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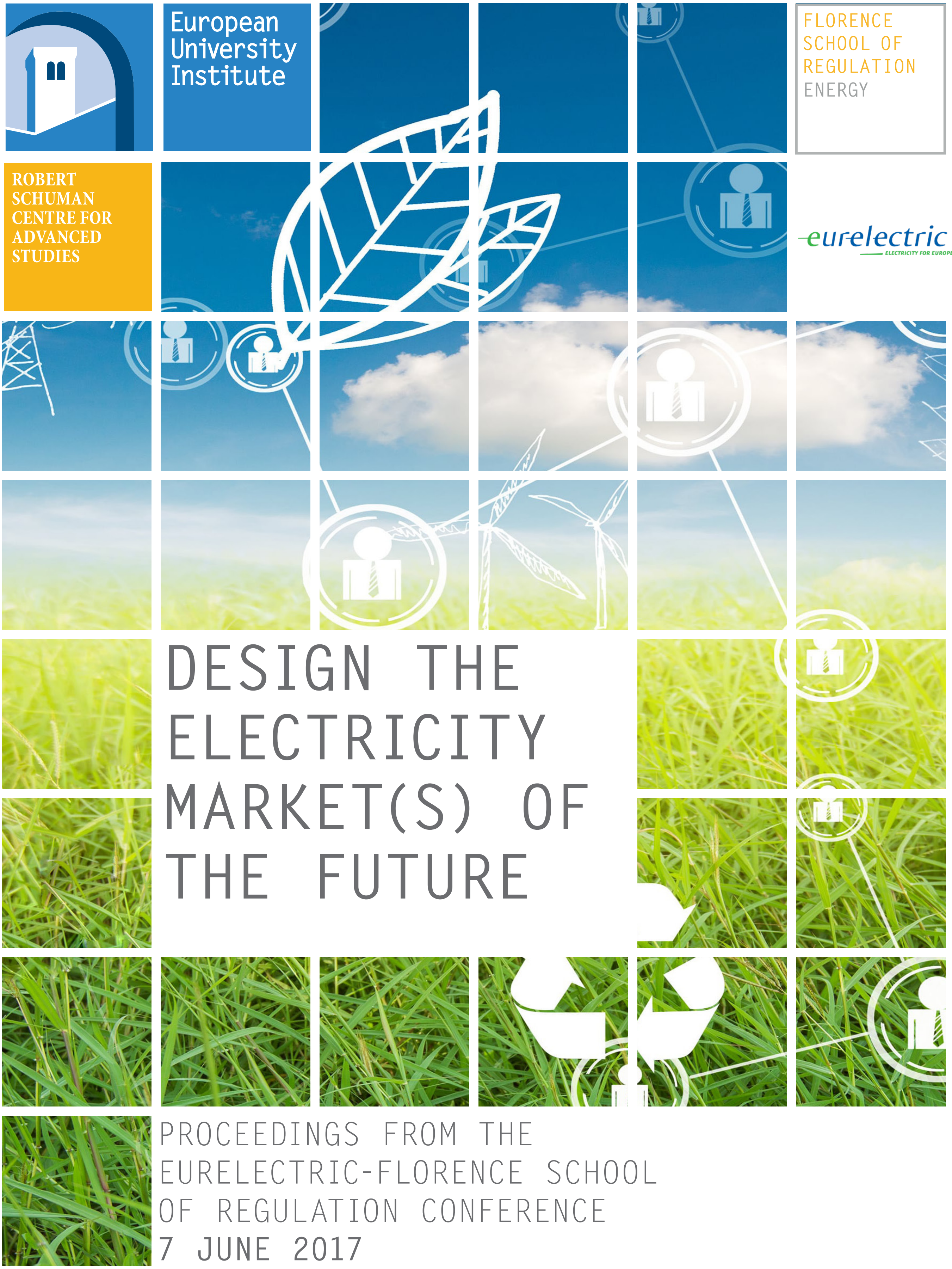

DESIGN THE ELECTRICITY MARKET(S) OF THE FUTURE

PROCEEDINGS FROM THE EURELECTRIC-FLORENCE SCHOOL OF REGULATION CONFERENCE

7 JUNE 2017

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7 JUNE 2017

Edited by
Nicolò Rossetto

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ABSTRACT

The profound transformation of the European electricity system is putting the design of the electricity markets that emerged during the restructuring of the 1990s and early 2000s into question. The need for decarbonisation and the wave of innovation in ICT are affecting the optimal functioning of those markets. New options, such as the 'privatisation' of service reliability, are becoming a reality, while some of the solutions adopted in the past, such as the reliance on day-ahead energy-only wholesale markets based on marginal pricing, are no longer sustainable. These changes call for a rethinking of the way markets are built within the EU. This is a fundamental step which academics, practitioners and policy-makers have to make together if they want to provide the conditions for long-term investments, integrate a growing amount of renewable energy sources efficiently and securely, and ensure the active participation of customers and communities at the local level.

KEYWORDS

Electricity market design; electricity system operation; renewable energy integration; decentralisation of the electricity industry; digitalisation of the electricity industry

INTRODUCTION

Kristian Ruby – Secretary General EURELECTRIC

The European power system is facing profound changes as it transitions towards full decarbonisation. Stakeholders are confronted with the empowering of the energy customer through demand response and storage solutions and the deployment of decentralised, renewable generation, which progressively reduces the sector's carbon footprint.

The structure of the electricity market will have to adapt to these changes and we must develop new business models. In partnership with the Florence School of Regulation (FSR), EURELECTRIC has opened the debate and gathered innovative visions for the functioning of a fully decarbonised electricity market.

A joint call for contributions in 2016 triggered the interest of academics and energy experts from across the continent. They presented their suggestions at a dedicated event on 7 June, in Brussels. This e-book, built on the proceedings of that conference, is an attempt to provide insights for the public discussion and to inspire future debates on the topic.

The high-level papers present different scenarios for 2050. There are some interesting proposals on how to design a market which is flexible enough to face the challenge of increasing levels of RES. Also, attention is given to investment conditions, the perception of risk and the impact of risk adjustments on capital cost in a market where RES marginal costs could be near-zero. Other scenarios address the increasing interest in local electricity markets in a world where consumers are also prosumers and daily use electric vehicles and storage facilities, and have the flexibility to do so.

The power sector is undergoing a complex and long-term transformation: accelerated technological change, shifting consumer preferences, the application of ICT technology to link power generation and demand as well as the evolving EU climate and energy policy agenda are some of the key drivers impacting the industry. They provide unprecedented challenges but also important opportunities for the sector. In the midst of this energy transition, Europe needs to ensure secure, sustainable, affordable and competitive energy for all its citizens and businesses.

With this book we hope to stimulate the debate on the right market design for our common low-carbon future.

The electricity market design of the future

7 June 2017

Residence Palace

Rue de la Loi 155 - 1048 Brussels

www.marketdesignofthefuture.eu

#marketdesign2050

08h45	**Registration**	
9h00	Welcome and Introduction	**Kristian RUBY** Secretary General EURELECTRIC
09h15	**Will the Clean Energy Package pave the way for 2050?** *Keynote speech*	**Oliver KOCH** Deputy Head of Unit - Internal Energy Market, DG ENERGY
09h35	**The challenges of the market after the transition** *Keynote speech*	**Graham WEALE** Honorary Professor for Energy Economics and Politics, Ruhr Uni Bochum
10h00	**Coffee break**	

10h30 Parallel sessions

Session 1	Session 2	Session 3
The market goes local	**Solving the investment equation**	**Security of supply: A consumer's choice**
Pol OLIVELLA-ROSELL *Universitat Politècnica de Catalunya*	**Klaus SKYTTE** *Denmark Technical University*	**Gerard DOORMAN** *Norwegian University of Science and Technology*
Paul DE WIT *Alliander*	**Anthony PAPAVASILIOU** *Université catholique de Louvain*	**Christian WINZER** *Independent contributor*
Rens PHILIPSEN *Delft University of Technology*	**Ruth DOMÍNGUEZ** *University of Castilla-La Mancha*	**Malcolm KEAY & David ROBINSON** *Oxford Institute for Energy Studies*
	Christian GRENZ *Friedrich-Alexander University Erlangen-Nuremberg*	**Felicity CARUS** *Climate Policy Initiative*
Moderated by: **Juan José ALBA RIOS** Chair of the Markets Committee EURELECTRIC	Moderated by: **Leonardo MEEUS** Research Fellow Florence School of Regulation	Moderated by: **Peter FRASER** Head of Gas, Coal and Power Markets IEA

Full list of the speakers, institutions and contributions on page 2

12h30 Wrap-up and key takeaways

12h30	**Jean-Michel GLACHANT** Director of Florence School of Regulation	**Juan José ALBA RIOS**, EURELECTRIC **Leonardo MEEUS**, FSR **Peter FRASER**, IEA

13h00 Networking lunch

SESSION 1

THE MARKET GOES LOCAL

Moderated by
Juan José Alba Rios, Endesa & Eurelectric

THE MARKET GOES LOCAL

Juan José Alba Rios

Highlights

Local markets and customer empowerment are frequently linked in discussions about the energy transition. Distributed generation, batteries and smart home appliances give us the opportunity to become something more than passive consumers, by deciding whether and when we want to produce or consume energy. Digital technologies facilitate managing those decisions: our mobile phone or our home computer can decide when to consume or to store energy, and even trade with other "producers".

This session included two papers with conceptual descriptions of what a local energy market could look like.

Pol Olivella-Rosell and his colleagues presented their concept based on the Smart Energy Service Provider, a communication platform that would facilitate trading and scheduling to all members of the local community, and would deal not only with energy and flexibility, but with energy services, home automation, maintenance, etc.

Paul De Wit introduced a conceptual market model, where the system operator is still responsible for balancing supply and demand, but where all consumers can freely trade with each other.

A third paper, presented by Rens Philipsen and his colleagues, dealt with a completely different topic. The authors explained how, in current markets, hourly schedules based on generators trying to maintain a fixed injection of power in each hour, to respect their energy delivery commitments, lead to a discontinuity at the end of each hour, when generators adjust their production upwards and downwards, while consumption does not follow such a regular pattern. This causes significant frequency deviations at the turn of each hour. The authors proposed a new approach to dispatching, based on power, not energy, which would allow for a more natural scheduling where market participants would be able to schedule a trajectory of power within the hour, not a rectangular block, therefore preventing the discontinuities.

