Centre on Regulation in Europe
Improving network industries regulation

Regions – the future for the European Internal Electricity Market?

Discussion Paper

Professor Claude Crampes (CERRE & Toulouse School of Economics)

Professor Nils-Henrik von der Fehr (CERRE & University of Oslo)

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Centre on Regulation in Europe (CERRE) asbl
Rue de l'Industrie 42 Box 16 - B-1040 Brussels - Belgium
Ph: +32 2 230 83 60 - Fax: +32 2 230 83 70 – info@cerre.eu **–** www.cerre.eu

1. Introduction

The whole European electricity industry is under pressure from tighter regulations, most of them designed at the Union level. The 2030 Climate and Energy package[1] commits Europe to reducing greenhouse gas emissions, to increasing the EU-wide weight of renewables in final energy consumption and to improving energy efficiency. More recently, the Energy Union package[2] recalled that an ambitious climate policy is to give all EU consumers secure, sustainable, competitive and affordable energy. To achieve security, the Commission has the "*vision of an integrated continent-wide energy system where energy flows freely across borders, based on competition and the best possible use of resources, and with effective regulation of energy markets at EU level where necessary*."

Despite significant steps, much remains to be done in terms of keeping Europe at the forefront of reliable and affordable energy for all and making the EU a world leader in carbon-free energy. Achieving these goals demands a root and branch transformation of the EU energy system, including redesign of the electricity market and attracting investment in the sector. The Energy Union package, which sets out the agenda to meet this challenge during the present Commission term, was followed by several communications in the summer of 2015, notably including the launch of a public consultation on the new energy market design.[3] These initiatives have at their heart the promotion of greater regional co-operation and co-ordination of energy policies.

The CERRE Executive Seminar for which this paper has been prepared seeks to assess the progress with the regional concept as a central plank of the Energy Union package. It will examine the key challenges of developing the market in a regional context and examine some of the governance and structural challenges of moving to a coordinated set of regional markets. The aim of the event is to debate these important challenges among regulators, industry players and policy makers and to identify the key policy gaps that need to be addressed to move the Internal Energy Market (IEM) forward in a regional context.

In addition to a keynote address, which will provide an update on progress with the Energy Union package and the vital role of regions in taking the IEM to its next phase, the event will comprise two in-depth panel sessions with speakers from industry, regulators and the European institutions. Finally, a discussion session will aim to synthetize insights from the debate and identify areas for future research

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[1] "A policy framework for climate and energy in the period from 2020 to 2030", COM(2014) 15 final, http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014DC0015&from=EN
[2] "A framework strategy for a resilient Energy Union with a forward-looking climate change policy", COM(2015) 80 final, https://ec.europa.eu/energy/sites/ener/files/publication/FOR%20WEB%20energyunion_with%20_annex_en.pdf
[3] " Launching the public consultation process on a new energy market design", COM(2015) 340 final, https://ec.europa.eu/energy/sites/ener/files/documents/1_EN_ACT_part1_v11.pdf

The main topics that will be discussed at the Seminar are as follows.

(i) Panel 1: Can the market be made to work?

The first panel will consider what sort of framework is required to improve the market model and move that model into today's world of a renewable rich generation mix, very unlike the largely traditional thermal generation mix that prevailed when the IEM was first developed. The session will examine ways to provide clear price signals to encourage new investment in both transmission and generation infrastructure in a framework of public subsidies to renewables. The discussion will cover such issues as prolonged periods of zero prices, the scope for allowing 'free-run prices' in the market, how to incorporate measures such as capacity mechanisms and how these might need to evolve from national to regional instruments. We will also consider how energy storage and demand response can contribute to the balancing of the energy system both technically and financially. Finally, we will assess whether the necessary cross-border infrastructure exists to facilitate the move to regional markets and, if it does not, how one might incentivise incumbent players and new entrants to invest in cross-border infrastructure.

(ii) Panel 2: Is there a need for regional governance?

