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Abstract

The electricity sector is facing a new wave of changes supported by new business models, two of which are key to our understanding of the ongoing transformations. The first model secures ex-ante investments into fixed cost generation assets with guaranteed long-term revenue streams. It is typical of investments into green generation, be they wind or solar, onshore or offshore, utility-scale or individual prosumer, within regulated schemes or private bilateral contracting. The second model is built with the light asset approach typical of the digitalisation era. It favours particular product characteristics for targeted customers and has many variants: aggregators as new intermediaries; digital platforms bypassing intermediaries; direct peer-to-peer exchange such as blockchain; fleets of consumption, generation and storage devices managed 'behind the meter', such as mini-grids or off-grid. Between the two, transmission and distribution grids will have to reinvent, as much as regulatory frames will permit, to create efficient loops of deeper interaction with the active users of the grids in operation and investments.

Keywords

Business model, fixed cost generation asset, digitalisation, platform, peer-to-peer, grid regulation.

Introduction*

A new wave of changes is shaking the electricity sector. After witnessing the previous wave in the last decade of the past century, we already know that it can happen. In the 1990s, it was the combined cycle gas turbine (CCGT) and the open wholesale market: a new type of asset to generate electricity, and a new frame to price and trade electricity between 'wholesale size' units. Today, we may say the novelty is, on the one hand, windmills and solar PV, and, on the other hand, a deepening digitalisation to price and trade electricity between 'retail size' units. Of course, these new trends will not present the same characteristics nor occur at the same pace in different electricity sectors around the world. It will depend on a wide array of factors. If wholesale and retail markets are open to entry and competition or not. If vertically integrated companies and/or national governments control investments, technology choices, siting of the new assets, tariffs and support schemes, or not. If market operation and grid operation are ruled by governmental administration, the industry itself, or an independent body. Et cetera.

Nevertheless, the changes already visible today. Both large scale (the 'greening of electricity') and a small scale (the deepening digitalisation of 'retail size' units) are significant enough to be of great interest, not only for the future of those electricity sectors that have been liberalised, but also for those that are not -or not yet- market-based.

In a market-based industry, business models are key, as propellers for investments, technology choices, the definition of the characteristics of the products, and for the siting and operation of the asset base. Business model literature identifies up to nine possible components of sophisticated business strategies (Osterwalder et al. 2010). A simpler yet robust version can be built with only two pairs of components of business models differentiation. First, it can be the type of assets that are engaged and the revenue streams they can secure. Second, it can be the definition of particular characteristics for the new products put on sale, and the selection of customers targeted for that sale. This basic frame of two models works well with today's empirical evidence. On the one hand, the greening of electricity is strongly characterised by the kind of assets it requires to generate power, as well as the types of revenue streams that permit it to grow.

On the other hand, the ongoing digitalisation of 'retail size' units is deepening because new products and new characteristics are invented to attract targeted customers. In between, that is between the greening of electricity and the deepening digitalisation of 'retail size' units, we find the regulated grids (transmission and distribution networks) that must react to these changes, undertaken upstream and downstream, while being regulated businesses with limited space for autonomous strategic initiatives. Hence the three parts of this paper: (1) New assets and special revenue streams for the greening of electricity; (2) New services for targeted customers; (3) Between new assets and new services: the regulated grids.

I. New assets and special revenue streams for the greening of electricity

The energy contained in renewable resources like wind and solar is not owned by anyone and can be directly extracted by the generating units. It does not have to be harvested, concentrated or refined, transported, stored, and conditioned for injection into the electricity generating process. For this reason, wind and solar units look like hydropower plants: they are mainly made of fixed costs paid upfront. The recovery of these upfront costs is then left at the mercy of electricity system pricing, which depends on the interaction with the other generating technologies used in the market and the own variation of

* This is the first draft of a chapter to be published in 2020, in a 'Handbook of Electricity Markets', to be published by Edward Elgar, and edited with Paul Joskow and Michael Pollitt. I do thank Nicolò Rossetto and Piero dos Reis (both at Florence School of Regulation) for their research assistance: help into collecting the literature, reviewing it, and feeding the wind and solar part with facts and numbers. Plus their careful reading of this chapter. I am the only responsible for interpretation and errors.

demand. Other chapters of this book explain in detail how wholesale markets and their pricing mechanisms work with or without a significant amount of renewables. It is enough to remember that wind and solar would never have taken-off without particular types of revenue streams guaranteeing the recovery of their costly upfront investments.

Various revenue models have been invented to incentivise investments in renewables. They are mainly regulated schemes, pushed by public authorities. The most known are: *feed-in tariffs* (where RES generation is guaranteed a fixed price for each unit of output, irrespective of its economic value for the whole electricity system); *feed-in 'premium'* (where a fixed premium is added to the volatile market prices which express the fluctuating economic value of electricity at different times); *renewable portfolio standards* (which oblige every generator or supplier to incorporate a certain share of RES on average in her output). Another is very common for small scale generating units (roof-top PV): '*net metering*', which works in practice as a 'retail feed-in', by proportionally reducing the total bill (for energy, grid and taxes alike) paid by the prosumer after each volumetric unit of renewables generated at home.

