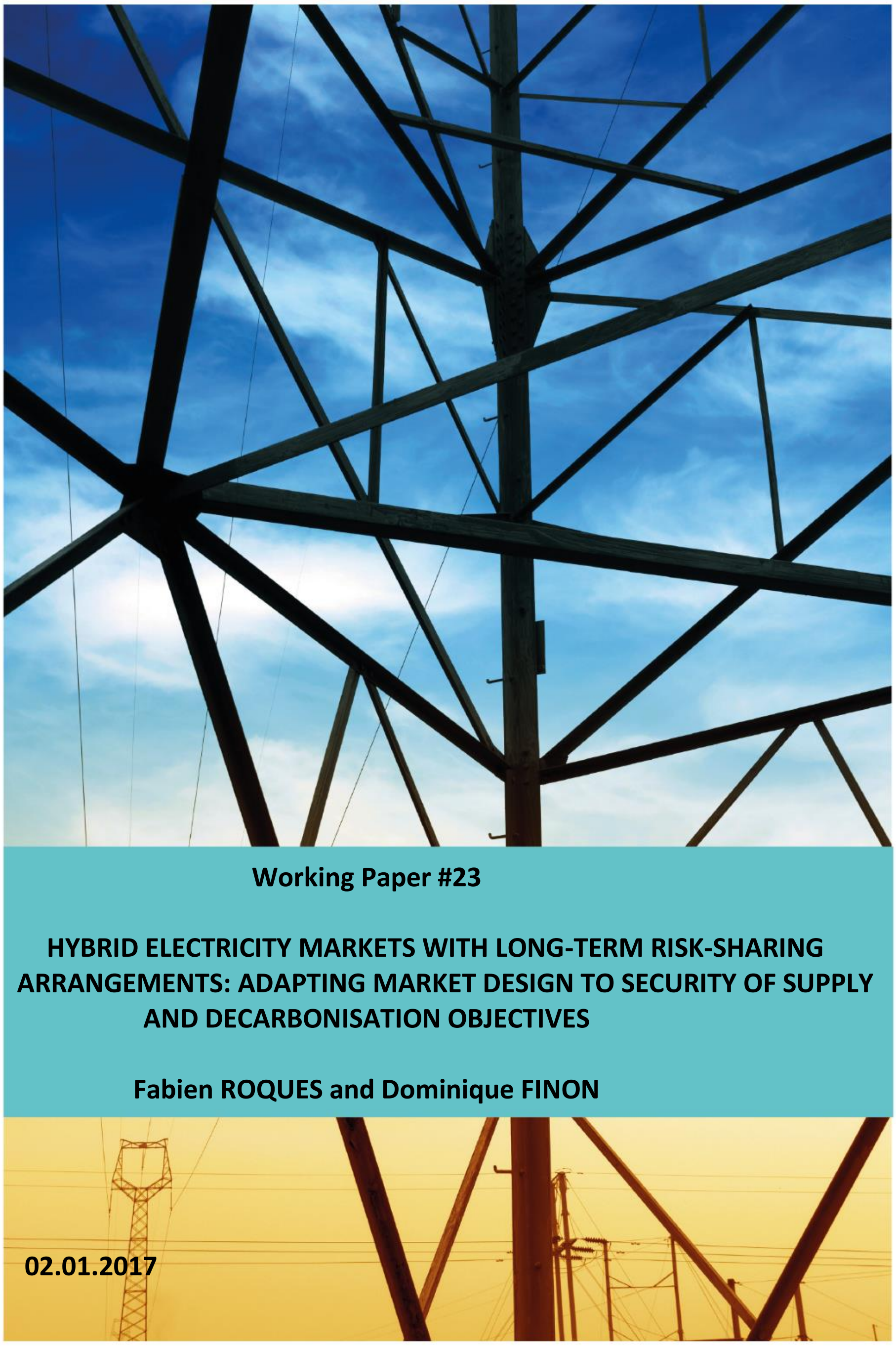
CHAIRE EUROPEAN ELECTRICITY MARKETS
Fondation Paris-Dauphine



Working Paper #23

HYBRID ELECTRICITY MARKETS WITH LONG-TERM RISK-SHARING ARRANGEMENTS: ADAPTING MARKET DESIGN TO SECURITY OF SUPPLY AND DECARBONISATION OBJECTIVES

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02.01.2017

DAUPHINE UNIVERSITÉ PARIS

Chaire de recherche soutenue par

GROUPE Caisse desDépôts

Hybrid Electricity Markets with Long-Term Risk-Sharing Arrangements: Adapting Market Design to Security of Supply and Decarbonisation Objectives[1]

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Abstract

The re-emergence of policy interventionism in electricity markets raises questions as to how market design can best be adapted to meeting the investment challenge associated with security of supply (SoS) and decarbonisation objectives. This paper takes an institutionalist approach in terms of modularity of the market design, and reviews the standard historical approach towards competitive markets, in order to analyse the roles and interactions of the initial and additional market "modules". We argue that a number of additional modules is required to achieve long-term policy objectives, such as decarbonisation and security of supply (SoS). But, in turn, they destabilise the initial modules of the market design, in particular by the entries of renewables. We review the international experience with hybrid market design and draw a number of policy recommendations at to best practices, as well as suggesting ways in which the initial market modules can be improved to prevent inconsistencies with the new modules. The move towards a hybrid market regime, which relies on a combination of planning, long-term risk sharing arrangements and improved markets entrenched in a function of short-term coordination, appears to be unavoidable where decarbonisation policies are adopted.

Key words: Electricity market, decarbonisation policy, market design, long-term contracts, low-carbon investment.

1. INTRODUCTION

Twenty-five years after the reforms were initiated to liberalise the electricity industry, many electricity markets around the globe are 'hybridised' with various forms of regulatory intervention and/or a significant role for the state in planning and capacity procurement. In this paper, we propose that the revival of policy interventionism is driving a transformation of the standard historical approach of competitive market design towards a hybrid regime that combines planning and long-term arrangements established with public or regulated entities on one side, and organised markets on the other side.

The primary motivations for public intervention in power markets comprise three drivers that have recently attracted attention in many countries : i) determination of part of the generation mix through support for the clean technologies, in particular those based on renewable energy sources (RES) with variable production; ii) the need to overcome the market failures that undermine investment in sufficient generation capacity to maintain security of supply (SoS) and offer sufficient

[1] **Acknowledgements:** This paper has benefited from the support of the Chaire European Electricity Markets (CEEM) of the Paris-Dauphine Foundation, supported by RTE, EDF, EPEX Spot and the Groupe Caisse des Dépôts. The views and opinions expressed in this paper are those of the authors and do not necessarily reflect those of the partners of the CEEM.

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flexible resources; and iii) system planning to optimise transmission and generation system development.

These drivers of policy intervention resonate in the OECD countries within a context that is characterised by the resurgence of government interventions aimed at guaranteeing SoS though the introduction of capacity mechanisms, with priority being assigned to decarbonisation through the support of clean technologies – decentralised RES, as well as centralised low-carbon technologies (LCTs; large off-shore wind, new nuclear, clean coal, CCS etc.) – and the growing challenges of network planning in the context of the development of variable RES generation. In the emerging economies?, the need for investment in capacity is more acute than in the OECD countries, given that the former are experiencing more significant growth in demand, causing them to be the forerunners of market hybridisation with planning and long-term arrangements.
These policy and regulatory interventions, in particular those that are aimed at promoting high-upfront-cost and low-variable-cost technologies (RES, LCTs), can exert significant impacts on electricity markets and undermine the ability of prices to provide adequate short-term and long-term coordination signals to market participants. This can create fundamental inconsistencies with the current market, as well as misalignments in different parts of the market design, e.g., merit-order effects on the power exchanges, limits on system balancing constrained by the rigidity of existing resources, poor market valuation of the flexibility of resources that are increasingly needed, and limits on transmission access rules without locational signals.

These inconsistencies, in turn, can lead not only to the adaptation of the former set of market rules, but also to the creation of new regulatory mechanisms to support long-term investment, so that by the end of the process, a new hybrid market regime emerges, as is indeed the case in many countries that are pursuing the objectives of sustainability and SoS. We argue that, beyond the various new 'out-of-market' mechanisms and patches that are being adopted in these countries, the underlying logic leads to a similar combination of modules of short-term markets, improved modules of networks access, and long-term coordination mechanisms, from the moment that the decarbonisation and SoS objectives are prioritised. The novelty lies in the fact that recent developments have demonstrated the strength of this logic in moving towards a regime that is articulated around two principles: short term coordination by markets (idealized by the so-called economic dispatching), and long term coordination by a combination of planning and long term arrangements between producers-investors and public or regulated entities.