The second panel session will go on to address some of the structural and governance challenges that a regional market poses. This will include an assessment of the changes required in the roles of ACER and the ENTSOs, the need to consider developments such as an Independent System Operator (ISO) or Regional Transmission Operator (RTO) model to manage the evolution to the regional model and the interfaces between the regions, and the changing role of the DSOs and TSOs as a consequence of greater consumer participation in the market. We will also discuss how regional cooperation between Member States can be an efficient tool in achieving the EU renewables target.

This CERRE event will be a unique opportunity to debate key challenges and identify potential solutions with a cross section of all the parties central to taking the Energy Union package forward. The policy gaps identified by the event will serve as drivers for CERRE's future research in the energy sector, as we aim to deliver policy recommendations and guidance to assist in meeting the objectives of the Energy Union package.

Focusing on the above questions and topics, this discussion paper aims at providing a background to the 16 March CERRE Executive Seminar's discussions.

2. Can the market be made to work?

In all countries where the electricity industry has been liberalised, lack of demand response together with the specificities of electricity (mainly non-storability), environmental and social concerns, as well as the Fukushima trauma, have provoked something of a regulatory backlash.

Reshaping electricity markets

The recent performance of several electricity markets across Europe raises the question of whether the current market design is sufficiently well suited to delivering secure, sustainable and affordable electricity. The design, conceived for reliable fossil-fuel plants where technologies with high/low operating costs and low/high capital costs had been progressively installed to match versatile demand, is being challenged by changes in the energy mix. The market now has to accommodate an increasing share of intermittent resources with high capital costs and operating costs going from zero to infinite, depending on the state of nature. This increasing disparity in the cost structures exacerbates potential flaws in the current market design. How can we link market prices, which reflect the operating costs of the marginal technology – based on coal or natural gas at some points in time and free wind or solar power at others - and the average costs of low-carbon resources and fossil-fuel plants? What is the value of the *risk premia* demanded by investors in order to provide back-up capacity that will have to recover its costs during an uncertain and reduced number of peak hours?

With attention moving from short-term issues (i.e. dispatch optimisation) to long-term issues (i.e. investment) the need to rethink the design of electricity markets is now compelling. The widespread energy-only, technology-neutral, approach to the regulation of electricity markets may not in itself internalise externalities created by the different technologies. For instance, the increased flexibility and reliability – which have public good attributes – provided by natural gas and hydro plants, may be under-priced in an energy-only market arrangement. Similarly, learning economies triggered by deployment of renewables will not be captured by investors through market prices alone; nor is their contribution to the reduction of greenhouse gas emissions reflected in market prices.

Several Member States – notably, Germany, the UK and France – have already implemented reforms to their electricity systems with the aim of facilitating decarbonisation without putting security of supply at risk.[4] Among the various elements of the reforms, these countries have created capacity markets, implemented mechanisms to boost carbon prices, or fostered the use of capacity tenders for low-carbon resources. Arguably, the absence of a common regulatory approach to the low-carbon transition has resulted in a patchwork of diverse policies across Member States that weaken the Internal Energy Market.

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[4] This is the topic of a CERRE study entitled: "Energy Reforms in Germany, the UK and France: Initial Lessons for the Energy Transition in Europe?" http://www.cerre.eu/sites/cerre/files/151006_CERREStudy_EnergyTransition_Final.pdf

Fossil-fuel plants, nuclear plants and hydro reservoirs remain indispensable as back up, but there is no consensus as to the regulatory framework necessary to provide the right investment incentives and avoid closure of plants still needed to ensure supply security.

The most widely adopted option in Europe has been the creation of capacity markets. For instance, the UK has opened its first Capacity Market auction in December 2014 to guarantee that around 48 GW of fossil fuel capacity will be available in 2018/2019. Gas was the auction's biggest winner, as it secured capacity payments for approximately 25 GW of new and existing plants.[5] However, capacity mechanisms also have flaws; in particular, they require regulators, as opposed to the industry, to take on the role of determining the amount and mix of capacity, they increase costs faced by consumers, and they may induce carbon-based power stations to stay open longer.

