lost for the electricity supply industry. While revenues from generation decline, the grid-related business of utilities (electricity transmission and distribution) secures a regulated (and capped) but stable stream of income. Utilities that own parts of the grid are in a more comfortable position than those that have been forced to unbundle or to create separate legal entities.

In the longer term, however, the grid-related services of utilities may be threatened in the same way as their generation business. Electricity can now be generated at the point of consumption, not just in centralized power plants, while costs of renewable energy installations have substantially decreased over the last couple of years. The European Union's research unit, the Joint Research Centre,

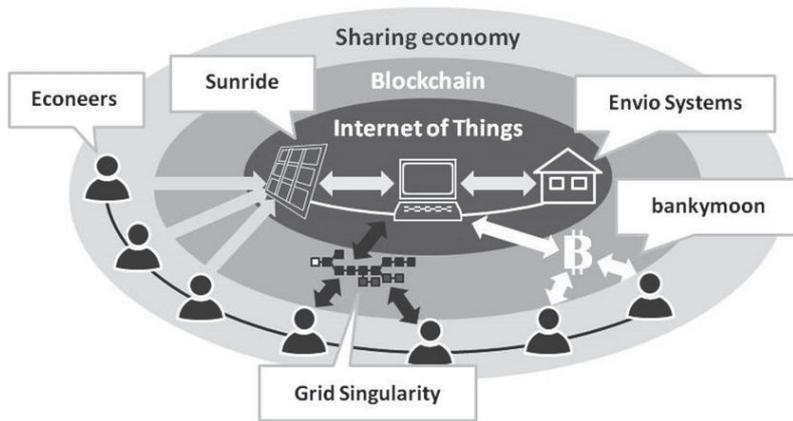
foresees electricity generation costs of around 0.02 EUR/kWh for photovoltaic installations that have already been written off; this is cheaper than any conventional generation technology except large hydropower. At a retail price of around 0.30 EUR/kWh for residential consumers in Germany, 0.28 EUR/kWh could potentially be spent on battery storage or other means to detach individual customers from the grid.

The 'Big Beyond'

Three overarching trends, which the authors call the 'Big Beyond', may lead to an erosion of the market position of incumbents, even in the regulated parts of their operations:

- 1 Frugal innovation and the **Internet of Things (IoT)** – a low-cost alternative to conventional solutions, especially in building efficiency;
- 2 The **blockchain** – a secure transaction technology for smart contracts;
- 3 The **sharing economy** – creating own networks, for example via financing but also operating.

Frugal innovations are innovations that are made at lower cost and lower complexity than standard solutions. Often they can be found in the context of developing economies, where many products used in the industrialized world are too expensive and over engineered. But even in wealthy countries, digitalization creates opportunities for founders and entrepreneurs to develop solutions for market segments that have been untapped, often in so-called legacy markets. Retrofitting existing building stock and increasing the energy efficiency of houses is one of the areas where frugal innovation takes place. Envio Systems, for example, is a Berlin-based start-up that intends to revolutionize existing commercial buildings. The company has developed



The ‘Big Beyond’ and exemplary companies

Source: based on C. Burger, S. Pandit, and J. Weinmann (2015). *ESMT innovation index 2014 – electricity supply industry: The ‘big beyond’*, ESMT Business Brief No. BB-15-01, (Figure 8).

a box called Cube that contains multiple sensors and connects to a digital optimization platform. In contrast to, say, Google’s residential building efficiency device Nest, Cube is able to detect whether there is anyone in a particular room, via a carbon dioxide sensor, and can adjust the heating or cooling activity accordingly. Envio System’s solution costs a quarter of similar installations offered by large competitors, such as Schneider Electric, Siemens, or Honeywell. The company estimates the market size in North America and Europe at more than 10 million commercial buildings.

If newcomers like Envio use the enhanced capabilities of devices connected via the **Internet of Things**, utilities operating in retail may lose revenues from an increasing number of lucrative commercial customers. Going one step further, if costs for batteries continue to decrease and storage becomes affordable on a larger scale, commercial, industrial, and even residential customers may decide to rely completely on self-production.

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‘[IF] STORAGE BECOMES AFFORDABLE ON A LARGER SCALE, ... CUSTOMERS MAY DECIDE TO RELY COMPLETELY ON SELF-PRODUCTION.’

The **blockchain** is a secure transaction database that is currently used for cryptocurrencies such as Bitcoin. Due to its configuration, it records all transactions ever executed in a transparent, decentralized internet protocol. Its main differentiating driver is that it can replace all intermediary institutions whose existence is primarily justified by their trustworthiness for all parties involved in the transaction. Banks belong to that group of intermediaries, but so do energy utilities acting as retailers or traders.

This technology may be particularly attractive in developing countries, where the poor often have no bank account and could potentially use the platform as a means to pay their bills. For example, South African start-up Bankymoon has introduced a system that allows users of smart meters to pay via the cryptocurrency Bitcoin, thereby bypassing banks.

New venture Grid Singularity intends to use the blockchain to introduce a decentralized energy data exchange platform. This would offer services enabling forecasting for grid balancing and would facilitate investment, the trade of green certificates, and eventually energy trade validation. Grid Singularity’s founders expect immense infrastructure cost savings, compared

to standard technical solutions that require a fully independent vertical integration for each energy market operation. The platform may also render some of the current key entry barriers to energy trade obsolete – such as a need to have special accounts and deposits, or a certification with an intermediary financial institution. The business model of utilities may be threatened if decentralized energy producers enter into direct interaction with their consumers. Any type of physical or monetary transaction that involves a trustworthy intermediary could be replaced by the blockchain.

The third element in the ‘Big Beyond’ is **crowdfunding**, which is part of the so-called **sharing economy**: exclusive ownership of goods has become less important for young people. The prime example is car-sharing services, where people rent cars for a limited amount of time. The service – in this case, travelling from A to B – is the only factor that counts. In the energy sector, founders promote their business idea on crowdfunding websites to collect money. Companies such as crowdEner.gy, econeeers, Trillion Fund, or SunFunder establish a parallel market that relies on the financial commitment of many individuals, rather than on any bank or single investor. For example, the German crowdfunding company econeeers requires a minimum financial involvement of EUR250 over five years; investors receive dividends and are financially rewarded if the venture or project is profitable. In 2015, econeeers received EUR750,000 in solar crowdfunding.

Berlin-based start-up Sunride takes the sharing economy one step further and implements software solutions to optimize neighbourhood-level photovoltaic installations that are jointly owned and used by inhabitants. In Berlin, more than 120 local associations have been founded to set up solar panels and generate electricity for self-consumption and grid feed-in.



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'BY EMBRACING THE BIG BEYOND, UTILITIES MIGHT BE ABLE TO TRANSFORM THEMSELVES INTO ENABLERS OF A DECENTRALIZED ENERGY SYSTEM.'

The 'Big Beyond' not only questions the grid-based business of utilities, but utilities in their very existence. If buildings become largely energy-

autonomous via the IoT, all transactions performed via blockchain, and finance is undertaken via the sharing economy, then utilities have to fear that they will become the dinosaurs doomed for a slow and painful decline of their operations. By embracing the Big Beyond, however, utilities might be able to transform themselves into enablers of a decentralized energy system. They

might even – rather than owning large-scale assets, producing electricity, and transmitting it to the customer – build, own, or operate decentralized energy generation assets, steering them at the point of consumption. It is only a matter of technologies and mind set, since the task – delivering energy to the customer – would remain the same.



Renewable integration and the changing requirement of grid management in the twenty-first century

Rahmat Poudineh

Background

Since the dawn of the electricity industry, uncertainty has always been an inherent characteristic of the system. The concept of uncertainty in the power system has evolved over time, but in the past it mainly implied demand fluctuation and components failure (generation and network). Traditional systems are equipped with a range of control mechanisms to manage these kinds of variability and uncertainty, in order to provide a reliable service. In such a paradigm, technologies are mature and the behaviour of load is fairly predictable. In recent years, however, supply-side fluctuations have presented a new form of uncertainty and added to the complexity of grid management. The source of supply-side variations is intermittency of renewable resources, such as wind and solar, whose penetration is accelerating as environmental regulations tighten around the world. For example, the wind and solar PV installed capacity in the EU region rose from 12.8 GW and 0.125 GW in 2000, to 128.7 GW and 88 GW respectively in 2014. This implies that solar PV constituted 10 per cent and wind represented almost 15 per cent of total installed capacity in the

EU in 2014. The rapid penetration of renewable resources imposes several operational and economic challenges on the electricity sector. The problem of the system operator is no longer to forecast load but net load, which is the difference between the total load and the supply from intermittent resources. This increases the need for *system flexibility*; an ability that the power system requires in order to utilize its resources and deal with variations in net load and generation outage over various time horizons.

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'THE RAPID PENETRATION OF RENEWABLE RESOURCES IMPOSES SEVERAL OPERATIONAL AND ECONOMIC CHALLENGES ON THE ELECTRICITY SECTOR.'

Integration of wind and solar resources necessitates system flexibility in at least three ways.

- 1 The stochastic nature of variable generation leads to a wider confidence interval of net load forecast; it increases the need for additional flexible resources. Although variability declines with aggregation and geographic dispersion, no

forecast measure is perfect and error will exist even at an aggregated level. Moreover, even with perfect prediction, without curtailment, the available flexible resources may not be sufficient to meet the variation in the net load.

- 2 The penetration of intermittent resources can displace conventional generation sources and this adversely affects the amount of online flexible resources.
- 3 A lack of system flexibility can result in more frequent occurrences of negative prices in wholesale markets; this imposes additional costs on renewable energy levies (where they exist) to cover the difference between contract and wholesale market prices (when guaranteed payments are linked to the wholesale energy price).

Additionally, even if all mechanisms for managing variability of net load are available, the current electricity markets may not be positioned to incentivize their efficient use. Thus, I contend that as intermittency increases and the need for flexibility becomes critical, the system requires new models of grid management both at operational and institutional levels.

Intermittency: a driver of change in grid management

In this section I briefly discuss some of the operational and institutional (market and regulation) changes in the power system that result from the penetration of intermittent resources.

Operational challenges

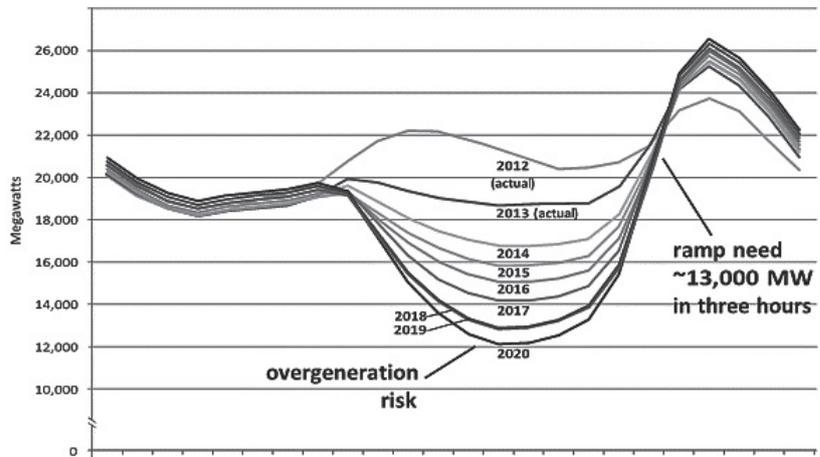
The operational challenges of penetration of variable generation into the power system depend on various factors such as:

- scale of intermittent resources,
- correlation with demand,
- flexibility of the power system.

In order to illustrate some of these challenges I use an example from the California Independent System Operator (CAISO) where the share of renewables in the generation mix has risen due to the ambitious goals of the California Renewables Portfolio Standard (33 per cent of electricity from renewable sources by 2020 and 50 per cent by 2030). These targets – along with environmental policies and regulation regarding retiring or mothballing of the power plants that use coastal water – are expected to change the energy landscape in favour of renewables in California.

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‘TRADITIONAL RELIABILITY METRICS NEED TO BE SUPPLEMENTED BY VARIABLE GENERATION INTEGRATION STUDIES.’

The increase of intermittency has already started to manifest itself in various operational challenges in California’s electricity sector. The CAISO power system is now experiencing short and steep ramps, such that the system operator needs to bring on or shut down power plants more often and within very short periods of time, in order to meet the variations in net load. Furthermore, during the hours of weak demand, the CAISO system runs the risk of over



California Independent System Operator (CAISO) duck curve

Source: ‘What the duck curve tells us about managing a green grid’, California ISO Fast Facts.

generation. This usually happens when the system prepares for its morning or evening ramp up, or during the night times when supply from must-take resources exceeds demand. These effects have given rise to a new phenomenon referred to as a ‘duck curve’ because the shape of net load resembles the body of a duck in which the system is at the risk of over generation at the lowest point of duck belly (see chart). Additionally, when there are a lot of renewables on line, and thus a limited number of flexible power plants, the system has a limited frequency response – a characteristic that is crucial for the power system to recover from faults (for example, sudden failure of a massive power plant).

In order to operate reliably under these conditions, new practices in planning and operation need to be introduced. Traditional reliability metrics need to be supplemented by variable generation integration studies. An example of such new metrics is the Insufficient Ramping Resource Expectation (IRRE); this can complement generation adequacy metrics (Loss of Load Expectation and other relevant indices) in order to assess whether planned capacity allows the system to respond to short-term changes in the net load. Such operational changes pave the way

for the power systems of the future in which:

- resources react quickly and meet expected operating levels for a defined period of time,
- ramp directions can change rapidly,
- energy can be stored or its use modified,
- power plants are able to start and stop multiple times per day,
- operators can make accurate forecasts of their operating capability.

Flexibility services can be provided by various resources such as: fast ramping thermal generations (for example, open cycle gas turbines), storage, interconnection, demand response, and even curtailment of renewables. The adequacy of transmission and distribution networks, in terms of having no bottlenecks and sufficient capacity, is also crucial to enable flexibility.

Market and regulation

Such changes in traditional operation and planning of the power system are necessary but not sufficient to enable a flexible power system. There is also a need for institutional changes, in terms of market (and product) design and



regulation. These changes are required to ensure not only that the current resource owners have the incentive to offer their flexibility services, but also that the market incentivizes new entrants to meet the flexibility requirements of the system. Many of the conventional generation sources have not been designed to take on the ramping and cycling duties that are now required, and such operational modes increase the of cost of their wear and tear and fuel consumption. Therefore, a market (or regulation) that values flexibility is required to enable these generators to cover the costs of operating in a flexible mode when needed.

In the author’s view, there is a range of measures that can be taken in order to align electricity markets with the requirements of a flexible power system. These include: modification of the current markets to make efficient use of available flexible resources, designing explicit incentives for flexibility services, and defining tradable flexibility products.

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‘IN MANY POWER SYSTEMS WITH FLEXIBILITY ISSUES, ELECTRICITY MARKETS ARE NOT POSITIONED TO MAKE EFFICIENT USE OF AVAILABLE RESOURCES.’
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In many power systems with flexibility issues, electricity markets are not positioned to make efficient use of available resources. For example, in some US regions where sub-hourly markets do not exist, normal short-term variation of net load is met by frequency regulation services – utilizing the fastest, but most expensive, flexible resources. However, in other regions (typically those with an ISO) such variations are managed at a much lower cost through procurement in sub-hourly markets. The presence of sub-hourly markets provides a unique opportunity for the system operator to exploit the inherent flexibility of a large

fleet of generation sources that can alter their aggregate output rapidly.

The definition of standardized tradable flexibility products is also an important part of the game. For instance, in order to help the system and use dispatchable flexibility, the California ISO is working on a proposal to incorporate a new product, called flexible ramping products (FRP). FRPs offer a five-minute ramping capability that will be dispatched to meet five-minute to five-minute variations in net system demand. In this context, the net system demand is defined as the load plus export minus the schedules of all resources that are not five minute-dispatchable, including renewables, imports, and self-scheduled resources.

Another example in line with such modifications in electricity markets is the UK review of balancing markets and changes to cash-out arrangements, which aims to make them reflect marginal rather than average costs. Sharpening cash-out prices provides incentives for the market players to offer, invest in, or secure flexible resources to balance their position at the time of system stress. On top of that, the market for flexibility services can be regional rather than national. This is specifically relevant to the EU region, in which short-term balancing markets can become integrated where there is sufficient interconnection capacity available (and will provide incentives for investment in interconnections). This promotes efficient procurement of flexibility services because, with the increase in the market size, more options become available to national system operators.

In addition to efficiency, another objective of a flexibility market is to ensure the sufficiency of flexible resources. This requires explicit incentives for adding flexible resources, since conventional capacity markets are

not a substitute for the flexibility market. This is simply because the standard definition of resource adequacy does not necessarily imply flexibility: a system can be adequate in terms of resources available to meet seasonal pattern of load profile (capacity exceeds demand with a margin at all time) but lack the operational flexibility to deal with within-day fluctuations of net load. Furthermore, when capacity markets do not explicitly value flexibility, the outcome of procurement favours low-cost resources that lack the capability to respond to short-term variation of net load (the UK capacity market is a good example for this). The bottom line is that flexibility is a component of scarcity; thus a single-product capacity market suffers from the very same ‘missing’ scarcity distortion that it was intended to address in the first place. Therefore, the current capacity markets in the EU region should be designed so that both capacity and operational capability of resources (and maybe also carbon emission reduction) are valued.

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‘...DEMAND RESPONSE IS A GOOD EXAMPLE OF HOW REGULATION CAN AFFECT THE FLEXIBILITY OF A POWER SYSTEM.’
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On the regulatory side, demand response is a good example of how regulation can affect the flexibility of a power system. For instance, the rules regarding the nature of demand response (equal treatment of it with other resources and types of markets in which demand response can participate) are important for utilization of this resource. In some US regions, demand response is allowed to participate in the ancillary service markets; this is an attractive arrangement for aggregators of demand response services. Such arrangements are also happening in the UK, which is trying to integrate the demand side in its balancing service;

for example, under the Frequency Control Demand Management (FCDM) scheme, frequency response is provided through automatic interruption of contracted consumers when the system frequency transgresses the low frequency relay setting on site. The UK National Grid is also trying to utilize slower-responding demand response for load following services under the Short Term Operating Reserve (STOR).

Conclusions

The widespread deployment of intermittent renewable generation in several countries has led to an increase in the relative and absolute magnitude of power generation with random output. This deployment constitutes a major paradigm shift in grid management, both at an operational level and also in terms of market design

and regulation. In addition to traditional resource adequacy metrics we need new methodologies, in order to quantify and assess the technically available operational flexibility of the power system to be utilized for planning and operation. Also, we need to ensure that electricity markets and regulations not only provide incentives for investment in flexible resources, but also make efficient use of available resources.