This process, where new assets introducing new generation technologies are getting special revenue streams guaranteeing their financial success, is very consequential for the other generation assets which can sell only to the remaining demand (the one not primarily covered by renewables). As a result, business models of conventional generators are perturbed and can be fully destroyed. It is not this paper's purpose to explain this phenomenon in more detail. The reader interested in knowing more can refer to the excellent piece that Paul Joskow recently published on the topic (Joskow 2019).

Another dimension of the same issue is that the economic value of renewables tends to go down when their penetration rate in the generation mix goes up because RES generation output does not necessarily follow demand and scarcity. In 2012, the economic value of electricity generated by the solar PV units installed in California was on average 125% of the electricity wholesale price. In 2018, that value was down to 79%. In Texas, where PV penetration was less pronounced, it was still 127% (Bolinger and Seel 2018).

With this in mind, new utility-scale onshore wind is already, and some utility-scale solar is becoming, cheaper than generating with fuels on a levelised cost basis and, when guaranteed access to demand irrespective of their intermittency, start to beat the competing conventional technologies. In many countries, the intermittency is dealt with at the system level, and not directly by the RES generator (IEA 2018). A few cases of 'subsidy-free' projects have therefore been seen in Spain, Italy, Portugal, etc. And in a few very advanced cases, as in the US, solar at utility-scale, plus storage, can also beat the cost of a new CCGT, and then enters the portfolio of tools that regulatory authorities allow to be employed in the system management portfolio (California, Arizona, Hawaii, etc.). Still, in the US, the levelised cost for the best onshore wind farms in 2018 was down to $29/MWh, seven dollars lower than that for coal plants (Lazard 2018).

Pure market-based renewables also appear, built on bilateral contracts linking a big-brand consumer, which benefit from green labelling (such as Facebook for 2,650MW, AT&T 820MW, Walmart for 670MW; Google, Apple, Amazon, Microsoft, Ikea…), or even skilled people from heavy industry with an understanding of how to incorporate such a contract into their large portfolio of energy supply (as the EU leader in aluminium, NorskHydro for 667MW; and its competitor Alcoa, for 524MW). These corporate power purchase agreements (PPAs) are still small compared to the whole volume of RES investments. Bloomberg NEF weighs them at 13.4 GW in 2018 (up from 6.1 GW in 2017) – ending with a cumulated total of more than 35 GW worldwide (BloombergNEF 2019), compared to almost 1,200 GW of total non-hydro RES installed capacity accounted by IRENA for the same year (IRENA 2019). However, according to Wood Mackenzie, corporate PPAs are the fastest growing segment for utility renewables sales, accounting in 2018 for about 22% of all new wind and solar procurement contracts in the US (Wood Mackenzie 2019). Moreover, a new type of corporate PPA is emerging, made up of groups of smaller off-takers led by bigger and more experienced partners – the “anchor tenants” (Bloomberg NEF 2019).

Four types of new businesses

Depending on the size of a typical generating asset, and on the particular skills needed for the siting and operation of these assets, at least four types of new renewables businesses have to be distinguished.

1. Onshore wind for all, or a few

The typical size of a single modern onshore windmill (500 kW to 2 MW) is small compared to traditional fossil fuel power units (x100 MW for CCGT to 1,800 MW for nuclear EPR), and – since 2017 – it costs less than a million dollars per MW for a typical 2 MW turbine, plus $ 500,000 to 1 million to install (Bloomberg NEF 2018). Entities able to invest $ 2 to 3 million are numerous, while the skills needed to site and operate are available on the market and usually not particular expensive. If a guaranteed revenue stream is set, investment flows. Local communities and cooperatives too can enter such a landscape, even by targeting the smaller windmills.

However, when the revenue stream is changed from feed-in to ‘feed-in premium’ with auctioning, players increasingly become pure professionals. They are able to manage the market pricing uncertainties and decrease output costs by bargaining with vendors, increasing the size of each turbine, and building a wind park of several units (average size of new projects in the US in 2017-18 was 85 MW, hence in the hundred million dollars range) (FERC 2018).

This shift to professional players according to the type of revenue stream offered is underlined by the successful entry in the US of green subsidiaries of EU utilities, as EDP Renovaveis (4th world wind capacity; and 5,300 MW in the US – near half of its world fleet), or ENEL Green Power (4,400 MW wind, and 230 MW solar in the US). The highest category of renewables units, the giant onshore wind farms (as in the US, India or China), goes from 500 MW to more than one GW, entailing investment each of $billion size.

2. Offshore wind for the champions league

Offshore wind is attractive because of its load factor, (around 50%, sometimes up to 60 or 70%) which is can go x2 to x3 times higher than onshore (French Britany 19%, Great Britain 25%), dramatically reducing the intermittency of generation. The wind farm size targeted is also larger, the latest project in the UK, for example, goes above one GW. The five latest farms (2019-2026) projected in the Netherlands are mainly 700 MW, and one giant stands at 4,000 MW. These Dutch investments are estimated at 1.6 to 1.9 million euro a MW, ending with a typical 1.2 billion euro for a 700 MW park. Size is not the only barrier to smaller investors. The other substantial barrier is the high level of skills needed for the siting and the building, which are required for offshore success. Only a handful of companies really master those skills at the world level; this fact explaining why, for example, the Danish Ørsted is number one in the UK as well as in Taiwan. For the moment, US investors have not yet entered much the offshore wind sector (only 30 MW of total capacity; while the Department of Energy estimates a potential of 22 GW by 2030 and 86 GW by 2050).

