Utilities Policy 30 (2014) 1–7

Contents lists available at ScienceDirect

Utilities Policy

journal homepage: www.elsevier.com/locate/jup

The EU internal electricity market: Done forever?

Jean-Michel Glachant [a,*], Sophia Ruester [b]

[a] Loyola de Palacio Chair, European University Institute, Italy
[b] Florence School of Regulation, European University Institute, Italy

ARTICLE INFO

Article history:
Received 30 July 2013
Accepted 11 May 2014
Available online 18 July 2014

Keywords:
EU internal market
Power sector reform
Renewable integration

ABSTRACT

Taking a quarter-century to build Europe's internal market for electricity may seem an incredibly long journey. The aim of achieving a European-wide market might be reached, but we went through – and should continue to go through – a process subject to many adverse dynamics. The EU internal market may derail greatly in the coming years from the effects of a massive push for renewables, as well as a growing decentralization of the production–consumption loop. Moreover, a serious concern is the risk of a definitive fragmentation of the European electricity market due to uncoordinated national moves with respect to renewable support and capacity mechanisms.

1. Introduction

It took us a while to build an EU internal market for electricity. According to the Single European Act strategy of Commission President Jacques Delors, signed in 1986, it should have been implemented back in … 1992 – but that turned out to be only the first chapter of a 25-year – still on-going – process.

Electricity sector liberalization started in the UK, followed by Norway, from the premise that while networks are natural monopolies requiring regulatory control, generation and trade are potentially competitive activities. The European liberalization process had been set out to simultaneously target two goals, i.e. first, to achieve competitive prices through the play of market forces, and second, to achieve a unified energy market and thus contribute to the "ever closer Union" that also will be conducive to ensure secure energy supplies.

Much has been achieved since the early 1990s. Wholesale and retail markets are liberalized; the eligibility of customers is mandatory with a general increase in the choice of suppliers and tariffs (ACER/CEER, 2012). Even though there are still significant differences between Member States in terms of electricity generation structure, in general, we no longer have a patchwork of closed national energy systems, each with a national-only company controlling the entire electricity sector (EC, 2012). However, certain anti-market arrangements, such as ill-designed regulated end-user prices, still prevail in many countries.

EU officials claim that a first version of this European-wide power market should work by 2015 – while we also know that this market is only going to implement the "old" goal of 1996, i.e. of the first EU Internal Electricity Market Directive.[1] So one might wonder whether this will be the end of the journey, or just a coffee break? The EU's internal electricity market is already seriously challenged by two waves of disruptive innovations – the renewable energy sources and the smartening of the energy system's interactions. It is also challenged by exogenous shocks like the economic and financial crises, the Fukushima accident, or the flooding of cheap gas and cheap coal as a consequence of the US shale gas revolution. Accordingly, the goal of building a cohesive set of market arrangements in the EU cannot stop today or tomorrow and we already know that what we need will be of a different nature than in the 1990s.

This paper argues that existing regulation – once fully implemented – adds up to a "European market", even though many market arrangements differ from the perfect textbook case (Stoft, 2002; Kirschen and Strbac, 2004) (Section 2). However, since the initial power sector reform draft has neither been conceived for systems with a massive penetration of renewables, nor for a decentralization of the production–consumption loop, there is, thus, a need to revisit regulatory practice in the whole spectrum of market and network arrangements (Section 3). This obvious need to adapt market design and regulation to "unforeseen" developments, however, is not the only challenge. What currently is becoming a growing concern is the risk of a deep fragmentation of

* Corresponding author.
E-mail addresses: Jean-Michel.Glachant@eui.eu (J.-M. Glachant), Sophia.Ruester@eui.eu (S. Ruester).

[1] Directive 96/92/EC 'concerning common rules for the internal market in electricity'.

http://dx.doi.org/10.1016/j.jup.2014.05.003
0957-1787/

the European electricity market due to uncoordinated national policy initiatives in the areas of renewable support and capacity mechanisms (Section 4).

2. Europe's single electricity market: done by 2015?

Taking a quarter-century (from 1990 to 2015) to build Europe's internal market for electricity may seem an incredibly long journey as well as an example of the EU's inability to accomplish serious industry reforms. But we should remember that no other "federal-style" government of a major country (such as the US, Canada, Brazil, Russia, India or China) has achieved an internal, continent-wide, open market for electricity so far.

There are many good reasons why Europe has been so slow with the liberalization of its electricity sector, as discussed in-depth in Glachant (2013). This market project aimed to open up national monopolies' territories to foreigners, and that of course was a radical project that inevitably triggered huge and fierce opposition. Second, there was no wave of disruptive technological innovation – unlike in the case of telecoms – to challenge the incumbent energy giants. Third, electricity is a difficult product to trade as it requires hundreds of technical, legal and economic rules and standards to be agreed on before it becomes tradable. Electricity is, after all, not more than a coordinated flow of electrons inside the millions of metallic wires of a gigantic interconnected network. Thus, electricity was for decades considered to be a typical "anti-market" product, best suited to natural or franchised monopolies. In fact, it has been the revolution in the ICT sector that enabled new market arrangements in the electricity industry. New information and communication technologies gave us the tools to register every move of electricity generators and consumers alike – and so permitting one generator and one consumer to trade bilaterally in a market in parallel to the electron flow variations. The fourth reason is that the various national arrangements historically developed between industry players and public authorities cannot easily be merged at the EU level into a common scheme of interoperable markets.