Market integration with energy-only markets and renewables: lessons of experience from Australia

Rabindra Nepal and Tooraj Jamasb

The establishment of wholesale electricity markets has been one of the hallmarks of the market-oriented electricity sector reforms and restructuring process that started in the early 1990s. The standard model of liberalization included the establishment of wholesale and retail competition, vertical separation of the distinct generation, network, and retail activities, and incentive regulation of electricity networks. A fuller physical and financial integration of the separate national or regional electricity markets was then required to enable a deepening of competition. For example in the EU, the process of creating a common and integrated wholesale market for electricity that started in the second half of the 1990s, remains a work in progress, while Australia has, since 1998, focused on creating an efficient and integrated National Electricity Market (NEM).

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‘THE ESTABLISHMENT OF WHOLESALE ELECTRICITY MARKETS HAS BEEN ONE OF THE HALLMARKS OF THE MARKET-ORIENTED ELECTRICITY SECTOR REFORMS...’

This article draws upon the NEM’s

experience with market integration, renewable energy, and network regulation, and merges the findings from recent studies: ‘Testing for Market Integration in the Australian National Electricity Market’, a paper forthcoming in the *Energy Journal* by Rabindra Nepal and John Foster; ‘Network Regulation and Regulatory Institutional Reform: Revisiting the Case of Australia’, an article in *Energy Policy* from October 2014 by Rabindra Nepal and Tooraj Jamasb; and ‘Electricity Networks Privatization in Australia: An Overview of the Debate’, an article in *Economic Analysis and Policy* from December 2015 by Rabindra Nepal and John Foster.

We discuss the context within which renewable energy development and market integration can be implemented as complementary policies in energy-only markets, citing Australia as a specific case, but drawing lessons for the EU. The NEM provides an interesting case study, since it is one of the most transparent energy-only wholesale electricity markets and it is located in an island economy, while it is also poised for greater uptake of renewable energy. The lessons from the NEM can be important for other regions

such as the EU, which is predominantly an energy-only market moving towards greater integration of renewables and electricity markets.

The next section of the article provides an overview of the structure and organization of the NEM; following this, the facts and underlying reasoning behind the idea that the development of renewable energy and electricity market integration can be complementary policy objectives in Australia, are presented. We then conclude by highlighting the broader implications for other energy-only markets, especially in the EU.

The National Electricity Market (NEM)

The NEM was established in 1998 in response to the overall restructuring of the Australian electricity sector. The NEM is a gross pool arrangement for wholesale electricity trade in Australia and operates a deregulated market in the physically interconnected, but separate, regions of New South Wales (NSW), Victoria (Vic), Queensland (QLD), the Australian Capital Territory (ACT), South Australia (SA), and Tasmania (TAS). Tasmania joined the NEM in 2005. Exchanges between



electricity generators and consumers take place in a spot market through a centrally coordinated dispatch where the output bids from all generators are aggregated and instantaneously scheduled to meet demand. A dispatch (or spot) price is determined every five minutes and six dispatch prices are averaged every half hour to determine the spot price for each trading interval in each of the regions of the NEM.

The dispatch price is the energy-only price and does not contain any components for capacity such as 'capacity payments'. The National Electricity Rules (the rules) set a maximum spot price (market price cap) of 13,100 AUD/MWh and a minimum spot price (market floor price) of -1000 AUD/MWh for the financial year 2013/14. The market price cap prevents wholesale spot prices from rising too sharply during extreme peak loads or at times of reduced baseload capacity. The negative market floor price allows generators to pay to stay online when the cost of staying online is lower than the cost of shutting down and re-starting their plants. Hence, the minimum spot price guarantees dispatch by bidding at negative prices when a generator is too costly to turn off.

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'THE GENERATION MIX IN THE NEM IS DOMINATED BY LOW-COST BASELOAD GENERATION.'

The generation mix in the NEM is dominated by low-cost baseload generation. Queensland, which has installed capacity that amply exceeds the region's peak electricity demand, is a net exporter in the NEM. Victoria also benefits significantly from low-cost baseload capacity, making it also a net exporter of electricity. New South Wales is a net importer of electricity and has limited peaking capacity at times of high demand. NSW mostly relies on local baseload generation. South Australia relies heavily on

electricity imports, although new investment in wind power has reduced its import dependency since 2005/06. For example, the registered capacity of wind and solar in SA in 2013 was 30 per cent of total capacity, while 2,987 MW of wind capacity will be added (equivalent to 61 per cent of the total generation mix) by 2023. Tasmania is also a net importer of electricity, although it became a net exporter in 2011/12 for the first time since its interconnection with the NEM, due to greater water availability and the installation of new gas-fired generation.

The Australian Energy Regulator (AER) determines the maximum revenue (*revenue caps*) that the transmission and distribution companies can recover from the network users in Queensland, Australian Capital Territory, and Tasmania. Likewise, the AER sets the maximum network tariffs that distributors can charge consumers (*price caps*) in New South Wales, Victoria, and South Australia. The transmission and distribution networks remain state-owned in Tasmania, New South Wales, Queensland, and part of the Australian Capital Territory. Victoria and South Australia have fully privatized electricity generation. Victoria corporatized and privatized its electricity networks between 1995 and 1999 and both the transmission and five distribution networks are now in private ownership. South Australia has privately owned transmission networks, while the distribution network is leased to private interests.

There are six operational interconnectors among the five electrically connected states in the NEM. There are two interconnectors operating between NSW and QLD, and two between SA and VIC, while VIC-TAS and NSW-VIC are each connected by a single interconnector. There is no direct interconnection between QLD-SA and NSW-SA. The existing interconnectors largely follow the state boundaries, covering a distance of

more than 5000 kilometres, running from Port Douglas in Queensland to Port Lincoln in South Australia. Hence, NEM is one of the longest interconnected power systems in the world. Geographical constraints as an island economy have led to the infeasibility of cross-border interconnections, to date, in the NEM.

Market integration outcomes

Despite more than 14 years having passed since the establishment of the NEM, wholesale electricity price differences persist across the Australian states. Average daily prices are lowest in VIC and QLD, while SA has the highest average price, followed by TAS and NSW. However, the average daily wholesale price differences between SA and VIC are the lowest among the physically interconnected states. The persistent differences in wholesale prices can be attributed to the presence of network constraints across the regional interconnectors; this impedes the wholesale market integration process in the NEM. The Australian Productivity Commission has expressed concerns about under-investment in transmission networks and in regional interconnectors. In response, the AER has, in the past, recognized the significance of congestion costs in the NEM and has allowed more investments in the transmission network.

Network constraints occur due to physical limits to the network's transfer capability. Network congestion can segment the market and increase the wholesale electricity price by displacing low-priced generation with more expensive generation. Congestion can also lead to market power in the segments of the market. Finally, congestion also promotes inefficient electricity trade flows between the regions, as electricity cannot be stored and 'demand and supply' have to be balanced in real time. The existing network constraints, due to underinvestment in

interconnectors, act as a barrier to the wider, and much expected, development of renewable resources, such as wind.



‘THE LACK OF ADEQUATE INTERCONNECTION CAN PREVENT THE DEVELOPMENT OF NEW WIND POWER IN THE RESOURCE-RICH REGIONS’



Australia’s wind resources are mostly concentrated in the regions with the lowest electricity demand, these include South Australia, Tasmania, and Victoria. Queensland and New South Wales exhibit high demand for electricity, but have a low concentration of wind resources. For example, South Australia can reach a wind penetration (percentage of average generation) of almost 70 per cent, followed by Tasmania at 50 per cent, while Queensland and New South Wales have wind penetrations of around 1 per cent and 11 per cent, respectively. The lack of adequate interconnection can prevent the development of new wind power in the resource-rich regions, and lead to curtailment of existing capacity. The costs in terms of lost revenue to the wind power plants as a result of curtailment are large, and hamper the country in its attempts to meet its national renewable energy targets.

Furthermore, wind projects are gradually moving to less congested parts of the networks across Queensland and New South Wales, but these areas enjoy lower quality wind resources, and will eventually face higher costs. The expansion of interconnectors, together with increased export capacity from low-demand regions (with high wind potential) to high-demand regions, is important in order to reap the security of supply and sustainability benefits from wind generation in the NEM. Improving market integration by increasing the cross-border power flow will also lead to benefits through efficiency gains, both allocative and productive, as well as through dynamic efficiency gains, because a well interconnected market will

facilitate the optimization of investments in both generation and transmission over time across the NEM market.

Conclusions and policy implications

The most important factor for market integration is to connect regional electricity systems, physically and adequately, through a transmission grid and interconnectors. The transmission capacity and prices will then determine the volume of trade between the different regions.

The EU is striving to create an integrated electricity market in Europe, while also aiming to significantly increase the share of its energy from renewables. However, as the EU has identified, the European transmission and distribution networks need to be adapted and extended to facilitate power flows from generation source to end users across borders. Achieving this objective will require substantial investments. The island economies with isolated electricity markets – in Northern Ireland and the Republic of Ireland – are also aiming to increase integration with the continental European electricity markets under the EU ‘Target Electricity Model 2014’. In addition, the Republic of Ireland has a target to generate 40 per cent of its electricity from renewables by 2020.

The NEM experience with market integration suggests that harmonization of regulatory and institutional frameworks and electricity market regulations can be coupled with private ownership of assets, to improve market integration across energy-only markets poised for a large intake of renewables in the wholesale trade. The case of NEM suggests that a solid regulatory framework could be a pre-requisite for the necessary infrastructure investments to take place in time for 2020. For example, the AER recognized the significance of congestion costs across the regional interconnectors and allowed

higher transmission investments in regulatory decisions in 2009.

The regulatory test for transmission expansion and network planning in the NEM is based on identifying investment options that maximize the net economic benefits. However, the EU currently has 28 different national regulatory frameworks. A fragmented regulatory system based on uncoordinated national policies can become an obstacle to the formation of an internal electricity market. Achieving an integrated European market is challenging, given the lack of adequate interconnections, and inconsistency in market design and rules among the member countries, while aiming to increase the share of renewable energy.



‘THE EU MEMBER STATES NEED TO IMPROVE THE HARMONIZATION OF THEIR REGULATIONS AND INCREASE COOPERATION...’



The Australian experience reveals that the large-scale development of renewable energy and the integration of regional electricity markets can be complementary; these policies do not necessarily conflict with each other under adequate transmission capability in energy-only markets. The EU can improve the number and capacity of interconnections in order to achieve a more resilient energy-only market and to implement the Energy Union (currently uncertain due to inadequate investments in electricity networks). The regulatory framework for wholesale markets and networks will be important for facilitating trade across the interconnectors; it will thereby improve market integration among energy-only markets with a high share of renewable energy. The EU member states need to improve the harmonization of their regulations and increase cooperation, in order to attract economically beneficial investments and achieve the Energy Union.





Reforming European electricity markets for renewables

Richard Green and Goran Strbac

If the European Union is to meet its 2030 target and get 27 per cent of its energy from renewable sources, it is likely that roughly half of its electricity will have to be from renewables. In 2013, renewable sources provided 27.7 per cent of electricity generation in the EU-28, including 12.3 per cent from hydro, 7.2 per cent from wind, and 2.6 per cent from solar power. A large increase in solar and wind capacity seems inevitable if the 2030 target is to be met, but this will pose significant challenges for the electricity system. More transmission capacity is planned, but the existing infrastructure needs to be used better, and that requires an appropriate market design. We argue here that more cross-border trading will be needed – of energy in the long term, and of balancing services (such as reserve) in the short term – and suggest changes that would facilitate this. The cost of expanding Europe’s renewable generation could be significantly reduced if coordination across the EU replaced the present patchwork of national approaches.

European integration and transmission capacity

Europe’s underused transmission capacity imposes significant opportunity costs on its people. Transmission currently supports energy arbitrage in day-ahead scheduling, buying in currently cheap markets and selling in more expensive ones, but it could also support capacity sharing and more efficient balancing in real time.

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‘...THE EXISTING INFRASTRUCTURE NEEDS TO BE USED BETTER, AND THAT REQUIRES AN APPROPRIATE MARKET DESIGN.’

The benefits of moving from the current member state-centric market design to one which is pan Europe-wide have been quantified by modelling at Imperial College, which provided the basis of two 2013 reports to the European Commission: one detailing the benefits of an integrated European energy market, and the other giving an impact assessment on a European electricity balancing market. That analysis demonstrated that the benefits of fully integrating EU energy and capacity markets would be EUR12–40 billion/year and EUR7–10 billion/year respectively by 2030, while integration of the EU balancing market would save an additional EUR3–5 billion/year. These savings go far beyond the EUR2.5–4 billion/year that the EU has saved through its existing measures to integrate its electricity markets through day-ahead energy arbitrage. The potential gains would be even greater if transmission capacity was used to support a more rational deployment of renewable generation.

Comparative advantage – significance of transmission

The policies of most EU governments have had the effect of spreading wind and solar power across the continent, making support available to a wide range of renewable generators. The UK government set feed-in tariffs at levels that encouraged the installation of 8.3 GW of solar PV capacity (to October 2015), even in the cloudy, northerly British Isles, while the German government has supported 34.7 GW of wind capacity, even with a 19 per cent average load factor that is only two-thirds of the average for the UK and Ireland. In other words, national policies have ignored the principle of comparative advantage.

In a paper forthcoming in *The Energy Journal*, working with Iain Staffell and Danny Pudjianto, we have calculated the benefits and costs of a more rational deployment of renewable capacity, one that would site a higher proportion of generation in areas where it will have high load factors. We find that by moving wind generation towards the windier areas of north-west Europe, it would be possible to get the same level of output from 15 per cent less capacity. Concentrating solar PV generation towards the south would save 8 per cent of installed capacity. Overall, this would save EUR19 billion a year in interest and depreciation costs. However, power flows across the continent would increase significantly, since a concentrated portfolio of renewable generators would produce stronger peaks and troughs in output than a dispersed one. Our modelling suggests that an additional EUR4 billion a year would be needed to finance additional transmission lines and peaking generation, for times when the local renewable output was low and even the new lines were congested. The net gain is therefore considerable, but there are significant challenges to overcome before such a coordinated deployment could be possible.

European energy market design

Many of these challenges are in the areas covered by the European Commission’s July 2015 consultation on a new energy market design. Electricity markets in Europe largely follow a common pattern; much trading is bilateral and concluded some time in advance, so that both generators and retailers can fix a price for most of their sales and purchases. There is a voluntary day-ahead auction run by an independent power exchange, which

may cover one country or a small group of neighbouring countries. Adjustments close to the time of delivery are made by the local transmission system operator, trading bilaterally with generators and a few consumers (or their aggregators) able to offer demand reductions at short notice.

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'ENCOURAGED BY THE EUROPEAN COMMISSION, MARKET COUPLING HAS GRADUALLY SPREAD ACROSS NORTH-WEST EUROPE...'

One spot market, Nord Pool, has been multinational since 1996, and uses a *market splitting* algorithm to set different prices on either side of a zonal or national border if transmission capacity is less than that required for the flows that would equalize prices. France, Belgium, and the Netherlands started *market coupling* in 2006, taking account of exports and imports in their national auctions, and setting their level to equalize prices across borders if possible, and exhaust the available transmission capacity if not. Encouraged by the European Commission, market coupling has gradually spread across north-west Europe, so that 19 countries had coupled their day-ahead markets by February 2015. If there is enough transmission capacity, an area from Portugal to Great Britain, to Norway, Finland, and the Baltic States, and from Germany via Austria and Slovenia to Italy could have a single day-ahead price.

Although day-ahead markets may be the most visible sign of a liberalized electricity industry, most electricity trading actually takes place on a longer timescale, while secure system operation depends on very short-term decisions. Long-term contracts allow generators and retailers to fix a price for most of their expected output and purchases, giving them financial security, even though the day-ahead

markets allow them to adjust their positions to reflect actual patterns of demand and plant availability. This ability to adjust positions is increasingly important as the share of intermittent renewables rises, since their outputs cannot be accurately predicted on the timescale of long-term trading.

If Europe is to concentrate its renewable generators in areas of comparative advantage, however, long-term sales contracts will certainly be required: the consumers supporting (still relatively expensive) generators abroad will want to know that they are getting some power in return for their support. This requires a mechanism for delivery, and long-term access to capacity on cross-border interconnectors has been made available through auctions for many years. There are two problems relating to the use of contracts for physical capacity.

- 1 In the past, there were fears that a contract holder might withhold capacity from the market in order to widen price differentials between the two ends of the interconnector. This problem can be resolved with a 'use it or lose it' rule that returns any unused capacity to the market if the contract holder has not scheduled the flows to which they are entitled.
- 2 The second problem, more fundamental, is that physical contracts do not reflect the physics of the grid. Power flows can be netted off each other. If 2 GW is sold from France to the UK, this would appear to use the full capacity of the cross-Channel link, but if a second deal sends 1 GW in the opposite direction, a third trade becomes possible, giving a gross contracted flow from France to the UK of 3 GW. It is highly unlikely that we could find a watertight way to issue physical contracts for 3 GW of power to flow over a 2 GW interconnector, because the third GW depends on a counter flow that might not happen in practice.

Financial transmission rights (FTRs) do not have the same restrictions as physical contracts. They offer price insurance for a cross-border trade by paying the buyer the difference in prices between two points on the system. As a purely financial contract, there is in principle no limit to the number of FTRs that could be bought and sold. In practice, there is a natural hedge for each FTR, and that is the revenue received by the owners of an interconnector when power flows across it from a lower- to a higher-price area. The capacity of the transmission system determines the net volume of FTRs that can receive this natural hedge – at most 2 GW in either direction in the case of the line mentioned above. However, a net volume of 2 GW is consistent with 2 GW of contracts in one direction, or 3 GW in one direction and 1 GW in the other, and so on. If the holders of 3 GW of FTRs from France to England are receiving a payment because the power price is higher in England, then the holders of the FTRs from England to France are *making* the same payment (per MW). The net result is that the transmission companies make the payment for 2 GW of FTRs, just matching the capacity that they would normally have available. Absent bankruptcy, the holders of the England–France FTRs are guaranteed to provide a financial counter flow in a way that cannot be ensured for physical contracts.