Similarly, Chinese companies concentrated on onshore parks, and have already entered the EU on this basis, not yet mastering offshore wind skills. Regarding this particular market segment, the Swiss bank UBS was predicting in 2018 the coming of a few highly skilled and easily financed ‘world majors’ of offshore wind, such as Ørsted. It could be Three Gorges, which already tried to control the Portuguese EDP and its green branch fully (before the Portuguese ‘green’ alliance with the French utility Engie in 2019).

3. PV at utility-scale

In the US, like at the world level, utility-scale dominates solar generation with about 60% of the total capacity. The whole US has about 2,500 utility-scale PV facilities, most of them with a capacity smaller than 5 MW. However, around 2/3 of their total capacity are with facilities larger than 50 MW (EIA 2019). In 2018, more than 500 new utility-scale projects were finalised, a typical one being 30 to 40 MW, for an investment of $60 to $80 million. The two best deciles of investors were 10% cheaper than the median, and the unique absolute best under half of that (Bolinger and Seel 2018).

At the world level, in open bidding, several utility-scale solar offers are below $30 a MWh, one at $21 in Chile. According to Bloomberg NEF specialists, it is hard to know what is due to intrinsic lowering costs or aggressive bidding. Because of the relatively low skills needed to enter that business (the largest practical skill is the cleaning of the PV panels), opposite to offshore wind, new entrepreneurs may bid aggressively to get a foothold, hoping to make their living later. However, because of this low barrier to entry, it is not obvious if margins will reconstitute and when, in this open world of calls. As a consequence, the considered 'major' international players do not necessarily come with a large installed base in their home market; as the two French EDF and Engie – mainly credited for the capability to attract bank financing and to convince developers that the park will be built after having won the call (Wood Mackenzie 2019).

4. Rooftop PV prosumers

According to the last Lazard costs review (Lazard 2018), prosumers costs for solar are still high in the US: $160 to 267 a MWh for residential, $81 to 170 for professional (compared to $36 to 46 for utility-scale). The continuous expansion of prosumers at the world level and its large PV market share (around 40% of total installed capacity) are therefore the result of favourable incentives, coming mainly from the rules and the tariffs used to bill final consumers – which work as a pure 'retail feed-in' tariff when the bill tariff is based on net metering.

In California, this effect is amplified by the local regulation of domestic tariffs. The use of categories of prices goes up when the volume of electricity consumed is higher. This works as an additional incentive for the wealthier to defect by investing in roof-top PV. In Australia, on the contrary, the mass market for roof-top PV is said to be flooded by the middle class with a desire to escape high bills (125 to 200 Euro a month) pushed by high demand for air conditioning which triggers costly grid reinforcement (Sioshansi 2017, 2019).

II. New services for targeted customers

Electricity was known for long as a heavy industry: one where you have to make large investments to do business. A typical extreme is EDF's investment in a British nuclear power plant at Hinkley Point: $7.67 million per MW of capacity. Even with a government-guaranteed price, the annual turnover per MW will be – at best – in the range of $700,000, putting the investment/ turnover ratio at 11 to 1. Factor in the size of a single unit: here 3,260 MW; then $25 billion for the whole plant. Such numbers explain why, in this case, it is the link between the type of assets engaged and the possible revenue streams which are at the core of the business model.

Opposite to this extreme is a 21st Century new trend: the 'light asset' industry (Haskel and Westlake 2018); typical of the 'new economy' in a digital era. Here the core of any business model is to identify particular products characteristics that can attract certain targeted customers, by creating 'value for the customer'. The accuracy of any 'light-asset / new product' strategy will be revealed by the targeted customers themselves, as they are the only ones able to validate the particular value they are offered. As consumers need time to discover novelties and to react to them, while the capital engaged to attract the targeted is not too high, the confirmation of the business sustainability of new offers may have to wait, up to a decade, as demonstrated in the tech industry by the rise of the very first 'digital platforms' (Choudary 2015).

Where can new services be conceived to create value within the electricity sector, deeper in its demand side? The first step is to bridge activation of demand and the wholesale trade. Traditionally, demand was able to react to differentiated wholesale signals only if tariffs had a time of use component. The idea of demand selling its activation at the wholesale level was confined to big interruptible customers. This is what 'aggregation' changes: all retail can re-enter wholesale as an offer to balance the system. The second path addresses another type of trade, typical of a 'platform economy': the direct trade between small units, bypassing the control that utilities, like generators or suppliers, have had on electricity trade in open markets over the past three decades. This can go down to very direct 'Peer-to-Peer' (P2P), with automatic trading supported by blockchains. The third path is a departure from the unilateral control that electricity grids and their system operators have always kept on exchange schemes taking their infrastructures as unavoidable 'delivery loop'. There comes the creation of '*Behind the meter*' (BTM) smart management systems. As soon as more consumption units (within the demand side of the electricity systems) can coordinate their self-generation, storage, and various devices consumption profiles directly, the grids lose their unilateral control loop (Sioshansi 2017, 2019).