A lively debate followed the presentations. Most of the questions and comments from the audience dealt with the local markets. To what extent do these concepts offer something new? Aren't these services already offered by suppliers, who can exchange flexibility and energy with consumers, and help them in home automation? Don't current regulation, market arrangements and commercial practices already allow all this? How can the proposed solutions be made compatible with the natural monopoly of the grid, and deal with the likely conflicts of interest? In activities that present significant economies of scale, thanks to the power of digital devices, what is the advantage of being local and small scale?

DESIGN AND OPERATIONAL CHARACTERISTICS OF LOCAL ENERGY AND FLEXIBILITY MARKETS IN THE DISTRIBUTION GRID

Pol Olivella-Rosell, Jayaprakash Rajasekharan, Bernt Arild Bremdal, Stig Ødegaard Ottesen, Andreas Sumper and Roberto Villafafila-Robles

Introduction

The current decarbonisation of the European electricity system via the proliferation of distributed and renewable energy production sources have created a global surge of interest in local electricity markets for local energy communities (European Commission, 2016). In 2050 the European electricity system is expected to have millions of prosumers, electric vehicles and storage units willing to provide energy and flexibility. They will be mainly concentrated and active in distribution grids. Coherently, our vision is that of an integrated wholesale market with geographical distributed multiple local markets.

The topic has caught the attention of policy makers, regulatory bodies and researchers alike. In this paper, we present some of the results on local market design and operation that has been developed in Work Package 6 of the EMPOWER Horizon 2020 project (Olivella-Rosell et al., 2016) and presented in (Olivella-Rosell et al., 2017).[1]

1 This work was supported by the European Union's Horizon 2020 EMPOWER Project under grant agreement No 646476 and by the Innoenergy PhD School.

The local market overview

We propose a new market player role titled Smart Energy Service Provider (SESP), which manages the local market for energy, flexibility and other services as described by Ilieva et al. (2016). A local market (LM) is an ICT electricity trading platform, provided by the SESP, to sell and buy electricity and flexibility in the local energy community (LEC). LM players are the local DSO, prosumers, consumers, storage owners, distributed generators and others entities allowed to participate in the LM (Figure 1). The SESP supervises the local market operations with the aim to maximize social welfare for its LEC members, while also acting as an aggregator able to participate in wholesale markets for supplementing its local market operations.

The SESP essentially represents a peer-to-platform approach. Decision on local issues are made centrally by the SESP and all interactions are executed through the platform, similar to several other network markets as described by Parker et al. (2016). This concept alleviates the transaction-related burden on each trader, supports pool oriented energy exchanges and provides the SESP with essential information pertinent to future and past assessments.

The local market architecture is characterized by the multiple interactions and relationships between various players as Figure 2 shows. These relationships are specified by means of separate contracts that each player has with the SESP for energy, flexibility and other services.

The LM ambition is to encourage local generation and active participation of prosumers to exploit the flexibility that this creates, for the benefit of all those connected to the local grid. The LM objectives are listed as follows:

1) Support a business model whereby locally produced energy is primarily targeted towards local consumers:

- Offer a competitive market place,
- Facilitate local trade;

2) Promote the installation of distributed renewable generators:

- Create an attractive and competitive market place that forges incentives to buy energy from local

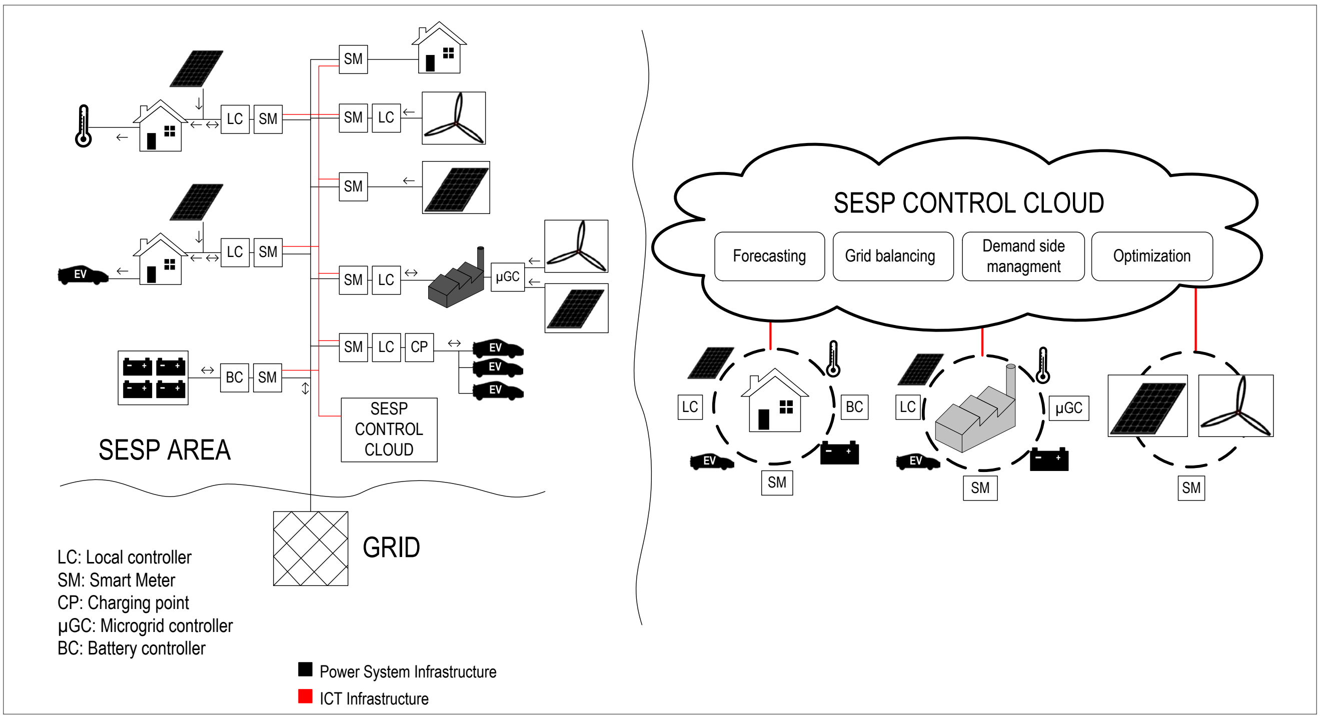

Figure 1: Local market overview with components and ICT infrastructure

and renewable resources,

- To cater for increased investment in distributed renewable resources;

3) Support trade of end-user flexibility for the benefit of the DSO and its operations:

- Managing grid bottlenecks,
- Providing power curtailments under request;

4) Support power system balancing in wholesale markets:

- In intraday markets,
- In balancing markets such as TSO tertiary reserve market.

The SESP platform must facilitate all processes associated with creating an on-line community of consumers, prosumers and producers. The overall lifecycle process for a community member consists of the following distinct steps:

- Recruitment: it includes all processes related to attracting users, signing in and profile creation;
- Commissioning: it includes all activities related to introducing equipment and technical data into the platform and checking their veracity;
- Engagement: it includes all the processes related to defining contract prices and renewal processes; moreover, engagement also involves the members so that they become active LEC members;
- Exchanges: it includes all processes related to verifying and monitoring energy and flexibility trades and exchanges;
- Settlement: it defines the total amount of energy and flexibility activated and requested; it produces the delivery note to be sent to LM participants.

According to the peer-to-platform approach, all LM participants need to have a contract with the SESP and direct negotiations between traders are not allowed. For example, consumers have a contract for consuming electricity and producers for selling electricity, and these contracts can be renewed periodically every month, week or day depending upon participation levels. The SESP issues all contracts and offers a brokering, clearing and price settlement service.

The contracts are between:

- SESP-DSO: it defines the information shared,

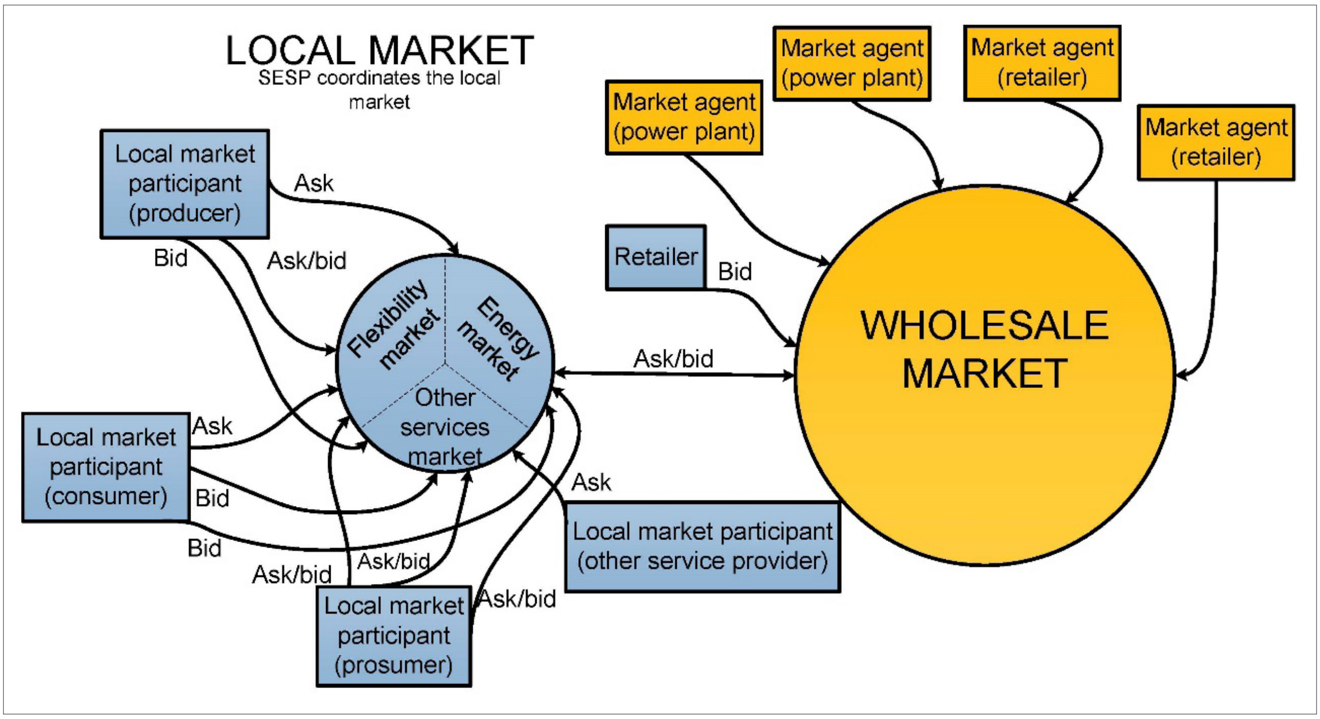

Figure 2: Local market interaction with wholesale markets

message exchanges, actions, timetable, responsibilities of each partner and the rewards for each service provided by SESP;

- SESP-Consumer: it defines the energy consumption price, flexibility reservation and activation prices, and penalties for failures to meet contractual obligations;
- SESP-Producer: it defines the price for energy and flexibility supplied to the grid and compensations for energy curtailed.