Revamping the emissions market

The EU Emissions Trading System (EU ETS), the cornerstone of the European Union's policy to combat climate change by capping and trading carbon emissions, has been under constant criticism since its beginning in 2005. To stimulate the market, the Commission has decided to delay the auction of a certain number of allowances for 2014, 2015 and 2016 and to re-introduce them in 2019 and 2020.[6] This is not a straightforward cancellation, but a rescheduling based on the expectation that the current low levels of demand will not continue. This deferral is something of a risky bet as one cannot exclude the possibility that economic activity (and therefore demand for rights to emit greenhouse gases) will be even more depressed in future.

A more radical reform will be introduced in Phase IV of the ETS, with the establishment of a Market Stability Reserve.[7] This is a tool to gradually reduce the stock of excess allowances, that is to say, allowances that have been hoarded since 2008 (the total volume of allowances made available minus recorded emissions). The surplus is almost equivalent to the total amount of new yearly permits (two billion tonnes), meaning that businesses have little incentive to purchase new emissions rights. The plan is therefore that, from 2020, 12 per cent of the stock of unused allowances held by businesses (or at least 100 million tonnes) will be removed from the quantities that have to be auctioned off and held in the stability reserve. If there is a year in which unused stock falls below 400 million tonnes, the quotas auctioned will be increased by 100 million tonnes, taken from the reserve. The Commission's rationale behind this mechanism is to ensure that businesses required to take part in the carbon market do not make poor

[5] Results of the Capacity Auction on 10th December 2015, are at https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/2015%20T-4%20Capacity%20Market%20Provisional%20Results.pdf

[6] Commission Regulation n°176/2014 of 25 February 2014 amending Regulation n°1031/2010 in particular to determine the volumes of greenhouse gas emission allowances to be auctioned in 2013-20, http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32014R0176&from=EN

[7] Decision 2015/1814 of the European Parliament and of the Council of 6 October 2015 concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading scheme and amending Directive 2003/87/EC; http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015D1814&from=EN

technological choices when faced with fluctuating prices that are, on average, too low. The Stability Reserve will give investors greater security in phase IV (2021-2030).

Are these two remedies sufficient, or should we expect more regulatory intervention? Indeed, the effects of the back-loading decision have been deceiving. Between July 2014 and September 2015, the reduction of around 700 million tonnes of CO_2 sold in auctions drove the price up from €6 to €8 per tonne, far from the €100 that is typically viewed as the threshold for making it profitable to capture and store CO_2 emissions. As long as the EU authorities try to reach a target price by using a quantity process, one can expect new rules to arrive, with the unfortunate side effect of increased regulatory uncertainty.

Demand response and energy storage

It is generally acknowledged that the European electricity market needs to move from “load following” to “load leading”. Whereas the traditional thinking in the industry was that supply had to adjust to the realised level of demand, the intermittent nature of new, renewable generation requires demand to respond much more to available generation. Furthermore, where demand response is insufficient, storage is warranted to ensure that low-cost surplus energy is not wasted. However, storage at large scale – except via pumping stations - is not yet profitable.

Technological developments – particularly in information and communication technologies – provide some ground for optimism. While further innovation would certainly be welcome, for example with regard to batteries, it would appear that available technologies are sufficiently developed to allow for “smart” demand and medium scale storage management. Indeed, it does not seem that the real barrier to demand response and storage is a lack of requisite technology, but rather a failure to exploit opportunities provided by available technology. It will take more time for storage, but economies of scale and learning-by-doing effects could dramatically decrease battery costs, as they have done in the manufacturing of photovoltaic panels.

In order to exploit these opportunities, fundamental changes may be required, both with respect to the industry itself and to the regulatory framework that governs it. The question is, of course, which changes are required and how they can be accomplished. Will the responsibilities of system operators – at the transmission as well as at the distribution level – have to change? Will current industry players be willing and able to facilitate demand response, or do we need new entrants – perhaps from very different sectors – to supply these services? Do current regulations provide the right framework for active and engaged consumers? In addition, do markets provide correct incentives for efficient utilisation of storage and demand resources?