Additionally, smart consumption units can act as autonomous 'mini-systems' or 'mini-grids' ('micro-grids', if you prefer this image, as closer to 'microeconomics'). It can be a fleet of electric cars, a '*zero net consumption*' building, a world of smart homes or premises equipped with digital assistants and interactive devices connected via the '*Internet of Things*'. Hence, three coming items: (1) Aggregation re-entering retail into wholesale; (2) Peer-to-Peer bypassing utilities as intermediaries; (3) Autonomous territories 'Behind the meter'

1. Aggregation re-entering retail into wholesale

Building open electricity wholesale markets was the big innovation of the 1990s, questioning how retail would be linked to their 8,760 hourly or 17,520 semi-hourly wholesale pricing units. A first response was the use of a proxy (the '*profiles*') creating a two-step settlement in the wholesale (a first step, being based on the proxies; the second occurring later, with availability of accurate detailed numbers). A more comprehensive response was a one-step full bridge with '*smart metering*', twinning each individual consumption in real time with the proper wholesale equilibrium short timeframe. '*Dynamic pricing'*, in the meaning of full exposure of an individual consumer to each hourly or semi-hourly wholesale price, can then appear. It gained a certain consumer interest in the Nordic countries. However, as explained by the Nordic Council of Ministers in 2017[1], other conditions must be met to fully re-enter retail activation into the wholesale. First, the wholesale time pricing has to be shared by consumption units in the very same timeframe to permit a rationale retail response. Second, the consumption devices have to be controllable and monitored within the same time frame. And then, third, ICT has to ensure fully interactive communications in two directions (from wholesale to retail and the other way around). Furthermore, rules at both electricity system operation (at distribution and transmission level) and wholesale market operation have to be adapted to welcome consumption variations as offers taken into account into the wholesale equilibrium.

This is exactly where aggregators appear, as intermediaries reducing the transaction costs on both sides. On the wholesale side, the cost of dealing with units too small and heterogeneous, and, on the retail side, the cost of understanding, adapting and reacting to the actual wholesale process. Finally, aggregators work as 'reverse retailers': instead of selling the wholesale output to feed consumption units on the retail side, like retailers typically do, aggregators sell the control of consumption units output to the wholesale side.

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1 Nordic Council of Ministers, *Flexible Demand for Electricity & Power. Barriers & Opportunities*, 2017.

On this wholesale side, transmission system operators may also have to buy downward adjustments from aggregators. But another trade can be made at a local level, if distribution system operators and aggregators arrange it in an adapted frame. The work of 'value creation' by the aggregator is therefore to 'build' a portfolio of consumption units, of actionable consumption devices, and of certified ICT tools to better answer the particular needs and special operation requirements of the wholesale or local buying counterparts. These needs and requirements vary considerably from one market to the other, as well as from one system operator to the other, making the concrete job of aggregator very 'conditions specific'. For example, the TSO can impose a particular type of communication tool to guarantee the control of a consumption unit, with a related expense up to euro 6,000 for each unit control box; such a requirement excludes, by definition, the activation of small and medium consumers. Other TSOs allow cheaper communication ways such as xDSL. If consumption devices themselves were going to be standardised (electric vehicles, heat pumps, fridges, etc.), the size of the aggregation business potential could dramatically increase. The same remark is also valid for the market rules. As long as flexibility is not very accurately priced in wholesale markets, the potential of business for aggregators is reduced.

The landscape of aggregation companies is still very diverse. Some are subsidiaries of big electric utilities (as Enel X). Others are typical start-ups to be sold later to 'deep pocket' players, sometimes coming from outside the electricity sector (Shell buying Limejump, for example). A few independent aggregators continue to grow in the EU (as Next Kraftwerke managing 7,000 units and 6 GW, which makes its average unit at 857 kW). According to ENTSO-E 2019 and PJM 2019, independent aggregators are the most numerous and still have the largest market share.

2. Peer-to-Peer bypassing utilities as intermediaries

Having understood what an aggregator does (reducing transaction costs to open trade for a new type of product with targeted customers), we only have to go a step further to find the next business model. Aggregators build private portfolios of clients, harvested within a formal contract which gives them an exclusive franchise on the final reselling. 'Platforms' act very differently to reduce transaction costs. They define particular products' characteristics and implement particular rules for operation and interaction within their own 'club' of trade, while letting the two sides of their market platform (both the sellers and the buyers) to match directly, at their initiative, within the frame of the platform. We have seen that the aggregator was substituting her intermediation to any direct link between the upstream and the downstream.

On the contrary, the platform re-establishes a direct link. This link, however, stays framed by the precise characteristics defined for the product and its trade process (including delivery and settlement). This said, many different platforms can appear and live their own life, as each is free to define its products and trade characteristics, as to attract this or that particular user.