This paper analyses the dynamics of change in the market design and investigates the issues associated with 'hybrid market models' that combine a role for the market with strong public governance. Our objectives are:

- To introduce a functional approach that builds on the body of literature that identifies a number of "modules" in the standard market design, in order to analyse the evolution of electricity market design towards a stabilised hybrid market regime;
- To analyse a number of case studies involving different "best practice" combinations of coordination by the market and by direct policy intervention, and to identify the inconsistencies emanating from these overlapping coordination approaches.

In Section 2, we present a conceptualisation of market design in terms of modules (i.e., blocks of operational and transactional rules), and the dynamics of change (in functional terms) of this design. We identify the drivers of the "reforms of the reforms", namely market failures in current markets in the first stage, and thereafter, the inconsistencies that arise between the initial modules and those introduced subsequently to correct market failures. Section 3 concentrates on the modules that provide the long-term signals that usher in a new hybrid market regime: the Long-Term Contracts module; Capacity Market module; and RES-Decarbonisation module. In Section 4, we consider the lessons that have been learnt from international experiences with these modules, in terms of how they provide long-term signals for efficient design and for the articulation of planning and market coordination principles. Section 5 deals with the inconsistencies between these new "long-term" modules and the initial modules, and the remedial measures that are needed to ensure an efficient interplay between the market signals and these "long-term" modules.

2. THE "REFORMS OF THE REFORM": TOWARDS HYBRID MARKETS

Since the initial wave of reforms in the 1980s and 1990s, liberalised electricity markets have continued to evolve around the globe. There are several strands in the literature that focus on explaining the drivers and dynamics of this evolution. These are considered below.

- **The institutionalist perspective on reforming industrial organisation and regulation**

The implementation of reforms has followed different institutional trajectories and trial and error processes involving experiments with the different elements of the market designs (see for instance, Newbery, 2002; Glachant, Finon, 2001; Jamasb, Pollitt, 2005; Joskow, 2008a; Pollitt, 2008; Correlje, De Vries, 2008; Borenstein, Bushnell, 2015). The institutionalist stream are focused primarily on explaining the variety of liberalisation reforms in terms of the differences between institutions and policy development strategies, as well as the steps to establish the initial structures and regulation of the electricity industry . These have served to separate, in a timely way, the natural monopolistic activities and competitive activities, so as to establish a regulatory authority, and thereafter to enable privatisation (Newbery, 2002). Holburn and Spiller (2002), Spiller (2009), and Henizs and Zellner (2010) have focused on the reforms that have been implemented in emerging economies that are confronted with the challenge of attracting investment. They have insisted on the importance of the credibility of public governance (referred to as the "public contract") in facing this challenge. They have also shown how the roles of interest groups, the pressure exerted by public opinion, and common beliefs interfere with more objective drivers of market reform. Correlje and De Vries (2008) have explained the variety of reforms in OECD and emerging economies in terms of differences in policy goals, political cultures (for example, beliefs in the benefits of markets and competition versus confidence in the efficiency of technocracies) , degrees of institutional centralisation, levels of efficiency of former public utilities, and the legacies of these former vertical utilities, as well as some specific issues, such as the legacy of nuclear assets and the availability of primary domestic resources.

- **A functional analysis in terms of the modularity of the electricity market regime**

This paper belongs to the strand of the literature that applies a "functional perspective" to the dynamics of evolution of market design. We focus on institutional changes designed to improve the long-term efficiency of the electricity system and to include new policy objectives toward decarbonisation. More specifically, our approach builds on the "modularity" framework introduced by Glachant and Perez (2009), who in turn followed the work of Baldwin and Clark (2000), regarding the design of rules in industrial organisations, as well as the technical definition of modularity as a particular design structure, which distinguishes between the technological constraints within non-separable clusters of tasks on the one hand, and a strong institutional constraint on the design of interfaces that connect task clusters that are technologically separable on the other hand. Glachant and Perez (2010) identified a set of distinct functional and institutional modules along the electricity value chain, each of which have different potentials for the introduction of market and competition factors?

This approach has proven to be particularly convenient for analysing the introduction of competition into formerly vertical and monopolistic power industries by establishing boundaries between network-based monopolistic activities and potentially competitive activities. The electricity industry indeed comprises different modules of competitive activities, in that it has a different set of wholesale markets (forward, day ahead, intraday), a module of retail supply competition, and a module of real-time (balancing) and ancillary services managed by the system operator, based in particular on a market-balancing mechanism. In addition, there are a number of modules associated with regulated monopoly activities, such as the module of transmission rights, which is based on regulatory access rules, and the module of distribution grid access.

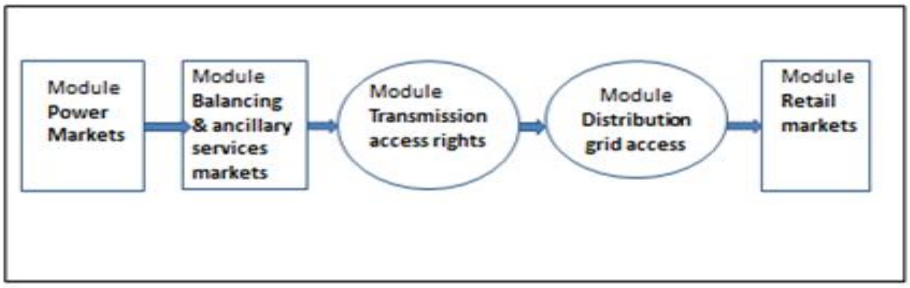

Figure 1. Chain of modules for the initial industrial organisation of an unbundled electricity sector.

In the electricity industry, the different modules cannot be considered as independent because of their technical and regulatory complexities, as emphasised by Glachant and Perez (2009), in contrast to the pure independency of the modules in the analytical framework of Baldwin and Clark (2000). The interdependency of the different modules is one of the explanations for the variety of reforms at the different levels of the value chain (Glachant and Perez, 2009, 2012). In addition, this interdependency implies that the modules that are already in place need to react and adapt when a new module is introduced, and that the new modules should be consistent with the existing ones, as well as with the institutional environment. A typical example of the effects of inconsistencies that can arise between old and new modules (as developed later in this paper) is the effect of the "renewables support" module on the other modules, given the variability of the production profiles of RES generators and their low variable cost. Indeed, in many countries that have RES-E policies, when their development exceeds a 10% threshold in terms of energy share, important discrepancies and misalignments are created in the power market module, the system balancing module, the transmission access module, and in terms of de-optimisation of the technology mix in relation to the existing conventional plants, and the relatability of supply in every situation (capacity adequacy).

In this paper, we build on this strand of literature and use the modularity framework to analyse the "reforms of the initial reforms". In particular, we consider the following three functional aspects of the evolution of the market design towards a stabilised hybrid market:

- The introduction of new modules, to address market and regulatory failures that affect investment incentives, as well as modules that correspond to the out-of-market mechanisms put in place to support the deployment of clean technologies;
- The adjustment of the new modules through "learning by doing" or through the transposition of foreign "best practices", to make them more efficient or conform more closely to their legal environment;
- The identification of the issues that emerge from the overlap of the new modules with the initial ones, and the correction of some of the inconsistencies.

The interdependencies of the modules suggest that the introduction of a new module would have a number of unexpected effects on the existing modules that need to be improved. More importantly, interdependency entails the need to make modules consistent both with each other and with the institutional environment, in particular in the context of competition policy.[4] Besides this «functional determinism », local institutional, legal, and political parameters and exogenous factors affect the processes of adaptation, correction, and adjustment of the general market design and the different modules installed at different steps of the evolution process. However, despite the variety of rules and arrangements adopted in different countries that focus on the objectives of sustainability and SoS, the best practices chosen for each new module tend to be adopted sooner or later.