Creating long-term FTRs might also be a way of financing the extra investment in transmission assets that will be needed to accommodate the more volatile power flows as renewable capacity rises. Companies expecting to trade power over long distances will pay the companies developing transmission assets for the FTRs that the traders need to lock in prices; the combination of the FTR payments and the price differences that they hedge



gives the transmission owners a more stable revenue stream, independent of day-to-day fluctuations in fuel prices or renewable outputs.

FTRs would help create a single electricity market that operates on long timescales but the short-term markets that are crucial for the secure delivery of power remain largely national. While system operators rely solely on plants and consumers within their own borders to provide balancing services, they are likely to miss alternatives that offer better value. In the early days of the New Electricity Trading Arrangements in England and Wales in 2001, the system operator had to set high imbalance prices because of the cost of buying power from a relatively small number of flexible generators inside the market. As soon as the operator realized that flows from France and Scotland could be adjusted by similar amounts within the required timescales, the presence of a much cheaper option helped prices to fall dramatically.

Balancing mechanisms that allow cross-border participation require the effective exchange of information on short timescales. They also need transmission capacity to be available, and we do not currently have a mechanism that allows for this. If cross-border capacity is entirely allocated at the day-ahead stage, there will be none available for the country importing energy to also import balancing services from its neighbour.

Case for Transmission System Operators

North American power markets jointly optimize energy and reserve decisions, for they have learned that separate optimization increases costs for consumers. Since the markets are run by Independent (transmission) System Operators, they take the constraints on the transmission system into account when they do this.

Transmission capacity in Europe is currently allocated by power exchanges trading energy, while separate institutions deal with reserve and balancing. That implies that all the transmission capacity is allocated to energy arbitrage, which is unlikely to be the optimal outcome. The European Commission sought views on whether cross-border Transmission System Operators should be encouraged: promoting more efficient balancing is one area in which they would have an advantage over the current arrangements. In principle, and already sometimes in practice, the operator in one country can acquire balancing services from its neighbour, but the extra stages of decision making and communication involved are likely to reduce the benefits of doing so.

It is a sign of progress that the European Commission thinks the establishment of cross-border Transmission System Operators is worth consulting on: in the past,

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'...CONCENTRATING RENEWABLES IN MORE FAVOURABLE LOCATIONS WOULD BRING IMPORTANT SAVINGS.'
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national electricity markets were fiercely separate. National renewable energy policies are still uncoordinated, and concentrating renewables in more favourable locations would bring important savings. Even with the current capacity mix, the gains from greater trade have become apparent, and will increase as the share of wind and solar generation continues to rise. The existing linkages between day-ahead markets need to be supplemented with greater coordination on longer and shorter timescales. Cross-border trading of long-term contracts for energy would be facilitated by the use of Financial Transmission Rights that hedge price differences between areas, while respecting the laws of physics in a way that past commercial arrangements for long-distance power flows have not. Short-term balancing costs could be reduced if system operators sometimes bought balancing services and reserve from their neighbours. To integrate balancing between countries, however, we may have to integrate energy and reserve markets inside each country. American experience shows that this can be done, but the political challenges in creating a good market design should not be underestimated.



Supporting renewable generation in the UK

David M. Newbery

Introduction

The European Commission's proposed Energy Union Package (introduced in the document subtitled 'A Framework Strategy for a Resilient Energy Union

with a Forward-Looking Climate Change Policy' dated 25 February 2015) proposes integrating electricity from renewable energy sources (RES-E) into the market. It aims to move away from the unresponsive

standard feed-in tariffs (FiTs), replacing them by Premium FiTs (PFiTs), which pay a premium on the market price but require generators to take responsibility for selling and balancing their power. This article examines the logic,

drawbacks, and possible resolutions of this proposal for future UK renewables support.

History of UK renewables support

Britain has tried almost every form of renewables support since the first Non-Fossil Fuel Obligation auctions in the 1990s and so is a useful testbed for the efficacy of differing forms of renewables support. As the name suggests, the first form of support was a series of auctions for the prices to be paid for various categories of non-fossil fuel (which was extended to other non-fossil fuels from nuclear power under pressure from DG COMP). The early auctions demonstrated their competitive effect by driving down costs (or the auction prices), but either the winner’s curse, or the lack of any penalty for multiple bids between which the winner could choose in light of subsequent planning application success, led to a fall in the rate at which auction winners delivered commissioned plant. Inflexibilities in project definition (size, exact location) also meant that small changes rendered the initial contract invalid.

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‘BRITAIN HAS TRIED ALMOST EVERY FORM OF RENEWABLES SUPPORT SINCE THE FIRST NON-FOSSIL FUEL OBLIGATION AUCTIONS IN THE 1990S...’

These objections could surely have been overcome, but a change in Government in 1997 from Conservative to Labour resulted in a reconsideration, and with it the Utilities Act 2000 that placed an obligation on electricity supply companies to source a specified share of their sales from renewable generation, or pay a pre-set penalty for any shortfall. Companies producing RES-E were awarded a specified number of Renewable Obligation Certificates (ROCs) for each MWh they produced; however,

they were responsible for selling the electricity and dealing with any imbalances, in contrast to the less risky FiT schemes which required the System Operator to handle all off-take, and under which the developer was paid a set price for metered output. The value of ROCs is determined by supply and demand and the penalty price for not delivering sufficient ROCs to meet the targets.

One obvious advantage that quantity-based instruments like ROCs enjoy is that the volume of RES-E to be supported can be limited, and hence the impact on the budget is also predictable and controllable. In the case of ROCs, the volume required to be bought by the utilities is set each year, usually with some ‘headroom’ that is an estimated uplift on the predicted capacity during the year. The excess demand from retailers’ penalty payments produces additional revenue that is returned to increase the value of the ROCs. By reducing the headroom, or if developers are unusually successful and exceed the predicted amount, the market price for ROCs will fall and discourage further expansion. In contrast, a fixed FiT with no cap on the number that can be issued risks excessive demand and excessive budgetary cost. While wind developments take years to proceed from the initial idea through planning to grid connection agreements and construction, and hence can be predicted well in advance, solar PV panels can be ordered and installed within weeks. Spain and Italy (and the UK) have demonstrated that if the FiT is set too high compared to the rapidly falling cost of PV, installation rates can accelerate and create such fiscal pressures that the support system can collapse.

One other important advantage that ROCs or PFiTs have is that they can give better locational signals than the classic FiT, which normally pays the

same amount regardless of location. In the UK, wind developers have to pay locational Transmission Network Use of System charges, which vary very significantly across the country. If electricity were locationally spot priced, as in many parts of the USA, the temporal and spatial signals would provide additional efficient location signals, with the premium payment remaining as a support to the high capital cost. The limitation to these locational signals is that if the same premium is given regardless of location, the benefit of generating in a high wind area with a higher capacity factor will be unnecessarily amplified, distorting location decisions to such locations and providing excess rent to the developers there.

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‘... THE IDEAL FORM OF SUPPORT WOULD TARGET THE CAPITAL COST, NOT THE OPERATING COSTS.’

As the aim of the support is to encourage deployment of high capital cost plant to drive down future costs, the ideal form of support would target the capital cost, not the operating costs. Germany has a very simple solution which largely achieves this by paying support for a specified number of MWh/MW capacity, so windier areas receive only slightly more support than less windy areas (by receiving it more quickly). This has the advantage of reducing excessive rent to high wind areas, and effectively treating the electricity produced as of equivalent value to any other electricity – correctly, as the electrons are not coloured grey or green depending on source.

The downside to the benefit of controlling the quantity and hence the fiscal cost of support is that developers find it hard to predict their future revenue. With ROCs there is a double uncertainty: the future value of ROCs and also the future price of electricity. Further, the price of electricity in the



UK is set by either coal or gas (and the price of carbon), as fossil plant remains at the margin for all but a few hours per year. As a result fossil plant enjoys a natural hedge while low-carbon plant with low variable costs is fully exposed to the very volatile wholesale price.

The result of the higher risk facing RES-E developers in the UK has been a slower uptake than might be expected, given that the UK has far better wind resources than Germany. In 2004 the UK generated about 8 per cent of the amount that Germany generated from wind, but by 2011 the proportion had risen to more than 30 per cent, reflecting the UK's higher rate of growth as it started from a very low base (figures taken from the Eurostat website).

In response to concerns about the high cost of supporting RES-E, combined with its lagging performance, as well as growing concerns over security of supply, the UK Government passed the Energy Act 2013, which launched the Electricity Market Reform (EMR). EMR was intended to meet the EU RES and climate change targets at lower cost while maintaining reliability. In contrast to the Energy Union Package, it aims to replace PFITs with Contracts-for-Differences (CfDs) for RES-E,

closer to the classic FIT, as the way to lower the cost of RES-E support. The Department for Energy & Climate Change (DECC) initially set the strike prices for these CfDs on the basis of an assumed hurdle rate, which the Panel of Technical Experts, commenting in a 2013 report on the delivery of the EMR, criticized as being too high. Instead, the Panel suggested that auctions were a better way of eliciting the price at which developers would be willing to invest, and under pressure from DG-COMP again, DECC announced an auction for RES-E CfDs on 1 September 2014. The results of that auction are given in Table 1.

It is clear that the auction prices are considerably less than the administratively set strike prices and it is simple to estimate the reduction in the implied hurdle rate by comparing the administered strike price with the auction price. Given the auction prices, the administered strike prices, and assumptions about the cost of wind turbines, their capacity factors, and operating costs it is straightforward to compute the difference in the internal rates of return between the two alternative income streams. The differences are large at 2.2–3.4 per cent real (depending on these

parameters and whether any credit is given for post-contract operation at the unsubsidized price).

The Energy Union Package

Just after the UK's first CfD auction in February 2015, the Energy Union Package was launched, stating that:

... renewable production needs to be supported through market-based schemes that address market failures, ensure cost-effectiveness and avoid overcompensation or distortion. Low-cost financing for capital intensive renewables depends on having a stable investment framework that reduces regulatory risk.' (Energy Union Package, 2015).

This Commission proposal appears to pay more attention to the advantages of PFITs mentioned above than to their impact on risk and financing costs, and would seem to reverse the logic, painfully learned in the UK, of moving from PFITs to FITs with their revenue guarantee and hence reduced risk and cost. German, Danish, Spanish, and Italian case studies (reported in two articles in the journal *Energy Policy*: 'Environmental policies and risk finance

| CfD auction allocation: round 1 | | | | | | | | |
|--|---------------|-------------|-----------------------|----------------|----------------|---------------|-----------------|---------------------|
| Technology | | Admin price | Lowest clearing price | 2015/16 | 2016/17 | 2017/18 | 2018/19 | Total capacity (MW) |
| Advanced conversion technologies | GBP/MWh MW | 140 | 114.39 | | | 119.89 36 | 114.39 26 | 62 |
| Energy from waste with combined heat and power | GBP/MWh MW | 80 | 80 | | | | 80.00 94.75 | 94.75 |
| Offshore wind | GBP/MWh MW | 140 | 114.39 | | | 119.89 714 | 114.39 448 | 1162 |
| Onshore wind | GBP/MWh MW | 95 | 79.23 | | 79.23 45 | 79.99 77.5 | 82.50 626.05 | 748.55 |
| Solar PV | GBP/MWh MW | 120 | 50.00 | 50.00 32.88 | 79.23 36.67 | | | 69.55 |

Note: the GBP50 bid for solar PV in 2015/16 was withdrawn.
 Source: DECC 'Contracts for Difference (CfD) Allocation Round One Outcome', 26 February 2015.

in the green sector: Cross-country evidence' by Chiara Criscuolo and Carlo Menon, 2015, and 'Lessons for effective renewable electricity policy from Denmark, Germany and the United Kingdom' by Judith Lipp, 2007, and also in the EPRG Working Paper 1603 'Energy subsidies at times of economic crisis: a comparative study of Italy and Spain' by Arjun Mahalingam and David Reiner) demonstrate that a well-designed FiT can be cost effective (with suitable degression tracking falling costs), can deliver rapid deployment, and encourage the cost reductions that are the logic behind the European Commission's Renewable Energy Directive.

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'THERE ARE GROWING CONCERNS ... THAT THE UNANTICIPATED MASSIVE INCREASE IN RES-E PRODUCTION IS LOWERING WHOLESALE ELECTRICITY PRICES...'

However, there are growing concerns from electricity generating companies that the unanticipated massive increase in RES-E production is lowering wholesale electricity prices, particularly in Germany, which has massive wind and solar PV penetration (see, for example, 'The impact of wind power generation on the electricity price in Germany' by Janina Ketterer in the

journal *Energy Economics*, 2014). There is concern that excessive generation at some particular time and place would normally lower prices and discourage further investment there, but a fixed FiT would remove that feedback. On the other hand, a PFIT that just pays a (normally fixed) premium on the local spot price would provide the necessary feedback.

The practical question is how to combine the advantages of a PFIT with the risk-reducing properties of a FiT or CfD. The logic of the Renewable Energy Directive is that it solves the 'club good' problem of financing deployment to reap the dynamic economies of scale (learning-by-doing), which is primarily more about the design, location, and installation of the RES-E plant, and less about its operation (which, if it is mature enough to warrant mass deployment, should primarily depend on the resource: wind or sun). This would suggest rewarding RES-E for availability rather than output, or per MW rather than per MWh, making renewables just like capacity in a capacity auction (of the kind successfully implemented as part of the EMR), as the aim would be to identify the 'missing money' needed to justify deployment, while providing a long-term contract for availability that addresses the 'missing (futures)

market' problem. See the forthcoming article by David Newbery 'Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors' in *Energy Policy*.) To reduce risk further, balancing and other ancillary services could be procured competitively by the System Operator, while the RES-E developer could be offered a cost-reflective contract whose cost would be factored into the auction for capacity availability. Other aggregators or supply companies could offer power purchase agreements (PPAs) for the metered output, based on a prediction of the local wholesale price, further reducing transaction costs and risks.

Conclusion

The intention behind the Energy Union Package – of making RES-E face more efficient price signals – is sound but needs to be reconciled with a sufficiently stable investment climate that allocates risk to those best placed to bear it, while providing adequate incentives for efficiency. This article argues that capacity contracts with suitable PPAs and contracts for ancillary and balancing services (with all contracts reflecting efficient market value) are the logical solution and should support the delivery of low-carbon electricity at least cost.



Centralized or decentralized? Remove first the regulatory barriers

Ignacio Pérez-Arriaga and Scott Burger

Regulation matters

Electric power systems are currently facing significant changes as a result of the deployment of information and communication technologies (ICTs), advanced power electronics, and distributed energy resources (such as gas-fired distributed generation, solar

PV, small- and medium-sized wind farms, electric vehicles, energy storage, and demand-side management). These distributed energy resources (DERs), unlike 'traditional' centralized generating units, are characterized by their small capacities (several kilowatts to several megawatts), their diverse

nature (generation, storage, responsive demand, or any combination thereof), and their connection to low and medium voltage electricity distribution grids. DERs, if properly integrated, may have the potential to deliver not only the valuable electricity services that are traditionally provided by centralized



generating units, but also new services that are enabled by their distributed nature.

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‘WHILE DERS ARE CERTAINLY GAINING TRACTION IN POWER SYSTEMS, THE DEGREE TO WHICH THEY WILL PROVE INFLUENTIAL REMAINS AS DIFFICULT TO PREDICT AS EVER.’

Bold claims have been made – by the CEOs of some of the most important electric utilities in the world, by regulatory authorities like those from the state of New York or the UK, by the European Commission, by the most important associations of the power industry, and by energy think tanks – announcing the future, even imminent, disruptiveness of DERs in the provision of electricity services. Our research group at MIT – currently working on the ‘Utility of the Future Study’, in collaboration with the Institute for Research in Technology (IIT) at Comillas University in Madrid (details available on the website of the MIT Energy Initiative) – has surveyed over 200 different kinds of recently created business models that employ DERs in some way. Something is certainly going on, but, while DERs are certainly gaining traction in power systems, the degree to which they will prove influential remains as difficult to predict as ever.

From a strict economic viewpoint, the answer to the question of whether the future provision of electricity services will be predominately centralized or decentralized, and in what likely proportion, will depend on the characteristics of the services to be provided and the cost and performance of the diverse means of supplying them. Other factors – such as customer preferences driven by cultural background, environmental concerns, fashion, satisfaction with or animosity towards the incumbent

utility, social pressure, and the impact of neutral or biased information – will also have a significant influence on the outcome.

This paper argues that regulation of the power sector, as the materialization of national or supranational energy policy, either correctly designed or flawed, is perhaps the most important factor presently influencing the level of penetration of DERs in the short to medium term. The present regulation is woefully inadequate to meet the incoming challenges; an in-depth review and corresponding modification is essential to create an economically neutral playing field, enabling centralized and decentralized resources to compete and collaborate efficiently, while recognizing that they perform under very different conditions, in terms of size, technology, or location in the network, among other characteristics. This is an urgent task, since so much is at stake. The irruption of DERs has added pressure to the need for regulatory changes to be introduced (changes that should have been made some time ago).

This paper makes the case that going back to applying the fundamentals of microeconomics to power systems, is the best way of adding value to the current debate about decentralization and evolution in the provision of electricity services. This requires:

- 1 Reconsidering the definition of ‘essential electricity services’;
- 2 Examining how to compute the prices and regulated charges that should apply to every agent in the system so that economic efficiency (optimization of social welfare) is maximized; and
- 3 Understanding what, if any, is the value that aggregation of DERs and any associated business models may bring to the entire power system.

Essential electricity services and their prices and charges

Regardless of the regulatory framework, only a small number of mutually exclusive and collectively exhaustive electricity services are needed for the correct (efficient, reliable, and environmentally sound) functioning of a power system: energy (kWh), firm capacity (kW), operating reserves at several time response levels, network capacity (kW), voltage support, and management of constraints and losses. We term these essential services ‘primary services’.

Some of these essential services, like operating reserves, may exhibit slightly different definitions under different conditions; however, the basic concept does not change. Perhaps in the future, the physical evolution of the power sector and its organization will require the addition of novel primary services to our list; however, we postulate that the set described herein is exhaustive given today’s paradigm, and that any potential future additions will adhere to the same philosophy that we describe.

A comprehensive system of economic signals is needed to allow the anticipated large diversity of agents to compete and to collaborate in the efficient provision of these services, while maintaining the reliability of the power system. These economic signals are *prices* (for those services provided in competition via markets) and *regulated charges* (for the regulated monopolistic activities); furthermore, these signals act as the power sector’s nervous system, efficiently and effectively communicating, to all the providers and consumers of electricity services, the prices and charges that correspond to the particular services provided in their specific situation in time and space.