Several successive packages have then been needed to get (near to) all EU countries to implement compatible market arrangements. These include the European Commission's three energy packages (adopted in 1996, 2003 and 2009, respectively) with the third[2] calling for effective unbundling of generation and supply interests from the network and increased transparency of retail markets. Plus the establishment of an Agency for the Cooperation of Energy Regulators (ACER) in order to ensure effective coordination between national regulatory authorities and to take decisions on cross-border issues. As well as the establishment of a European Network for Transmission System Operators (ENTSO-E) pushing all grid operators to cooperate and to develop common commercial and technical codes or security standards. Moreover, a supplementary Infrastructure Package[3] (adopted in 2013) defines rules to identify "*projects of common interest*" (PCIs) for infrastructures within a number of key trans-European energy corridors and areas.

If today we ask ourselves whether these existing arrangements – once fully implemented – add up to a "European market", the answer is yes. Whereas in the old times, trade across borders of areas controlled by different transmission system operators (TSOs) was mostly guided by security rather than economic considerations (Newbery, 2009), we today have a set of national, day-ahead wholesale markets that are mostly connected by implicit access given to physical interconnections from the trade floor. Any bid accepted in an exchange is simultaneously taken into account by the other exchanges and by the TSOs that manage the interconnections in between. Whenever there is significant congestion in the network, the European market splits into smaller regional or national markets until the congestion is ended. Second, we have more and more intraday and "real-time" arrangements by which offers of capacity and energy services also cross the borders of electrical zones. Third, the network is itself becoming more and more Europeanized. New grid operation codes are being conceived at EU level, and a common strategic planning of the EU grid is taking place under the "*Ten Year Network Development Plans*" adopted bi-annually by ENTSO-E. The set of PCIs is also due to adapt our infrastructures better to the internal market's needs.

Having said all this, it is nevertheless true that many anti-market arrangements still survive in too many European countries. At the *wholesale level*, byzantine market arrangements can add up to a "re-regulated access regime", not only in France and Spain, but in the UK too in light of its new nuclear power program (UK Government, 2013). At the *retail level*, national governments have typically been reluctant to eliminate regulated end-user tariffs (de Suzzoni, 2009; ERGEG, 2010), which, however, discourage consumers from searching for alternative suppliers and, even more consequential, might prevent their exposure to more elaborate price signals. Unfair competition arises if these tariffs are not even aligned with wholesale prices and instead establish values deliberately below the minimum levels needed to cover the cost of energy (plus the regulated charges, which include also network tariffs, subsidies to renewables, taxes, et cetera). It may result in billions of euros of "tariff deficits", as is notably the case in Spain already in the range of €25 billion (Marañón and Morata, 2011). Moreover, insufficient unbundling of distribution companies can be a serious obstacle to competition (Davies and Waddams Price, 2007; Nikogosian and Veith, 2011, and references therein) given that DSOs shall act as "*entry gates to retail markets [...] making them an important influence on the level of competition as well*" (CEER, 2013).

The degree of market liberalization and competition still varies significantly across the EU and there is consensus about "room for more competition in power markets" (Lowe, 2011). National distortions have significant effects, but they cannot entirely block the internal market's functioning. However imperfect the EU's internal market may be, there can be no doubt that we now are very near to the market target set in 1986.

3. Europe's single electricity market: but also done forever?

It is far from guaranteed that this late internal market for energy will work forever. The many national compromises that have been realigned and harmonized in successive EU compromises dealt with the past, and aimed at opening up an EU market as conceived in the 1990s. However, many unforeseen but dramatic changes happened during the past 20 years. And these shifts from the initial power reform draft are not at the periphery of the system. They are at its core. We might call them the "major sins" of our EU market and network reform. Their actual number is heavily debated. Let say five to seven.

What we now live in the EU is not the former "common market – yes; common energy policy – never" which was framing the European policy for twenty years after 1986. We now stand in a common energy policy frame designed at the EU level in 2007, when the European Council decided in Berlin to go for it. To this end, in 2009, a set of Directives, well-known today as "20–20–20

[2] Directive 2009/72/EC 'concerning common rules for the internal market in electricity'; Regulation 714/2009 'on conditions for access to the network for cross-border exchanges in electricity'; and Regulation 713/2009 'establishing an Agency for the Cooperation of Energy Regulators'.

[3] Regulation 347/2013 'on guidelines for trans-European energy infrastructure'.

climate and energy package", was approved.[4] Parallel to that a wave of "smart" innovations, such as advanced electricity meters, automation and remote control technologies, et cetera is growing. You might end up with an internal market headache: the energy policy frame did move, and key technologies too are moving.