3. THE NEED TO COMPLETE MARKET DESIGN WITH MODULES THAT PROVIDE LONG-TERM SIGNALS AND HEDGING

In theory, the electricity market has two coordination functions. First, in the short-term, it ensures the efficient operation of the total fleet of plants. Second, it signals a scarcity of capacity for different technologies *via* price signals that orient investors' long-term decisions. There is, in theory, complete consistency between short-term and long-term market coordination when there is pure competition, perfect information, and no risk aversion.[5] The infra-marginal rents generated on the wholesale markets, where prices are aligned according to the variable costs of the clearing marginal plant, plus the scarcity rents during peak periods are supposed to allow recovery of the fixed costs of all the plants and provide a return on the invested capital. The optimal technology mix that results from the investment decisions of market players is quasi-identical to the long-term optimum of a benevolent social planner, which minimises the long-term costs, except for some differences linked to the cost of risk management and the inclusion of option values in the decision criteria.

However, in practice, electricity markets are incomplete and suffer from a number of imperfections. This has prompted policy makers and regulators to implement various reforms and additional mechanisms. In particular, electricity markets seem to be capable of driving competition in the short-term, although their ability to deliver investment incentives that could lead to a socially optimal generation mix remains uncertain. In addition, policies aimed at supporting the use of renewables have had significant effects on electricity markets in Europe.

In our institutional framework, the missing modules are implemented to resolve these issues. In general, the mechanisms that are introduced are seen as transitory measures, providing time for the system to evolve sufficiently, particularly in terms of new technologies that enable demand response, and for the technology costs to decrease, before allowing the market to regain its full short-term and long-term coordination functions. However, the experience to date suggests that these mechanisms are here for the long term, creating an irreversible movement towards a hybrid market regime. In the following sections, we introduce three such "long-term" modules, and then show how these mechanisms have self-reinforcing effects, leading to their perpetuation, thereby consolidating the foundations of these hybrid markets in the long term.

- **The Long-Term Contracts module for investment risk hedging**

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[4] In his seminal book on comparative institutional analysis, Aoki argues strongly that the effectiveness of a regulatory and organisational model depends upon not only its internal consistency but also on coherence with the institutional environment (Aoki, 2001). The institutional environment includes formal rules, including competition policy rules, and soft laws, besides "informal" institutions (for instance, market culture or consensus on greening policies in our case).

[5] A theoretical microeconomic analysis of power systems shows that, under a number of stringent conditions, the short-term price that results from a competitive market provides efficient outcomes, both in the short and long run [see Bohn et al. (1984), Caramanis et al. (1987), Vazquez et al. (2002) , Hunt and Shuttleworth, 1997]. In this way, infra-marginal energy revenues provide the necessary income for the recovery of both the operational and investment costs.

There is a structural problem that results from the disconnection of prices that are aligned with short-term marginal costs, the total costs for new equipment, and the risk of not recovering fixed costs. The restructuring of the electricity markets is based on the idea (Joskow and Schmalensee, 1983) that if electricity generators are not able to carry investment risks, vertical integration can be replaced by bilateral contracts between generators and retailers or large consumers, with the assistance of multilateral markets for spot trading and financial markets for hedging arrangements. This idea assumes completeness of the markets, including financial hedging products with long maturity periods (see, for instance, IEA, 2007).

However, in practice, electricity market restructuring that is based on unbundling activities and market exchanges has certain market-related imperfections, as compared to the theoretical model. There is no financial market for long-term hedging products (see Roques et al., 2006, Gross et al., 2010), and there are weak incentives for suppliers/retailers and electricity generators to contract forward and share risks in the long term. The problem arises from the fact that the interests of generators and wholesale buyers (suppliers, large consumers) are not aligned regarding the duration of contracts on the price and quantity provisions (Roques, Newbery, Nuttall, 2008, Chao, Stoft, Wilson, 2008; Finon, 2011). Electricity producers that prefer such long-term contracts cannot find credible counterparts among suppliers or large consumers (Roques et al, 2008, Green, 2004, 2006). Retailers are hesitant to sign long-term contracts when their customers can simply switch to an alternative provider in the case of reversal of the market price trend.[6]

As a result, these market imperfections increase the cost of capital and hurdle rates for investors in power-generation technologies. This, in turn, can lead to a suboptimal generation mix, as producers are encouraged to invest in technologies that have the lowest capital intensity and that are 'self-hedged', such as combined cycle gas turbine (CCGT) plants (Roques et al., 2008; Roques, 2011).

To overcome the obstacles to establishing risk-sharing mechanisms and long-term contracts, the governments of many countries have introduced 'out-of-market' mechanisms to secure investments (Finon, 2011; Finon and Roques, 2013; Genoese et al., 2016). In the case of clean technologies, the various forms of support mechanisms have all involved some protection in the long term against market risk. Similarly, recent reforms to introduce capacity mechanisms in Europe have introduced a role for long-term capacity contracts in securing revenues and facilitating financing. In addition, these policy interventions are supplemented by the creation of a credible counterparty for these long-term contracts, either the state or suppliers, *via* obligations placed on them to procure these contracts.

The risk-hedging mechanisms and Long-Term Contracts module represent a combination of programming procedures and market-oriented selection of contracts with public agencies or counterparties with a regulated obligation to enter into long-term contracts, albeit with many variants. It is noteworthy that the implementation of such arrangements relies on their compatibility with the legal environment. In Europe, for instance, the competition policy rules tend to restrict to specific cases the possibility to establish long-term arrangements.[7] Under current legislation, long-term contracts are subject to case-by-case approval decisions, which can create significant uncertainties.

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[6] Transaction cost theory offers a clear-cut interpretation of this situation in terms of the risk of opportunism on the side of the counterpart in a transaction that concerns the development of a specific asset (see Meade and O'Connor, 2011).

[7] The legal framework of competition policy and anti-trust measures could limit the development of such policy instruments, as is the case in the EU (Marty, 2015; Hauteclocque, 2013). However, recent reforms in Europe have resulted in the European Commission adopting a pragmatic approach and weighing the pros and cons of long-term contracts with respect to competition (Roques et al., 2013).

- **The Capacity Mechanism module**

According to the peak-load pricing theory (Boîteux, 1949, Joskow, 1976), situations of short-term scarcity during peak load periods play a key role in returning investment costs and providing adequate signals for investment. However, there is growing evidence that the current markets cannot guarantee reliability of supply in every situation in the long-term, for various reasons: 1) price caps and barriers to scarcity pricing that result from politically unpalatable high power prices often lead to a chronic shortage of revenue for plant operators (the so-called "missing money" issue, as referred to in the academic literature); 2) aversion to risk associated with investing on the basis of very uncertain revenues from scarcity rents; 3) the incentive for power generators to maintain, through tacit collusion, a situation of relative scarcity; and 4) the difficulty related to hedging or transferring risk on a long-term basis (Cramton, Stoft, 2006; De Vries, 2007; Joskow, 2008b; Roques, 2008; Cramton, Stoft,2014; Keppler, 2016). This issue of guaranteeing reliability of supply in the long term is exacerbated by the development of variable RES (VRE), which amplifies price volatility in peak and creates greater uncertainty for annual sales by peaking units (Cramton, Ockenfel, Stoft, 2013).

Indeed, the origin of the problem lies in two issues: 1) a market imperfection, which entails the absence of price-reactive demand; and 2) the willingness of policymakers to define an administrative SoS criterion that may differ from the socially optimal one. This calls into question the rationale of relying on market forces to determine the level of installed capacity that is adequate to guarantee SoS (Keppler, 2016).

The solution lies in the introduction of a capacity remuneration mechanism (CRM), even if a wide range of options exists with different performance profiles in terms of effectiveness and cost efficiency. The scope of this paper does not allow a comparison of these mechanisms, which are well-covered in the literature.[8] Nevertheless, the CRMs that are the most efficient at reaching a desired target of capacity adequacy in a timely way and that avoid market power exercise issues are those based on a "quantity-instrument", which combines planning through setting a reserve margin target and auctioning forward contracts (central auctioning or eventually decentralised calls for tenders by obligated suppliers).