Prices

Strict application of microeconomics to the joint mathematical formulation of power system operation and planning results in prices that are the dual variables – also called shadow prices – of the constraints in the problem, with the commodities of the corresponding electricity services being the magnitudes on the right hand side of these constraints. In simpler words, the price is equal to the additional system operation cost of tightening the constraint by one unit. For instance, the constraint requiring the balance of demand and generation, at each network node and at any time, results in a specific energy price at each moment in time at each node: the energy nodal price or 'locational marginal price' (LMP). Other constraints emerge due to the system operator's desire to guarantee that certain essential services (such as primary, secondary, and tertiary reserves, or firm capacity targets, perhaps with some minimum flexibility requirements) are provided in prescribed quantities. There are also prices for relieving voltage- and congestion-related network constraints.

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'... THE PRICE IS EQUAL TO THE ADDITIONAL SYSTEM OPERATION COST OF TIGHTENING THE CONSTRAINT BY ONE UNIT.'

Regulators may want to impose additional constraints – such as emissions or renewables targets, fuel quotas, or banned technologies – all of which result in additional services and their associated prices and charges. Secondary services can be derived from the essential ones, such as financial products based on the prices of energy or network congestion.

LMPs are just energy prices, but they are a reflection of the diverse costs

of production and demand response everywhere, as well as of the impacts of network losses and technical constraints. Ideally nodal prices should reach every customer, and even every appliance, but practical reasons may advise differently. Deciding the optimal granularity – in other words, how far to go with spatial and time differentiation – of all relevant prices and charges is a major design issue for the power sector of the future. This is strongly related to the value of aggregation that is discussed later.

Charges

Network charges

Regulated network charges are necessary to recover and to allocate properly the total network costs. Given the physical and economic characteristics of actual networks, this is not possible with just the differences between LMPs. Distribution utilities have to apply network use of system (DNUoS) charges to recover the total costs of investment, operation, and maintenance. DNUoS charges can also signal to network users how their utilization patterns impact network costs.

Regulators are faced with the double challenge of: a) recovering network costs and b) sending efficient economic signals to the network users. These signals must enable a level playing field between electricity service business models connected everywhere in the network to exist. Furthermore, the implementation of network charges must not unnecessarily distort energy prices.

The customary design of DNUoS charges, meant for pure consuming agents in power systems where DERs are considered a minor exception, does not hold anymore. It should be urgently fixed, before more substantial

distortions occur. The new design should conform to these criteria:

- Ignore what happens beyond the meter; network charges should only be based on the network location and the individual profiles of net power injection or withdrawal.
- Assume a well-established procedure exists that designs an efficient or 'well-adapted' network for an estimated future pattern of injections and withdrawals; this procedure should allow the identification of the underlying cost drivers, such as *Connection* (the network that is needed to provide a 'basic or minimum' level of electricity service to all network users), *Capacity* (the additional network that is needed to meet the expected most demanding conditions of injections and/or withdrawals), and *Reliability* (the extra network necessary to satisfy some required quality of service standard for all operating conditions).
- The individual network charges will be determined following a common method that determines the contribution of each individual utilization profile, at any given location, to each cost driver. The costs of any network capacity that is not directly required by the cost drivers should be socialized. Socialization of network costs is a common practice today, but a sound justification is needed.
- The network charges will be the amounts of money (per month, for example) associated with each cost driver and this is how they should be presented in the electricity bills. Traditional tariffs (USD/kWh, USD/kW, USD/customer) should be abandoned, since they are inadequate to represent the diversity of behaviours of network users (what kWh? what kW?).



Policy charges

In addition to network charges, in most power systems there is a diversity of other costs that have been traditionally recovered from electricity consumers (such as: subsidies to domestic fuels, clean technologies or social tariffs; charges for efficiency, energy conservation or innovation programmes; competition transition charges, etc.)



'IN SOME COUNTRIES... THESE

ADDITIONAL REGULATED COSTS MAY BE COMPARABLE TO THE AMOUNT OF NETWORK COSTS.'



In some countries the total magnitude of these additional regulated costs may be comparable to the amount of network costs. Therefore the method of allocation should not be taken lightly. Cost causality is weak or inexistent for these costs, so it has to be decided in the first place whether electricity consumers should shoulder them or not. Flawed allocation approaches may encourage grid defection. It may be advisable to include most of these costs in a general taxation system, unrelated to electricity rates.

Consumers should not be able to avoid them, as they are unrelated to consumer or producer behaviour. However, this avoidance is possible if policy charges are allocated using the same criteria as for network charges. This is the case of 'net metering', which is discussed later.

The value of aggregation

One can argue that, conceptually, under a well-designed system of prices and charges, it should be immaterial if DERs or any other agents, centralized or decentralized, are or are not aggregated. What is, then, the value of aggregation, and how does it depend on regulation?

Aggregation is the grouping of distinct agents in a power system to act as a single entity when engaging in power system markets (both wholesale and retail) or when complying with power systems regulations. Aggregators may act as intermediaries between the complexity of the power system, with multiple electricity services and a price or charge for each one of them, and the simpler signals that each agent is capable of handling at a given instant in time.

Identifying the value of aggregation is relevant, in order to determine whether this activity should be facilitated, or even encouraged, or, on the contrary be left to the initiative of the agents. Aggregation has many points in common with retailing, and a key regulatory issue is to ensure impartial procedures for the access of all aggregators to trading platforms and agents' data. Understanding the value of aggregation is a prerequisite to addressing the economic viability of any proposed business model.

Three categories or sources of the value of aggregation can be identified: opportunistic, fundamental and transitory. *Opportunistic* value emerges as a result of regulation or market design flaws that allow an agent or aggregation of agents to increase their economic wellbeing without increasing – or even decreasing – the economic efficiency of the power system. This is the case for the rules of allocation of balancing costs and procurement of balancing services in some countries. Netting peak consumption through aggregation is another example. So called 'net metering' – the combination of a single standard meter at the connection point and mostly volumetric tariffs – results in a substantial subsidy for the aggregation of demand and local generation, with the subsidized amount being passed to the remaining network users. The only solution to the 'net metering problem' is to replace

the standard meter by an hourly one and to follow the tariff design principles explained in the previous section.

Other cases of aggregation have value under present conditions, by increasing the power system efficiency. Examples include: sharing, among several agents, some unavoidable costs of participation in some electricity services markets; or facilitating the access of small agents to hedging products; or eliminating the information gaps or the threshold size barriers; or promoting the technical capability to handle all the relevant information associated with participation in complex markets. The *fundamental* component of the value remains, since it is intrinsic to aggregation and is independent of the market or regulatory context. On the other hand, the *transitory* value may extend some time into the future, but certain technological or regulatory improvements will reduce its magnitude until it disappears.

Conclusion

Any sensible long-term visions of the power sector should be based on regulation that correctly implements any future priorities of energy policy. Sound regulation will be essential to efficiently blend centralized and decentralized resources in future power systems. If regulatory innovation cannot keep pace with the changing nature of the electric power system, large inefficiencies may result. In the absence of regulatory innovation, network users and new businesses will find ways to arbitrage the growing disconnect between ill-adapted



'ANY SENSIBLE LONG-TERM VISIONS OF THE POWER SECTOR SHOULD BE BASED ON REGULATION THAT CORRECTLY IMPLEMENTS ANY FUTURE PRIORITIES OF ENERGY POLICY.'



regulations and new market and technological realities.

The MIT Utility of the Future Study is examining an ensemble of power sector regulatory issues that need a thorough review, and maybe also significant adaptation, in the presence of a substantial amount of DERs. Wholesale markets may have to be redesigned to include the active participation of distributed generation, demand, and storage. Regulators need to reduce the uncertainty and the information asymmetry in the estimation of distribution network

costs, while incentivizing efficiency, but without jeopardizing innovation. The present organization of the power sector has to be reconsidered. This process will include issues such as: the creation of neutral trading platforms, data ownership and management, the more complex new roles of the Distribution System Operators (DSOs), the relationship between DSOs and Transmission System Operators (TSOs), and the level of separation between commercial and regulated network activities when conflicts of interest may exist. Finally, considerable attention should be paid to the

growing interactions that are already taking place between the power and gas sectors, and the buildings and transportation sectors, each with its specific regulations.

Regulation does matter. And most of the regulation that is mentioned here has to be supported by quantitative analysis – such as a portfolio of computer software tools that can represent the impact of DERs on the electric power system under different geographical and temporal perspectives. This will be the subject of another paper.



Wind power and electricity supply security in Colombia

David Harbord, David Robinson, and Ivan M. Giraldo

The current regulatory regime in Colombia is intended to be technology neutral, but in reality it is not. This article describes some of the characteristics of the Colombian electricity system and how auctions are used to ensure sufficient ‘firm energy’ (the capacity to produce electricity reliably) to cope with uncertain hydrological conditions. It also explains why wind power would be attractive for the Colombian system and how current regulations discourage wind power investment.

The Colombian electricity system and auctions for firm energy

Colombia’s electricity system is heavily reliant on hydro, which accounts for about 64 per cent of its current generation capacity and 80 per cent of electricity produced during normal weather conditions. There is growing concern, however, about how to ensure supply security during periods of low rainfall, specifically during El Niño periods such as occurred in 2009–10, when hydro’s share of electricity generation fell to 67 per cent (see the

table below). To avoid shortages, the missing hydro generation needs to be replaced with generation from other sources.

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‘THERE IS GROWING CONCERN ABOUT HOW TO ENSURE SUPPLY SECURITY DURING PERIODS OF LOW RAINFALL...’

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The traditional source of back-up has been electricity generated from thermal power plant burning coal or natural gas. Many of these plants are not required to generate electricity

during normal hydrological conditions. In 2010, which saw the effects of El Niño at the beginning of the year, thermal plant accounted for 27 per cent of electricity generation, while in 2011 (not an El Niño year) this fell by 40 per cent to 16 per cent of electricity produced.

Because of their low load factors, many thermal plants would not recover their investment costs if they were being paid for solely on the basis of revenues earned in wholesale spot and contract markets. In order to ensure the building of sufficient generation

| Generation output 2010–11 for the Colombian electricity system | | | | | | |
|--|-----------------|------------|-----------------|------------|----------------|----------|
| | 2010 | | 2011 | | Change GWH | Growth % |
| | GWH | % | GWH | % | | |
| Hydro | 38,088.6 | 67 | 45,583.1 | 78 | 7,494.5 | 19.7 |
| Thermal | 15,590.7 | 27 | 9,383.7 | 16 | –6,207.0 | –39.8 |
| Minor plants | 2,985.6 | 5 | 3,336.7 | 6 | 351 | 11.8 |
| Cogeneration | 222.7 | 1 | 316.9 | 1 | 94.1 | 42.3 |
| Total | 56,887.6 | 100 | 58,620.4 | 100 | 1,732.8 | 3 |

Source: XM, the company that operates and administers the Colombian wholesale electricity market.



capacity, in 2006 the Colombian energy regulator (the CREG) introduced a scheme to ensure the long-term reliability of the electricity supply, and in particular to guarantee the system's ability to meet peak demand during El Niño periods. The scheme allocates 'firm energy obligations' (OEFs) to new and existing generation plant at prices determined in competitive auctions. OEFs are 'option contracts' that commit generating companies to supply given amounts of energy at a predetermined Scarcity Price whenever the spot price in the electricity market rises above that Scarcity Price. The companies receive the spot price for any additional generation above their firm energy obligations, and pay a penalty if they cannot meet their firm energy obligations.

In return for agreeing to supply electricity at the Scarcity Price, generators with OEFs receive a fixed annual option fee (the firm energy price, or *Cargo por Confiabilidad*) for each unit contracted. This option fee makes an important contribution to the recovery of fixed costs for generating plants that produce very little in normal times – such as the CCGT plants in central Colombia that generate infrequently outside of El Niño periods. New plants chosen in the auction have a guaranteed revenue stream for 20 years, even if they are never required to generate.

The maximum amount of 'firm energy' that a generator may offer in a firm energy auction is known as its ENFICC (*Energía Firme para el Cargo por Confiabilidad*). A generator's ENFICC refers to the amount of energy of a given type it can reliably and continually (in terms of kWh/day) produce during periods when hydro generation is at a minimum. It is essentially a lower bound for the amount of energy that a given type of plant will be able to provide at some unpredictable point in the future. The following table shows

| ENFICC % for different technologies as of 2012 | |
|---|---------------------------|
| Technology | Maximum ENFICC (%) |
| Hydro with storage | 55 |
| Hydro without storage | 30 |
| Coal | 97 |
| Natural gas | 93 |
| Fuel oil | 88 |

the typical ENFICCs for different generation technologies in Colombia as a percentage of a plant's CEN (effective net capacity).

To date, there have been two firm energy auctions (in 2009 and in 2011). In the first, about 9,300 GWh per year were allocated to new resources; this included 1,117 GWh from new coal plant and 1,678 GWh from new gas-fired generation plant at an auction-determined option fee of 13.998 USD/MWh. In the second, 3,700 GWh of OEFs were allocated to five new generation projects, with an option fee of 15.7 USD/MWh. In the second auction, thermal plant accounted for over 89 per cent of the OEFs assigned.

Firm energy from wind power in Colombia

There is growing interest in the potential for wind power to provide back-up for hydro, as an alternative to thermal generation plant. In part this is a reflection of the falling cost of wind-based generation, but it also reflects evidence that wind power potential is negatively correlated with hydro in certain regions where wind speeds are higher during dry periods. There are also environmental reasons – in particular lower carbon dioxide emissions – for preferring renewable sources of energy to hydrocarbons.

For wind power to be a viable

alternative to thermal generation, the firm energy auctions need to accurately reflect the contribution of wind energy to system security. The challenge is to determine the quantity of firm energy that can be provided by different energy sources when the system is under stress, which in Colombia corresponds especially to peak periods under El Niño (low hydro) conditions. For coal and natural gas, which can be stored, the auction regulations assume that the plants can provide firm energy at about 90 per cent of their rated capacities. For wind power, on the other hand, the energy regulator (CREG) assumes low levels of firm energy, about 6 per cent of rated capacity in 2011. Studies carried out by the World Bank and by the Oxford Institute for Energy Studies suggest that the quantities of firm energy from wind in some parts of Colombia are significantly higher, in the range of 20–45 per cent.

The lower the firm energy attributed to wind energy, the lower the revenue streams that can be earned in firm energy auctions. If the firm energy contribution of wind power has been underestimated, this acts as a barrier to investment in wind power in Colombia, and indirectly raises the cost of meeting system security. The financial consequences for investors are significant. Following the 2011 CREG approach (at a 6.3 per cent firm energy rating), a 100 MW wind plant would earn approximately USD735,734 per annum in guaranteed payments for 20 years at the firm energy price (13.998 USD/MWh). Using an approach to measuring ENFICCs that was proposed by the World Bank for Colombia (which resulted in a 36 per cent firm energy rating) a 100 MW wind plant would earn approximately USD4.4 million in annual firm energy payments. This makes a significant difference to the financial viability of wind farms in Colombia.

The question is whether the CREG really does underestimate the contribution of wind power to system security. To assess this, the authors looked at the relevant economic principles and at selected international experience.

Economic principles and international experience

There is no universally accepted method for calculating the contribution of intermittent generating technologies (such a wind) to system reliability. However, there are some basic principles that guide the methodology to be used, as well as experience in the application of this methodology.

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‘THERE IS NO UNIVERSALLY ACCEPTED METHOD FOR CALCULATING THE CONTRIBUTION OF INTERMITTENT GENERATING TECHNOLOGIES TO SYSTEM RELIABILITY.’

The main principle for calculating the contribution of wind power to system reliability is to reflect the amount of firm energy the system can rely on when there is a high risk of shortages. In most systems, this occurs during periods of peak demand. However, in Colombia, the probability of shortage is highest during El Niño periods – in other words when hydro generation is low. So the question is how much firm energy can be provided by wind power in those periods.

One way of calculating a firm energy factor is to use historic data to determine the minimum amount of energy that can be provided by wind power in periods of system stress. Each system has different periods of shortage, and each wind power station within a system will have output that coincides, more or less, with those shortage periods. To the extent that wind generation is higher at times of

shortage, the plant will have a higher firm energy factor.

There are different ways to use the time period-related data to approximate wind’s firm energy factor. One method that we think is sensible is used in PJM (the Pennsylvania–New Jersey–Maryland Interconnection, a regional transmission organization in the USA). This approach averages the wind-related generation over the relevant shortage periods in recent years in order to estimate the level of firm energy that can be expected during a period of system stress.

Application of the PJM methodology to Colombia

The relevant shortage periods in Colombia are mainly El Niño periods, especially during peak hours. Following the logic of the PJM approach, we estimated the ENFICCs for wind power using hourly generation data from the experimental Jepírachi wind farm in Colombia’s Guajira region, between April 2004 and April 2011. The ENFICC estimate (shown in the table below) uses the PJM methodology, applied to wind output on a daily basis and during peak hours during the last three El Niño periods. This yields average estimates of ENFICC between 27 per cent and 33 per cent, compared to the CREG’s estimates of below 15 per cent.

This suggests that the CREG’s original 2011 methodology, with ENFICC below 15 per cent is too conservative. Both we and the CREG measure ‘firm energy’. In their original methodology, the CREG measures it by reference to the lowest average monthly (in kWh-day) figure for output from the pilot wind plant; their ENFICC thus has a 100 per cent (or 95 per cent) probability that wind output would be greater than the historic minimum. That plant-specific probability is too low because system reliability depends on the probability of the combination of plants providing energy, not simply on the probability related to an individual plant. This is especially important when there is an inverse correlation between wind and hydro generation. Recently, the CREG has changed its methodology and increased the ENFICC for wind. However, UPME, a government body responsible for long-term planning, argues that the methodology is still very conservative and ignores the complementarity between wind and hydro generation.

In contrast, we measure firm energy (using the PJM methodology) by reference to the historic average wind output during the periods of significant system stress – which occur during El Niño periods. By narrowing our focus to periods when the systems is under stress, our ENFICC reflects wind’s contribution to system reliability when hydro generation is low.

| PJM methodology to determine ENFICC for wind power in Colombia | | |
|---|---------------------------|----------------|
| ENFICCs base | 5–7 a.m.; 6–8 p.m. | All day |
| Niño 1 | 24.13% | 29.05% |
| Niño 2 | 27.32% | 37.02% |
| Niño 3 | 30.34% | 33.78% |
| <i>Average</i> | 27.26% | 33.29% |
| | 5–7 a.m.; 6–8 p.m. | All day |
| All 3 Niños | 27.52% | 32.58% |



Conclusion

At the beginning of 2014, wind power in Colombia (all from the experimental Jepirachi plant) accounted for only 0.1 per cent of total generation capacity. There are new wind projects under study, with the potential to generate up to 674 MW (as of July 2015), but none have yet entered the construction phase. However, the current very high energy prices – which are the result of reliance on diesel oil-fired generation to replace hydro

power during the current El Niño event – reinforce the need for a more diversified energy mix, which would include alternative sources like wind power.