It can be a platform where a British distribution network operator buys local ancillary services to solve congestions and postpone physical investments in the grid. It can be a platform where German prosumers sell certified local renewables to neighbouring consumers. It can also be a platform for sharing local storage, charging electric cars, etc. These platforms can work in an open environment, targeting particular customers within open crowds. They can also voluntarily restrict themselves to a particular audience; even to a closed milieu as the new European legal notion of '*Energy Communities*'. Restricting access is a simple mean to define particular groups of 'targeted customers'. Since the cost of establishing a platform business is mainly represented by software development, customer's enrolment, database and process management, the initial size of a new business can be quite small.

Another way of simplifying trade in well-defined audiences, or within established communities, is to automatise trade with blockchain algorithms. Blockchain trade within large anonymous crowds (as with crypto currencies) is quite complex and expensive; while within 'energy clubs', with conditions for entry, blockchain trade can be easy going and cheap. End of last year, a Mexican regulator considered using it for self-registered prosumers (identified by a smartphone scan of their PV panel barcode) to manage the green certificates attached to generation.

Both 'simple' platforms and advanced blockchain groups can bypass utilities as intermediaries and implement new types of 'Peer-to-Peer' exchange. However, several cases also show an active role for some utilities as with Axpo – Wuppertal Stadtwerke (in Germany) and Piclo-UK Power Networks (in the UK). The growing number of prosumers and 'prosumagers' (prosumers endowed with storage units) feeds the process and nurtures the hopes of many start-ups (Sioshansi 2019).

3. Autonomous territories 'behind the meter'

The last type of new business model encountered here is yet another step ahead. Aggregators link wholesale with activated retail units. Peer-to-Peer recreates direct interactions between the individual ultimate buyers and sellers. What else can be done, differently but in a similar vein, which could make business sense? It is to organise autonomous economic zones beyond the traditional electricity system: '*behind the meter*'[2]. As soon as individual units, on the consumption side, can program and coordinate their own generation, own storage, and the various load profiles of their various consumption devices, they become something entirely new as 'autonomous electrical territories'. They behave as sub-nodal systems – from the entire traditional electricity system – and like mini-grids – from the incumbent distribution grid. Aggregators and, to a large extent, peer-to-peer trade still need the traditional grids as their unavoidable 'delivery loop' -which is a significant constraint and a real limit to their creativity and business models (see MIT 2016, and the following up in Burger & Jenkins in 2019). The new territories created 'Behind the meter' bypass the traditional electricity system, including its grids, and the energy regulator. It is a gigantic 'free zone', open to many innovations and experiments, while not requiring any kind of 'regulatory sandbox' from any energy authority.

A first candidate there could be the management of electric car fleets. As electric cars managed in a fleet can easily choose where to connect to the grid and what to do when connected (withdrawing or injecting – then storing, how much and how frequently, at what speed, etc.), they can easily behave like an autonomous electricity system 'on wheels', surrounding the 'site specificity' of fixed set of cables and substations owned by the distribution companies. A simple estimate of a car battery, in 2030, at 60 kWh puts a 1,000 car fleet at 60 MWh full charge, and the annual EU battery market for new cars, in say 2040, would be near to one TWh (at 900 GWh) / year. If you estimate a single car battery at 120 kWh then there would be near two TWh of batteries entering the total EU car fleet every year.

Another obvious candidate is the '*zero net consumption*' building, with an EU-wide regulation soon becoming mandatory, as in California, for all new buildings. Each new building will have to generate, to store (if economical), and to manage its various internal loads as to be regulation compliant. It is clearly a case for a mini-grid and a sub-nodal electricity system.

Lastly, future 'smart home' or 'smart premise' also make good candidates, with digital assistants, fed by local sensors and obeying to a wide artificial intelligence operating system, will communicate with local interactive devices connected to the 'Internet of Things'. This is yet another vision of the latest species of mini-grids and sub-nodal systems.

III. Between new assets and new services: the regulated grids

Placed between the new assets deployed to greening electricity and the particular services conceived for specially targeted customers, grids (transmission or distribution) might enjoy a formidable business position, as Amazon does by combining both a physical delivery loop and a digital space for trade. But this is certainly not the case yet, and presumably it will never be, as these grids are tightly regulated.

[2] J-M Glachant, *Foreword*, in F. Sioshansi, 2019, pp. XXVII-XXXIV.

Their investments, technology choices, entry into new businesses, definition of product characteristics and categories of targeted customers, as well as each related price, is all regulated. Either by the energy regulator, or by the energy ministry from behind; if not by the parliament, the competition authority[3], or the courts.

This is not to say that the grids do not act or play a role. Their role, however, even when fully appropriate, is more reactive than proactive, letting the upstream assets' move and the downstream services' blossom to strike first. Of course, there are exceptions where the grids are chosen, or accepted, by the relevant authorities as 'champions' for this or that particular change or challenge – but usually only as exceptions.

Therefore, the grids new business models are heterogeneous and subject to many future transformations or revisions. Because they depend on both the business models chosen by other players (being the grid customers), and on the reactions of many authorities to this newly created landscape.