3.1. *Today's generation mix is split into two opposite sets of generators*

In the early 1990s, we were pretty sure that most of the "steam for markets for power" was there. At that time generation did not seem like any type of natural monopoly except in very rare cases where the size of the market is too small to duplicate the existing generation facility (pocket market). Free entry in generation, free choice of the fuel or primary resource, of the technology and the plant size (if not the location) should act to break the old world of chartered territories for incumbent generation self-planning. This belief is heavily questioned today.

Renewables are pushed in the electricity sector from outside the market. Both wind and solar PV energy run at the speed of their feed-in tariffs, or similar forms of subsidies (see e.g. Held et al., 2010; Marques and Fuinhas, 2012; Ragwitz, 2013). Germany, for instance, is already deploying renewable generation to "*a spectacular – and destabilizing – extent*" (Buchan, 2013). The country doubled its renewable generation capacity, which increased from less than 40 GW in 2008 to more than 80 GW today. With virtually no barriers for entering the electrical system, renewables enjoy considerable advantages: they have always guaranteed access to existing consumption, whereas conventional thermal generation only has access to the residual demand. In some EU countries, renewables also have the right to connect to the grid, and the grid owner has a duty to invest accordingly (Ecofys et al., 2011).

Step by step, a significant proportion of Europe's thermal power plants are selling less and less energy while providing more and more "flexible capacity" for the electrical system. Some countries like the UK and France are looking at bridging that power generation revenue gap by re-organizing their national market's capacity arrangements. Obviously enough, this might well break up the EU's internal market, as some thermal generators would still be paid only for the energy they can sell, while others would get both those energy revenues and a national capacity payment.

Even if there was no capacity splitting of the market, the present wholesale market might well undergo profound changes under the pressure of the growing share occupied by renewables. Large amounts of energy generated by renewables that enter the wholesale market greatly depress the market price. The variable cost of generating electricity with renewables is low, and a competitive energy market uses the variable cost of marginal power generation to price the market as a whole. That price can then easily drop close to zero if the market is flooded by renewable energy. It can even fall below zero into negative prices, as is regularly observable within e.g. the German market area (EEX, 2013). Some thermal generators in such situations prefer to pay for the right to keep their plants running, as thermal plants may face difficulties when reducing their output (they have to contend with huge output start-up costs and other dynamics).

But in depressed conditions of this sort, how could the wholesale day-ahead market, that is the strongest backbone of the EU internal market, maintain its central position in the chain of electricity market arrangements that stretches from futures to real-time? The renewables push through feed-in tariffs largely locates the generation structure change in the realm of a public authority. The renewable priority of dispatch both reduces the market size remaining for non-renewable generators and breaks the price trend at which they can make money or break even. Hence, the generation set is deeply fractured into two opposite sets of generators: on the one hand "new" generators bearing no significant risk for capacity, volume or price thanks to e.g. feed-in tariffs/premiums and priority dispatch, and on the other hand the "conventional" generators bearing a significantly increased uncertainty, and a foreseeable depressed future.

3.2. *Technological shocks can have unpredictable impacts on the available set of and relative cost of generation technologies*

The current EU Energy Roadmap scenarios (EC, 2011) build on a menu of essentially known technologies. They also have been criticized as relying on outdated cost assumptions for different low-carbon technologies (Hirschhausen et al., 2013). For sure, 2050 is 37 years from now and thinking 40 years ago, there had not been the oil crises yet. European energy markets had only national structures and electricity generation from renewable sources only included some hydro power. In 2050, the energy system will probably be extremely different than it is today. Composing an adequate portfolio of generation technologies has a very long time horizon; it is not only about looking ahead to the 2050 decarbonization target, but to technological lock-ins that might persist even beyond (Ruester et al., 2013d).

On the one hand, some unforeseen technological shocks can eliminate technology options. For instance, a "*2050 bridging role*" was given to nuclear in the first version of the German energy strategy in late 2010, whereas one year later the country announced a nuclear phase out until 2022 as a response to the Fukushima accident.

On the other hand, unforeseen technological revolutions can also add new or cheaper means of generation and decarbonization. For instance, whereas the International Energy Agency in its World Energy Outlook 2007 (at the time when the 20–20–20 strategy was adopted by the European Council) predicted a moderate growth for US gas production. Four years later, the World Energy Outlook 2011 was centered about a possible "*golden age of gas*". Assuming that the US will become a large-scale exporter of cheap gas and that it is possible to replicate its experience in other parts of the world (from the UK to Poland or Ukraine; from India to China), the availability of cheap gas in the market would allow for a degree of decarbonization at low cost (or even net benefits: one should decarbonize to make more money in the market). The 'rational' price of carbon might then fall extremely low under the push of shale gas as a market-based decarbonization technology. Hence, cheap gas may not only substitute for *dirty* coal but also for *expensive* renewables.