We think the reluctance to invest is at least partly due to the current regulations in Colombia, which underestimate wind power's potential contribution to electricity system security. Given the recent evidence of the Colombian government's commitment to develop alternative

energies, particularly wind power, and its tradition of technological neutrality, the authors encourage a regulatory rethink, in particular to recognize the complementarity among renewable resources in their contribution to system security. If this cannot be done through the reliability auctions due to complexity or for other reasons, then other regulatory measures should be considered to take account of this complementarity and to lower barriers to investment in wind power.



Decarbonization through electrification – the importance of energy taxation being in line with long-term energy policy

Graham Weale

Electrification as a major instrument for decarbonization

With the success of the COP21 Meeting in Paris the world has shown itself more determined than ever to combat climate change. Europe has been at the forefront of this initiative since the late 1990s and in 2010 the landmark Roadmap 2050 was published by the European Climate Foundation, showing how the EU could achieve its 80 per cent decarbonization aim. At the heart of the plan lay a greatly enhanced role for progressively decarbonized electricity within the overall energy supply. Electricity would be needed to play a leading role in transport (supported by biofuels and fuel cells) and also in the space heating sector through the installation of heat pumps.

According to the Roadmap, electricity demand would increase by up to 40 per cent against the baseline by 2050, with an additional 740 TWh and 700 TWh being required respectively for transport and heating (in both the household and industry sectors).

This prospective growth of over 1400 TWh should be put in the context of final electricity demand in the EU-28 of 2843 TWh (2010) and 2771 TWh (2013).

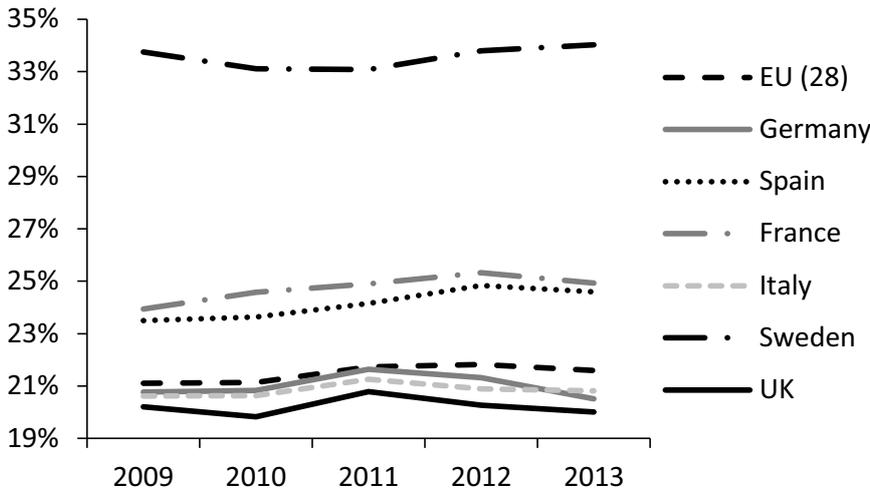
Whilst there are alternative solutions for the future supply mix – whether there should be more emphasis on renewables outside the power sector or whether hydrogen may become an important fuel for the transport sector – there is widespread agreement that substantial electrification will be crucial. It then becomes important to see whether the conditions are in place to allow this to be achieved and the necessary infrastructure built up smoothly along the way, rather than being challenged by short- or medium-term declining electricity demand.

The current energy taxation policy is hindering electrification

The statistics for European electricity demand in 2010 and 2013 cited above point to an initial decline in demand rather than the start of a new electrification

trend. One factor contributing to this development is that the energy carrier in several countries (notably in Germany) is loaded with considerably more tax and other surcharges than competitive energy carriers. Excise taxes on vehicle fuels are renowned for being high, but (at least in Germany) these have now been overtaken by the taxes and surcharges on electricity for electric vehicles.

Two important messages concerning the market share of electricity in the final energy consumption mix are seen in graph overleaf. Most noticeable are the very different positions which electricity holds in different countries – 34 per cent in Sweden and 20 per cent in the UK – results which have not generally arisen due to conscious planning on the part of government. Only in France was a policy introduced to place emphasis on the role of nuclear electricity as a central means of primary energy supply, in response to the 1973 oil supply crisis; this led naturally to a relatively high electricity market share. Sweden has a high electricity share due to a very limited gas supply, abundant



Market share of electricity in final energy consumption

hydropower, and a policy of not over-taxing this form of energy.

‘...ELECTRICITY’S MARKET SHARE IN ALL FOUR OF THE LARGEST EU ECONOMIES IS STARTING TO DECLINE.’

The second message from the graph is that electricity’s market share in all four of the largest EU economies is starting to decline. Of course there could be various reasons for this, but the classical price elasticity effect – due entirely to taxation and surcharges – is certainly one factor.

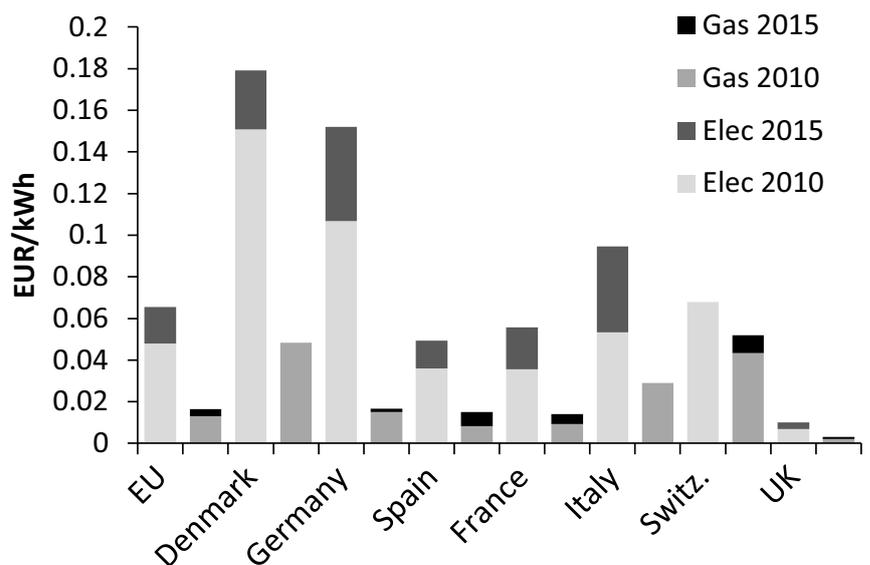
The graph on the right shows clearly by how much electricity taxes and surcharges have increased over the last five years (far more than those on gas), principally as a result of renewables development in the sector. Eurostat has applied a particular definition of taxes and surcharges and therefore small differences may be noted when compared with other sources. For example, according to UK DECC Statistics in 2013 the total levies amount to 0.026 EUR/kWh.)

The development of sound energy policy is challenging at the best of times, and it is difficult to anticipate all the side effects every time. The

particular means of implementing and financing national targets for renewables in various EU countries is a case in point, where the focus has been on meeting renewables targets and financing them by consumer levies. It has proved practical to reach those national targets for renewables by concentrating on electricity, while some countries had the additional aim of replacing certain forms of thermal power generation. As a result, in the

EU-28 over the period 2004–13 the renewables share of the power sector increased by 11.1 per cent; at the same time, the increase in the heating sector was 6.6 per cent, while that in the transport sector was 4.4 per cent. Both Germany and the UK saw twice as much growth in the renewables share in their power sectors as in their heating and transport sectors together. Conversely in Sweden much more emphasis has been given to the heating and transport sectors.

These developments in themselves are not necessarily to be criticized, but the consequence which now deserves attention (and which was most likely not originally considered), is **the relative increase in the end-consumer price of electricity as compared to competing sources of energy** (mainly gas and oil products). Higher prices of energy in general increase the incentive for energy efficiency investments, an evidently positive outcome. However, high relative prices of electricity risk setting in motion a development that may threaten the long-term goal of



Taxes and surcharges on electricity and gas – household consumers

Note: Values for 2015 are incremental over those for 2010. Denmark’s value for gas in 2015 was lower than its 2010 value (0.483 EUR/kWh). Figure 2 shows the 2010 value.

Source: Eurostat – Prices and Taxes for Household Electricity and Gas Consumption.



decarbonization through electrification. In the worst case it could trigger the so-called 'utility death-spiral' (an expression coined in the USA as the growth of consumer PV ate into utility revenue and profits), whereby infrastructure (required both to deliver centrally generated electricity and to support the growing decentralized generation) would struggle to invest as required for the longer-term electrification goals.

The problem of the rising taxes and surcharges on renewables, shown in the second graph, can be compounded by two further factors that can make the situation even more serious. Both relate to developments in the tariffs for the distribution networks.

- The first factor at play in some countries is the cost of connecting renewables, when this is borne by the customers rather than the project developers and therefore translates into higher network charges. In Germany (including VAT), these charges have increased by up to 0.02 EUR/kWh between 2010 and 2015 to accommodate the increased number of windfarms, the production of which is essentially exported to southern Germany, with the local consumers enjoying absolutely no benefits (other than modest employment effects).
- The second factor relates to the pernicious consequence of having to spread a fixed cost operation (of which the power industry is becoming an example par excellence as the role of fossil fuels decreases) over progressively fewer units of energy. There are two elements at work here. First is the increase in self-generation, reducing the net consumption flowing from central sources through the grid. The second is the decline in gross power generation; this has been

catalysed by both the price elasticity effect (an incentive to reduce electricity consumption, together with other energy efficiency initiatives), and the incentive to favour, in relative terms, other forms of energy (the cross-price elasticity effect), whether by switching away from electricity or not switching to it (for example, heat pump applications).

The issue of the price elasticity effects coming into play and working against longer-term electrification appears not yet to be showing up on government radar screens. If the current early trends continue, there is the risk that switching away from electricity may gather momentum, leading to developments which are in contradiction to the longer-term electrification aims, before such switching can be slowed down and reversed.

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'IF THE CURRENT EARLY TRENDS CONTINUE, THERE IS THE RISK THAT SWITCHING AWAY FROM ELECTRICITY MAY GATHER MOMENTUM...'

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Electrification, as one important means of decarbonization, will most likely take place at the lowest cost if there is a smooth development from the current position out towards 2050. Therefore, the right long-term signals need to be put in place to incentivize the progressive development of electricity infrastructure, rather than its premature downsizing.

Solution: bringing energy taxation policy into line with energy and climate policy

How then can progress towards meeting EU and national renewables targets be maintained and longer-term decarbonization be kept on track? The answer lies in a root and branch review of energy taxation policy, which would include renewables surcharges. Fortunately, even without designing

potential new systems there is a helpful range of policies (whether actual or under discussion) from which to draw.

Option 1: Supporting renewables from general taxation

Turning first across the Atlantic, the policy in the USA has been to support renewables mainly out of general taxation. Onshore wind farms currently benefit from production tax credits which are worth around 25 USD/MWh, and solar plants from 30 per cent investment tax credits. The result is that renewables have grown without increasing the consumer price of electricity and thereby reducing its market share. Of course there have been other side effects of the policy. Long-term Power Purchase Agreements (PPAs) for wind power have been signed at 25 USD/MWh or even lower, and these have artificially brought down the wholesale price, which has put certain thermal plants, in some cases even nuclear, under pressure.

Option 2: Technologically neutral quota systems

Within Europe, whilst feed-in tariffs have been the rule, some countries (such as Sweden and the UK) have followed quota systems. Sweden is one of the few countries to have followed a technologically neutral quota system. This led to a focus on a single technology at any given point in time: first biomass (2000–7) and then onshore wind. Other countries, in contrast, opted for the parallel development of more than one type of technology; this has the advantage that some of the more challenging forms of technology (such as offshore wind) which are essential to meet climate goals, have a greater chance of being successfully developed, and of being brought to commercial maturity more quickly, than under a technologically neutral support system. But it increases the costs over the short term.

Even though the quantities of renewable electricity which Sweden has developed on the basis of technological neutrality are modest, its average support costs are low, at only 24 EUR/MWh. This compares with a weighted average of 95 EUR/MWh for the eight EU countries with, in total, the most renewables, while the figure for Italy – at 177 EUR/MWh – is almost twice as high.

Option 3: Spreading the cost of renewables across all forms of energy

France has an electricity surcharge: CSPE (Contribution au Service Public de l'Électricité). Approximately two-thirds of this surcharge covers renewables, the remainder goes towards other costs to be socialized (such as the higher costs of electricity in the French islands and cogeneration). The level of the CSPE was 0.02 EUR/kWh in 2015 (less than one third of the German equivalent) but there is an ongoing discussion, partly because electricity prices are politically particularly sensitive, as to whether the cost of the renewables subsidy should be spread over more (or potentially all) forms of energy.

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'EVEN IN THE USA THE FUTURE OF FURTHER TAXATION SUPPORT IS FAR FROM CERTAIN...'

Whilst the public taxation option has some compelling logic, the efforts being made by almost every national Finance Ministry to reduce their budget deficit makes it an unlikely runner. Even in the USA the future of further taxation support is far from certain, and at the time of writing the US legislators were considering a plan to phase out all tax support over five years, with support for solar power potentially disappearing sooner.

The most realistic option then, one which should certainly be addressed,

is a careful reform of energy taxation with the aim of ensuring maximum consistency with long-term energy and climate policy. There are a number of dimensions to such a reform which need to be considered:

- (a) The need to avoid disadvantaging electricity by taxing it disproportionately in relation to other fuels – the main theme of this paper.
- (b) Ensuring, over the long run, that the price of different forms of energy is close to the full cost, including externalities.
- (c) The need to ensure, above all else, a strong incentive for energy efficiency (but not for any particular fuel, other than as dictated by its overall carbon footprint).

This would mean, first, that there should not be fuel-specific taxes – such as an electricity tax rather than a gas tax. Also, to the extent that taxes as such would have revenue-raising objectives, then they should be proportional to the energy element. (There is a different argument in the case of motor fuels where taxes are needed to pay for the road infrastructure.)

There may appear, at first sight, to be a contradiction between (a) and (b) above, but renewables raise the challenge that they originally needed support (and to some extent still do) in order to bring them to commercial maturity. So far as the support required for this purpose, as opposed to the future steady-state financing costs, can be separated, the author is arguing that such learning costs should either be spread over all forms of energy or, where possible, covered from general taxation. In Germany, for example, almost half of the current annual 0.063 EUR/kWh renewables support charge relates to the legacy support for PV. This cost component has no relationship to the long-term costs

of renewables electricity generation and including it as part of the final consumer electricity price (including VAT, it represents around 12.5 per cent of the price) is inconsistent with objective (b) above.

The multiple political and environmental requirements placed on the energy system, and in particular on the power system, militate against a clean economic solution. In the previous decade, the EU aimed, through market-based methods, to meet the welfare objectives of the Single Market (through the internal wholesale market – with progressive improvements to its working) and the objective of decarbonization (through the carbon emission trading system). However, these were quickly and comprehensively usurped by various out-of-market mechanisms. It is now unrealistic to expect too much emphasis to be placed on the (originally foreseen) simple and fundamentally market-based methods to meet power demand and decarbonize.

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'...THE NEED FOR ENERGY TAXATION TO BE IN HARMONY WITH ENERGY POLICIES AND STRATEGIES HAS SO FAR BEEN COMPLETELY OVERLOOKED.'

However, whilst the wholesale markets have been heavily distorted, leaving them poorly equipped to achieve much more than the optimal dispatching of existing plants, other economic forces are still very much at work, including the aforementioned price elasticity effects, which cannot be ignored.

European governments are being challenged in many different directions, both by requirements to meet their specific 2020 goals, together with national policy objectives. There is thus the risk that they give inadequate attention to the strategies required



to reach the 2050 end goal of 80–95 per cent decarbonization (and at a reasonable cost), and are pulled off course. The longer-term importance

of the need for energy taxation to be in harmony with energy policies and strategies has so far been completely overlooked. It is now time to open

this book and make the necessary corrections so that, over time, there will be a smooth and optimal cost path to the 2050 goals.



View from the USA: rapid transformation of power sector calls for new tariffs

Fereidoon P. Sioshansi

Conventional electricity tariffs

It should come as no surprise to anyone that the cost of providing electric service to most customers – notably residential consumers – is mostly fixed. Studies by the Electric Power Research Institute (EPRI) and others put the fixed component of the cost at around 60 per cent for the typical residential user in the USA, which is the main focus of this article. What is surprising, however, is that for over a century, for most consumers, the bill has been mainly determined by the volume of electricity consumed: a multiplier (cents/kWh) times the number of kWhs used. Even today, most residential consumers in the USA pay virtually all their monthly bills on the basis of volumetric consumption. Relatively little is collected through fixed fees or connection charges.

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'THE COST OF PROVIDING ELECTRIC SERVICE TO MOST CUSTOMERS – NOTABLY RESIDENTIAL CONSUMERS – IS MOSTLY FIXED.'

The volumetric scheme did not make much sense when it started, but was a convenient way to measure and bill consumers. For regulators, it was an easy way to adjust the 'multiplier' every so often to reflect changes in fuel, operating, or investment costs. For consumers, the concept made sense. Many still believe that electricity should

be billed on the basis of volume, as with gasoline. If you don't use much, you don't pay much.

It did not much matter throughout the industry's formative decades, when demand continued to grow, encouraging massive investments in generation and in transmission and distribution infrastructure, which could be financed through the simple volumetric scheme. With average retail tariffs flat or declining in real terms and rapid demand growth, everyone was happy – the consumers, the utilities, and the regulators.

Effects of distributed generation

Conditions are different today. Electricity demand in the USA – and in nearly all other mature economies – is virtually flat or in some cases actually declining (see the table below). As buildings and appliances become

more efficient, less energy is needed to operate them. Moreover, with the rapid fall of the cost of distributed generation (DG), notably in rooftop solar photovoltaics (PVs), consumers can produce more of what they consume, which means less is bought from the network, the grid.