While such conditions do not favour giving a simple and coherent view of the business models renewal for electricity grids, there is an underlying general logic at work here. And it will be made clearer within four steps. Step 1- Building grid assets in reaction to offshore green generators investments: the influence of the grid/generators incentive frame. Step 2- Acknowledging the loop between onshore grid owners' revenues stream and onshore active users' incentives to invest. Step 3- Building an efficient loop between business models for grid users and grid companies. Step 4- Slow moving and fragmented decision-making.

1. Building grid assets in reaction to offshore green generators investments: the influence of the grid/generators' incentive frame

As the offshore grid case will exemplify, the relation between the amount of new green assets that are connected to the grid and the amount of assets the grid companies have to invest in reaction is far from being purely technical, as one might have thought. The case of the offshore grids is interesting to look at, because no offshore grid was existing anywhere before the deployment of green assets. It shows us a case of pure assets grid reaction to investment decisions taken by the green generators.

At the beginning of 2019, the offshore wind industry (wind turbines manufacturing, wind park developers and builders, grid developers and builders, operation) was still dominated at world level by Europeans; specifically by sea parks by two countries: the UK, with more than 8 GW, and Germany, with less than 6 GW. Comparing these two countries is therefore of interest, if not a 'natural experiment' (Meeus and Schittekatte 2018).

The British frame for offshore grid development and building is typical of the new RIIO regulatory frame implemented from around 2009 onwards. It is centred on the incentives given to the players intervening offshore. It assumes that offshore generators are strongly innovative and interested by the success of the design, building and operation of the offshore grids that connect their farms to the onshore grid. If they choose to, they are then allowed to lead the initial stages, the design and building, of the offshore grid. If they do not want to do so, they can externalise these early tasks to a third party (called OFTO: *Offshore Transmission Owner*). Regardless, when the offshore grid assets are built, offshore generators are asked to auction them off to an OFTO, selected via this auction. Therefore, offshore green generators in the UK are fully responsible for the practicalities and costs of their connection to the shore.

[3] In the US, the federal competition authority (Minister of Justice) has the tradition of not intervening in the electricity sector for implementing its anti-trust policy, letting the federal energy regulator (FERC) doing it on its own. In the EU, it is the opposite, the federal competition authority (DG Comp at European Commission) has the tradition to frequently intervene into the electricity sector, as it wishes, to implement its anti-trust policy or to help new European law-making undertaken by the Commission to be better adopted.

The German frame also experienced changes, it is different. Until 2013, the offshore green generator was free to settle in priority sea areas defined by the federal maritime agency (BSH) and the federal energy regulator (BNetzA). The coastal onshore TSO had the obligation to connect any wind farm located in the sea. Starting in 2013, German TSOs were collectively producing a ten-year offshore development plan (0-NEP), updated yearly and submitted to the energy regulator. From 2017, in a new change, the federal maritime agency and the federal energy regulator produce jointly centralised sea parks and an offshore grid 'Area Development Plan', which defines the generation sites, offshore farm capacity, auction timing, offshore grid converters and substations locations, and the cable routes connection. The green generators are still kept aside from this process, while they also do not pay for offshore grids, since they benefit from super-shallow connection charges. Both offshore and onshore grids costs are borne by the TSOs, and socialised among all the electricity network users.

A recent comparative study, performed by the leading economic team at the federal research institute DIW in Germany, permits to weigh both approaches (Girard et al. 2019). The study finds the German regime 40% more expensive than the British, after correction for connection lengths, technologies, environmental requirements, and financing conditions[4], ending with a 10EUR surcharge per MWh. The study does not believe that the new 2017 regime will put an end to this gap and values the total excess costs from 2013 to 2030 at more than 8 billion euro. The study designates the non-involvement of the offshore green generators into the design and building of the offshore grids, and the absence of any other open competitive process to substitute to that policy choice, as the strategic error in the German incentive frame.

2. Acknowledging the loop between onshore grid owners' revenues stream and onshore active users' own incentives

The fact that in the offshore case, the amount of grid assets to be invested is not fully determined by technology and engineering but substantially influenced (up to 40%) by the incentive regulatory framework used, is not an exception that escapes the economic logic linking investors in green assets and investors in grid assets, as we are going to verify again. This time, by linking the onshore grid revenue streams, as defined by the regulated grid tariffs, and the incentives given to individually active grid users (the individual '*prosumers*') investing in their own set of individually owned assets.

When individual grid users face new technologies permitting small units of investments, allowing them to become self-producers ('prosumers') and operators of their own unit of storage ('prosumagers'), what they mostly look at is the change that their investments will trigger for their individual electricity bill. It is exactly what a Florence School researcher, Tim Schittekatte, investigated with a new modelling approach, taking into account that many (passive) grid users are not willing to invest on their own, but some (active users) actually will. Active users take changes in their bill as a key parameter to make investment decisions (Schittekatte 2019).

Let's assume that all grid costs are sunk, and that grid tariffs are only used to allocate these costs among grid users. Introduction of new technologies, permitting individual grid users to invest into units of generation and storage, as small as their own individual consumptions' needs, creates a reaction function to the individual bill changes permitted within the currently applied grid tariff. This reaction function creates both equity and efficiency concerns. Equity concerns because the sunk costs that active users bypass must be recovered from the remaining passive users. Efficiency concerns because individual investors add new costs (at a system-wide level) when leaving the grid billing because of 'low enough' unit costs of new individual investments (for their own generation and storage) vis-à-vis the expected bill changes (be they volumetric or capacity based)[5].