To date, the experiences with CRMs are diverse, as some European countries (UK, France, Italy, Greece, Poland) have only recently taken steps to introduce forward capacity markets, whereas some US actors (for instance, the US regional electricity transmission organisation PJM) have gradually reformed their capacity markets over the past 15 years. Interestingly, some Latin American countries that reformed their electricity markets in the 2000's so as to guarantee both energy reliability and capacity adequate for their growing demand (Brazil, Colombia) have installed a module that is based on long-term energy and/or capacity contracts and that merges the Long-Term Contracts and Capacity Adequacy modules (see Section 4.1). Another interesting case study is the British capacity mechanism included in the Electricity Market Reform law, which is based on long-term forward contracts for new conventional plants and shorter-term contracts for existing plants (see Section 4.2). It is noteworthy that, as is the case for the Long-Term Contracts module, competition policy rules at the supranational or federal level might restrict the autonomy of governmental decisions on this matter.[9]

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[8] The respective advantages and drawbacks of the different CRMs are compared in several publications (Cramton and Stoft, 2006; De Vries, 2007; Roques, 2008; Finon and Pignon, 2009; Cramton et al., 2013; The Brattle Group, 2012, 2014).

[9] The capacity mechanisms adopted by some EU Member States are subject to an EU state-aid review.

- **The RES-Decarbonisation module**

Several studies have shown that the price signal of power markets alone fails to incentivise fully investments in RES and LCTs *via* the carbon price signal for a number of reasons (Hepburn, 2006; Jaffe et al., 2005; Grubb et al., 2008; Finon and Roques, 2008; Lehmann and Grawell, 2013). First, RES technologies are not yet fully mature, and RES plant manufacturers and investors cannot yet reap the benefits derived from cumulative learning, which reduces the incentive to invest in non-mature technologies. Second, these investments are exposed to the usual risks of high upfront costs on the power markets (see above), to which can be added the high investment risks inherent to immature technologies combined with important political and regulatory risks inherent to these technologies, even for the small-sized RES projects. Third, the carbon price signal stemming from carbon markets inherently lacks credibility in terms of playing its role as a signal for investors.

The conclusion drawn is that it is necessary to use long-term arrangements with a public regulated entity in order to decarbonise power systems and stimulate investment in LCTs, in addition to the implementation of a carbon price (Neuhoff et al., 2007, Grubb et al., 2007; Boot, 2010; Grubb and Newbery, 2008; Newbery, 2011; Finon, 2011; Finon and Roques,2009, 2013). For mechanisms that are not based on such arrangements, in particular the green certificate obligations, the experience in the UK and the US states is that the logic of the functioning of the decentralised obligations leads developers and obligated suppliers to enter into long-term contracts to share risks (Mitchell and Baucknecht, 2006) .

The experience with policies that aim to support RES-E in liberalised markets shows an evolution in favour of mechanisms based on long-term arrangements to guarantee revenues, e.g., the abandonment of renewables obligations in favour of FITs and the auctioning of long-term contracts in Europe[10], and the self-development of power purchase agreements (PPAs) inside the renewables portfolio standards (RPS) mechanism in the restructured markets in the US (Wiser et al., 2007; NREL, 2014). These mechanisms have the dual functions of subsidisation and risk sharing; the latter function gains importance as technologies come close to commercial maturity. In fact, the three main mechanisms of RES support, feed-in tariffs (which are guaranteed in the long term by the government), auctioning for the assignment of long-term purchase contracts, and the system of renewables certificate obligations imposed on energy suppliers (combined with certificate exchanges), have in common that they impose an obligation to purchase RES electricity on clearly specified agents (either public agencies or regulated agents), eventually in the form of a green electricity obligation on the suppliers, and that they establish long-term arrangements between RES investors and these credible counterparts. Recent changes to the FIT mechanism in Europe (since 2015) towards a floating feed-in-premium (FIP), and the auctioning of physical long-term contacts to contracts for difference (CfDs), which implies that the RES-E producers sell their electricity to the wholesale markets, are consistent with these principles, whilst improving the incentives of RES generators to participate in wholesale markets.

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[10] The renewables obligation (RO) was supposed to be superior to FITs in terms of incentives created by the market pressures to more efficiency when investing and operating, although in reality the RO appears to be more costly for the obligated purchasers and consumers than a feed-in tariff mechanism, due to the risks borne by investors and the higher risk premium associate with the capital cost (Butler and Neuhoff, 2004; Mitchell, Bauknecht, 2006; Mitchell, 2007; Woodman and Mitchell, 2011). Indeed, a major issue with the RO mechanism is the foreseeability of revenues: there is a dependency of the revenue value on the timeframe of the mechanism (the horizon of the obligation that defines the time-scale during which a new project could draw a value from its certificates), the regulatory changes linked to the design (adaptation of technology bands, buy-out price, etc.), and the uncertainties of certificate prices and wholesale electricity prices. At the end of the day, a policy based on an RO is less effective than a FIT, given that developers are more restrained by risk management, and is more costly due to the higher cost of capital.

In summary, different market and regulatory imperfections have led a number of countries to embark on wide-ranging market reforms in order to provide better incentives for the following investments: in all technologies in countries with fast-growing demand; in RES and low-carbon plants in countries with decarbonisation policies; and in fossil fuel plants (peaking units) through capacity mechanisms in countries that are vigilant regarding the security of electricity supply. This marks a significant shift away from the theoretical textbook electricity market design, in which investment decisions are made by market participants based solely on price expectations. These long-term 'out-of-market' modules are designed to guarantee the recovery of fixed costs and to de-risk investment *via* some risk-sharing arrangements between producers and consumers, while they make it possible to subsidise production in the long-run for the new technologies. However, this raises the issue of the consistency of these new market modules with the wholesale markets, and their subsequent evolution, which is the focus of the next section, which is based on a number of international case studies.

4. LESSONS FROM INTERNATIONAL BEST PRACTICES FEATURING MODULES THAT PROVIDE LONG-TERM SIGNALS

Overall, the hybrid markets comprise a form of public intervention in terms of SoS, determination of the generation mix, and/or the development of transmission networks. However, these hybrid models vary widely depending on the objective and type of public intervention, as well as on the resulting allocation of risks for investment between private generators and government or consumers. This section investigates a number of case studies of hybrid power markets from Latin America and North America, in which the power markets are complemented by long-term modules to ensure the adequate and timely development of generation plants in terms of energy and capacity, as well as cases from European experiments with decarbonisation, in particular the comprehensive approach of the UK, which synthetises the different types of market "hybridisation".

4.1. Adjunction of long-term modules to support investment in generation

- **"Reforms of the reform" in Latin America**

The initial wave of electricity market reforms that started in several Latin American countries in the 1980s failed to stimulate timely investments, in particular in high-sunk-cost equipment, such as hydraulic plants. Moreover, as many of these systems include a large share of hydraulic generation, market designs that produce volatile prices have been very vulnerable to episodes of drought in Argentina, Brazil, Chile, Colombia, Peru, etc., with long-lasting price spikes and the imposition of rationing for consumers. This triggered a second wave of electricity market reforms in the early 2000s, which introduced long-term contracts to support and coordinate investment (Battle et al. 2010; Moreno et al., 2010, 2011; Rudnik et al., 2002, 2006).

These arrangements have identified specific roles for the spot market and for long-term contracts:

- Short-term system optimisation (dispatch) based either on variable costs (Brazil, Argentina, Chile, Peru, etc.) or on bid prices (Colombia, etc.); and
- Long-term investment decision-making, largely driven by auctioning of long-term contracts either for capacity as in Colombia (Larsen, 2004; Harbord, Pagnozzi, 2012), for energy as in Chile and Peru, or for both as in Brazil.

This hybrid market framework ensures competition in two forms: 1) competition "for the market" through the auctioning of long-term contracts; and 2) competition "in the market", where existing power generators compete to supply energy through the spot market.

In practice, there are significant differences in the key implementation parameters across Latin American countries, such as the degree of centralisation of the arrangements, the responsibility for load forecasting for anticipating capacity needs, the types of products procured (energy or capacity or both, delivery date, etc.), and the auction procurement approach (frequency, type of auctions, etc.). For example, the Brazilian model features centralised procurement of long-term contracts, while the Chilean model features a decentralised procurement model based on an obligation being placed on retailers to commit to long-term contracts to cover their future loads.

Beyond these differences, a common condition for the feasibility of these different market designs is the remaining retail monopoly of the distributors (with the exception of the supply for very large consumers). As discussed further below, this allows a credible long-term commitment on the side of the retailers and an efficient risk sharing between the investors and their counterparts within the contractual structure.