Local energy and flexibility markets

As shown in Figure 2, the LM can be split in three segments, two of which have clear parallels in the wholesale markets. The Local Energy Market (LEM) has a negotiation period equivalent to the wholesale day-ahead market, while the Local Flexibility Market (LFM) is equivalent to the intraday and the balancing wholesale markets.

SESP acts as a retailer in the LEM; it buys and sells local and renewable energy from/to local market participants respectively. Additionally, the double prosumers' role requires a special contract with prices for generating and consuming electricity.

In the LFM the SESP controls its members' flexible resources such as thermal loads, electric vehicles, batteries, etc. during certain time intervals and rewards them accordingly based on their offered prices in flexibility contracts.

The LFM can be used for:

- Complying with DSO's requests to prevent grid overloads caused by consumption or generation from community members or others connected to the same grid. Thus, the LFM allows the DSO to prevent grid damages and postpone grid reinforcements;
- Compensating local deviations due to forecasting errors or other issues to reduce deviation penalties for the SESP in wholesale markets. The SESP uses the ICT platform to send flexibility control signals to compensate community deviations, if the deviation penalty is higher than the flexibility costs;
- Bidding in balancing markets by aggregating community members' flexible assets. These bids support TSO's operations thanks to the SESP's capability for increasing or decreasing consumption

or generation. SESP sends bids to the TSO based on the system status prognosis.

In order to schedule LEC flexible assets, the LFM executes an optimization algorithm that minimizes the costs involved in allocating the required flexibility. It can be formulated as a single-side auction between flexibility providers and the SESP as flexibility consumer. This function can maximize the LEC welfare or it can be a minimization operation cost for SESP.

Moreover, flexibility rewards can be formulated as pay-as-bid or pay-as-clear. However, pay-as-clear proposition in small scale auctions could increase the cost of using flexibility. For example, in case of meeting a DSO request, if the clearing offer is more expensive than the other accepted offers, it could imply an over cost for the DSO and therefore for the end customers. Therefore, this work proposes to use pay-as-bid option and a minimization cost function in contrast to maximizing the social welfare. Nevertheless, this is an open question and the answer could be different case-by-case.

During the operation, the flexibility provided by an end-user is measured as the power forecasted between the switch off and on signals. This proposition has the disadvantage of including forecasting deviations in the flexibility estimation.

In the other services market, SESP takes advantage of the technical infrastructure found in a given area and uses the information to create new business opportunities. SESP can provide its members with technical maintenance, insurance, home automation functionalities, energy efficiency tips and others. Therefore, SESP increases the level of service that community members can enjoy. Additionally, new opportunities through innovative services can occur and cross-subsidies can benefit local energy trade.

The fundamental guiding principle for SESP operations is represented by the equation:

$$E_P(t) + E_C(t) = E_{WM}^{DA+ID}(t) + E_{REQ}(t) + E_{\Delta}(t) + E_{DEV}(t)$$

where $E_P(t)E_P(t)$ and $E_C(t)E_C(t)$ are the local energy production (positively valued) and consumption (negatively valued) during period $t. t.$ $E_P(t)E_P(t)$ and $E_C(t)$ $E_C(t)$ are considered the baseline and not included in the flexible consumption and production.

$E_{WM}^{DA+ID}(t)E_{WM}^{DA+ID}(t)$ is the energy sold $(E_{WM}^{DA+ID}(t) > 0E_{WM}^{DA+ID}(t) > 0)$ or bought $(E_{WM}^{DA+ID}(t) < 0E_{WM}^{DA+ID}(t) < 0)$ in the day-ahead and intraday wholesale markets. $E_{REQ}(t)E_{REQ}(t)$ is the total requested flexibility by external agents like DSOs and TSOs, and $E_{\Delta}(t)$ $E_{\Delta}(t)$ is the flexible energy for up-regulation $(E_{\Delta}(t)E_{\Delta}(t)<0)$ and down-regulation $(E_{\Delta}(t)E_{\Delta}(t)>0)$. According to Wangensteen (2012) and the Danish TSO Energinet.dk (2007), up-regulation refers to more generation or less consumption and vice-versa for down-regulation.

$E_{\Delta}(t)E_{\Delta}(t)$ can be decomposed into the following flexibility components:

$$E_{\Delta}(t) = E_{STO}(t) + E_{FL}(t) + E_{FG}(t)$$

where $E_{STO}(t)E_{STO}(t)$ is the flexibility available from storage units for charged energy $(E_{STO}(t) > 0$ $E_{STO}(t) > 0)$ and discharged energy $(E_{STO}(t) < 0$ $E_{STO}(t) < 0)$, $E_{FL}(t)E_{FL}(t)$ is the flexibility available from loads for up-regulation $(E_{FL}(t) < 0E_{FL}(t) < 0$ $)$ and down-regulation $(E_{FL}(t) > 0E_{FL}(t) > 0$ $)$ and $E_{FG}(t)E_{FG}(t)$ is the flexibility available from generators for up-regulation $(E_{FG}(t) < 0E_{FG}(t) < 0$ $)$ and down-regulation $(E_{FG}(t) > 0E_{FG}(t) > 0)$.

Finally, $E_{DEV}(t)E_{DEV}(t)$ is the total energy deviation. The decision variable that can be controlled in the LM are $E_{WM}^{DA+ID}(t)E_{WM}^{DA+ID}(t)$, $E_{STO}(t)E_{STO}(t)$, $E_{FL}(t)$ $E_{FL}(t)$ and $E_{FG}(t)E_{FG}(t)$.

The LEM and LFM constitute a strong investment signal because they allow to integrate more renewable production without threatening distribution grids and offer a platform to obtain additional benefits with their flexibility. Finally, it is expected that in 2050 national regulatory agencies guarantee that such platforms are standard and members can switch from one SESP to another. That is necessary to ensure the long term investments in generation and, consequently, the continuous and secure operation of the system.

Conclusions

The design and operational aspects developed in this work for local energy and flexibility markets provide the functional specifications for the local market and

SESP ICT trading platform. The proposed trading platform and local markets are designed to be scalable, adaptable and customizable in order to suit the diverse conditions and regulations.

The proposed local market design and operation concepts constitute hypotheses that will be tested at pilot sites in Norway, Germany and Malta during 2017.

Assumptions considered for this work include that the three local markets described are integrated to cover all functionalities around the local trading and they cannot work individually. Additionally, it is assumed that market participants have automatic trading agents to adapt their local market offers to the participant's energy needs. Regarding the LFM, it is assumed that DSOs and TSOs can buy flexibility from SESP for managing technical constraints. Finally, it is also assumed that SESP has the capability to measure the distributed flexibility activated via accurate foresights and real time data.

The LMs proposed in this work have important implications for energy policy and regulation. Currently, LMs are facing important obstacles. For example, electricity tariff structures in the LEC have to be reconsidered to allow energy exchanges between prosumers and their storage assets to avoid double taxation. Moreover, information from smart meters has to be accessible for third parties like SESP and aggregators. Additionally, this information should be refreshed every hour or quarter of hour to favour local flexibility markets deployment and real time operations in distribution grids. Otherwise, third parties should deploy their own measurement and communication infrastructure and that could kill the business.

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THE FUTURE PROOF MARKET MODEL

Paul de Wit

Introduction

To create a future proof market model the model must be as simple as possible. The future proof market model I will present here is extremely simple and is built around the customer. It is purely market based. It is based on the assumption that the future is uncertain and that the model must be flexible to support different markets and changing business models of market parties. This model can support today's market model and future market models. Instead of making more rules this model tries to simplify the market model as much as possible.

Assumptions and approach: the basics

This model is designed for a public grid infrastructure. A system operator (SO) is in charge of keeping the grid stable, e.g. by preserving a frequency of 50 Hertz within a certain bandwidth. It is possible that the SO operates a European wide network, a nation wide network or a local community network.

In this future market model everyone connected to the grid is a market party. The consumed or produced electricity is measured per period with an electricity meter (smart meter). This period is used for settlement (e.g. per five, 10 or 15 minutes). At a certain frequency (e.g. daily) the measurements per settlement period are settled.

Everyone connected to the grid is responsible for his own physical balance of production and consumption. The meter is read by the system operator with a certain frequency, for instance daily. If the prosumer has taken electricity from the grid, he must specify, per settlement period, all market parties from whom he has bought and how much. Every buy and sell is one transaction between two parties and contains a certain amount of electricity. The transaction is specified by the buyer and is confirmed by the selling party. Only transactions which are confirmed are valid transactions.

Some parties are only administrative parties. They sell and buy electricity (like today's traders). A prosumer can contract such an administrative party to take over his risk of consuming more than the amount of energy he has bought or take over the risk of the prosumer of producing more than he has sold. Like today's balance responsible parties.

Parties who have consumed too much have bought this amount of energy from the SO and parties who have produced too much have sold this surplus to the SO. The SO keeps the physical balance of the total system. Buying and selling from the SO is discouraged (i.e. it is more expensive than resorting to the market on time). The grid losses are the difference between the measured total volume of the production and measured total volume of the consumption. The SO is responsible for these grid losses.

Methodology: the market

There is at least one public market place operated by the (public) SO, but everyone is free to do his trades wherever he wants. The only regulation required is that everyone must specify his transactions (buys and sells) before a certain deadline, otherwise it is assumed that he has bought his consumption, or sold his production (surplus), to the system operator. This means that parties are still able to trade after real time. The SO can only be a buyer on the public market place. He buys upwards or downwards regulation (kW) for a certain period of time. This translates into upwards or downwards energy (kWh). It is possible that the SO buys such energy in a specified region to solve a local congestion or anywhere to balance the system.