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4 The gross difference was over 100% , with 19 euro more in Germany than the 16 euro/ MWh in UK.

5 T. Schittekatte, March 2019, Chapter 2.

Let's now assume that demand can evolve, that grid use, and costs, can grow. What active prosumers invest can be used positively by the grid in a forward-looking tariff setting, as long as 'fairness' is not a too big of an issue for the grid designers. If tariff designers want to push fairness as an intended protection of passive grid users, against the reduction of active grid users' contribution to total costs, the future-oriented efficiency is lost. There is no magic, simultaneously cost-reflecting tariff for all, future-oriented for the active, and fair for the passive[6].

Let's now go deeper into individual storage investments allowed by capacity-based and volumetric tariffs. "*When all grid costs are sunk, all network tariff design options will over-incentivise battery options'. 'In contrast, when many future grid costs are to be made […] tariff design options will mostly under-incentivise battery adoption". "Time-varying energy prices do improve the business case of storage'*, but '*unwanted interactions between the network tariff design and time-varying energy prices' can occur*[7]*"*.

In the previous case, for offshore grids, the role allocated to the green generator in the grid building incentive scheme was influencing variations in the amount of assets invested into the offshore grid, in reaction to the same amount of green assets. In the new case, for onshore grids, the incentives sent by the onshore grid revenue stream frame to the prosumers, via changes in the electricity bill, influence variations in the amount of investments undertaken by these prosumers, and change the total amount of assets put into the whole electricity system to deliver the same amount of energy consumption.

1. Building an efficient loop between the business models for grid users and grid companies

Knowing that business models for grid users and business models for grid companies interact, a normative question emerges: what would be an efficient loop to put in place between these two worlds? There are already two approaches addressing that question: a conceptual vision, like the RIIO frame introduced by the British regulator, OFGEM, in 2009; and a techno-economic model, as described in the '*Utility of the Future*' report published by the MIT in 2016.

- RIIO, at OFGEM

As already seen with the offshore case, the new British regulatory framework – established about ten years ago – considers the incentive frame as key to the success of grid regulation. It is also the message conveyed by the conceptual formula '*Revenues = Incentives + Innovation + Outputs*' (Rious and Rossetto 2018). *Incentives* are targeting both Capex and Opex, in an open 'menu of contracts' where companies reveal their own core choices (such as choosing to design and build the grid, or to externalise that, as in the offshore case). *Outputs* can be availability, energy losses, or environmental impact, etc. *Innovation* is a bit fuzzier and covers alternative blueprints and candies for tests, pilots, or beauty contests.

- Utility of the Future, at MIT

The MIT proposal fits well in the RIIO conceptual world and is also centred on the 'incentives' rebuilding. The distribution grid stands between many new business models of 'Asset/Revenues' and 'Services/Customers' and has to stay neutral vis-à-vis all of them, whether wind, solar, heat pump, storage, peer-to-peer, retail-to-wholesale, etc. The distribution utility of the future shall not look at 'behind the meter' usages to discriminate and has to treat all injections and withdrawals equally, as long as they are equal from the point of view of the grid. This 'equal treatment' calls for a finer granularity, both spatial and temporal, as to get an efficient 'distribution nodal price system', taking each connection point to the distribution grid as a unit of calculation, and the smallest unit of time of distribution operation as a unit of time for settlement. Then two simple principles must lead the tariffs rebuilding. 1-

[6] T. Schittekatte, March 2019, Chapter 3.

[7] T. Schittekatte, March 2019, Chapter 4, p.86.

For grid users: peak-coincident capacity charges -reflecting users' contribution to incremental costs incurred-, and scarcity-coincident generating capacity charges; 2- *For grid owners*: forward-looking multi-year revenue trajectories, with profit-sharing mechanisms. Beyond this core of 'right incentives', the MIT proposal is also open to the 'o*utputs*' and '*innovation*' add-ons foreseen in the RIIO frame. However, the last survey published by Burger, Jenkins, Battle & Perez-Arriaga in 2019 (Part 1 and 2) shows that the full implementation of this vision has not yet started.

4. Slow moving and fragmented decision-making

The need for a comprehensive reaction to the new business models introduced into the electricity sector has been acknowledged for several years. The New York Public Utility Commission's new conceptual framework for the transformation of distribution grids into open platforms surfaced in April 2014. The MIT proposal 'Utility of the Future' in December 2016. The European utility industry launched its manifesto for 'distribution grids transformation into platforms' at the beginning of 2019 (Colle et al. 2019). And the European Council of national energy regulators programmed a three-year regulatory regime review led by 'Digitalisation and Dynamic Regulation' in 2019-2021 (CEER 2019). However, in practical terms, the move is slow. The biggest contribution that we know of is from OFGEM, which did react for offshore grids with two implementable regimes in 2009 and 2014.