These 'hybrid markets' have attracted significant interest from investors in a range of technologies, including large hydro projects through the Long-Term Contracts auctions. One key benefit of long-term contracts is that they support an efficient allocation of risks and enable project financing with reasonable hurdle rates, thereby reducing financing costs. They have allowed the development of renewables projects, initially through technology-specific auctioning and subsequently through the normal process, which is techno-neutral.[11]

- **The UK Electricity Market Reform: the ideal type of comprehensive reform**

The UK, as well as several other EU Member States (Belgium, Italy, Sweden, Poland) first implemented a market-based instrument, the renewable obligation, complemented by a certificate exchange, which was supposed to be consistent with electricity market functioning. However, the functioning of the mechanism was perceived to be: ineffective in terms of capacity installation (the obliged suppliers preferring to pay the buy-out price for a significant part of their quotas); costly per RES-E MWh (due to the risk premium for the cost of capital); and exposed to regulatory capture for the definition of rules (technology bands, target, etc.). After Year 2010, given the increasing importance placed on climate policy and the poor efficacy of the renewables obligations, the UK government preferred to implement a wide-ranging market reform using long-term arrangements to maintain SoS and support clean technologies (RES as well LCT).

In the past 5 years, the UK has implemented a wide-ranging reform of its electricity market arrangements (OFGEM, 2010; DECC, 2011, 2013). The 2013 Energy Act focused on reforms aimed at attracting the investment needed to achieve decarbonisation of the sector while simultaneously ensuring SoS. The Electricity Market Reform (ERM) introduced two main mechanisms based on auctioning of long-term contracts:

- Auctioning of long-term contracts for RES and LCT projects in the form of contracts for difference (CfDs) to be established with a public agency or a regulated entity.[12] CfDs provide a top-up payment for the energy produced by these generators with respect to the reference market price (while it obligates the producer to reimburse the difference between the

[11] However, concerns remain the effectiveness of the auction mechanisms, and continuous improvements have been made over the past decade (Tolmasquilm, 2012).

[12] In power markets, a contract for difference (CfD) is a long-term financial contract between two parties, typically described as the "buyer" and "seller", which stipulates that the seller will pay to the buyer the difference between the current value of the energy on the hourly market and its value in the contract (if the difference is negative, then the buyer instead pays to the seller). In effect, CfDs integrate symmetrical option contracts that make it possible to guarantee a long-term revenue for the investor.

contractual price and the market price when the latter is lower). CfDs are intended to provide support to large-sized RES and LCT plants, in addition to the investment signal generated by the carbon price, and to hedge the market risks between the developers and the public agency. They are complemented by feed-in tariffs for the small-sized RES units.

- Feed-in-tariffs for small-size RES units to avoid the uncertainty and risks of the renewables obligations and the revenues thereof, and to reduce the transaction costs and administrative risks of contracts auctioning for these small units.
- A capacity market that includes long-term capacity contracts for new conventional equipment, besides short-term forward contracts for the existing conventional plants. The capacity market is based around a centralised auction process that is active 4 years ahead of delivery for new and existing capacities (excluding those already benefiting from the CfDs auctioning system). Unlike the US forward capacity market, new resources can secure long-term capacity contracts (up to 15 years, which are structured as CfDs, making them closer to the Latin-American mechanisms.

In parallel to the EMR,[13] the UK is performing several other reforms of the market arrangements. The electricity balancing reform aims to provide better price signals that value scarcity and flexibility. The reform of zonal network charges aims to provide better locational incentives and coordinate network and generation development.

4.2. Lessons for the design of the long-term modules

Interventions to power markets take very different forms depending on the market surveyed. Our review of international experiences focuses on countries whose market designs retain a role for the market in operational decisions, alongside complementary mechanisms designed to support any (or almost any) investment in generation in different contexts of either demand growth or decarbonisation policies.

The different policy objectives of the experiences surveyed make comparisons difficult, so our ambition is merely to evaluate the conditions under which these different complementary long-term modules, in their centralised or decentralised forms (planning and tendering mechanism versus increasing mandatory obligations), supplement the functioning of the market in a constructive way, so as to compensate the failures of the long-term coordination function of the market. They should drive investment towards technologies that are needed to meet environmental objectives and/or to maintain SoS. These long-term arrangements again provide a stable return on the investment, in the case of additional short-term energy revenues, and thus allow the recovery of total equipment costs. Table 1 shows the comparisons of the long-term arrangements for supporting investment in the different case studies. The elements examined include public governance, the degree of centralisation of the mechanism, the autonomy allowed to generators in terms of investment, the length of contracts to guarantee a revenue over the long term, the degree of technology neutrality, and the means of ensuring flexibility (exchange of certificates, secondary markets, etc.). We draw five lessons from the information in Table 1, and these lessons are discussed in the following sections.

- **The need for careful design of the interfaces between the market and complementary modules**

The first lesson is that the experience with hybrid markets suggests that caution should be taken with their implementation, as complementary mechanisms can be counterproductive if not carefully

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[13] These measures have been complemented by a carbon price floor on the fossil fuel used in the conventional plants to increase the revenue from RES and low-carbon equipment through the market (and reduce subsidies), and by the imposition of an emission standard on new fossil fuel plants to restrict the development of fossil fuel-related equipment**.**

designed. Designing an efficient hybrid market with complementary mechanisms to support system planning and allocate risk efficiently is possible but it requires clear definitions of the roles and responsibilities. The experience gained from Latin America underlines, for instance, the complexity of designing an efficient system for planning and procurement processes with a residual role for the market in the matter of long-term coordination. A key issue relates to the responsibilities and incentives of regulatory authorities and/or operators who are in charge of these planning and coordination mechanisms. Independence from policymakers and the ability to resist potential capture by vested interests are essential. However, the planning process does not necessarily have to be centralised. The experience of Chile, although it highlights the complexities of a decentralised approach, demonstrates that obligations on suppliers to contract generation in the long term can avoid some of the pitfalls usually associated with central planning.

- **Advantages and pitfalls of strong public governance and a centralised approach**

Centralised approaches with strong public governance allow efficient monitoring of LCT capacity development, efficient contracting with effective risk sharing, and lower transaction costs for new projects owing to the possibility of contract standardisation. This is an advantage that the Brazilian centralised auctioning mechanisms for capacity and energy contracts have over the Chilean mechanism for a long-term contracting obligation for distributors with various contractual arrangements being made between the retailers and the generators (Moreno et al., 2010).[14] The British mechanisms (auctioned CfDs, capacity mechanism) present the same advantages of contract standardisation related to the centralism of the hybrid market design.

Another key issue is the responsibilities and incentives of the public entities in charge of these planning and coordination mechanisms. With strong public governance, the ministry, as well as the regulator and the system operator are generally risk-adverse in matters of supply reliability and capacity development. Therefore, if the definition of the target for maintaining capacity adequacy is in the hands of these actors, there is a risk of exceeding the capacity and of excessively favouring some specific options, such as demand response programs in the market segment for small consumers to the detriment of more effective options (load shifting programs in industrial consumer segments, international intraday and balancing markets integration, fast ramping gas turbines, etc.). In other words, there is a trade-off between improved certainty of prices and the remuneration for potentially higher costs due to the cost of imperfect decision-making. That being said, one way to resolve this issue is to organise a multi-level decision process that includes independent expertise, as well as ministries, system operators, and regulators.

Moreover, the planning process does not necessarily have to be centralised from the beginning to the end of the decision process. The experience of Brazil shows that long-term load forecasts can be established by the distribution companies prior to their aggregation by the planner. The experience of Chile, although it highlights the complexities of a decentralised approach, also demonstrates that obligations on suppliers to contract generation in the long term can avoid some of the pitfalls of central planning.

Table 1: Characteristics of long-term modules in some comprehensive reforms

[14] Another aspect of the institutional and industrial structures, namely the presence of State-owned companies, raises the problem reported by Moreno et al. (2011). If auctions make markets more contestable in the presence of State-owned companies, their partial presence, as in Brazil, Colombia, and Peru, suggests possibilities for auction price manipulation, with the government being able to lower auctions prices by making low-value bids during the auction process. This risk needs to be monitored.