Interconnections between two grids can be operated by a private company or a public company (joint venture between the SOs). If the interconnection is operated by a private company the interconnection is seen as a normal connection at both sides. Interconnections between SOs create the only exemption in the system. Transactions which buy electricity from neighbouring grids require a booking in advance. If the total booked capacity exceeds the physical capacity, the booking is rejected. Also the booked transaction needs to be confirmed before a certain deadline by the counter party.

The present and the future

We can create such a system already in today's market. The customer is then in full control. In theory, every customer can buy or sell per settlement period (e.g. 15 min) any amount of electricity to any party who is registered in the system. Of course, it is most likely that today only large customers use the full potential of this model and that customers with smaller connections only use a small subset of the possibilities. Market parties like today's suppliers are likely to provide a standardised profiles to customers and today's balance responsible parties will take over the risk of the differences between the measured values and estimated consumption/bought production. But other business models are also possible. Obviously, evolutionary steps can be defined to provide fall back options to customers. In that case the customer starts with a supplier/balance responsible party who takes over the risks from him (like it happens mostly today).

How to reach a decarbonised electricity market in 2050?

There is an EU tax on CO_2 emissions (like todays EU Emissions Trading System). This way energy produced with CO_2 emissions is more expensive than energy produced without CO_2 emissions. The tax is set relatively high and by this way the market is stimulated to find solutions to produce electricity with as less CO_2 emissions as possible in the most cost effective way. It stimulates investments in new CO_2 free generation assets.

How to address system adequacy

Because of the active participation of all prosumers, this model stimulates decentralised, CO_2 neutral, generation as much as possible. The most cost efficient balance will be reached between centralised production, decentralised production, energy savings and demand side response. The prosumer can choose to produce and consume his own electricity or to reduce his consumption during expensive peak times. This has a direct financial impact on the prosumer. Of course, it is most likely that a prosumer will not do this manually but by using an energy management system present in his home.

Large scale centralised (CO_2 free) production of electricity is still possible. It is very likely that large scale off-shore wind parks are also profitable in this model. The model is technology neutral. It does not favour a specific type of technology over another one. But because of the taxation of the CO_2 emissions, it stimulates CO_2 free production of electricity.

What is the difference with today's market design?

The essential difference between today's system and this future system is that the customer is allowed to specify his allocation/transactions. The allocation is not determined by the SO but by the customer.

In this model there is no day-ahead, intraday or balancing market. There is only one public market, where parties are allowed to trade wherever they want. As long as a transaction is confirmed by both parties. Parties are also not obliged to forecast their production and consumption (maybe only very large ones). There is only one market role in this market model and that is a market party. Everyone can sell any service to anyone else. The only obligation that a connected party has is to register himself on the connection and to specify his transactions (allocation) regularly to the SO. Obviously, he can hire a market party to fulfil his obligation to provide the SO with an allocation (like a normal energy supplier does today).

If parties do not confirm their trade, they cannot be trusted. This is the same as an on-line shop that does not deliver the goods. No one would like to trade with parties who cannot be trusted. However, no extra legislation is required for this. The market will solve this like today with on-line shops.

Trading companies also need to be registered. Otherwise, their (administrative) balance cannot be determined.

The advantages of this model

The proposed model is extremely simple and therefore very easy to automate and implement. New technologies like the block-chain technology are very suitable for this model. However, it is crucial that first the market model is simplified as much as possible before the full potential of new IT technologies can be harvested.

Today's IT capabilities make it possible to see all injections and withdrawals from the grid as administrative transactions. This was not possible in the past.

A simple market model still leaves the option open for governments to execute their policies. For example, it is still possible to implement a tax on CO_2 emissions.

This model unlocks the maximum demand side response capabilities and creates a level playing field for everyone. This model lays the foundation for all kind of future developments. It is up to the market parties to come up with innovative solutions.

A NEW MARKET DESIGN FOR DAY-AHEAD MARKETS WITH POWER-BASED SCHEDULING

Rens Philipsen, Germán Morales-España, Mathijs de Weerdt and Laurens de Vries

Introduction

With the introduction of renewable energy sources (RES) to the electricity system, the European electricity market must undertake a number of changes if its current security of supply is to be maintained. In electricity systems, supply and demand must be in balance at all times. In order to accommodate for the increased installation of RES capacity, we must compensate for fluctuations in both supply and demand. To ensure this balance, we employ markets to coordinate who consumes or supplies how much energy during a programme time unit (PTU). Any remaining imbalance during a PTU is covered by reserves, which are contracted by the system operator.

Existing electricity markets, however, inefficiently use the available reserves, because the penalizing mechanism for imbalances is based on the total energy supplied or consumed during a PTU. Even with such a mechanism in place there is no guarantee that momentary imbalances do not arise. While the total amounts of energy supplied and consumed during the entire PTU are equal, it would be incorrect to assume this balance also holds at each moment.

What is perhaps even more staggering is that this system in fact *is responsible for* momentary imbalances: while aggregated electricity demand is mostly a smooth curve, power plant operators sharply change their output at the start of a PTU in order to supply the contracted energy. This behaviour causes deterministic and predictable shocks in system frequency which can be observed all over Europe [1]. Despite recent advancements, our existing electricity markets are therefore far from optimal: even if no uncertainty exists, they are unable to prevent imbalances.

It is important to note the effect this has on RES integration and the reduction of thermal power plants: as more intermittent resources are connected, the share of thermal power plants can only decrease if they are not needed for the provision of reserves. The share of RES in the generation mix is therefore capped by the necessity of maintaining reserves, and that cap is artificially lowered by our overly high reserve requirements caused by imperfections in the market design. As reserves are usually procured for a longer period of time, thermal generators are effectively subsidised, making RES relatively less competitive. Consequently, these deterministic imbalances, stemming from the market design, hold back the widespread adoption of RES in Europe.

Our proposed solution is to make day-ahead schedules based on *momentary power output*, rather than total energy output. This would be a radical change in the way the electricity system is operated from day to day, freeing up flexible resources to deal with actual uncertainty, rather than with deterministic scheduling inaccuracies. Such power-based scheduling was proposed and analysed in [2] and [3]. In power-based scheduling, day-ahead schedules assigned to both generators and loads are defined as piecewise linear trajectories. These power trajectories ensure that day-ahead schedules are actually in continuous balance, and can better account for the actual physical constraints on the system. Traditional energy-based scheduling, by contrast, does not correctly incorporate generator flexibility. This flexibility can be both over- and under-estimated in making schedules, resulting in infeasible solutions in the first case, and inefficient solutions in the second. As a consequence of that, power-based scheduling is a necessary step towards a more efficient operation of the electricity system.

The challenge we currently face is to implement this technological solution in practice. Although the technical advantages are well-understood [2], [4]–[7], it is as of yet unclear which changes in the market regime must be effected in order to make power-based scheduling the standard. Products must be redefined, and, as a result, changes may be necessary on the way markets are cleared and products priced. We therefore start by describing the minimal requirements to which a newly designed market should conform. From there, we propose a combination of market rules which ensure a continuous network balance, enabling more efficient use of the available generation capacity.

The central question we aim to answer is the following: *which set of market rules can efficiently ensure that there exists a moment-to-moment balance of supply and demand in day-ahead planning?*[1]

Market design

To delineate our analysis, we focus on a specific market, close to the existing market design: day-ahead is cleared 24-36 hours ahead, in a single discrete two-sided auction. For this discrete auction, we must define the following aspects: bid definition, clearing rules, and pricing rules. We specify these in the following sections. Broadly speaking, we define multi-period bids as our starting point, where parties communicate their physical constraints (such as ramping or output limits), soft constraints (such as deadlines) and variable costs. The market is cleared for a fixed horizon (e.g., the next day) and communicates the precise power trajectories all parties will have to follow. We then discuss the minimal requirements a pricing mechanism should conform to, and define prices as a price per megawatt (and not megawatt-per-hour) of output at the end of each PTU.

Bid definition and clearing rule

The first step is to define what constitutes a bid. In defining a bid, we opt for a broader bid than the existing hourly orders in order to better capture the true flexibility offered by both sides of the market. Our preferred option is for both power plants and consumers to place bids which closely resemble their physical characteristics. Bids consist of lower and upper production limits, maximum up and down ramp rates, and a price for energy. Furthermore, these bids can be extended by including minimal and maximal total energy demand.

We emphasize two things: first of all, this bid definition is a generalization of the bids possible in the existing markets, and can therefore recreate them without any loss of accuracy. On the other hand, they can be extended in the same manner to include more complex constraints, such as minimal income conditions, block orders, or linked orders. Such bids can then be used to incorporate physical or economical restrictions, but their use is likely to be lower than in current markets due to the fact that our basic bid already allows for restrictions on the range within which a plant can be operated.

Pricing rule

Primarily, our aim is to guarantee *cost recovery* for both generators and loads: no generator will produce electricity below its cost, and no consumer will pay more than its willingness to pay. In terms of mechanism design, this means we insist on *ex-post individual rationality*.[2] As a second objective, we aim for *socially efficient outcomes*.[3] This is a very natural objective for a regulating authority and is already the objective of the existing Euphemia [9] algorithm. Thirdly, the market operator should stick to that function only, and should not have to contribute any money to transactions. We therefore ask for a *strictly balanced budget* as a third requirement.[4]

Economic theory, unfortunately, contains a number of impossibility theorems which show it is impossible to design a market which is provably impervious to manipulation, given the objectives described above. Note that this does not imply it will be easy to influence a market, nor does it say anything about how inefficient the market will be if bidders behave strategically. Although robustness against manipulation is important, we leave the issue of *how* vulnerable a

1 Although we focus here on day-ahead markets, the proposed market design can (and should) be applied to any other market, e.g., intraday or real-time markets.

2 Participants to the mechanism receive non-negative utility from participating in all possible states of the market (ex-post).

3 Given the bids of all generators and load-serving entities, social welfare is maximized.

4 A mechanism is budget-balanced if the sum of payments by the market operator is precisely zero.

market design is to manipulation for future work, and for now note only that we cannot give a theoretical guarantee.

Marginal cost pricing is already well-established in the power systems community. It follows from the dual variables which are associated with constraints in mathematical optimisation problems. These dual variables, in an economic setting also referred to as shadow prices, indicate the sensitivity of the objective function to a relaxation of that constraint. These shadow prices form a competitive equilibrium and ensure envy-free prices for all participants, who all recover their costs [8]. This in turn implies individual rationality. They are therefore suitable candidates for our pricing rule.