3. Is there a need for regional governance?

Strengthening the common electricity market entails increasing cross-border trade within the European Union. Not only is this a political objective, it is also technically and economically critical.

Inter-country power trade

European countries are gradually diverging when it comes to choosing their electricity policies. For example, while Germany commits to renewable energy by setting the ambitious goal of 80 per cent of electricity production from renewable sources by 2050, France continues to rely on nuclear energy, and the UK appears to be moving towards a balance of nuclear and renewables. It is precisely this difference between national policies that makes cross border trade valuable. When the sun is shining and the wind is blowing, Germany will generate excess electricity at essentially zero marginal cost and export it to France. On the other hand, on winter nights with no wind, Germany will import electricity from France. With very different power production facilities and heterogeneous demands in each country, being able to trade proves mutually beneficial.

To increase electricity flows between Member States, the Commission proposes a quantitative infrastructure target: transmission capacity between each Member State and its neighbours must be at least 10 per cent of the installed electricity production capacity in the country by 2020, and this figure will rise to 15 per cent by 2030. It is true that the current infrastructure is not adequately developed and will be even less well adapted when power generation facilities become more diverse. However, there seems to be little economic justification for uniform quantitative targets (although one could argue that such targets are useful politically, to remind Member States of that they have signed up to increasing interconnection capacities). Additionally, whereas Portugal and Spain have to make simple decisions to reach the target, the choice of pivotal countries, such as Italy, can have a strategic dimension since they can choose to reinforce some interconnections that are not the EU-wide market's best choice.

Rather than imposing across-the-board criteria, it would be more efficient to concentrate attention on high-value interconnections.[8] To identify these projects, the profits from an

[8] Some progress has been made. The European Commission has drawn up a list of 195 key energy infrastructure projects known as projects of common interest (PCIs). See the list at http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:JOL_2016_019_R_0001&from=EN. PCIs may benefit from accelerated planning and permit granting, a single national authority for obtaining permits, improved regulatory conditions, lower administrative costs due to streamlined environmental assessment processes, increased public participation via consultations, increased visibility to investors and access to financial support from the Connecting Europe Facility from 2014-2020.
ENTSO-E has published in February 2015 a "Guideline for Cost Benefit Analysis of Grid Development Projects", https://www.entsoe.eu/Documents/SDC%20documents/TYNDP/ENTSO-E%20cost%20benefit%20analysis%20approved%20by%20the%20European%20Commission%20on%204%20February%202015.pdf

interconnection should be compared with the cost of its installation and operation. Since interconnections (and transmission lines in general) enable the transfer of kilowatt-hours between two countries or regions, the economic value of trade is the difference in price between the two ends of the line.

The greater the capacity of the line and the higher the number of lines between two countries, the more energy is transferred and the more the price difference between the two ends of the line is reduced. The "optimal" interconnection capacity is determined by a marginal criterion: the cost of increasing capacity must be equal to the difference between the prices of energy at the two ends of the line. Rather than setting a uniform quantitative requirement, it is more efficient to concentrate on high added-value interconnections, namely those linking Member States with sufficiently different energy generating facilities. For example, interconnecting German wind turbines with Scandinavian hydropower reservoirs would increase the ability to store in these reservoirs the surplus wind power produced in Germany, and then release it when there is no wind. Although a strategy of picking 'winners and losers' runs its own risks, efficiency requires that one aims at concentrating investments in the most valuable projects from an EU-wide perspective.

Coordination of TSOs

The Commission emphasises the need to construct new lines. However, constructing new infrastructure, in particular transmission lines, is a longer and more difficult process today than in the 1970s and 1980s. Ambitious global network expansion plans come up against opposition from local communities who do not wish to see power lines criss-crossing their landscape. In some cases, construction is simply impossible, while in others it is possible only if the lines are put under ground. With underground lines, the extra cost involved is significant; for example, the recently inaugurated underground line between France and Spain costs eight times more than an aerial line.