	Long term Contracts Module			Comprehensive reform with RES-Decarbonisation and Capacity Mechanism modules			
Country / Province	**Brazil**	**Chile**	**Ontario**	**UK (up to 2015) Renewable obligations**	**UK Capacity Mechanism**	**UK CfD auctioning**	**UK (since 2016) Germany Feed-in Tariffs**
Public governance	Strong	Light	Strong	Strong	Strong	Strong	Light: Eventual quantity cap
Degree of centralisation of mechanism	Joint auctions by a central entity before transferring contracts to distributors	Distributors organise and manage their auctions, possibility for joint auctions	Calls for tender for PPAs by the Ontario Power Authority (OPA)	Decentralised decision to establish contracts	Ministry organises capacity contract auctions and payment by consumers	Ministry organises auctioning of CfDs and payment by consumers	Freedom of developers' decisions
Autonomy allowed to generators in terms of investment	No freedom of timing Techno-neutral	Freedom of timing Techno- neutral	No freedom of timing	Freedom of timing	No freedom of timing	No freedom of timing	Freedom of timing Techno-neutral
Buyers	Regulated users	Regulated users	OPA as single buyer	Obligated suppliers	TSO with some parameters defined by ministry	TSO with some parameters determined by ministry	TSO
Sellers (existing and new capacities)	Separate auctions for existing and new capacities	Existing and new capacities in the same auction	New plants only	Developers and existing RES capacities	Existing and new capacities, demand response and interconnections	Investors for CfDs	RES plants only
Contracts structure	Capacity and energy terms/ Energy part as an option contract	Energy contracts	PPAs with capacity and energy (pay-as-bid). Exposition to market price	Payment of 1-year certificate	CfDs on capacity Long-term for new contracts Mid-term for existing contracts	CfDs on energy Exposition to market price	Long-term revenue guarantee (No exposition to market price /priority access)
Degree of technology neutrality	Techno neutral (with occasionally RES-specific auctions)	All technologies compete together	Specific calls for tender per technology	Abandonment of techno neutrality (Technology bands)		Techno-neutral for RES technologies	Techno-specific feed-in-tariffs
Exchanges	Secondary market		No	Yes	Yes		No

- **The issue of counterparty credibility**

The experiences in Latin America and in the UK point towards the importance of the credibility of the counterparties in the establishment of long-term contracts as the only solution to facilitating financing, allowing greater leverage, and reducing hurdle rates and financing costs. These measures allow the use of project financing or hybrid financing approaches, with clear allocation of risks between the different stakeholders. Similarly, in the UK, long-term contracts within the capacity mechanism (which contrasts with the 1-year contracts in the US forward capacity markets) have an impact on the financing arrangements.

In Europe, the difficulty associated with hedging generation risks without a 'sticky customer base' is a barrier to entry for new investors who develop equipment with high upfront costs. In contrast, in Latin America, tenders for long-term contracts that are established with distributors who legally retain their retail monopolies have driven intense competition for investment in the market, and a number of new entrants has successfully entered into the generation market without having a prior established consumer base in the past decade. In the present European context, the role of long-term contracts in supporting risk transfers and investment is undermined by the total opening up of retail competition required by EU directives.

The long-term contracts needed to develop any new plant should be in fact driven by regulation, more precisely by long-term arrangements established with a public agency or a regulated entity (as the grid companies are), that shares price and volume risks with investors, as in the UK electricity market after the reform. In fact, in Europe, a state counterparty appears to be the easiest way to hedge the risks faced by investors and to facilitate financing and reduce the cost of capital. However, a body that groups solitary suppliers could also act as the counterparty in long-term contracts, as envisaged in the UK for CfDs.

- **Efficiency of long-term contracts auctioning and impact on competition**

Experience demonstrates that long-term contracts can have a pro-competitive effect and support an efficient allocation of the risks between market players. An issue is the access to information and the asymmetry with market players for the authority in charge of system planning, which points towards the use of information-revealing mechanisms, such as auctions. The organisation of competition 'for the market' through the tendering of long-term contracts has proven in Latin America and in the UK to be an efficient way to exert competitive pressure on investors and to drive down the costs for both LCTs and thermal plants, in particular in terms of the financial costs (Maurer, Barroso, 2010; Newbery, 2011, 2016; Mastropietro et al., 2014).[15] This was the spirit of the reform proposed in Year 2014 by the European Commission in relation to renewables promotion policies in the EU, designed to suppress FITs, which were regarded by the latter as distorters of the market and competition. The reforms of the support mechanisms that are being currently introduced in the EU Member States follow the Year 2014 Guidelines on State Aid (DG Comp, 2014) and are intended to promote greater cost-efficiency of RES capacity development through auctioned CfDs or floating Feed-in-Premium arrangements.

[15] Newbery (2016) showed that the first CfDs for RES were priced initially by bureaucrats at the DECC, on the advice of consultants and after discussions with investors, using a high WACC of 7.9% with a CfD. However, when the DECC decided to adopt auctions for allocating specified volumes of RES (mature, less-mature, off-shore wind and immature technologies, tidal stream etc.), the resulting clearing prices for on-shore wind reduced the WACC by 3% real.

5. INCONSISTENCIES BETWEEN OLD AND NEW MARKET MODULES: THE NEED FOR RECURRENT ADJUSTMENTS

In the hybrid market regime that results from the adjunction of some of the three long-term modules, several issues arise from the interactions between the market and supplementary modules. Where modules are in place to reduce risks for peaking units, for RES and LCTs, or for any technology (as in Latin America), there are concerns regarding how these affect the remainder of the initial modules and regarding the physical effects on system operation of large-scale VRE production.

It is mainly in Europe that the low-carbon policies based on variable renewables have raised the issue of inconsistencies being introduced between the additional modules and the initial modules of markets and network access, particularly when the VRE capacity and production have reached significant shares. Indeed, the tensions between modules are revealed when these shares in capacity and energy production of the system reach a threshold, let us say, of10%–15%. Beyond this threshold, the system costs of the RES production (which are not internalised with the FIT by the VRE producers) and the total cost of the RES policy (assimilated into the difference between the market prices and the feed-in tariffs) become significant. On one side, the system operators must bear the system costs caused by VRE production, without compensation. On the other side, the increasing importance of the levy to finance the policy cost in the total price paid by the consumers leads a government to envisage control of this cost by reforming the mechanism. A complementary element of this awareness is the effect of RES-E production on the hourly prices and the revenues of the conventional plants, which reflects the important stranded costs for the conventional plants and strong depreciation of these assets, which are generally owned by the dominant companies.

In this section, we identify the tensions that can occur between the new long-term modules and the existing modules, their self-reinforcing effects, and ways to limit or remove these tensions by improving the initial modules for markets and grid access.

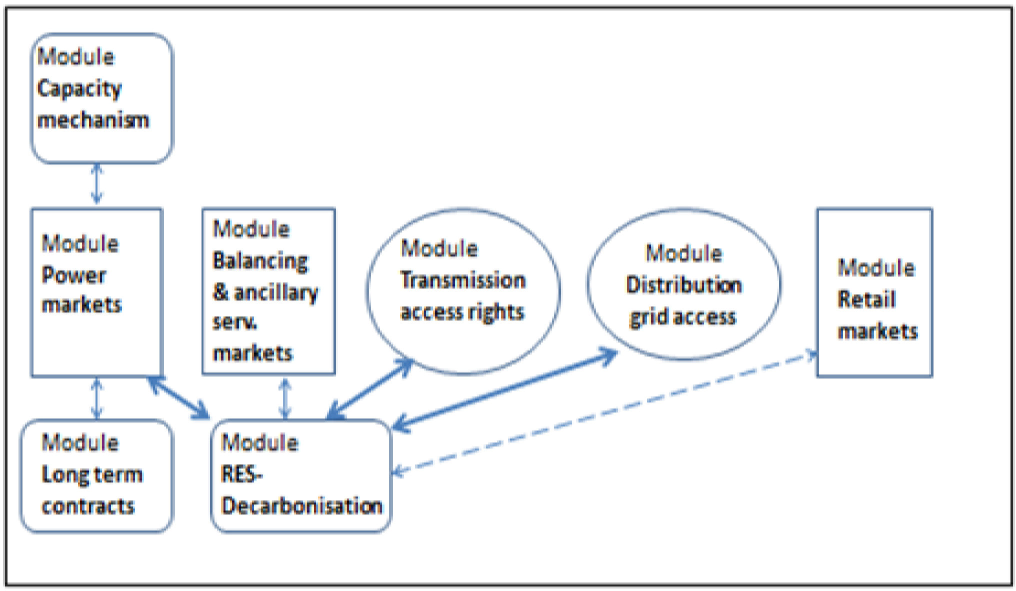

Figure 2. Interactions between initial modules and long-term modules

5.1. Common tensions between the Long Term Contracts and RES-Decarbonisation modules and the Power Market module

In the countries with market designs that include a Long Term Contracts module that covers every generation investment in RES (Latin American countries in our sample above) or those with an RES-Decarbonisation module, which triggers the majority of investments in mature markets with a prioritised decarbonisation objective (as in EU countries with former FITs, and now auctioning for FiP contracts or CfDs), the power market loses the function of long-term coordination, while the mechanisms of these two long-term modules self-reinforce.