In defining shadow prices, we must overcome one hurdle. In our redesigned market, PTUs are irrevocably linked to each other due to the linear power trajectories, where increasing the output of a generator at the end of one PTU increases the amount of energy in both the preceding and in the subsequent PTU. Although these trajectories correspond to a unique energy profile, we do not price the energy profiles themselves: instead, we define point-to-point schedules, and we therefore base prices on the power output at these points, which lie at the end of a PTU. Using the shadow price of the power balance constraint at the end of an hour as the price for power delivery at that moment, bidders are rewarded for being able to provide both energy as well as ramping flexibility – analogous to the value for providing energy *in the right location* when locational marginal pricing is applied. The total payment to a generator then equals its output at the end of an hour times that price.

Difference with existing markets

Now that the necessary rules for a market implementing power-based scheduling have been outlined, we compare the resulting market with the existing day-ahead market. One of the advantages of a power-based approach is that flexible demand can be rewarded for its flexibility in the day-ahead market already. Since the payments to the market participants now consist of both an energy part and a ramping part, it is easier to properly schedule the flexibility offered by flexible parties. This is especially important for flexible load, as they may have a maximum consumption constraint.

Our work in [7] compares alternative formulations of the day-ahead optimal scheduling problems, based on unit commitment (UC) formulations. Case studies are carried out on the IEEE 118-bus test system. When comparing ideal stochastic energy-based with power-based UCs, the power-based UC presented 33% less curtailment and 5% lower actual operational costs.

Conclusions

Existing electricity markets are inefficient. Ensuring energy balance during a PTU, unfortunately, does not guarantee the momentary balance of supply and demand which is a necessary condition for the safe and reliable operation of electrical power systems. Power-based scheduling can alleviate the imbalances which follow from the existing market design, preventing frequency shocks which threaten security of supply and freeing up expensive reserves. This reduces costs for consumers and reduces the need for online thermal power plants, improving the competitive position of renewable electricity sources. Day-ahead schedules based on power trajectories are, in all ways, superior to energy-based schedules.

Coordinating power-based trajectories in a market was until now an unresolved problem. Our market proposal fills this gap by providing bid definitions and rules for bidding, market clearing, and pricing, delivering a comprehensive overview of the changes necessary to arrive to a power-based future. The proposed market model is very much in line with the operation of existing markets, making only the minimal changes necessary to fully capture the advantages of power-based scheduling. In doing so, it improves economic efficiency and makes way for further integration of RES.

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SESSION 2

SOLVING THE INVESTMENT EQUATION

Moderated by
Leonardo Meeus, Florence School of Regulation
& Vlerick Business School

SOLVING THE INVESTMENT EQUATION

Leonardo Meeus

Highlights

Oliver Koch from DG ENER was one of the keynote speakers before our panel discussion. He presented the EU Clean Energy Package and noted that: "maybe the missing money problem only exists if you look at the future with a mind-set of the past".

Utilities are indeed missing money, but not only because the market is designed imperfectly; at least part of the problem is that utilities underestimated the speed of the energy transition and the policies that support it (financial crisis also did not help). Incumbents in fast-moving industries do have a tendency to underestimate changes.

Many, however, continue to advocate, also at this conference, that power plants should receive a remuneration for capacity in addition to the money they get for offering the energy they produce into the market. These so-called capacity remuneration mechanisms are already implemented in some countries, but remain controversial (see also the 2016 Sector Inquiry by DG Competition on the issue).

I had the pleasure to moderate the session on investments with Anthony Papavasiliou, Ruth Dominguez, Klaus Skytte, and Christian Grenz. Christian presented his proposal to organize the markets based on long term contracts that would be auctioned in a different way than the way we do in capacity markets today. Anthony, Ruth and Klaus proposed to fix the market design by adding a premium or uplift to peak prices. Instead of giving up on energy scarcity pricing, we could indeed first try to reinforce peak prices. This would then also incentivize demand response and other flexible resources.

We also discussed how these fixes are only needed to the extent that reliability is still a public good in 2050. For the time being, we do not know yet the willingness to pay of each electricity customer, and most customers can also not be excluded when prices peak above their willingness to pay. And even if we could, the question is whether we should: are we "protecting" customers, or are we making them pay for a level of reliability they would not choose, if they had the choice? We will know in 2050. See you then.

FLEXIBLE ELECTRICITY MARKETS FOR A DECARBONISED ENERGY SYSTEM

Klaus Skytte, Claire Bergaentzlé, Jonas Khubute Sekamane and Jonas Katz

Introduction

Reaching the European decarbonisation objectives will require a higher contribution of electricity generation from variable renewable energies, as well as the electrification of other sectors such as heat, transport, and gas. Future decarbonised systems will therefore impose new challenges in terms of flexibility, but they also will provide access to new, more-flexible solutions, provided the right market design is put in place to facilitate them.

Existing markets designs, with a few minor adjustments, could, in most cases, provide the needed flexibility to ensure optimal short-term dispatch, reliability and long-term capacity adequacy. However, in high-residual load periods, there is a need for better scarcity pricing to solve the missing money problem.

In this paper, we combine a premium that strengthens scarcity prices and a mechanism that significantly mitigates the risk on the investment side, while effectively sharing it with consumers. Our vision for a future electricity market uses a combination of plausible approaches to support flexibility. It aims to address the framework conditions necessary to activate flexible resources based on: i) renewable energy-based wholesale market designs; ii) cross-sectoral coupling; and iii) innovative scarcity pricing and risk reductions through reliability options.

Our proposed vision improves the design of electricity markets and establishes new sets of frameworks that support flexibility as the core element in a decarbonised energy system with a large share of variable renewable energies.

The future power market

European energy markets are going through a green transition toward a future with a decarbonised energy system. Centralised, fossil-intensive electricity generation is being replaced by decentralised renewable energy. A large share of variable renewable energy (VRE) sources, especially wind and solar, will be deployed, in addition to other traditional storable renewable energy sources, such as biomass and hydropower. By nature, the temporal supply of VRE is highly variable because it depends on weather conditions, uncertainty due to forecasting errors and location specificities, as the primary energy source cannot be transported, like coal or biomass (Borenstein, 2012; Hirth et al., 2015). Such properties point to major VRE integration and flexibility challenges for the future energy system. Simultaneously, the traditional and flexible fast-responding, fossil-based peak-generators are being phased out, increasing flexibility challenges.

Future European energy systems should be consistent with the threefold targets set to improve competition, reliability, and sustainability (see Figure 1). Existing power markets were created before or simultaneously with setting up the EU goal of developing an Internal Energy Market, which facilitate low consumer prices through competition and reliability by matching electricity demand and supply (EU Directive 2009/72/EC). The market design that emerged over the years might have to be adapted according to the green transition such that it enables necessary short- and long-term flexibility in the system.

The future market design should be based not on the perspectives of the traditional electricity sector, but rather on an integrated decarbonised energy system in which electricity becomes a cornerstone in the sustainable energy transition for other energy sectors – such as heat and gas – as well as for transport and other service sectors with a large share of electrification (Skytte, Pizarro and Karlsson, 2017b). The progressive coupling between the electricity sector and the other sectors will increase the volumes traded on the electricity market, as well as competition that ultimately will benefit consumers. If sector coupling is done in a 'smart' way, it also may increase the flexibility of the system – especially on the demand side – by unleashing the potential for electrification via flexible load units with ramping capabilities such as electric boilers in heating systems, electrolysers in power-to-gas or smart charging of electric vehicles (Skytte et al., 2017a; Ropenus and Skytte, 2007).

Though increased flexibility, thanks to cross-sectoral coupling, will play a key role in reaching decarbonisation targets, the right market design will be required to ensure a high level of short-term reliability and long-term capacity adequacy at the lowest cost.

Price setting in energy markets

In most of the present power markets, the wholesale electricity price is determined according to the marginal cost of the last dispatched generation plant (see left panel in Figure 2). It has been shown to be a very effective market design that so far has entailed energy prices that both support optimal dispatch/short-term reliability (Skytte and Grohnheit, 2017) and optimal investment/long-term capacity adequacy (Biggar and Hesamzadeh, 2014; Green, 2006; Schweppe et al., 1988). Although only energy is traded on the power markets, flexibility is valued, as demand and generation units with flexible ramping capabilities can make a better business case in volatile markets, compared with slow ramping units.

The success of the existing design also must be seen in the context of a large deployment of renewable energy-based capacity. This capacity has received additional financial support from outside the market, resulting in overcapacity on the supply side. Therefore, there is presently limited need for additional investment in conventional generation capacity. Nonetheless, with increased demand from sector coupling and the phasing out of fossil-based generation, additional generation capacity will be needed in the future. Simultaneously, support for renewables will be phased out in accordance with the maturing of technologies and it can be expected that future deployment will be mainly market-based (Skytte, 2000; Skytte, 2006; van Kuik et al., 2016).