Certainly, technological developments, shocks and revolutions can have important, unpredictable impacts on the available set of and relative cost of generation technologies.[5] How can we stimulate

[4] In order to achieve the "20–20–20 objectives" (i.e. a 20% reduction in EU greenhouse gas emissions from 1990 levels; raising the share of EU energy consumption produced from renewable resources to 20%; and the reduction of EU primary energy use by at least 20% compared with projected levels – all by 2020), this package included a strengthening of existing policy tools as well as the implementation of new instruments. It mainly stands on three pillars: (a) a revision and strengthening of the EU emissions trading system (Directive 2009/29/EC); (b) an Effort Sharing Agreement governing GHG emissions from sectors not covered by the EU ETS (Decision 406/2009/EC); and (c) binding national targets for renewable energy (Directive 2009/28/EC).

[5] Possible technology paths toward a 2050 (decarbonized) electricity system are outlined also e.g. in ECF (2010), Greenpeace (2010), Eurelectric (2011), and IEA (2012).

sufficient innovation in low-carbon technologies in case of a degree of decarbonization at very low cost and the resulting lack of a strong carbon price signal? How will this interact with the market and network arrangements that we use in the EU as our common market model or network operation frame?

3.3. Transition from 'top-down' toward 'distributed local' electricity systems

We observe changes in the generation mix not only in the form of a shift from conventional fossil fuels toward renewables, but also in the form of a shift from centralized toward decentralized resources. More mature technologies for local renewable generation, decreased investment costs thereof and ambitious national support schemes led to a significant market penetration of distributed generation (DG) in many EU countries, and an important share of renewable energy is not fed anymore into the transmission grid but at distribution grid level. In Germany, for instance, "*in many places, the DG output of distribution networks already exceeds local load, sometimes by multiple times*," see Eurelectric (2013).

Also distributed storage might become viable soon at all voltage levels and in significant amounts, becoming a critical component of the grid of the future (Beaudin et al., 2010; Ruester et al., 2013b). Likewise, the use of electric vehicles charging from local grids, and possibly also being able to inject power back to it is expected to grow (see e.g. Kampman et al., 2011; Pasaoglu et al., 2012). In addition, recent innovations in metering and communication devices enable active demand response and enhanced distribution automation. Whereas at the beginning of the liberalization process, demand response has been considered only interesting for large, typically industrial, customers (S. Littlechild is one of the very few having always advocated for retail competition and demand response), technological advances today make this concept appealing also for residential consumers (see e.g. Olmos et al., 2011; He et al., 2013; and references therein).[6] Millions of these smart consumers are already or might be soon also be producers of electricity, thanks to solar PV panels. This is famously turning these consumers into "prosumers" and it may therefore have a significant impact on both the offer and demand sides of these fast changing segments of energy markets.

This newly emerging broad range of "*distributed energy resources (DER)*" (Ruester et al., 2013c) – be it distributed generation, local storage, electric vehicles or demand response – has also the potential to drive significant changes in the planning and operation of the power systems. Traditional power systems had been designed to send electricity top-down from generation connected to the transmission level to end consumers connected at distribution grids. And the distribution grid had been designed accordingly such that there were no significant bottlenecks or congestion. In contrast, today's distribution systems are challenged by new features such as increased volatility of net demand and peak demand fluctuations, reverse flows from the distribution to the transmission grid in times of local generation exceeding local demand. It also increases the feasibility and the likelihood of having energy and power trades at the local level, "du jamais vu"!

All these changes bring challenges for electricity distribution system operators (DSOs) and their regulation alike, ranging from increasing uncertainty in distribution grid flows to the necessary integration of new DER business models into retail markets. As we can already see that the distribution grids might become the new core of the EU internal market, the key question we should ask, from a market policy point of view, is how will they operate and how will they be regulated and monitored? Should we avoid a situation in which several thousand DSOs throughout Europe fragment at national and sub-national level the existing EU internal market by spontaneously diverging through myriad of different rules and arrangements? Nobody yet knows how the corresponding new services, whether communication-related or energy-related, and new markets that are immediately responsive to retail demand, will evolve.

[6] Given a positive cost–benefit analysis, at least 80% of European households are supposed to be equipped with intelligent metering systems by 2020 (EC, 2009).

3.4. Network neutrality

Considering network neutrality as another important sin ("unforeseen" shift) from the initial power reform draft may be controversial while it should not because it actually is a major departure. As a natural monopoly, networks had to be detached from market operation, neutral vis-à-vis fuel mix and cost-based for hosting generation capacity. The main positive outcome that we expected from the networks in the liberalization process was to reduce their costs to their bones, à la RPI-X formula (Ofgem, 2009). Transmission as well as distribution grids, however, are now seen as the vanguard of a significant shift of the whole industry to new business models.

3.4.1. Transmission grid and TSO regulation

Challenges accompanying the connection and integration of large-scale renewable energy sources are manifold. First, we observe an *increasingly unbalanced regional distribution* of supply and demand and therefore the transmission grid needs to be reinforced – inside countries but also via extended interconnection capacities – to be able to transport electricity from its sources to its sinks. Second, we expect an *increasing share of remote generation*, outside the today's European core grid, and new lines need to be built to connect e.g. offshore wind parks, or one day solar power plants in Northern Africa. Furthermore, the economic features of these new resources may presumably be different (different timing of investment and construction; and technically: different load following, production ramping and dispatch firmness profiles). The proper development and operation of networks, far from staying neutral, will strongly interact with the new services, the new users and the new usages of transmission services.