In the first group of countries, the investment in various technologies that are promoted by the long-term arrangements requires a significant share of low-variable-cost technologies (hydro plants, large-sized RES units) to achieve the optimal mix. These investments tend to lower the annual average price on the hourly energy markets by displacement of the merit order in favour of new lower SRMC plants.[16] This fact reinforces the existing mechanism, which is based on long-term, risk-sharing arrangements, and consolidates the comprehensive hybrid model adopted in these countries

In the second group of countries, this interaction between the RES-Decarbonisation module the Power Market module is clearer. The production of RES units enters the system *via* out-of-market arrangements (helped by priority dispatch, which avoids them having to pay for their system costs), to the detriment of existing conventional plant equipment on the day-ahead market. Dispatch distortions exert two important effects on the merit order[17]: a decrease in the wholesale prices and a decrease in the yearly production of existing plants, with each effect being uncertain to occur in any subsequent year. New zero (low)-variable-cost plants based on RES or LCTs displace more expensive thermal plants and reduce the average power prices.[18] The recovery of the fixed operational costs of existing equipment is challenging, and the price signal to trigger investment in conventional technologies, which are still necessary to back-up the VRE production, is definitively distorted. Indeed, the revenues of any new conventional plants are lowered and placed at risk by the uncertain outcomes of the policies in terms of the shares of energy production.

- **Consequences**

This has two important consequences for general market design. First, the use of long-term arrangements for promoting RES and LCTs is likely self-reinforcing, even with commercially mature technologies, which moreover would be made more profitable with a high carbon price. Investment in capital-intensive RES/LCT plants would not be financially viable if these mechanisms were removed. This definitely raises questions as to the transitory role of these arrangements as politically presented. In fact, if decarbonisation is retained as a priority objective, the evolution towards a power market regime, including long-term arrangements, appears to be irreversible.

Second, it becomes necessary to complement the revenues of the existing conventional plants, as well as those of potential new plants. Existing base-load and peak-load units tend to be operated with much smaller and uncertain annual load factors and to have lower revenues when they are dictated by the hourly market, which leads to decisions as to early retirements. A number of existing

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[16] This is the case irrespective of the energy market design, whether it is the classic bid price-based form or the cost-based form, as in several Latin American countries where the market operators refer to the SRMC of the different plants that declare their availability (for the market design in Brazil, see Tolmasquim, 2012).

[17] Not to mention negative price episodes due to the rigidity of the equipment fleet (which is discussed later in relation to the problems associated with system balancing).

[18] An example is the increase in the average electricity price reduction from 5 €/MWh in 2010 to around 13 €/MWh in 2015 in Germany, while the RES share of energy production increased from 10% to around 30% during the same period (Öko Institut, 2013; Praktiknjo and Erdmann, 2015).

conventional plants, even recent ones, cannot even cover their operational fixed costs, without mentioning asset depreciation to their owners. This leads to decisions of 'early retirement' and definitely deters investment in thermal plants in the EU countries, where they are needed as back-up for variable RES production (NEA-OECD, 2012). In other words, the market fails to compensate fully for the stranded costs and depreciation adjustments that result from the RES and low-carbon policies, and fails to signal the new equilibrium with an optimal share of flexible conventional plants other than RES and LCT capacities, for back-up of the variable production.

A solution to the problems of the decreasing economic value of non-RES plants generated by the energy markets and the barriers to new investment in conventional technologies is the creation of a capacity mechanism. In order for it to be attractive to investors, conventional plants would need to procure complementary revenues. This could not come solely from new ways to remunerate flexibility products on intraday markets, balancing mechanisms, and ancillary remuneration (which are detailed below), as some have argued (Hogan, 2015). Indeed, efficient remuneration of flexibility products and system services introduces such high volatility in revenue streams that they become barely credible as a long-term price signal for investment in conventional plants with flexibility qualities[19].

5.2. Tensions between the RES-Decarbonisation module and the Balancing-Ancillary Services module

Existing electricity systems are generally poorly adapted to offering flexibility services at the level needed in a system in which a very high share of renewable energy has been reached. While some heavy industry demand responses, pumped storage hydro, and merchant interconnections have been accommodated within existing electricity markets, this is a long way short of offering the high degree of flexibility that an electricity system with very high shares of renewable energy would require. The solution to developing flexibility resources mostly lies in market incentives to develop flexibility resources, in particular in improving the Balancing-Ancillary Services module. The development of VRE reinforces the need to reward operational flexibility, as well as dependability over short time-frames, both for flexible power plants and demand-side response. The value of operating flexibility is typically captured through price variations in day-ahead or intraday markets, balancing mechanisms, and ancillary service contracting. This should be where prices optimise the system in the short run, reveal the value of electricity-related products on an hour-by-hour basis, and thereby orient investments towards flexible resources in the long run (IEA, 2016).[20] This issue is crucial for the European markets, in which existing market designs are both less-detailed in terms of products than the US market designs (Saguan, 2009) and are poorly adapted to value flexibility and thereby direct investment towards flexible resources.

- **Consequences**

In European countries, there are growing concerns that such short-term price signals do not reflect accurately the scarcity value of operating flexibility in many countries, leading to calls to revisit the current arrangements for intraday trading, real-time/balancing market mechanisms, and ancillary

[19] The limited scope of this paper does not allow us to develop this issue. Some researchers argue that flexibility services remuneration would be sufficient to trigger investment in flexibility resources and by this route, it should be possible to solve the problem of 'missing money' for investment in capacity for improving the reliability of the system in any situation (Hogan, 2014).

[20] Improvement could be made through the development of 'ancillary services' products and improvement to intraday energy markets on the one hand, and market-based mechanisms for reserves and (ancillary) system services on the other hand. This could be achieved by moving trading on system service markets closer to real-time. Market operators should facilitate trading as close as possible to real-time (for instance, by the introduction of power delivery contracts that allow the trading of electricity in 15-minute blocks rather than in blocks of one full hour, as before) and up to 45 minutes before real-time (rather than 1 day before real-time).

service procurement, so as to orient investment towards flexible resources and to lower the operational costs of the system. As a first consequence, each sequence of these successive markets should be improved to reflect scarcities over time, including the perspective to integrate the intraday and balancing markets between systems. This should be accompanied by improvement of transmission pricing to reflect scarcities over space (see below).

A second consequence is the necessity to drive the evolution of the RES-Decarbonisation module by:

- 1) making RES producers pay for their system costs, so that they have an incentive to reduce these costs (through better production anticipation on day-by-day and hour-by-hour bases, self-curtailment, offering ancillary services, etc.);
- 2) easing the market valuation of flexibility services. Indeed, for developing exchanges of flexibility products, it is important that VRE producers become responsible balancers, in order that these markets become liquid through creating high demands on the intraday and real-time (balancing) markets. Flexible resources, such as fast ramping plants and storage units, should find higher value on these markets with more granular products.

5.3. Tensions between the RES-Decarbonisation module and the Transmission Access and Distribution Grid Access modules

The VRE units, which are mainly decentralised, are connected to the distribution grids, without any price signal to indicate the districts behind congested transmission lines. The locations of these units could generate new congestions within the transmission system. This raises the issues of optimisation throughout the network and of generation that is made increasingly complex by the growth of this variable generation, as well as the need for flexible resources (demand response services, different types of storage plants etc.). The absence of locational price signals or locational transmission charges does not allow for economically optimal development of the network and generation system.