While the impact of DG is uneven, in some places its effects are becoming pronounced. For example, Energex, a distribution utility serving the Brisbane metropolitan area in sunny Queensland, Australia already has nearly 300,000 customers with rooftop solar PVs, making it among the highest on a per capita basis.

Making matters worse is the massive cost of maintaining and upgrading an ageing infrastructure upstream of the meter – the costs of which must be spread across a shrinking base. This leads to higher retail tariffs, which

| Get used to it: no growth in utility business – New York or elsewhere | |
|---|-------------------------------------|
| Average electric sales growth in New York, 1966 to 2013 and projections to 2024 | |
| Period | Avg. sales growth for period |
| 1966–76 | 3.8% |
| 1976–86 | 1.5% |
| 1986–96 | 1.4% |
| 1996–2006 | 0.9% |
| 2003–2013 | 0.3% |
| 2014–2024 | 0.16% |
| <i>Source: New York Public Service Commission, 26 February 2015.</i> | |

encourages more investment in energy efficiency and DG, which leads to even higher tariffs – the so-called utility death spiral.

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‘ELECTRICITY TARIFFS ARE THUS IN NEED OF OVERHAUL AS CONSUMERS BUY LESS AND GENERATE MORE.’

Not surprisingly, consumers in many European countries, where electricity is heavily taxed and/or loaded with levies, are also looking for any measure at their disposal which would enable them to buy less; this means using less and self-generating more when it is cost-effective to do so. Electricity tariffs are thus in need of overhaul as consumers buy less and generate more.

Future of electricity tariffs

In this context, the debate on what to do with electricity tariffs is heating up in many parts of the world, as regulators and politicians grapple with finding ways to keep the incumbents solvent without necessarily crushing the rapid uptake of solar PVs, which are enormously popular among consumers.

A recent article in *The Wall Street Journal* (20 October 2015), entitled ‘As Conservation Cuts Electricity Use, Utilities Turn to Fees’, described the dilemma faced by utilities and regulators in the USA as they try to adjust consumer tariffs by shifting more of the costs of service to fixed fees – which is how it should have been in the first place. It said:

Electric utilities across the country are trying to change the way they charge customers, shifting more of their fixed costs to monthly fees, raising the hackles of consumer watchdogs and conservation advocates.

Traditionally, charges for generating, transporting and maintaining the grid have been wrapped together into a monthly cost based on the amount of electricity consumers use each month. Some utilities also charge a basic service fee of \$5 or so a month to cover the costs of reading meters and sending out bills.

Now, many utility companies are seeking to increase their monthly fees by double-digit percentages, raising them to \$25 or more a month regardless of the amount of power consumers use. The utilities argue that the fees should cover a bigger proportion of the fixed costs of the electric grid, including maintenance and repairs.

The basic logic of what the utilities are trying to do makes sense, but changing utility tariff structures is complicated, slow, and convoluted. Making matters worse, it is highly political. Any change in current tariffs means shifting costs to other customers, who do not like paying more.

Many believe that the electricity grid is essentially a public good and, therefore, must be paid for by everyone who benefits from it.

Utilities in at least 24 states have requested higher fees. Confronted with the facts, regulators in a number of states are sympathetic to the plight of utilities but are reluctant to raise fixed fees too aggressively.

Fixed fees have their critics. Consumer advocates point out that they disempower the customer and discourage investments in rooftop solar and energy efficiency.

Fundamentally, the thinking is to move towards tariffs that reflect

cost-causality so consumers get charged for the costs they impose on the network while raising sufficient revenues for the maintenance and upgrading of the grid and the reliability that it offers. These include several well-known tariff options such as:

- **Time-of-use (TOU)** rates;
- Increased **fixed charges**;
- **Three-part tariffs**; and
- **Demand subscription.**

Three-part tariffs are getting some traction as they purport to closely follow the costs attributed to serving customers in the emerging business environment. One such tariff introduced by the Salt River Project (SRP), a non-regulated utility operating in Arizona, for example, consists of the following three components:

- A fixed charge of USD18–20 regardless of usage level, peak demand, or anything else. It may be considered a connection or network fee;
- An energy charge, slightly lower than the previous volumetric charge, to recover the variable cost of fuel and/or purchased power; and
- A demand charge, which varies based on how customers’ peak demand coincides with the network’s peak demand.

For a customer with an 8.5 kW solar panel, for example, the demand charge varies from USD41/month in the winter to USD126/month in the summer.

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‘THE REGULATORS DO NOT WISH TO ANGER THE SOLAR CUSTOMERS BUT ARE BECOMING SENSITIVE TO THE PLIGHT OF THE UTILITIES...’

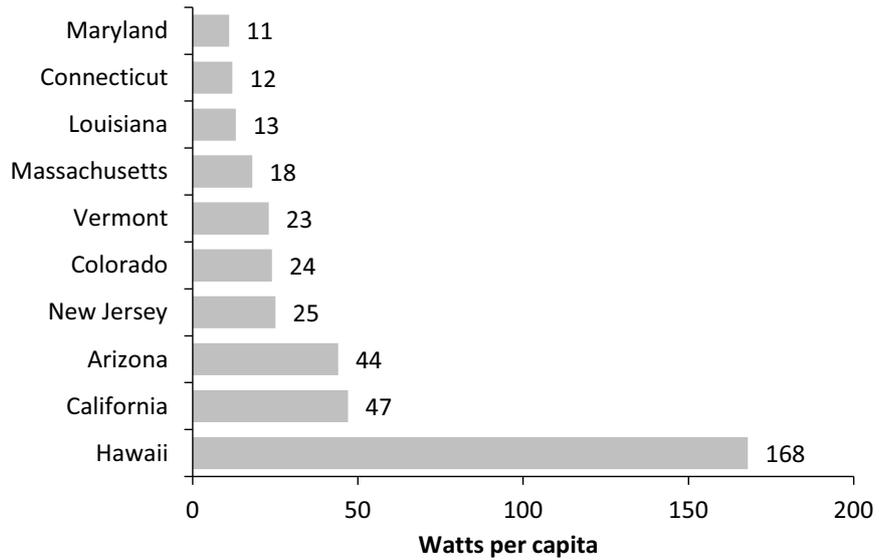
Other states examining three-part tariffs include Nevada. Describing the



merits of its recent application for solar customers filed with the Public Utilities Commission of Nevada (PUCN) in early August 2015, Kevin Geraghty, NV Energy's vice president of Energy Supply said:

A three-part rate design better reflects the unique costs of serving our net metering customers and eliminates the unreasonable shifting of costs between those that can access rooftop solar and net metering and those that don't, [adding that] This is a proven rate structure that has been in use by our commercial customers for more than 50 years. Under the proposal, net metering customers still have the opportunity to reduce their bill from NV Energy if they reduce the impact they have on the grid.

The regulators do not wish to anger



Sunshine states: states that get most electricity per capita from residential solar panels, 2014

Source: Rebecca Smith and Lynn Cook, 'Hawaii wrestles with vagaries of solar power', *The Wall Street Journal*, 29 June 2015.

the solar customers but are becoming sensitive to the plight of the utilities which are suffering from revenue

erosion while higher costs are being shifted to non-solar customers. The battle is just beginning.



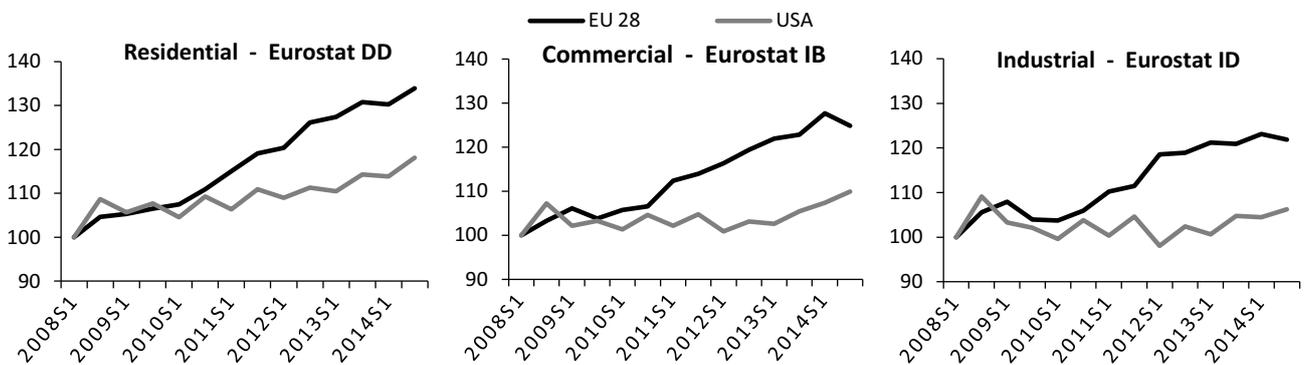
A comparison of US and EU electricity prices: the relevance of the government wedge

David Robinson

This article is a short English summary of my recent report, published in Spanish ('Análisis comparativo de los precios de la electricidad en la Unión

Europea y en Estados Unidos: Una perspectiva española'), comparing trends in final electricity prices in the EU and the USA over the period 2008–14.

The article explains why final consumer electricity prices in the EU, especially in Spain, increased significantly more than in the USA between 2008 and 2014.



1. Evolution of average final electricity prices in the EU and the USA, 2008–14

Source: Eurostat and US DOE-EIA

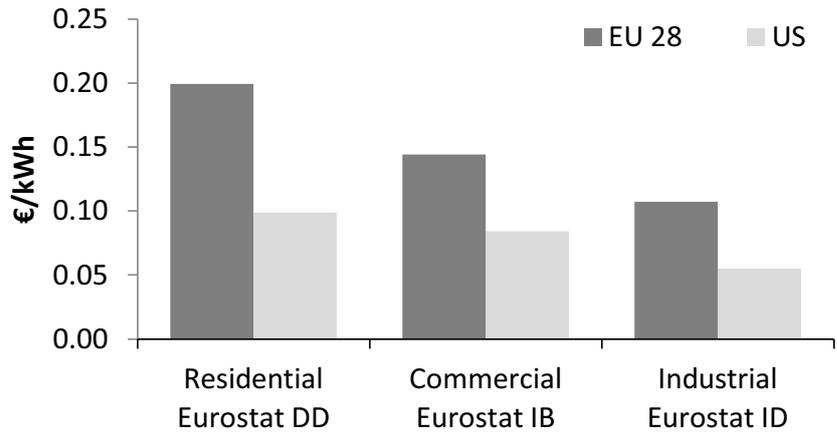
It concludes that the primary explanation is not related to differences in conventional determinants of electricity price (the demand for and the cost of wholesale electricity and networks) but rather to differences in taxes, levies, and other charges related to financing public policies, notably support for renewable power.

Comparing final prices

Graphic 1 includes electricity price indices for residential, commercial and industrial consumers in the two regions since 2008. They illustrate clearly that average prices in the EU have risen significantly faster than in the USA. For instance, prices for residential consumers rose by 34 per cent in the EU (EU 28) and by 18 per cent in the USA. For industrial consumers, average electricity prices rose by 22 per cent in the EU and by 6 per cent in the USA.

.....
 ‘...AVERAGE PRICES IN THE EU HAVE RISEN SIGNIFICANTLY FASTER THAN IN THE USA.’

At the beginning of the period, US prices were much lower than in the EU.



2. Final electricity prices in the EU and the USA, 2014-S2

Source: Eurostat and US DOE-EIA

By the end of the period, the difference was even greater, with average EU prices approximately twice as high as in the USA for each of these customer categories (see Graphic 2).

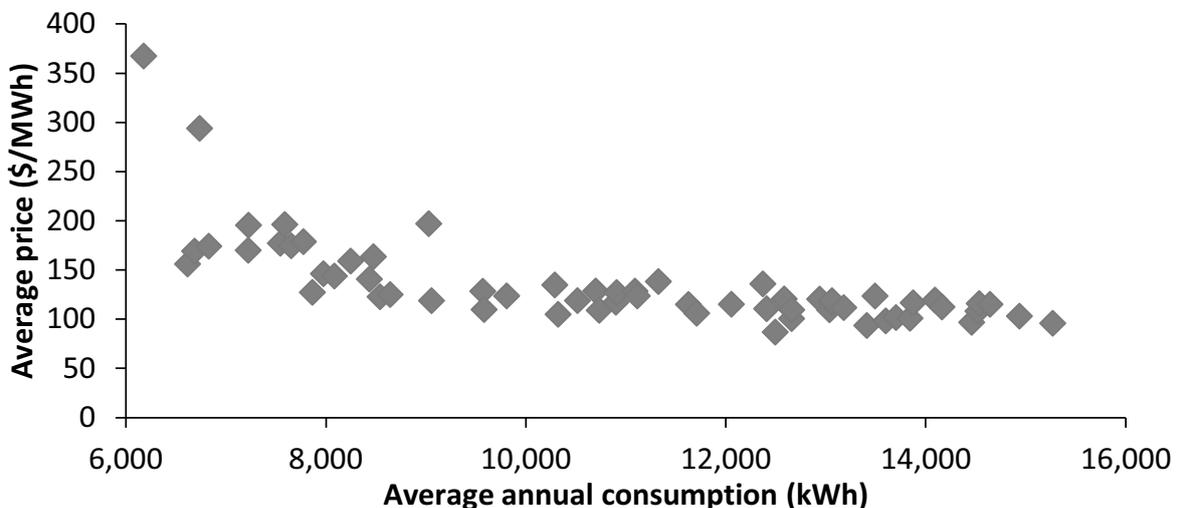
Why is there a large divergence in final price trends?

I consider various possible explanations for divergent price trends, including differences in electricity demand and in the two most important costs of electricity supply: wholesale electricity market prices and the cost of networks.

Demand

The average demand per household in the USA is more than twice the average level in the EU (4,137 kWh in 2009). Since the electricity industry has high fixed costs, higher volumes for any given fixed costs usually translate into lower unit costs and prices, as illustrated by Graphic 3, which plots prices and consumption per household in the US states.

Although lower EU consumption per household may help to explain higher average prices at any given time, it does not explain why average EU prices have risen so much faster than



3. Price per MWh versus average annual electricity consumption per household in US states



in the USA since 2008. If US electricity demand had grown significantly faster than in the EU, this might help to explain the faster rise in EU average prices. In fact, US electricity demand was approximately the same in 2014 and in 2008, whereas EU electricity demand fell by about 3 per cent over the period. That difference may explain a small part of the price divergence, but not very much. For instance, if the fixed costs of networks were 30 per cent of the final price, a difference of 3 per cent in demand growth would translate into an increase of about 1 per cent in the final price.

Wholesale market prices

The availability of low-cost shale gas helps to explain why US wholesale electricity prices have not risen since 2008 – indeed, in nearly all US wholesale markets, they have fallen, as illustrated in the right side of Graphic 4. However, this does not explain the difference in final consumer price trends because wholesale electricity prices follow a similar pattern of flat or falling prices, depending on the dates chosen, in both the USA and the EU. In the EU, prices have been depressed by a combination of excess generation

capacity, low coal and carbon dioxide emission allowance prices, depressed demand, and high penetration of intermittent renewable electricity.

Network costs

The costs of transmission and distribution networks have increased in the EU and the USA at roughly the same rates over the period, so they do not explain the diverging price trends.

I conclude that the diverging paths of final prices between the USA and the EU cannot be explained convincingly by any of the traditional demand or supply cost factors, alone or together.

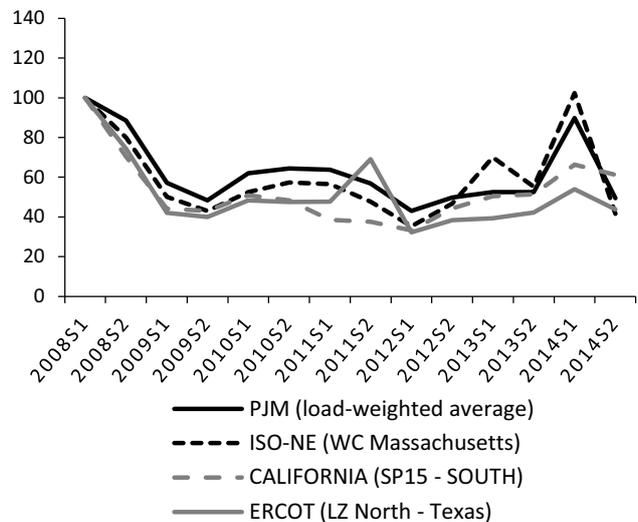
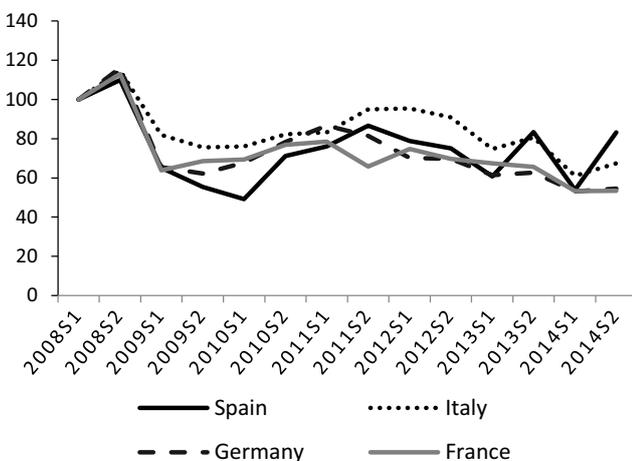
The government wedge

The term ‘government wedge’ refers to taxes, levies, and other charges that finance public policies through the electricity tariff. The wedge does not include the cost of policies that are financed through the government budget; it only covers those costs that are financed through tariffs. The wedge is the third component of electricity prices, with the other two being competitive energy prices (for wholesale energy and retail services) and regulated network costs.

.....
‘THE TERM “GOVERNMENT WEDGE” REFERS TO TAXES, LEVIES, AND OTHER CHARGES THAT FINANCE PUBLIC POLICIES THROUGH THE TARIFF.’

The government wedge has been growing steadily in most European countries since about 2008. According to the electricity industry lobby Eurelectric, between 2008 and 2012 the government wedge rose by 31 per cent for residential consumers and by over 100 per cent for industries, whereas wholesale energy costs fell and network costs rose by only 10 per cent and 17 per cent for residential and industrial consumers, respectively.