For the coming three decades, the Commission estimates that investments in transmission network infrastructures in the range of €100–200 billion are to be realized (EC, 2011b). The Infrastructure Package could help to identify priority projects; a methodology for cost–benefit analyses is currently developed in order to facilitate the selection of such PCIs (see also Meeus et al., 2013). Nevertheless, serious challenges for investors, grid operators and regulators remain. How to mobilize the required funding, given that under current evolution of transmission tariffs, only half of planned investment could be financed (Henriot, 2013)? How to allocate grid costs, considering that the way we designed grid tariffs for our yesterday's priorities cannot stand forever and that instead new grid tariffs have to be aligned with the new system needs (see e.g. Olmos and Pérez-Arriaga, 2009)?[7]

[7] An interesting proposal is the German "Bürgerdividende". Citizens directly affected by the expansion of the electricity grid shall get the opportunity to take a stake in these new assets with a guaranteed return on investment of up to 5%. See http://www.bundesregierung.de/Content/DE/Artikel/2013/07/2013-07-05-buergerdividende-zum-netzausbau.html.

3.4.2. Distribution grid and DSO regulation

For high amounts of distributed energy resources (DER), the total costs of business-as-usual management of distribution networks will likely increase in most systems. Substantial future investments are also required to properly connect all these new DER to the distribution networks, to enable the system to deal with increased volatility of net demand and peak demand fluctuations, and to set up an ICT infrastructure that empowers DSOs to employ DER for their daily grid operations. DER offer a new set of instruments for grid operation and thereby a tool for DSOs to perform their tasks of electricity distribution. DER also allow for an *active distribution system management* and have the potential to decrease the total costs of DSOs compared to not relying on these new resources in local system management, see Cossent (2013).

As discussed in-depth in Ruester et al. (2013b), the use of DER in distribution grid management can decrease OPEX compared to a business-as-usual treatment of these resources. In contrast, how the use of DER will impact CAPEX is not obvious. Integrating DER in grid operation procedures can decrease CAPEX in the longer-run if grid investments can be deferred, for instance, relying on DER to solve local congestion can postpone investments in new lines (CAPEX hence being substituted for OPEX). On the other hand, in the short-run, significant expenditures for investments into grids and ICT infrastructures supporting grid monitoring and automation are needed upfront. A challenging task for regulators, therefore, remains to design sound regulation that efficiently incentivizes DSOs to engage in active system management and, thus takes account of the changing OPEX and CAPEX structures and of trade-offs among both (Cossent, 2013).

To end, grid operators are much more than “simple regulated infrastructure monopolies” (like bridge or road) where it might suffice that regulation primarily aims to decrease their costs. Instead, grid operators are becoming important market facilitators who shall favor all welfare-enhancing business models under any future market development. Both transmission and distribution grids are supposed to become smarter platforms for deeper market interactions. Regulators realize that there is more to competition than setting price equal to cost (Littlechild, 2012; Khalfallah and Glachant, 2012). In this vein, grids may be remunerated for hosting more of the “socially preferred” generation mix or even to start innovating and running pilots or demonstration (e.g. offshore grids). At the end of the day, average grid costs will go up with increased investment costs. The low cost, market distant and energy mix neutral grid revolution may fade away.

3.5. Market integrity

A highly concentrated industry structure is detrimental to the development of a functioning and efficient internal energy market. Our initial wisdom was that a “good enough” generation structure is a necessary pre-condition to market opening: why bother to open markets which structurally are unable to be competitive? This was a key question in the UK in 1990 as it is in France today. Illiquid wholesale markets exposed to dominant market players, might not only have negative consequences in terms of potential market power abuse (see e.g. Green, 2006; Weigt and Hirschhausen, 2008), but might also delay the transformation of balancing mechanisms into integrated balancing markets or the development of further interconnection.

Improving the industry structure, however, has been and still is one of the main difficulties in the construction of the internal energy market as Member States are sovereign in defining their industrial structures (Glachant and Lévêque, 2009). The Commission has no right to intervene except in cases of major mergers and acquisitions.

Competition has to be “*at least workable*”[8] (Bergman, 2009). The consensus was a magic number of five or more competitors, none with more than 20% market share. The Californian crisis with FERC blindly sticking to its Herfindahl–Hirschman concentration index prejudice opened many eyes to other unacceptable deficiencies. Wolak (2003) showed that more accurate definitions of market power and more sophisticated econometrics might be able to identify most of the “new industrial economics” way in which market power is abused in power markets.