- Moving slowly

The change in the regulatory framework is slow because many conditions must be met to make it work. On the grid side, the MIT 2016 Report and 2019 (Burger, Jenkins, & v.a) subsequent papers made clear that utilities have to have accurate data on each grid user and on the grid itself, an extensive smart grid / smart metering infrastructure with a two-way ICT, significant data accumulated, the right and comprehensive engineering model of the distribution grids, responsive enough algorithms, plus favourable property rights frame and incentive alignment (= a proper new revolution, as big as the past building of open wholesale markets). On the grid users' side, the Nordic Council of Ministers report also made clear that calculating 'right' price is not enough. Grid users must be able to react to pricing: having real time access to the prices, devices able to be actioned by price signals, as well as a certified settlement and billing process duly acknowledging the activation. Researchers at Comillas Madrid have also shown that sending waves of price signals to active individual users does not even guarantee that these grid users will be able to coordinate their reactions to the signals, and to prevent the creation of other grid problems. Therefore, there are new 'coordination tools' to be defined and tested to make that new 'distribution platforms + active prosumers' revolution coherently work both at short term and at long term horizons (Abdelmotteleb et al. 2019).

- Fragmented decision-making

Setting aside the fairness issue, which complicates the agenda for regulators hyper sensitive to public opinion (Burger, Schneider & al. 2019), building a new frame is made difficult by the need for grid users to have several things changed in their realm (i.e., behind the meter). Active grid users tend to be wealthier and prone to change their life frame by investing money into it. Passive grid users include poor and low-income people who just live their lives with their current revenues and cannot invest to reframe their future lives. Many of them also do not own their dwellings and depend on their landlords to take 'activation investments' decisions. If these numerous grid users cannot invest into the activation of their consumption and stay highly inflexible to refined price signals, any shift to a strongly incentivising price system would act mainly as a fixed tax increase (Fredriksson and Zachmann 2018).

Nevertheless, even when restricting the decision-making area to the professionals, the fragmentation is still an obvious key factor, when it comes to the implementation of a reform change where no single player can act in the common interests of the whole system, corresponding to the normative interests of the society as a whole (see Glachant 2018 for typical EU regulatory gaps and regulatory roadblocks; Burger, Jenkins et al. 2019, for TSO-DSO coordination).

Activating flexibility is identified by many regulators and regulated companies as a core tool to build less grid assets, and to end the costly '*Fit and Forget*' doctrine for grid assets investments. But new research at the Florence School shows that implementation of new trade schemes to incentivise flexibility delivery is deeply dependent on whom takes part in the decision process: a really independent platform, allying with six different distributions grids; or two competing established wholesale exchanges allying either with a TSO and a DSO, or only with DSOs; or four leading DSOs grouping with their national TSO in a single coordination mechanism. All these different initiatives have different product standards definition, different links with the sequence of wholesale markets, different rules for reservation payments (Schittekatte and Meeus 2019).

Conclusion

The electricity sector is, again, facing a wave of radical changes, as big, or potentially bigger, than the invention of open markets three decades ago. Some of these changes can be seen from a business model angle: a market-based industry always needs adequate frames to feed investments, choose technology and product characteristics, and steer operation.

At least two business models are at work within this revolution. The first model, favoured by green electricity investors, is to secure ex ante high fixed costs generating assets with long-term guaranteed revenue streams. Be they professional investors, or individual prosumers, identifying and securing ex ante long-term revenue streams is key to take such an irreversible investment decision, and to get banking or financial investors support. The small, but fast growing, segment of purely private contracting, via corporate power purchase agreements, exhibit the same logic of ex ante long-term revenue guarantee. The second model, rooted in an era of light asset digitalisation, links particularly defined product characteristics to specially targeted customers. Innovators push novelties, hoping that customers will react and welcome. Many areas are opened or opening soon. New intermediaries such as aggregators linking retail units to wholesale trade, digital platforms bypassing intermediaries and permitting direct trade; other peer-to-peer exchange chains, such as blockchain, fleets of consumption units self-managed as mini-grids or off-grid. Many of these initiatives are still pilots, some in regulatory sandboxes. Their business scalability and sustainability is still, most of the time, to be demonstrated.

Between these two models, grid companies – both transmission and distribution –will have to find their way. Some of them already host many prosumers: 1 million in Germany, 2 million in Australia. However, for many grid companies, it is not for today. In France, for example, one finds less than 50,000 prosumers and no giant offshore park yet. Even looking forward, appropriate new business models for the grids will have to be invented and tested. It will not make sense to remunerate TSOs with a guaranteed return on the amount of steel and concrete put into their balance sheets for much longer, nor to back DSOs for the 'fit and forget' expansion of their network capacity. As if the network owners and the network users did not have to be put into interactive loops of key performance indicators (KPIs), incentives, coordination and commitments regarding the way electricity is injected, withdrawn or stored, and the grids planned and used. Regarding the way players invest into their portfolio of assets, be they connected or off-grid. New incentive regulation and coordination tools have to be invented and inserted into a multi-level operation and investment frame, to permit smarter interactions between the grid users and the grid owners, via their new digital interface or intermediaries, at all levels: transmission, distribution, behind the meter, and off-grid.

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