In a period with scarce supply – e.g., when the residual demand is large due to little wind or solar production and with simultaneously high demand – the price in the power market is likely to be set by the marginal consumer benefit (see right panel in Figure 2). This is called *scarcity pricing*. Scarcity is a necessary (although not a sufficient) condition for a well-functioning market and optimal allocation of resources – often referred to as the first principle of micro-economics. The main dilemma in the power market is that the current demand side is relatively price-inelastic (the demand

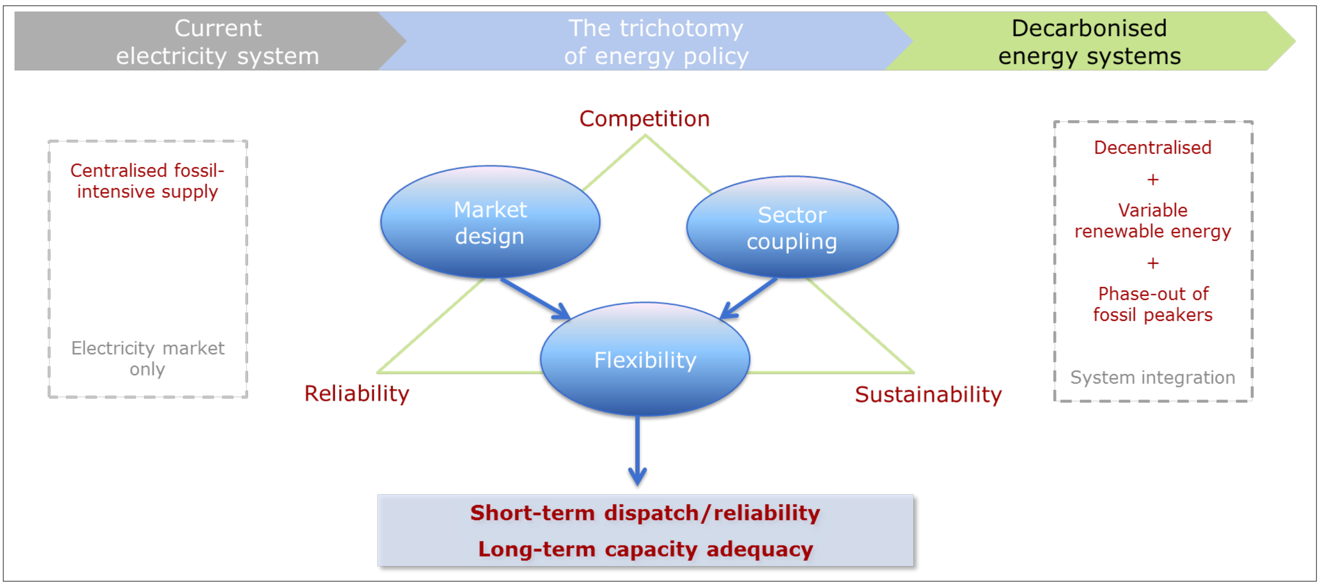

Figure 1: Goals and framework of the future energy market

curve *D* in Figure 2 is almost vertical), which implies that it is hard to determine a sufficient scarcity price. We call this missing flexibility on the consumer side the *missing consumer problem,* which may imply that the price does not reflect the marginal consumer benefit or, at worst, that an equilibrium between demand and supply cannot be found. Within energy economics, the marginal consumer benefit in scarcity periods is often estimated as the value of lost load (VOLL) for marginal consumers, i.e., the amount they are willing to pay to avoid a disruption in their electricity supply.

Electrification and sector coupling will increase electricity demand and might also increase the availability of flexible load units with ramping capabilities – and, thus, the marginal price elasticity needed to solve the missing consumer problem. However, the problem of determining an efficient level of scarcity pricing also affects the supply side. If the estimated VOLL is set too low, investments in new capacity may be withdrawn, leaving the market unable to ensure long-term adequacy. Lower prices in the power market increase the need for higher scarcity prices to ensure investment, as a low price level implies that a large share of the revenue to cover the investment costs must come from scarcity periods, when the price is higher than the marginal cost of the last generating unit (right panel in Figure 2).

VRE, such as wind and solar, will be the main suppliers of electricity in the future, as more controllable renewable energy-based technologies such as hydropower and biomass involve more limited resources or are subject to restrictions on further deployment. The dominance of low marginal cost VRE technologies implies low average prices on the wholesale markets (Skytte and Grohnheit, 2017). As mentioned above, a low price level, combined with insufficient scarcity prices, could imply that potential investments in new capacity are withdrawn (Joskow, 2008; Joskow and Tirole, 2007). This is called the *missing money problem*, i.e., the revenues in the energy market will not cover the needed investments in new capacity, thereby failing to ensure the long-term adequacy of the system. In addition, price caps have been implemented in many markets to protect consumers from high peak prices that might result from market forces. Such price caps will limit scarcity prices and contribute to the missing money problem.

Need for re-design

The existing market design and its marginal pricing, with a few minor adjustments, works in most cases. However, in the event of scarcity, there is a need for better scarcity pricing to solve the missing consumer and missing money problems.

The general problem is that market imperfections exist in the power market (Skytte, 1999). In addition, the uncertainty of future prices increases risks for investors and may, as a consequence, hinder new investments. Better risk-hedging possibilities for investors, in addition to the existing forward and other financial markets, may be required.

Therefore, we do not support capacity mechanisms just to have enough capacity available, but rather to fix

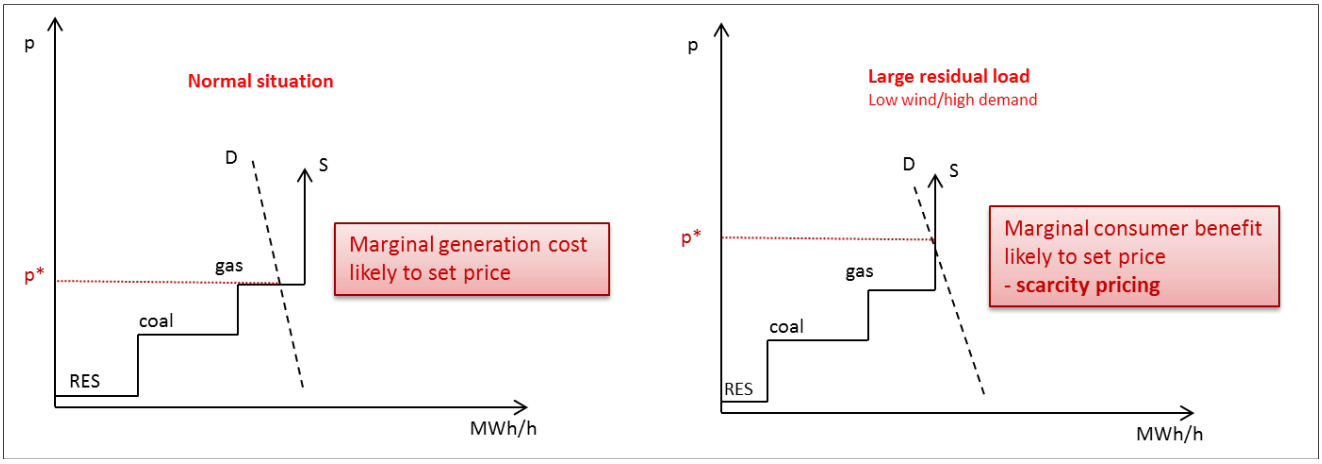

Figure 2: Price setting on the power market (RES = renewable energy sources)

the existing scarcity-pricing problem in the energy-only market – with as little interference from market mechanisms as possible – and to reduce investment risk.

In this paper, we propose a combination consisting of a premium that enforces scarcity prices and a mechanism that, to a certain extent, mitigates the risk on the investor side and effectively shares it with consumers. The constructed mechanisms draw on Hogan (2013) and Cramton et al. (2013). We introduce a premium in scarcity periods, and we also allow generators to sell *reliability options* that reduce their risk of investment. These two instruments work concurrently, with the premium increasing the revenue of generators, while the reliability options allow generators to swap revenue from the few high-price periods with a stable, risk-free payment. The following subsections describe the premium and reliability options in turn.

Ensuring scarcity prices with premiums

One should seek a re-design of the energy markets that respects the first principle of economics in terms of scarcity. One way to do this is to strengthen scarcity prices through a premium based on the VOLL and the loss of load probability (LOLP).

At times of high demand in the energy spot market, there will most often be sufficient capacity to clear the market because the system typically will contain a certain capacity margin. In this situation, there will be no scarcity and prices will stay at moderate levels, presumably at the short-run marginal cost of the most expensive unit in the market (left panel in Figure 2). The high demand for capacity may, however, create a tense situation regarding operating reserves that are retained at any given time to deal with unexpected events, such as a sudden increase in electricity demand or the loss of a generator or transmission line. Typically, the system operator would define an inelastic demand for operating reserves. When the reserve market does not clear itself, the only solution might be to shed load or to use other out-of-market transactions, both of which will not be reflected in the operating reserve or the spot-market prices. By defining a proper demand curve, such issues could be prevented and scarcity signals could be sent to all market participants.

We propose using a downward-sloping, *operating-reserve demand curve* (Figure 3), which is determined by the expected value of lost load (i.e., the product of loss of load probability and value of lost load; LOLP by VOLL) at any given time (Hogan, 2013). The more capacity available for operating reserves, the lower the LOLP, yielding the slope in the demand for reserves. This translates into an implicit premium ("price adder") on top of the electricity price in scarcity periods (right illustration in Figure 3). The underlying assumption is that generators will be able to either supply energy to the spot market or stay available for reserves. With rising demand in the spot market, the available capacity for reserves will be smaller. Due to the shape of the operating reserve-demand curve, this may result in sharply rising reserve prices. Therefore, in scarcity periods, when the probability of loss of load is high,

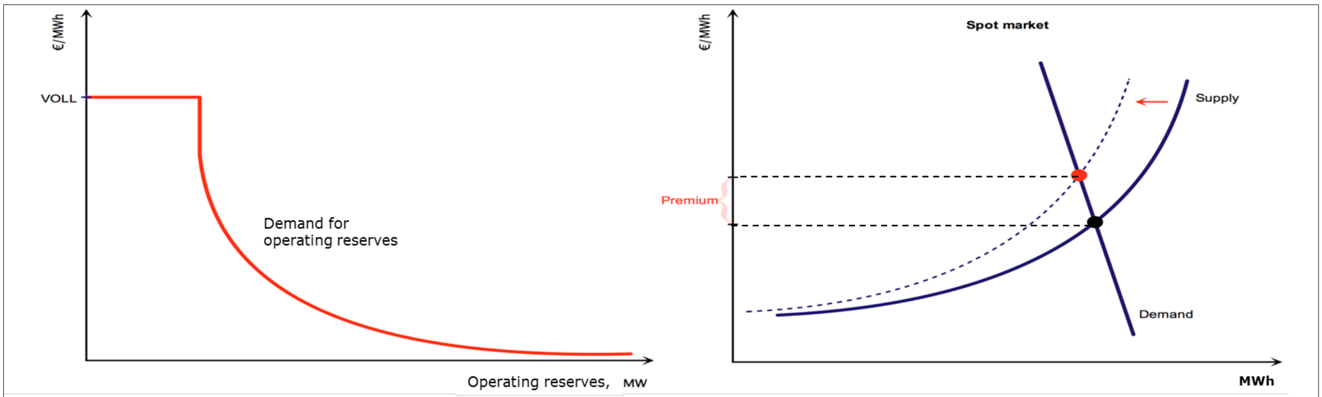

Figure 3: The downward-sloping Operating Reserve-Demand Curve (left figure) as a basis for a scarcity premium on energy prices (right figure)

the implicit premium is correspondingly high, while in other periods, in which the probability is negligible, the premium is close to zero.