However, many other doors remained open between market and manipulation. How to deal with thieves or criminals like Enron and others in the financial markets (maybe Barclays or JP Morgan in the US) and how to deter them from destroying the market from inside? If we cannot guarantee ex-ante transparency and integrity in power markets, how can we rely on these markets to bridge physically (unit commitment, dispatch, capacity allocation and congestion management) and financially (price arbitrage, portfolio and risk management, et cetera)? Today we still know more about the “fire alarm” strategy of monitoring (how to assess ex-post the fairness of actual behaviors on existing markets) and less on the “police patrol” strategy (how to ex-ante prevent manipulations or crimes). An obvious link between ex-ante and ex-post strategies is how we conceive the definition and the collection of data, the architecture and languages of data bases and the screening tools, the market models and the software. Moreover, we know more about a “country market” monitoring but did we achieve enough across borders and across markets? Finally, another key issue is how to manage the loop between market monitoring, market investigation and market fixing.

3.6. Market design

Market players cannot entirely design power markets by themselves because power markets are structurally incomplete (Smeers, 2003a,b). We saw that market players can easily trade energy until the “market gate closure”; but they cannot easily trade the corresponding transmission capacity and reserve availability needed to implement this “ex-ante” energy trade. To alleviate these market difficulties, power markets play the wholesale trade through a series of steps, which mimic the simple offer and demand arrangement of a textbook market. Power markets are actually “sequences of markets” from the pre-commitment of plants at day(s) ahead to the real-time balancing of actual injections and withdrawals, via the allocation of transmission capacity and the necessary management of unforeseen congestions.

Making electricity marketable actually means to complete the textbook market with more central coordination, more third party intervention and market intermediation. If one wants to make electricity a homogenous good, easier to contract and to trade, one has to deal somewhere with the growing gap between the actual physical flows and the notional traded good. The very nature and the right amount of “third party” coordination in power markets are still under discussion after twenty years. We not only disagree on how to design complements or auxiliaries to the market but we also disagree on what to keep free for trade.

We did not really foresee how deeply market trade and market interactions will depend on the market arrangements agreed by policy makers here and there. Even if we bypass more than a

[8] The author in this vein refers to a market that is “*perhaps less perfect than the textbook vision of a competitive market but yet generally free from monopolistic pricing and various forms of collusion and manipulation.*”

decade of wholesale storyboard (see also e.g. Boisseleau, 2004; Zachmann, 2008; Glachant, 2010) — UK Pool and New Trading Arrangement, Nord Pool, Germany's dual competing power exchanges, et cetera — today we are still discovering how to connect the existing market areas across the existing electrical control zones. Should we "couple" the existing markets within a harmonized nodal frame? Or only with an explicit … or implicit … transmission capacity auctioning? Only on the day-ahead horizon? Should then it be "flow-based" or with rigid predetermined "net transfer capacity"? Should we also couple for intraday trade? With a few successive windows of price fixing? Or with continuous trading? Should we extend to pooling adjacent markets on their balancing horizon? Through a "loose" common pool of offers where several system operators may pick up for their needs? Or through a "tight" cross-border common management of all balancing options? Why not then a loose system operator auxiliary (like CORESO) or a more substantial EU light ISO?

4. Conclusion: toward a (re-) fragmentation of the European electricity market?

Building a European internal market for electricity has been a slow process of some 25 years, but it is near to be achieved. We Europeans conceived our internal market arrangements "our way", even though many other ways were, or still are, envisageable. Europe could for example, have opened up the wholesale market without opening the retail market. Or it could have made opening the wholesale market mandatory with a centralized exchange system operating a single price algorithm, just as England did for more than 10 years.

In the end, it has been — and should continue to be — a process subject to lots of dynamics. What we now call the EU internal market is in many elements a compromise among all the other national-level compromises. It is so far from being a perfect mechanism capable of serving us for everything, whatever the prevailing conditions. This emerging EU market may suffer greatly in the coming years from a massive increase in renewable energies, or from a deep decentralization of the production–consumption loop. The future, as is already debated a post-2020 strategy, is far from clear. What is clear, though, is that the introduction of new ICT-based technologies could radically modify the economical and physical functioning of the electricity system and as a result the functioning of the market. What, therefore, is urgently needed now is "*a realistic design for the transition process from today's low-ICT, high-carbon energy systems to a high-ICT, low-carbon system of tomorrow*" (Vasconcelos, 2013).

The need to adapt market design and network regulation to "unforeseen" developments is not the only challenge. What currently is becoming a serious concern is the risk of a re-fragmentation of the European electricity market due to uncoordinated national moves. It is true that national diversity has first and foremost been a predictable result of the nature of the compromises made when scoping the first electricity directive. The 2nd and 3rd Packages successfully managed to reduce the scope of this diversity. However, we observe now an again increasing impact of national initiatives. Diverse renewable support schemes resulted in a patchwork of effective, but market-distorting subsidies (see e.g. Ragwitz, 2013; CEER, 2013b). Moreover, a number of Member States consider introducing various forms of capacity mechanisms. In Germany, for instance, it targets the high share of intermittent generation blowing conventional generation out of the market and therefore out of money; whereas in the UK it reacts to a shortage in overall capacity due to the shutdown of several dirty power plants.