To take one example: in Spain, final electricity prices for residential consumers have risen by over 50 per cent since the end of 2008. The government wedge explains over 70 per cent of the increase and in 2014 it accounted for 46 per cent of the final price for these customers. VAT and special electricity taxes are the most important component of the wedge for residential consumers. Then comes the financial support for renewable electricity and cogeneration, and interest payments on the EUR25



4. Selected EU and US wholesale electricity market price indices, 2008–14

Sources: OMIE, EEX, GME, ERCOT, PJM, CAISO, ISO-NE, MorningStar

billion tariff deficit (in other words, the accumulated difference between regulatory entitlements and the tariffs set to collect the cost of these entitlements). The wedge also includes, inter alia, funding for domestic coal suppliers, compensation for higher costs of supply on the islands, and payments to certain consumers.

The government wedge in the USA is difficult to measure, largely because published data for the sector bundles any policy-related costs into the categories of generation, transmission, and distribution. It is also difficult to compare states which have vertically integrated and regulated electricity monopolies with states that have unbundled the sector and have competitive wholesale or retail markets.

Nevertheless, the available evidence suggests that the wedge is much smaller in the USA than in the EU. The first piece of evidence is the greater investment in, and penetration of, intermittent renewable energy in the EU, as illustrated in Graphic 5. On average, intermittent renewables account for more than 6 per cent of EU electricity generation and for less than half that percentage figure in the USA.

Second, the USA finances an increasingly significant part of the costs of renewable power and other

public policies (such as energy efficiency and smart grids) through federal and state taxes, rather than through electricity tariffs. Total federal subsidies for renewable power – both direct payments and tax credits – were over US\$11.7 billion in 2013, up from about US\$1 billion in 2007. The federal government also provided subsidies of US\$1.2 billion for smart grids and transport in 2013. The US Congress has recently extended the regime of investment credits for solar energy and production credits for wind power.

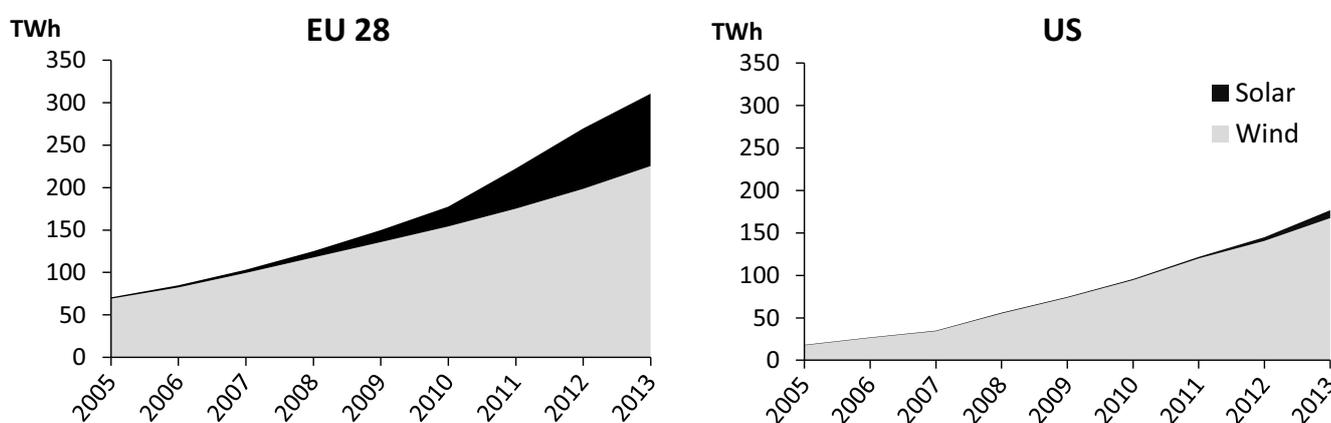
In addition to federal subsidies for the power sector, there are many state-level subsidies. Texas, for instance, offers tax credits for renewable power that were worth approximately US\$1.4 billion in 2013, up from about US\$700 million in 2007.

Third, most European countries levy VAT and other taxes on electricity consumption, whereas in the USA electricity is often not taxed, or is taxed at a much lower level. The average VAT levied on electricity in the EU rose from 15 per cent in 2008 to 17 per cent in 2012. This is not an issue for commercial and industrial consumers since they can recover these taxes. However, it does have an important impact on residential consumers who are unable to recover these taxes.

Implications and recommendations

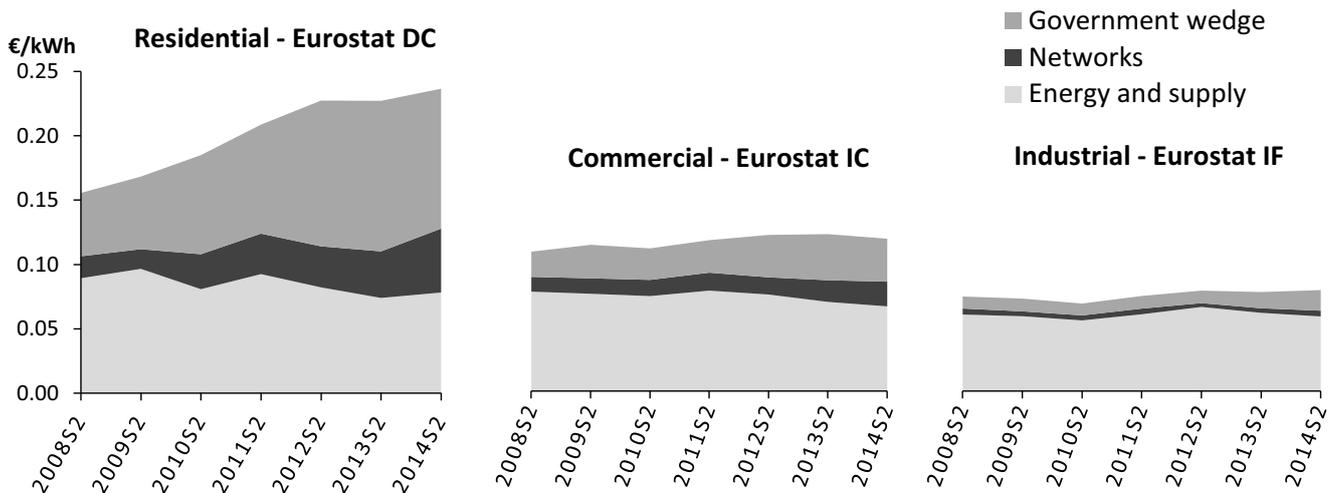
The immediate consequence of rising prices in the EU has been to reduce the disposable income of residential consumers, especially in countries with a very high penetration of renewable power, notably Germany and Spain. Although industry and commerce have also seen rising prices, the bulk of the extra costs have been born by residential consumers. This is the case in Spain, as illustrated by Graphic 6, where the top part of the graphic reflects the government wedge, with the residential consumers on the left, commerce in the middle, and industry on the right hand side.

A second implication is the distorting effect on energy markets. Facing final prices that exceed the (long or short run) marginal costs of electricity supply, consumers are encouraged to behave in ways that are not efficient, in particular to discourage the use of electricity and instead to encourage consumption of fossil fuels, for instance in heating. If the EU is to achieve its political objective of reducing greenhouse gas emissions by 80–95 per cent by 2050, this will require almost complete decarbonization of the electricity sector and large-scale electrification of transport, heating, and even industrial energy consumption.



5. Electricity generation from intermittent renewables in the EU and the USA

Source: Eurostat and US DOE-EIA



6. Composition of average final electricity prices in Spain for residential, commercial, and industrial consumers in 2013-S2

Source: Eurostat and own calculations

I make a number of *policy recommendations*. The first is that EU countries should be rethinking how best to finance public policies, especially in view of the Paris Agreement. It is evident that in most countries, electricity decarbonization is a necessary and efficient way of reducing carbon dioxide emissions. This will involve additional costs for society, at least initially. I think it is a mistake to finance the additional costs of decarbonization incurred in the electricity sector almost entirely through the electricity tariff, especially given the distributional consequences.

Instead, I favour the introduction of a *rising minimum carbon tax* on fossil fuels specifically for those activities (such as transport and heating) not covered by the European Union Emission Trading Scheme. This tax should also help to level the competitive playing field between electricity and fossil fuels. The carbon tax should be neutral from a fiscal perspective, in the sense that there should be corresponding reductions in other taxes, with the aim of having a positive net impact on the economy (in terms of, for example, GDP, public debt, employment).

Second, for public policies that have nothing to do with the efficient and secure supply of low-carbon electricity, I favour

recovering some of the related costs through the general government budget rather than through electricity tariffs.

This would have positive distributional consequences since income tax is progressive whereas high electricity prices are a burden on the poorest consumers. In principle, it also makes sense for public policies that aim to meet broad European or Spanish political objectives (industrial, regional, or social) to be financed through the tax system rather than through electricity tariffs. Nevertheless, along with the carbon tax, this sort of fiscal reform requires careful study to ensure that the outcome is optimal for the economy as whole.

.....
‘TRANSPARENCY IS REQUIRED NOT ONLY FOR FAIRNESS, BUT ALSO TO ENSURE A LEVEL PLAYING FIELD IN THE EU...’

Third, in many EU countries, we need *greater transparency* about which costs are being collected through the electricity tariffs, who is receiving the benefits (subsidies), and who is bearing the burden. In some countries, notably Germany, there is significant transparency. In others, notably Spain, there is very little. Transparency is required not only for fairness, but also to ensure a

level playing field in the EU when it comes to knowing whether state aid is being granted to certain industrial consumers.

Fourth, with respect to tariffs, the challenge is not simply to reduce the level of final prices, but to *design an efficient network tariff structure* to recover recognized costs. Redesigning tariffs to collect fixed costs through a fixed charge may help to overcome the incentive to bypass the system. However, the higher the government wedge included in the tariff (whether in the fixed or variable component), the harder it will be to sustain these tariffs, politically and economically, especially as the costs of distributed generation fall.

Finally, whether public policy costs of decarbonization are financed through the electricity tariff or through the budget, we are left with the same underlying problem: a growing tension between existing electricity market design and the need to decarbonize the economy. To date, this has resulted in growing government intervention that has distorted and possibly broken electricity markets. It is time to rethink the design of electricity markets and their regulation, to be consistent with decarbonization and with increasing decentralization of energy resources.



Assessment of demand response in Shanghai

Malcolm Keay, Xin Li, and David Robinson

Introduction

Interest in demand response (DR – sometimes referred to under the more general heading of demand side management, DSM) has been growing worldwide and there are some familiar examples in the OECD. For instance, the USA has recently seen a considerable growth in demand response aggregators such as ENERNOC, which manages around 25 GW of peak load DR capacity, and the PJM (Pennsylvania–New Jersey–Maryland) interconnection in the north-east, which has well developed DR markets. In the UK, demand response has, for some time, been an element of the National Grid's Short Term Operating Reserve and the Grid has recently been developing new instruments like the Demand Side Balancing Reserve. The idea underlying all these approaches is that it is often better to deal with periods of imbalance between electricity supply and demand by adjusting demand rather than generation. Supply and demand have to be kept in balance at all times because of the difficulty of storing electricity; traditionally most systems have relied almost exclusively on flexibility on the supply side (indeed many still do). Including demand in the calculations may not only be more efficient, it may also help to expand the whole debate.

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'[CHINA] IS STARTING TO EXPERIMENT WITH A MORE ECONOMIC APPROACH TO DEMAND RESPONSE.'

While developments in the OECD are familiar, it should not be forgotten that there are also examples from outside the OECD, in particular in China, which is the focus of this article.

China has, in fact, practised a form of administrative demand management for some time. However, as it moves towards the greater use of price incentives within its electricity system, it is starting to experiment with a more economic approach to demand response. In 2014, Shanghai was selected by the National Development and Reform Commission (NDRC) as the first pilot city in China to trial municipality-led DR programmes.

The NDRC has also designated four other municipalities (Beijing, Suzhou, Tangshan, and Foshan) as DSM cities and instructed them to undertake DR pilots. As part of this process, the OIES, working with the Environmental Change Institute (ECI) of Oxford University, undertook an assessment of the Shanghai pilot on behalf of the Natural Resources Defense Council (NRDC – not to be confused with the NDRC!). Their work (available on the NRDC website as: 'Assessment of Demand Response Market Potential and Benefits in Shanghai', dated September 2015, and referred to in this article as 'the Report') is designed to provide an assessment of the potential for, and benefits of, demand response in Shanghai, drawing both on the outcome of the pilot and on experience across the OECD. This article summarizes the findings of the Report.

Chinese context

In many ways, the factors driving China's interest in DR are the same as elsewhere in the world, and reflect a number of important trends, including the following:

- **Increasing penetration of intermittent generation** and, as a result, declining flexibility on the

supply side. China, like many other countries, has been investing heavily in renewable sources and in particular in wind power – wind capacity has increased more than 300-fold since the beginning of this century. The decreasing controllability of the supply side, resulting from the introduction of intermittent sources, makes flexibility on the demand side more valuable.

- **Growth in demand side flexibility.**

With the development of smart grids and smart meters (and localized generation, which often acts effectively as a demand-side resource) the cost and practicality of providing flexibility on the demand side is growing, and it is becoming easier to coordinate large numbers of distributed loads.

- **Liberalization of electricity markets**

is also helping to encourage more flexible and innovative approaches to pricing and system management – system operators are becoming more open to the idea that not everything has to be controlled from the centre.

- Finally, **government policy** is also increasingly favourable to the idea of demand response. Concerns about climate change are leading to increased emphasis on reducing carbon emissions and encouraging lower resource use – the power station which remains unbuilt, and the tonne of carbon not emitted, are seen as valuable goals in themselves.

However, it is also important to take account of the very different design and history of the Chinese electricity system. In particular, it has in the past put much less emphasis on economic



incentives and price signals than is seen in the OECD. Consumer prices are regulated and do not necessarily reflect the full cost of supply. System operation is also generally on an administrative basis rather than on the sort of merit order we are familiar with in the West – dispatch of power stations takes place according to generation plans which guarantee a certain level of output for generators, as a way of offering them a secure income stream. Interregional and interprovincial power exchanges also normally take place according to a fixed schedule. To balance supply and demand, utilities in China have therefore operated administrative load management programmes, including load shifting and avoidance, and restrictions on electricity use or curtailments in the event of severe power shortages. As a result of these programmes, and of the importance of industry in Chinese power demand, the profile of electricity demand in China is very flat by OECD standards. (Shanghai is not entirely typical of the Chinese system; it has a large commercial and residential load, and increasing air conditioning demand; it operates a form of merit order based on generation efficiencies; and it also imports a significant proportion of its power from outside.)

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‘TO BALANCE SUPPLY AND DEMAND, UTILITIES IN CHINA HAVE THEREFORE OPERATED ADMINISTRATIVE LOAD MANAGEMENT PROGRAMMES...’

However, the Chinese electricity system is changing. In particular, the authorities are encouraging the use of more market-based incentives, and the DR experiments are part of this initiative (see ‘Opinion on further Deepening the Power Sector Reform’, a reform plan issued by the State Council in March 2015). In accordance with this process, voluntary interruptible contracts

between customers and utilities are being developed. Electricity demand is also changing as the balance of the economy shifts from industrial production to a greater share for consumption and public services. Also, given the growth of the air conditioning load in cities such as Shanghai, the ‘peakiness’ of electricity demand is likely to increase; the DR pilot is aimed, inter alia, at reducing the need for new gas peaking plants. Finally, China is, like other countries, increasing its focus on environmental issues: from local pollution (for instance, coal-fired power plants, other than combined heat and power, are not allowed in the eastern coastal regions such as Shanghai) to global climate change (China has a target that carbon dioxide emissions should peak by 2030 or earlier). The Shanghai pilot was set up against this background.

Potential

A number of factors have to be taken into account in calculating the potential of DR in Shanghai. In particular, the Report considered two main benchmarks:

■ **Experience with the 2014 pilot.**

The pilot was relatively limited in scale. It involved 27 large commercial customers who were asked to reduce demand during peak periods (which generally take place between 1 p.m. and 3 p.m. on summer days, because of the air conditioning load). It achieved an overall reduction of 9 per cent in demand among these customers, although individual customers managed to reduce their loads by much more significant amounts, while higher overall reductions (up to 30 per cent) were also achieved over short periods (up to 15 minutes). Amongst other things, the pilot was looking at the potential for developing the role of

aggregators (on the same general lines as in the USA).

■ **International experience.**

Experience in other countries provides a general guide to the potential, but clearly it cannot be translated directly. Much depends on the policy instruments used (such as direct control of loads vs price signals); the structure of supply and demand in the systems concerned; the nature of the market involved; and the precise form of demand response (such as whether the service being provided is short-term frequency control or a wider contribution to reducing peak capacity).

Taking account of these factors, and of the policy instruments which might be used in Shanghai, calculations were made of the potential reduction in peak capacity in the period up to 2030 under various scenarios. On a relatively optimistic scenario, the analysis showed that the market potential of DR resources could reach 2.5 GW in 2030, or about 4 per cent of peak demand in that year, though more conservative scenarios were also presented under which the reductions could be less – as little as 214 MW on the most pessimistic forecast.

Benefits

The benefits of DR extend throughout the electricity system – in principle, it should reduce the need for new generation capacity and, potentially, for new transmission and distribution capacity. It should also reduce the need for generation from existing facilities, together with the emissions entailed. In addition, it may contribute to a reduction in system balancing costs and provide services such as frequency response. Most of these benefits come in the form of avoided costs – that is, they cannot be observed directly but must be

estimated. The costs of demand response are also system and customer specific and, especially given the need to look into the future, not calculable with complete precision. Indeed, the Report focused on avoided costs and did not assess the costs of demand response. Nonetheless, it attempted to produce an indicative overall assessment of the benefits.

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'[DR] SHOULD REDUCE THE NEED FOR NEW GENERATION CAPACITY AND, POTENTIALLY, FOR NEW TRANSMISSION AND DISTRIBUTION CAPACITY.'