The resulting premiums provide generators with additional revenue, improving the incentive to invest in new capacity (mitigating the missing money problem) and at the same time providing a stronger price signal to the demand side, to which the consumers can react.

However, the scarcity premium does not remove investor risk due to the uncertainty of future prices. Therefore, it is not certain whether the mechanism ensures sufficient capacity in practice. It could still be an important adjustment to the existing operating reserve markets, as the short-term price signals become more precise. While the profitability of investments would be improved, the cash-flow timing and investment risk are not addressed. We introduce *reliability options* to bridge the remaining gap to achieve adequate investments.

Reliability options

Reliability options allow generators to swap revenue from a few scarcity periods with a stable, risk-free payment. We propose that the system operator organises annual auctions to buy a predetermined number of reliability options (corresponding to the expected future capacity needs) with a predetermined strike price and a time horizon that allows for the introduction of new capacity. When a generator sells a reliability option, it will still receive the spot price for the energy it produces, but only in those hours when the spot price is lower than the strike price (see Figure 4). In all other hours (scarcity periods), it receives the strike price for the energy it produces. Note that in our case, the spot price includes the implicit premium stemming from the demand for operating reserves. In addition, the generator earns the selling price of the reliability options. Thus, the generator swaps the revenue it would have earned during the infrequent high price periods (i.e., above strike price) with a stable and risk-free payment for the reliability option. While the option payments compensate for the price risk during scarcity periods, market participants will still be fully exposed to price variations below the strike price. Standard forward contracts might, therefore, be used as a supplement to manage price risk below the strike price.

The advantage of reliability options is that they maintain the incentive for generators to produce electricity in scarcity periods, as the system operator sets the strike price such that it is above the marginal cost of the most expensive generation unit (resembling the scarcity situation in the right panel of Figure 2). Thus, any generator will earn a positive profit from producing electricity at the strike price. Just as under the option contract, a generator is obliged to pay the difference between spot and strike price whenever the strike price is exceeded, not producing in such an event will produce significant losses – a strong incentive to provide full capacity during scarcity events.

System reliability can, to a certain degree, be considered a public good. Improving reliability benefits all consumers because load curtailment at the individual level is currently not widely available. Thus, consumers have an incentive to free-ride and let others pay for improved system reliability. For this reason, we propose that system operators purchase reliability options on behalf of all consumers in a centralised auction and distribute the cost according to their respective shares of the load. In exchange, consumers receive a hedge against high electricity prices and inadequate capacity. This hedge against price peaks will have the same objective as present price caps which most likely

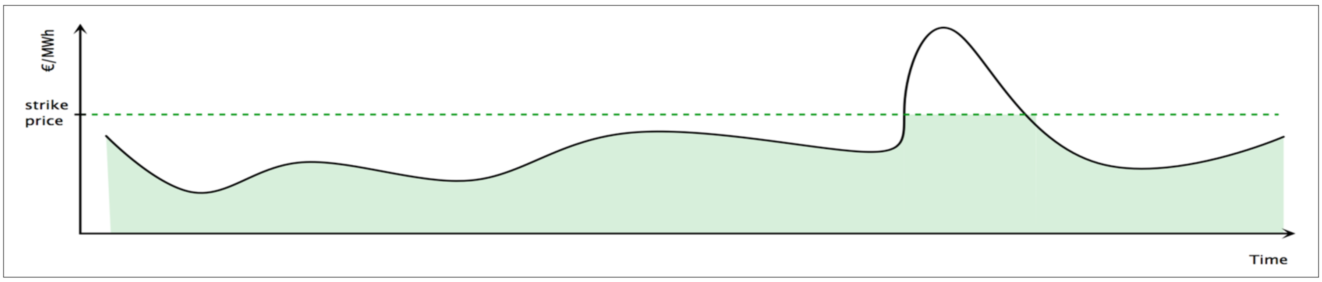

Figure 4: Reliability options and the spot and strike prices

will be removed in the future power market in order to allow for scarcity prices. Finally, from the point in time when the reliability option is sold until the contract takes effect, a few years will pass. This will allow new capacity to compete with existing capacity, as there will be time to construct new capacity between the auction and the delivery period.

If load curtailment at the individual level becomes widely available, the centralised auction can be replaced with a market for reliability options, in which consumers can decide whether to buy or not. If they decide not to purchase, they will accept the risk being curtailed in case of scarcity.

Discussion

Why choose our proposed scarcity premium and reliability options instead of traditional capacity-remuneration mechanisms? Different capacity-remuneration mechanisms (Table 1) are often mentioned during discussions about adequacy concerns and as a means to minimise investor risk. However, conventional strategic reserves and capacity payments or markets (capacity obligations or auctions) exhibit some deficiencies that regulators prefer to avoid (Finon and Pignon, 2008; Traber, 2017). Strategic reserves, for instance, remunerate capacity, so that it remains available and can be dispatched in times of scarcity. Typically, strategic reserves are mainly targeted at existing capacity and do not have a direct impact on new investments. As a long-term mechanism to ensure adequacy, they are, thus, not applicable. Among other capacity-remuneration mechanisms, reliability options have an advantage in that contracted capacity provides a distinct incentive to be available during periods of scarcity, while it does not profit from extreme energy prices directly (Cramton et al., 2013). Therefore, potential issues with market power in the energy spot market can be avoided to some extent.

Texas has implemented a variant of scarcity prices based on the operating reserve demand curve (ERCOT 2014), while a variant of reliability options has been implemented in the Colombian electricity market and in New England (Ausubel and Cramton 2010). However, to our knowledge, no one has combined the two approaches yet.

Throughout this paper, we assume a future in which large-scale electricity storage remains prohibitively costly, and commercial and residential demand-side response is limited. It is worth noting that the proposed mechanism can fall back to an energy-only market if a different future materialises. That is, if the loss of load probability is zero, the premium vanishes. Similarly, if storage or demand-side response completely eliminates price spikes and increases the average spot price, reliability options would lose their value as well. Thus, the proposed mechanism is not path-dependent, but easily reversible.

In theory, neither the premium nor the reliability options distort short-term dispatch incentives. However, further research is needed to determine how forecast errors by the system operator affect the market, i.e., forecast errors in the expected value of lost load, expected future capacity need, or marginal cost of the most-expensive generation unit. Further research is also needed to determine the exact interaction between the two mechanisms.

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Volume-Based				Price-Based
Targeted	Market-Wide			
Strategic reserves	Capacity obligation	Capacity auction	Reliability option	Capacity payment

Table 1: Capacity-Remuneration Mechanisms

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MARKET DESIGN FOR A DECARBONIZED EUROPEAN ELECTRICITY MARKET

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Challenges

The steadiness with which the European Union has pursed its ambitious Roadmap 2050 policy objectives [EC11] is an encouraging sign in the backdrop of a highly uncertain future for global energy policy. Despite the upheaval of environmentally-minded policies in the United States following the Trump election, the damage that the Trump administration can inflict on the global renewable energy and electricity market transformation agenda is expected to be limited as a result of major technological innovations, global market forces and the general momentum of EU policy makers towards de-carbonization and decentralization of the electricity industry [B17].

In this context, we identify the following major challenges for the decarbonized European electricity markets of 2050: *(i)* the shifting of value from energy markets to services in a near-zero-marginal-cost market; *(ii)* the lack of harmonization between regional markets and between time frames; *(iii)* the need to mobilize distributed resources; and *(iv)* the need to engage demand-side resources through scalable aggregator business models.

Proposal

The following four pillars are proposed as a means of overcoming the challenges mentioned in the previous section.

Pillar One: Real-time markets and scarcity pricing. The large-scale integration of renewable resources shifts value away from energy markets and into markets for ancillary services, and especially reserve markets. The central role of reserve markets in power systems dominated by renewables implies that reserves need to be valued accurately by the demand side. Due to the fundamental arbitrage relationship that links energy market opportunity costs to reserve capacity prices, a consistent pricing of reserve capacity will result in an adjustment of energy prices so as to accurately represent real-time scarcity. It is therefore important to value reserve capacity in real-time markets in a way that is consistent with system operation: increments of reserve under tight conditions are more highly valued by system operators than increments under comfortable system conditions, because they have a greater effect in reducing loss of load probability under scarcity.

Scarcity pricing already exists in certain European systems, for example in the Belgian market the imbalance price is corrected by a constant offset whenever the system is exceedingly long (above +120 MW) or short (below -120 MW). There is a sound economic theory [H05, H13] that can be developed in order to support this form of scarcity pricing. The fundamental ingredient of such a theory requires introducing a reserve capacity demand function. The introduction of operating reserve demand functions is predicated on the simultaneous clearing of energy and reserves, and the trading of real-time reserve capacity, which is currently absent in European energy markets. The resulting scarcity adder which is the real-time price for reserve capacity also corrects the real-time price for reserve energy, and is a price signal which rewards resources that support the system in real-time balancing while penalizing those resources that cause real-time imbalances. Ultimately, the proposed design results in price jumps of lower amplitude, and more predictable frequency. The correction of energy prices under conditions of scarcity can occur even if bids are mitigated due to regulatory concerns over the exercise of market power. The approach respects the fundamental design of an energy-only market, thereby safeguarding the integration of the common European energy-only market. At the same time, the design of such a demand function, coupled with a consistent day-ahead forward market, ensures the back-propagation of long-term investment signals that can support the expansion of much-needed flexible capacity. There is nothing to preclude the coexistence of the proposed mechanism with capacity remuneration schemes. However, the successful design and implementation of the proposed mechanism would render any capacity remuneration scheme less critical and, therefore, would mitigate some of its unintended consequences.

Pillar Two: Alignment of real-time and day-ahead markets. The design of a harmonized real-time market that simultaneously clears energy, reserve capacity and transmission capacity needs to be accompanied with a consistent day-ahead market design. Lack of consistency creates gaming opportunities, and introduces operating inefficiencies. Under some conditions, as experience from the USA market indicates, this lack of consistency between the markets can be detrimental to their efficient functioning and, more importantly, to the reliability of the system at a huge expense to consumers. Therefore, we propose a transition from the existing day-ahead power exchange towards the simultaneous auctioning of energy, reserves and transmission capacity in the day-ahead time frame. The integration of reserves and energy in market clearing allows for a more granular sizing of reserves, a more efficient commitment of thermal generators, and a correct pricing of reserve capacity which becomes the main service offered by thermal generators to the grid. The latter creates the opportunity for the introduction of improved scarcity pricing, as discussed under pillar one. The clearing of transmission with a proper representation of physical constraints within the auction allows the mitigation of congestion management costs, the coordination of resources from different areas to balance out local renewable supply fluctuations, and the seamless sharing of reserve capacity.