We know that the Commission will use its powers for policing state aids and, for instance, approve national capacity mechanisms only if the respective Member State devotes funds to improving its interconnections with neighbors (Buchan, 2013). It does not tell if European Competition Policy will be the tool able to seal the many wounds of EU market arrangements. Our electricity markets and networks are at the gate of a sea of perils. There is no guarantee that they will sail till the next safe harbor.

References

ACER/CEER, 2012. Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2011. Report published on 29 November 2012.

Beaudin, M., Zareipour, H., Schellenberglabe, A., Rosehart, W., 2010. Energy storage for mitigating the variability of renewable electricity sources: an updated review. Energy Sustain. Dev. 14 (4), 302–314.

Bergman, L., 2009. Addressing market power and industry restructuring. In: Glachant, Lévêque (Eds.), Electricity Reform in Europe. Edward Elgar.

Boisseleau, F., 2004. The Role of Power Exchanges for the Creation of a Single European Electricity Market: Market Design and Market Regulation. Delft University Press.

Buchan, D., 2013. Europe's unresolved energy versus climate policy dilemma. In: EU's Internal Energy Market: Tough Decisions and a Daunting Agenda. Friends of Europe discussion paper.

CEER, 2013. Status Review on the Transposition of Unbundling Requirements for DSOs and Closed Distribution System Operators. C12-UR-47-03.

CEER, 2013b. Status Review of Renewable and Energy Efficiency Support Schemes in Europe. C12-SDE-33-03.

Cossent, R., 2013. Economic Regulation of DSOs and Its Adaptation to the Penetration of Distributed Energy Resources and Smart Grid Technologies (PhD thesis). Comillas University Madrid.

Davies, S., Waddams Price, C., 2007. Does ownership unbundling matter? Evidence from UK energy markets. Interecon. Rev. Eur. Econ. Policy 42 (6), 297–301.

de Suzzoni, P., 2009. Are regulated prices against the market? Eur. Rev. Energy Mark. 3 (3), 1–30.

EC, 2009. Directive 2009/72/EC Concerning Common Rules for the Internal Market in Electricity.

EC, 2011. A Roadmap for Moving to a Competitive Low-Carbon Economy in 2050. COM(2011) 112.

EC, 2011b. Smart Electricity Grids. SETIS Technology Information sheet. http://setis.ec.europa.eu/system/files/Smartgrid.pdf.

EC, 2012. Energy Markets in the European Union in 2011 (Chapter 2.3). SWD(2012) 368.

ECF (European Climate Foundation), McKinsey, 2010. A Practical Guide to a Prosperous Low Carbon Europe.

Ecofys, Fraunhofer ISI, EEG, LEI, 2011. Renewable Energy Policy Country Profiles. Report prepared within the Intelligent Energy Europe project RE-shaping — shaping an effective and efficient European renewable energy market.

EEX, 2013. European Energy Exchange (EEX) — power trading data. http://www.eex.com/en/Market%20Data/Trading%20Data/Power.

ERGEG, 2010. Status Review of End-User Price Regulation as of 1 January 2010. E10-CEM-34-03.

Eurelectric, 2011. Power Choices — Pathways to Carbon-Neutral Electricity in Europe by 2050.

Eurelectric, 2013. Active Distribution System Management — a Key Tool for the Smooth Integration of Distributed Generation. Discussion paper.

Glachant, J.-M., 2010. The Achievement of the EU Electricity Internal Market through Market Coupling. European University Institute. EUI working paper RSCAS 2010/87.

Glachant, J.-M., 2013. The three ages of Europe's single electricity market. In: EU's Internal Energy Market: Tough Decisions and a Daunting Agenda. Friends of Europe discussion paper.

Glachant, J.-M., Lévêque, F., 2009. The electricity internal market in the European Union: what to do next? In: Glachant, Lévêque (Eds.), Electricity Reform in Europe. Edward Elgar.

Green, R., 2006. Market power mitigation in the UK power market. Util. Policy 14 (2), 76–89.

Greenpeace, 2010. Energy (R)evolution — towards a Fully Renewable Energy Supply in the EU-27.

He, X., Hancher, L., Azevedo, I., Keyaerts, N., Meeus, L., Glachant, J.-M., 2013. Shift, Not Drift: towards Active Demand Response and Beyond. THINK report. Available at: http://www.think.eui.eu.

Held, A., Ragwitz, M., Rathmann, M., Klessmann, C., 2010. RE-shaping: shaping an effective and efficient European renewable energy market. EIE/08/517/SI2.529243 Indicators Assessing the Performance of Renewable Energy Support Policies in 27 Member States. Fraunhofer ISI, Karlsruhe.

Henriot, A., 2013. Financing Investment in the European Electricity Transmission Network: Consequences on Long-Term Sustainability of the TSOs Financial Structure. European University Institute. EUI working paper RSCAS 2013/27.

Hirschhausen, C.v., Kemfert, C., Kunz, F., Mendelevitch, R., 2013. Europäische Stromerzeugung nach 2020: Beitrag erneuerbarer Energien nicht unterschätzen. German Institute for Economic Research. DIW Wochenbericht 29/2013.