In this perspective, it is not only important that electricity prices and transmission charges convey locational signals to optimise the operation of networks, production levels, and loads in different nodes of the network, but also that they provide incentives to locate new production assets and flexible resources and to build new transmission and distribution lines, using price signals that are sufficiently tuned to allow socially efficient location (Li Fi et al., 2009; Glachant et al., 2013; EISPC, 2013).

However, the problem is not only at the central level. When the VREs are mid-size and small-size plants they are generally connected at the level of the distribution grid. This means that the reliability of supply problem is first raised by the VREs at the decentralised level. The roles of distribution system operators (DSO) should be changed, and the regulation of distribution grids should be improved. When the development of small-scale generation, distributed demand-side response, and electric vehicles are scaled up, which will affect the distribution system operation, these will be powerful incentives to make distribution grids “active”.

- **Consequences**

One solution is to move progressively from quite simple transmission access tariffs to zonal tariffs, or even better, to locational tariffs (reference).

An alternative strategy involves activation of the roles of the DSOs to complement the adaptation of the modules Balancing Services and Transmission Access. More efficient regulation will be valuable if it provides the right incentives to DSOs and allows them to optimise between CAPEX and OPEX: for example by using local flexibility – in coordination with TSOs – to facilitate RES integration and possibly limiting or postponing costly T&D grid investments, eventually through VRE production curtailment (see Brandstätt et al, 2011; Florence School of Regulation, 2013).

The distribution grid operators could decide to turn off renewables at times of excess generation, which is currently the case in Ireland, with different forms of compensation (Anaya, Pollitt, 2014), so as to make the VREs and other distributed generators participate in ancillary services (frequency and voltage regulation) at the local level and to engage in program load shedding or load shifting with the aggregators. Smart rules for curtailment could be a way to avoid over-investment in transmission and distribution grids (Kemfert et al., 2016).

5.4. Tensions between the RES-Decarbonisation module and the Retail Market module: the issue of RES policy cost

While the price signal of the power market becomes more inefficient for triggering investment decisions in conventional technologies, there is an increasing discrepancy between the energy market prices paid by consumers and the total costs of production. This results from the higher cost for MWhs produced by RES that have entered under a specific regime of long-term arrangements, including the system costs that they generate. To fill the gap, the money for subsidies needs to come from somewhere, generally from a specific charge paid by the consumers. However, the rules of the cost reimbursement process and its accountability are totally at the discretion of the government, which is far from the ideal textbook model of cost-reflective pricing. Indeed, governments are tempted to reduce the burden for energy-intensive industries for reasons of competitiveness and to overcharge medium and small consumers. This inequitable burden sharing has two consequences. First, it distorts the price signal of electricity to the large industrial consumers, which are not incentivised to adapt their consumption levels and their equipment to higher electricity costs. Second, it raises an important distribution issue, as underlined in the German case (Okö Institut, 2013).[21] Regardless of the reason, when the RES/LCT additional costs related to the market prices reach a very high level, governments are obliged to to reform the support mechanism , especially if the redistribution issue becomes critical in policy terms.

- **Consequences**

The main primary solutions rely on cost-containment procedures, through the definition of a cap either on yearly capacity to be installed by technology or on annual expenditures per technology and overall policy. Control of quantity through definition of capacities to be auctioned or by a quantity cap typically relies on a programming approach. The procedure in terms of a quantity cap, which is certainly easy to manage, could also be aligned from a social efficiency perspective, which follows the decrease in the economic value of marginal VRE capacities in the market as and when they develop. Research studies show that there is an optimal total share of VRE in systems (around 20%–30% of the energy), attributable to the effects of the order of merit, their system costs, and competition from other low-carbon technologies (Hirth, 2015), which can be identified using complex models that take into account the flexibility resources of the system.

6. CONCLUSIONS AND POLICY IMPLICATIONS

Electricity markets need to be supplemented with some form of public coordination of investment to meet the security of supply and decarbonisation objectives. Liberalisation reforms have eliminated this function, which combined long-term planning and public procurement in previous utility regimes. As a solution, adaptations can be made that introduce some form of long-term coordination

[21] Referring to the German case as being topical on this redistributive issue. When the RES share of energy production reached 21% and the total costs of the policy were €23 billion in 2015, the discriminatory levy (EEG) was 62 €/MWh for households and SMEs, while industrial consumers, in particular the larger ones, paid only 0.5 €/MWh. The large consumers pay only 5% of the cost of the policy while they account for around 30% of the total consumption.

of market participants, while incentives for competitiveness are preserved through auctioning long-term generation contracts with public or regulated entities. In parallel, the short-term market coordination function should be enhanced to optimise the operation of the power generation units of market players, so as to increase the supply of energy and improve the flexibility of the supply and the offer of flexibility products on the markets?. Thus, most of the electricity markets around the globe that are committed to the priority objectives of decarbonisation and supply security are currently (or will become) 'hybrids', with a mix of short-term coordination by markets and a significant role for the state in planning and capacity procurement, thereby replacing the long-term coordination role of the market.

In this paper, we apply a functional perspective of institutional dynamics to identify the additional modules of rules to be added to the initial market architecture, in order to pursue the long-term policy objective of decarbonisation while maintaining the security of supply. In addition, we identify the adaptations that need to be made to the established modules when the development of RES within the system reaches a significant threshold, beyond which system operation is dramatically affected. The functional approach allows us to identify some supplementary modules than can be used to address current market imperfections and/or achieve policymakers' objectives. In particular, there is a need for long-term arrangements to support investment in capital-intensive equipment, together with public or regulated entities, which would enhance risk sharing and coordination mechanisms.

The introduction of such additional modules will affect the pre-existing market, and adjustments will be required to overcome the resulting inconsistencies and overlaps. In particular, there is a need to improve the design of the former modules, for instance with regards to balancing, ancillary services, and network access, to improve scarcity pricing of the flexibility resources (i.e., fast ramping, storage, demand response) and locational congestion in the transmission and distribution grids.

While these market interventions were initially thought of as being temporary, it is important to point out the self-reinforcement effect of the need for these complementary mechanisms as the penetration levels of RES and LCT equipment at zero or low variable costs increase. This leads to a new hybrid approach to market design that differs significantly from the original textbook approach that guided the first wave of industry restructuring. The new hybrid market design relies on a combination of long-term risk sharing arrangements and improved markets that are entrenched in a function of short-term coordination, whilst long-term system development is primarily driven by the new 'out-of-market' mechanisms supporting the achievement of the policy objectives towards decarbonisation and security of supply.

One can, of course, question the convergence and irreversibility of these movements towards a hybrid market regime given the wide range of experiences and designs across the different countries. Local institutional, legal, and political parameters, as well as exogenous factors affect the processes of adaptation, correction, and adjustment of the general market design and the different modules installed at the different steps of the evolution process. However, despite the variety of rules and arrangements adopted in the different countries, the underlying principles that drive the 'reforms of reforms' are similar.

We review the international experience of best practices in relation to modules of hybrid market design and, in line with our functional perspective, we make a number of policy recommendations as to best practice in the design of the long-term modules (long-term contracts with public/regulated entities, RES arrangements, capacity mechanism). We highlight the need for careful design of the interface between the market and complementary modules, so as to minimise distortions and unintended effects. We also highlight the advantages and pitfalls of strong public governance and the use of a centralised approach rather than a decentralised approach for the procurement of new capacities for various technologies.

Overall, these considerations illustrate the institutional and regulatory developments that are underway in the countries with emerging economies and within the EU, and which are likely to occur in the USA in those states with liberalised markets following the implementation of the EPA's Clean Power Plan (US EPA, 2015). The move towards a hybrid market regime appears to be unavoidable as long as governments want to be involved in determining the generation mix and to guarantee SoS at an administrative level. While more research is required to bring forward a new 'target model' for electricity market design, the recognition that government involvement is here to stay, given the policy objectives of decarbonisation, would help to cast a new light on existing legislative and regulatory practices. For instance, this recognition would have profound implications for the EU, where market design and policy interventions are scrutinised under the competition policy and state aid rules.

More fundamentally, our institutional perspective on the evolution of electricity market design highlights the importance of a sound governance process that allows for a dynamic approach to market design. Policymakers and regulators need to recognize the need for periodic adjustments in the market and regulatory framework; this requires strong governmental direction and procedures that minimise the regulatory risk and do not have an adverse effect on investment.

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