In many cases, either the interconnections will not be constructed, or their cost will be so high that it will exceed any expected returns. The line will therefore be non-economic or reduced in size.

Rather than concentrating on highly uncertain infrastructure development, a more effective policy to increase power trade would be to increase the coordination between network operators. Today, each EU country has its own Transmission System Operator (TSO) that is responsible for "keeping the lights on" within national borders; it controls power flows on the grid in real time and makes decisions on load-shedding if necessary. Each TSO decides which action to take based on its own technical and economic rules for network management, and taking into account other TSOs' actions.

In Europe, around fifteen operators make independent decisions, without fully internalizing the impact of these decisions on their neighbours. This situation is inefficient. The simplest solution would be to integrate grid operation activities within a common framework. This is the Independent System Operator (ISO) or Regional Transmission Operator (RTO) model. In such a framework, national TSOs would retain their network assets, network access tariffs would be set at state level, but there would be a single network operations centre.

This model has been in place in the United States since the end of the 1960s: after a huge blackout in 1965, several North-Eastern US states decided to create "tight power pools", which centralise transmission network operations over several states and companies. When the electricity industry was restructured at the end of the 1990s, these "pools" became ISOs and then RTOs, managing the market.

The UK also adopted the ISO model. When Scotland was integrated into the England and Wales market in 2005, the Scottish transmission network remained under the ownership of Scottish electricity companies, but its operation was transferred to National Grid, the English TSO.

Whilst the ISO model as seen in the US is by no means perfect and would need to be adapted to a European context, it seems evident that the current national regime will not suffice especially if one continues to see the development of significant grid infrastructure in the North Sea region, be this offshore wind or interconnectors.

The Commission mentions the need for stronger coordination, but does not go so far as to recommend the (eventual) creation of a European ISO. Some TSOs do not support the emergence of a European ISO, which would take away some of their responsibilities, and, they fear, undermine system operations within their area. Similarly, some countries use the issue of national sovereignty to maintain a national dispatching centre. If there is a power failure and there is a need for load shedding, would a European ISO based in Brussels serve consumers in Belgium first, at the expense of those in France? The counterargument to this worry is that the European ISO would carry out load shedding following an established and transparent protocol, and not based on the moods or personal preferences of its employees. One could also argue that the creation of a European ISO would significantly reduce the likelihood of a power failure by coordinating all available generation and transmission assets.

Nevertheless, the establishment of a European-wide approach to system operations would not seem realistic, at least in the foreseeable future. However, one could envisage the development of a system of regional system operators, each of which would be responsible for a set of Member States. Such a development may not only meet with less resistance, but may also be a useful first step towards a more fully integrated European electricity system.

National regulators vs. European regulator

The discussion of the organisation of system operations is mirrored in the discussion of governance structure. In the same way that one may argue for the need of a European system operator, one may argue for a European regulator.

Again, the case is not obvious. Firstly, regional cooperation and market integration may develop without any supranational regulatory authority. The Nordic market provides an example of very close integration under a governance structure of independent regulatory authorities. Furthermore, with the establishment of CEER – the Council of European Energy Regulators – and

ACER – Agency for Cooperation of Energy Regulators - not only has cooperation taken an important step forward, but decision-making power has been vested in a truly supranational European institution.

It remains to be seen whether these steps are sufficient to ensure further development of an integrated European electricity market. However, one could easily envision a more regional approach – perhaps as a further step towards full European integration – where regulatory authorities of adjacent Member States enter into closer collaboration. Such a strategy may be seen as less demanding, while at the same time help to solve issues that arise between smaller groups of Member States.

Whilst the development of regional regulatory governance could be facilitated in ACER, it is not evident that this exists in the form that would be required to sit alongside, for example, a regional structure. Hence, ACER will also have to adapt its structure (just as the TSOs will need to do to accommodate the ISO) and have a much more formal regional element to that structure than is the case today.