International Energy Agency, 2012. Energy Technology Perspectives 2012 – Pathways to a Clean Energy System.
Kampman, B., van Essen, H., Braat, W., Grünig, M., Kantamaneni, R., Gabel, E., 2011. Impact Analysis for Market Uptake Scenarios and Policy Implications. Report by CE Delft. ICF International and Ecologic.
Khalfallah, H., Glachant, J.-M., 2012. An assessment of the tools of incentive regulation in electricity networks. Econ. Policy Energy Environ. 51 (1), 121–152.
Kirschen, D.S., Strbac, G., 2004. Fundamentals of Power System Economics. John Wiley & Sons Ltd.
Littlechild, S., 2012. Regulation and customer engagement. Econ. Energy Environ. Policy 1 (1), 53–68.
Lowe, P., 2011. Getting to 2014 – the completion of the EU internal energy market. Presentation available at: http://webcast.ec.europa.eu/eutv/portal/archive.html?viewConference=12953.
Marañón, M., Morata, A., 2011. Tariff deficit in retail electricity markets in Spain. Netw. Ind. Q. 13 (1), 23–26.
Marques, A.C., Fuinhas, J.A., 2012. Are public policies towards renewables successful? Evidence from European countries. Renew. Energy 44 (August), 109–118.
Meeus, L., von der Fehr, N.-H., Azevedo, I., He, X., Olmos, L., Glachant, J.-M., 2013. Cost Benefit Analysis in the Context of the Energy Infrastructure Package. THINK report. Available at: http://www.think.eui.eu.
Newbery, D., 2009. Refining market design. In: Glachant, Lévêque (Eds.), Electricity Reform in Europe. Edward Elgar.
Nikogosian, V., Veith, T., 2011. Vertical Integration, Separation and Non-Price Discrimination: an Empirical Analysis of German Electricity Markets for Residential Customers. ZEW discussion paper no. 11-069.
Ofgem, 2009. Regulating Energy Networks for the Future: RPI-X@20 – History of Energy Network Regulation. Ofgem supporting paper, 13b/09.
Olmos, L., Pérez-Arriaga, I.J., 2009. A comprehensive approach for computation and implementation of efficient electricity transmission network charges. Energy Policy 37 (23), 5285–5295.
Olmos, L., Ruester, S., Liong, S.-J., Glachant, J.-M., 2011. Energy efficiency actions related to the rollout of smart meters for small consumers – application to the Austrian system. Energy 36 (7), 4396–4409.
Pasaoglu, G., Honselaar, M., Thiel, C., 2012. Potential vehicle fleet CO_2 reductions and cost implications for various vehicle technology deployment scenarios in Europe. Energy Policy 40 (1), 404–421.
Ragwitz, M., 2013. EU renewable energy support schemes – status quo and need for reform. In: Presentation at the 'Workshop in Preparation of the Review of EU Guidelines on State Aid for Environmental Protection'. Brussels, 04 April 2013.
Ruester, S., He, X., Vasconcelos, J., 2013b. Electricity storage: need for a particular EU policy to facilitate its deployment and operation? Eur. Energy J. 3 (2), 23–31.
Ruester, S., Schwenen, S., Pérez-Arriaga, I., Batlle, C., Glachant, J.-M., 2013c. From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs. THINK report. Available at: http://www.think.eui.eu.
Ruester, S., Schwenen, S., Finger, M., Glachant, J.-M., 2013d. A Strategic Energy Technology Policy towards 2050: No-Regret Strategies for European Technology Push. European University Institute. EUI working paper RSCAS 2013/40.
Stoft, S., 2002. Power System Economics – Designing Markets for Electricity. IEEE Press & Wiley-Interscience.
Smeers, Y., 2003a. Market incompleteness in regional electricity transmission. Part I: the forward market. Netw. Spat. Econ. 3 (2), 151–174.
Smeers, Y., 2003b. Market incompleteness in regional electricity transmission. Part II: the forward and real-time markets. Netw. Spat. Econ. 3 (2), 175–196.
UK Government, 2013. Community benefits for sites that host new nuclear power stations. Written statement to Parliament by the UK Energy Minister Michael Fallon. https://www.gov.uk/government/speeches/community-benefits-for-sites-that-host-new-nuclear-power-stations-michael-fallon.
Vasconcelos, J., 2013. 'The stuff we have, a strong wind will blow it to pieces': two decades behind schedule, we need to re-think the single electricity market. In: EU's Internal Energy Market: Tough Decisions and a Daunting Agenda. Friends of Europe Discussion Paper.
Weigt, H., Hirschhausen, C.v., 2008. Price formation and market power in the German wholesale electricity market. Energy Policy 36 (11), 4227–4234.
Wolak, F.A., 2003. Measuring unilateral market power in wholesale electricity markets: the California market, 1998–2000. Am. Econ. Rev. 93 (2), 425–430.
Zachmann, G., 2008. Electricity wholesale market prices in Europe: convergence? Energy Econ. 30 (4), 1659–1671.