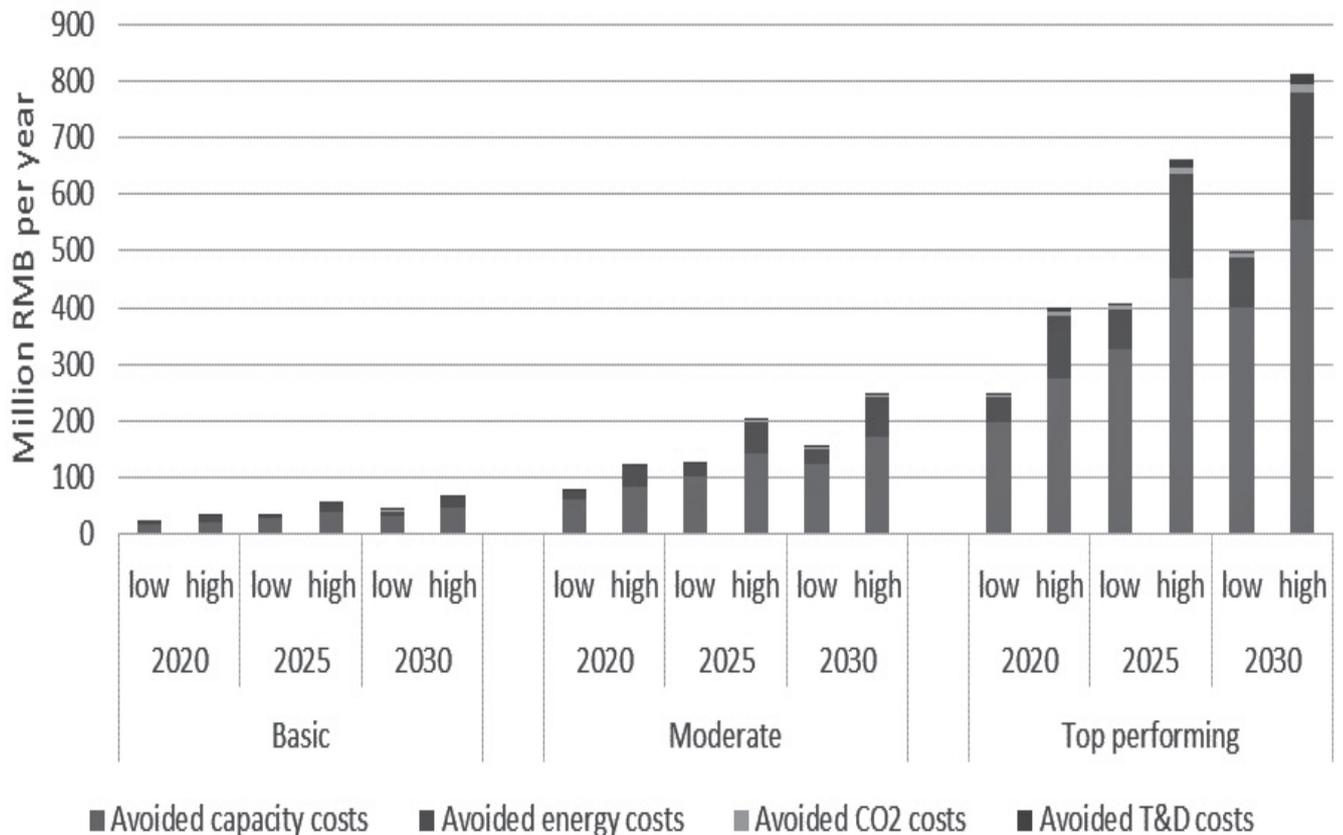
The biggest single element is the avoided generation capacity cost (taken as gas-fired plant, as required by regulation in Shanghai). A methodology often used in the OECD to calculate the avoided capacity cost is known as netCONE (CONE stands

for cost of new entry; netCONE is based on annualizing the capital and other upfront costs of a reference plant, taken to be representative of new plants on the system, and then taking account of expected market revenues to produce a net figure). The aim is to calculate the annual capital costs of new plants, which might be avoided by DR programmes. There are many estimates of such costs from OECD sources – for instance, in the UK a figure of 49 GBP/kW for netCONE was calculated as part of the preparation for the capacity auctions (though in practice the outcome was much lower, at less than 20 GBP/kW, partly because of the number of existing plants which were successful in the auction, partly because of the number of diesel plants involved – the reference plant for the CONE calculations was gas-fired).

As these complications suggest, such calculations involve a number

of assumptions and can never be definitive; furthermore, it is not easy to translate the assumptions or calculations directly from one system to another. In addition, although there are many estimates of construction costs from OECD sources, construction costs for new capacity in China tend to be much lower, so in the ECI/OIES study, estimates of Chinese costs were used rather than OECD ones. The value of the potential savings also depends to a significant extent on the discount rate (for which various alternatives were used for the purposes of the study) though discounting is not common practice in China. The study therefore produced a range of possible figures for the savings; benefits from capacity avoidance of around RMB550 million in 2030 were possible on the more optimistic scenarios.

The study also estimated other avoided costs, including those of energy,



Total avoided costs



carbon dioxide, and transmission and distribution, though these were of a lesser order of magnitude. Total avoided costs were estimated at a little over RMB800 million in 2030 at a discount rate of 7 per cent on the most optimistic scenario, with correspondingly lower figures for the pessimistic scenario (see the figure 'Total avoided costs'). However the study also warned that the figures were only indicative and might in some respects overstate the value of DR –

in particular because of the practice of administrative demand planning, which might have suppressed some economic demand, leading to a lower level of capacity than is economically justified, and because the study was also unable to include the costs involved in DR.

Conclusions

Despite the various caveats noted above, the study was particularly useful

as a 'proof of concept' in showing that DR could, in principle, be a useful policy tool in China, as in the OECD. It included recommendations for the design of DR policy instruments in China and for further research to develop a more robust evidence base for calculation of the potential of DR. Some of this work is now being undertaken and it is likely that, as elsewhere in the world, DR will increasingly be an important part of the electricity scene in China.



Power system reform to enable large-scale wind utilization in China

Zhang Xiliang and Xiong Weiming

Wind development and curtailment go hand in hand

Recognizing that wind power is one of the most mature, abundant, and rich sources of renewable energy, the Chinese government has made considerable efforts to promote it for the mitigation of carbon emissions and improvement of environmental quality. Over the last decade, China's wind industry has enjoyed dramatic growth, overtaking the USA as the biggest wind power market in 2010. By the end of 2014, China's total wind power capacity had reached 96.4 GW, accounting for 7 per cent of the country's total generation capacity.

.....
 '...CHINA'S WIND INDUSTRY HAS ENJOYED DRAMATIC GROWTH, OVERTAKING THE USA AS THE BIGGEST WIND POWER MARKET IN 2010.'

Despite this successful increase in wind capacity, however, since 2010 the industry has faced new challenges due to its ineffective utilization. In the first half of 2015, wind curtailment was as high as 17.5 TWh at national level, meaning that 15.2 per cent of

technically available wind power could not be connected to the electricity grid, so the wind turbines had to shut down. The problem of wind curtailment is more prominent in the wind-rich provinces. In Jilin, Gansu, and Xinjiang, the proportion of curtailed wind power generation in available wind output has increased to 43 per cent, 31 per cent, and 28 per cent respectively, making a negative impact on ongoing wind development. Although the growth of wind installation is still on the fast track, the ineffective utilization of wind capacity has caused energy waste, extra carbon emissions, and lower incomes for wind farms; this contradicts the original intention of ensuring significant priority to the promotion of wind power in national energy strategies. Hence, it is crucial for the future development of wind power in China to overcome wind curtailment issues.

What led to wind curtailment?

In order to address this issue, a deep analysis – to identify the obstacles constraining the large-scale utilization of wind power – is necessary. From

the technical perspective, curtailment is caused by the intermittency and volatility of wind power itself. However, we argue that it is essentially due to three main factors:

- 1 uncoordinated planning between wind and grid,
- 2 inflexible dispatch mode, and
- 3 the lack of policy incentives for stakeholders.

Firstly, inconsistency between wind deployment and grid planning has limited the transmission of wind power. China's rich wind energy resource is mainly concentrated in the Three North area (north-east, north-west, and North China), which accounts for approximately 90 per cent of national wind potential. In order to achieve large-scale development of the most wind-rich areas, central government has set the ambitious target of achieving seven large-scale (10 GW) wind farms by 2020, with six of them being located in the Three North area. By the end of 2014, the Three North area accounted for more than 80 per cent of China's total wind installations but its share of electricity consumption

is only 34 per cent. The uncoordinated distribution of wind capacity requires the provision of electricity transmission from wind-rich areas to load centres. However, China's grid planning has enjoyed neither comprehensive coordination nor a long-term prediction of the rapid growth of wind energy. As a consequence, not only has the weakness of China's transmission and distribution infrastructure limited the trade in wind power from large-scale wind projects to the developed cities at provincial level, but it has also created barriers which affect wind power connections to the transmission grid at country level.

Secondly, current regulation modes fail to take wind power integration into consideration. Overall provincial yearly dispatch planning is mainly based on the balance in each province, while inter-provincial trade is mainly for grid-security reasons. As the generation fleet is still dominated by coal-fired power plants, the annual minimum generation quotas are allocated among coal-fired units through a highly political process, with less consideration being given to wind power generation at the beginning of the year, when the long-term prediction for wind energy is inaccurate. Agreements relating to wind power are overlooked in favour of the output of coal-fired power, as the annual minimum quotas should be guaranteed. In addition, a daily dispatch plan is usually set by the dispatching centre 24 hours ahead, when the accuracy of wind prediction is limited. That puts pressure on both the dispatching centre and coal-fired units if there is a need to decrease planned

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'AGREEMENTS RELATING TO WIND POWER ARE OVERLOOKED IN FAVOUR OF THE OUTPUT OF COAL-FIRED POWER...'

coal power output for the purpose of wind integration.

Thirdly, current related policies, especially feed-in tariffs, are unfavourable for the promotion of large-scale wind integration, as they lack incentives for other stakeholders. Currently, the feed-in tariffs for wind power are divided into four fixed corresponding benchmarks according to wind resources only:

- 0.47 RMB/kWh,
- 0.50 RMB/kWh,
- 0.54 RMB/kWh and
- 0.60 RMB/kWh.

The implementation of feed-in tariffs for wind power has played a significant role in the development of wind energy, with the guaranteeing of wind farm investors' income at the early stage when wind generation only accounted for a small share of electricity consumption.

However, with the rapid growth of wind installations, the inflexible pricing mechanism has had a negative impact, while benefiting other stakeholders in the system, such as electricity grid operators and coal-fired power. The completely fixed tariff has not enabled any further large-scale expansion of wind energy utilization since the implementation of third-generation technology in the wind sector; wind power utilization lags behind that of coal power and hydro power.

From the perspective of wind power transmission among provinces, as the wind feed-in tariffs are higher than the tariff for coal power, there is no economic incentive for neighbouring provinces, especially the load centre provinces, to promote the large-scale import of wind energy. Moreover, the completely fixed tariffs cannot reflect the advantage of wind power in terms of low marginal generation

cost. In wind-rich areas, the increasing penetration of wind fails to reduce the spot price of electricity through price competition based on marginal cost, so it is difficult to find the true value of grid expansion and interconnection utilization for other areas.

From the coal-fired power perspective: as integration of wind increases, coal-fired power generation declines. With the absence of income transfer mechanisms from wind power to coal power, coal power units are likely to submit undervalued down-regulation ability to the dispatching centre to avoid a sharp decline of their utilization.

Thus, for grid operators, the current policy framework is unable to incentivize the flexible regulation of coal-fired plants. From the perspective of the remaining participants in the energy system, the fixed pricing policies on both the supply side and the demand side do not enable flexibility in the existing system. When wind energy is curtailed, flexible load (such as electric boilers and heat pumps) can technically enable the utilization of surplus electricity, but the retail price cannot be reduced, so this fails to release any flexibility in the system. Without suitable compensation to flexible generators and consumers, the necessary flexibility for large-scale wind utilization in the existing system is constrained and future improvements to flexibility (such as storage technologies and demand-side management) will not attract the economic benefits which would allow technology and business innovations.

As a conclusion, the current policy framework, especially the fixed feed-in tariff, is the main obstacle constraining the effective large-scale utilization of wind power; consequently the system's ability to manage the uncertainty and variability of wind energy is limited.



The failure of current government efforts to address wind curtailment

In order to improve the utilization of wind energy, the Chinese government has taken a series of actions. From 2013, the National Energy Administration (NEA) has required provincial governments and regional grid companies to make wind curtailment mitigation a priority in wind development. And regional grid companies must disclose the latest information relating to wind utilization. In addition, the importance of development in southern and eastern parts of China was mentioned in 2014; this showed that future development should consider not only the wind resource but also the local electricity consumption and grid structure.



‘FROM 2013, THE NEA HAS ... MADE WIND CURTAILMENT MITIGATION A PRIORITY IN WIND DEVELOPMENT.’



For grid construction, in 2015, the *Program for Strengthening the Prevention and Control of Atmospheric Pollution* (issued by the NEA) approved the construction of 12 ultra-high voltage (UHV) channels to further expand the scale of the transmission grid from north to south and from west to east. The UHV channels were expected to relieve the bottleneck of wind exports from wind farms to load centres. For localized wind power utilization, demonstration projects of wind heating are promoted to deal with wind curtailment in north-east China.

In early 2013, the NEA proposed a plan supporting the replacement of existing coal boilers with electric boilers, by setting a specific electricity price for each demonstration project, in order to use surplus wind energy for space heating during winter. For wind power storage, the NEA has

made an announcement suggesting the acceleration of pumped hydro station construction, for the purpose of providing potential regulation capability for wind integration.

Government measures have aimed at decreasing wind curtailment, and it seemed as if their efforts had seen some success in improving wind utilization – from 2012 to 2014, curtailments in wind power were: 20.8TWh, 16.2 TWh, and 14.1 TWh. However, these improvements in curtailment mitigation have been limited, and in the first six months of 2015 the wind curtailment was 17.5 TWh, which exceeded the annual curtailment in 2013. Particularly in the wind-rich provinces (such as Gansu) the curtailment issue has deteriorated rapidly, with more than 60 per cent of wind output in some wind farms was rejected by the grid in 2015.

Power system reform would bring new opportunities to solve the problem

Wind power, as part of the electricity system in China, is dominated by the administrative planning policy framework, which controls the quantity and price of electricity tightly. In a broad sense, China has succeeded in expanding the generation and transmission infrastructure needed to support its economic growth. However, the absence of market mechanisms has caused a failure to drive the electricity system onto a more efficient and green track.

To encourage efficient market competition, Beijing has ‘restarted the engine’ for power sector development by decoupling the transmission and distribution tariffs from wholesale prices, following a previous suspended reform proposed in 2002.

In May 2015, the State Council released *Document 9*, which issued the core principle on further deepening the

reform of the power sector. The first task is to overhaul the role of grid operators in the electricity market and to set independent tariffs for transmission and distribution, using the method of ‘cost plus reasonable profits’. The core idea of the document is to emphasize the role of market mechanisms, injecting competition into both the generation and retail segments of the industry through the operation of a modern and practical electricity market. The other main aspect of the reforms relates to assisting efforts to integrate renewable energy from the perspectives of power sector decarbonization, air quality improvement, and climate change mitigation.

As mentioned above, the case of wind curtailment demonstrates that promoting the role of a market-based policy framework in place of the current administrative planning structure is a vital approach for large-scale wind utilization. Based on the market and an incentive-based framework, spot market competition with flexible pricing would bring opportunities to solve the problem which can hardly be met in a heavily administrative planning system.



‘THE INTRODUCTION OF A SPOT MARKET WOULD PROVIDE ESSENTIAL PRICING SIGNALS FOR WIND ENERGY TRADING.’



Firstly, the introduction of a spot market would provide essential pricing signals for wind energy trading. In contrast to a fixed feed-in tariff, flexible wind pricing based on marginal cost can reflect the competitiveness of wind generation that relates to low variable operation cost. If wind energy is able to decrease the spot electricity price when wind resources are rich (such as in winter), neighbouring areas would then be willing to import electricity from wind-rich areas; this is

also preferable for wind power as it can then sell it rather than curtail it. From the long-term perspective, the development of wind power would have an impact on the spot market, meaning that the concentration of wind installations may increase the price variation and decrease the average electricity price. Hence, the prospective wind investor would reconsider the location of wind farms according not only to the wind resource itself but also to the correlation between wind resource and the local spot market prices. In addition, the spot market price differences between regions would provide the true value for grid expansion, which helps to optimize the grid structure and motivate the provision of transmission channels.

Secondly, the formulation of market and incentive-based mechanisms helps to remove reluctance on the part of coal-fired power plant and grid operators. Currently, greater utilization levels have not received a welcome from coal-fired power plant and grid operators because there is no reasonable compensation to cover their extra costs. Large-scale wind utilization would decrease the generation quota for coal power and attract extra costs when coal power is needed to regulate for wind. With a market-based framework, coal power plants could get extra benefits through peak-regulation and security backup – mechanisms whereby the income for wind generators could more easily be

transferred to coal power plants. That would also stimulate coal power plants to improve the flexibility performance of their units, in order to provide more ancillary services to the market.

Thirdly, market mechanisms motivate the remaining stakeholders to provide more flexibility for large-scale integration. According to the intermittency and volatility of wind power, the peak–valley price difference could be boosted. When wind generation is high, combined heat and power (CHP) plants could decrease their power output and increase their heat output, as the electricity price would be cheap. When wind generation is limited, CHP plants could increase their output of power at the expense of heat, while any remaining heating demand is supplied by heat storage, as the spot price is expected to increase. Thus, CHP plants – formerly a barrier to wind utilization in the heating period – could now play a positive role in ensuring wind utilization when there is enough wind and sufficient production capacity when there is no wind. Similarly, other stakeholders like demand-side management, storage technologies, and electric vehicles could also contribute to the balance of the electricity system.

In sum, the market-based framework proposed in *Document 9* has the potential to improve wind integration significantly, on the basis of both a broad spot market and a flexible pricing system for all the generators.

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‘THE MARKET-BASED FRAMEWORK PROPOSED IN *DOCUMENT 9* HAS THE POTENTIAL TO IMPROVE WIND INTEGRATION SIGNIFICANTLY. . .’

In the existing game, grid operators, coal-fired power, and wind power were all losing players without the incentive to decrease wind curtailment. With the ongoing power reform, it could be seen that the construction of a modern electricity market would promote coordination between wind energy and the rest of the energy system, which is the long-term key to the realization of large-scale wind utilization.

The task of the reform is to find the new equilibrium point for all the players. However, the capital cost of wind power is expected to be higher than that of coal power for the foreseeable future and protection for wind investors is therefore required to avoid market price drops and wind-limited periods. To set suitable flexible prices for wind power, a combination of feed-in tariff and market price is suggested here, in which the actual return of wind energy is divided into two parts: the fixed wind energy subsidy and the market price. The feed-in tariff (the successful policy instrument for wind promotion) should be replaced by a feed-in premium (market price plus fixed wind tariff) or by another flexible pricing system which combines the market price signal and subsidy.





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