Pillar Three: Coordination schemes for TSO-DSO operations. Although pillars one and two clarify how a wholesale market for energy, reserves and transmission would operate, the corresponding market design still conforms to a passive utilization of distributed resources. Under such a paradigm, distributed consumers absorb power at will and distributed energy resources inject power into the distribution system whenever primary energy is available. Instead, with the advent of distributed storage, the system can be handled more intelligently, thereby deferring infrastructure upgrades and improving operational efficiency significantly. Whereas the status quo places all the intelligence in, and sources all flexibility from, the high-voltage transmission grid resources, we envision a coordinated, active dispatch of transmission *and* distribution resources.

The proper coordination of transmission and distribution resources requires a clear definition of how transmission system operators will coordinate with distribution system operators in an energy system dominated by renewables. The focus here is on being able to utilize distributed resources as reserve, while respecting the constraints of the distribution network. A range of TSO-DSO coordination schemes can be envisioned, each of which would need to be explored more carefully for its relative merits and disadvantages. Under a fully coordinated dispatch of transmission and distribution level resources, there exist approximations and relaxations of the physical constraints governing power flows in both the high-voltage grid as well as the sub-transmission and distribution system which capture the non-linearity of power flows while remaining computationally tractable [FL13]. These relaxations properly account for the non-linearity of distribution grids, reactive power flows, voltage constraints and real power losses, features which cannot be ignored at the distribution level, while preserving a computationally tractable model. The idea of the fully coordinated dispatch of distributed resources with transmission resources is to have the transmission system operator operate reserves at both the transmission as well as the distribution level while accounting for distribution level constraints. Although this may appear as a daunting task due to the size of the problem and its non-linearity, recent evolutions in decomposition algorithms render this vision possibly achievable with highly distributed computing infrastructure [K+13]. From a market design point of view, this effectively corresponds to the simultaneous trading of distribution network capacity, reactive power and reserve capacity in a simultaneous auction that is cleared by the system operator. Such an auction produces a distribution locational marginal price which accounts for the contribution of limited line capacity, real power losses, reactive power losses, and binding voltage constraints to the formation of real power prices at individual distribution nodes [P17]. Alternatively, if such an approach cannot be implemented due to governance or other regulatory constraints, it is possible to decompose the problem and solve it sequentially. The decomposition is best facilitated by simultaneously computing prices for the entire TSO meshed portion of the network, before propagating down to radial network branches using local distribution markets. Our objective in this case is to compute and communicate prices that are consistent with one another without resorting to a massive, centralized optimization process.

Pillar four: Priority service. With a properly functioning short-term market in place and a clear definition of proactive distribution system operations, it is possible to determine new value streams for demand-side flexibility, *provided* consumers are confronted with scalable aggregator business models. Our proposed solution for mobilizing consumer flexibility is based on the premise that consumers perceive electricity as a service, instead of a commodity that they are willing to purchase in a real-time market. Inspired by the successful paradigm of other sectors, including telecommunications and information technology, we propose a paradigm which combines the best of both price-based and quantity-based control, while respecting the requirement of consumers for privacy, control and simplicity. As in the case of popular business models for telecommunications, consumers value **transparent** offerings. We propose an offering of electricity at various levels of reliability, which we argue consumers can value accurately, as opposed to their valuation for increments of power in real time.

In practice, our proposal is implemented as follows [PBF13]: aggregators offer *slices* of power at different reliability levels, with higher levels of reliability corresponding to a higher price. Consumers then choose the amount of power that they wish to procure at each level of reliability. They can further set colour tags on each plug in their home (see figure 1), in order to prioritize the consumption of power in different devices. Since slices with lower reliability are priced lower, they allow consumers to pocket the benefits of their flexibility, something which is largely impossible under existing retail tariffs. At the same time, consumers preserve **control** of their devices, because they can decide how to colour-tag devices throughout their home. Aggregators can collect this information over hundreds of thousands of households and apply stochastic distributed control strategies that allow for a rapid regulation of aggregate residential and commercial consumption. Since different colour tags correspond to different levels of reliability and valuations of power, the colour tags suggest the order in which devices need to be curtailed: in case of shortage the aggregator curtails devices in order of increasing reliability. The bidding of the load slices in the market is also straightforward, since the aggregator simply needs to utilize the price duration curve of the market in order to determine the offer price for power slices corresponding to different levels of reliability.

The challenge on the end of the aggregator is to design a menu with asymmetric information (i.e. without knowing how individual consumers value power, thereby respecting **privacy**), while ensuring that the reliability a renewable-based energy system can afford is the reliability that the consumers are entitled to through their reliability choices. There exists solid economic theory to guide the optimal design of such reliability-differentiated menus, either through capacity-based tariffs [CW87] or capacity and energy-based tariffs [C+86], while having the aggregator rely

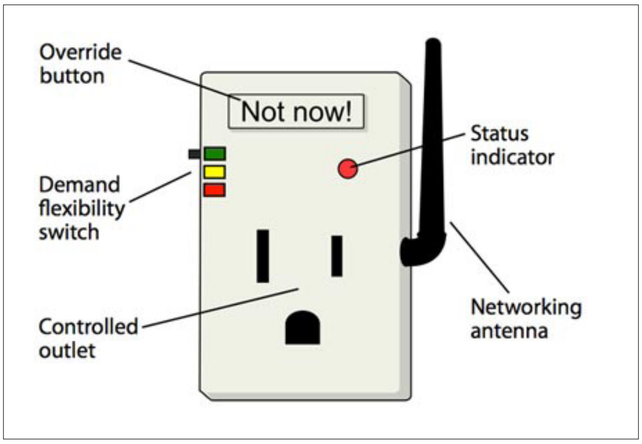

Figure 1: Illustration of a smart plug. Different colours of the switch correspond to different reliability levels. Source: http://mitei.mit.edu/news/ tomorrows-power-grid

on aggregate statistical information about the valuation of the population for power, a prerequisite which is clearly realistic.

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TOWARD A FULLY RENEWABLE EUROPEAN ELECTRIC ENERGY SYSTEM

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Introduction

Climate change is widely recognised as one of the major environmental problems the world is facing today. Investments in energy efficiency and low carbon energy technologies combat global climate change and promote a sustainable development. The European Union (EU) has taken the leadership in the mitigation of climate change since the establishment of an Emissions Trading System (EU-ETS) in 2005. More recently, the EU has raised its ambitions in the Energy Roadmap 2050, where a 80-95% reduction in greenhouse gas (GHG) emissions is foreseen by the middle of this century.[1]

The roadmap indicates several routes that can be undertaken to attain a more sustainable, secure and competitive energy system. These routes are characterised by investments in renewable energy sources (RES), in gas-fired power plants, nuclear energy, and in efficient technologies such as those based on "carbon capture and storage". Among them, the integration of RES in the European power system represents a key point, since more than 30% of the total GHG emissions are due today to electricity generation. However, electricity production from wind and sun, although more mature from a technological point of view, is still difficult to predict because it depends on intermittent sources that introduce high levels of variability and uncertainty in system planning and operation. On the other hand, renewable technologies such as concentrating solar power (CSP) and offshore wind, which suffer less from intermittency, are currently less developed and their investment costs are subject to high uncertainty.

The achievement of the European environmental targets is also influenced by the market design of the energy system. The liberalization of the European electricity market started with Directive 96/92/EC and then Directive 2003/54/EC. However, the creation of an efficient and flexible internal market, as pursued by the Third Legislative Package in 2009,[2] the related Network Codes[3] and the so-called "Winter Package"[4] is still under way.

In this paper we consider this complex framework where EU environmental policies, power production processes and electricity market design are strictly interrelated. In particular, we focus on the operation of a renewable-dominated power system in Europe. Specifically, we propose a fully integrated EU market for 2050 where energy and reserve capacity are simultaneously dispatched in the day-ahead market, taking properly into account the uncertainty related to the power production from RES and the consumption level. The numerical analysis is based on realistic data for 24 European countries and is conducted considering the cross-border limitations among Member States.

Market design

In this paper, we present a market design in which energy and reserve capacity are scheduled in a coordinated way in the day-ahead market. The market design proposed takes into consideration, for real-time operation, the variability of the electricity consumption and the intermittent production from renewables. We applied this model to the European electricity market for 2050, based on the projections made by the European Commission and the actual data provided by ENTSO-E for the 24 countries participating in the Price Coupling of Regions (PCR) project.[5]

The proposed market design is based on the assumptions described below.

1 https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/2050-energy-strategy

2 http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=en

3 http://networkcodes.entsoe.eu/

4 https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

5 https://www.epexspot.com/en/market-coupling/pcr

Assumptions

- The 24 **countries** considered are those currently coupled through the PCR plus Switzerland, namely: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, the UK and Switzerland. Each country is modelled as a single node in the network. The **interconnection capacity** among countries is that projected by ENTSO-E for 2030.[6]
- We consider that both the **energy and reserve markets** are cleared simultaneously in the day ahead of delivery (D-1) for the 24 countries, considering their cross-border limitations.
- The market design comprises **two stages**: the first stage represents the **day-ahead market**, where energy and reserve capacity are scheduled for the 24 hours of the following day; the second stage represents the **balancing market**, where upward/downward reserves are deployed to counteract the deviations from what forecasted for the consumption and the renewable power production.
- Furthermore, minimum upward/downward **reserve capacity requirements** are imposed for the whole system in each hour, which correspond to **3%** of the forecasted consumption and **5%** of the forecasted renewable production.
- The **generating system** comprises the following **technologies**: nuclear (Nucl), coal, combined-cycle gas turbine (CCGT), hydroelectric with reservoir (HRes), run-of-river hydroelectric (HRoR), onshore/offshore wind (Wons/Woff), solar photovoltaic (SoPV), concentrating solar power (SoTH) and biomass (Biom).
- All **generating units** can provide upward/downward reserve capacity except for the nuclear power plants. The cost of scheduling reserve capacity is 1% of their operating cost.
- Energy **storage** units, such as pumped storage or large-scale batteries, are included and considered as a resource for the TSO to maintain the reliability of the system (they can provide reserve services).
- The demand level and the wind and solar power production are considered as uncertain parameters. **Stochastic programming** is used to model the decision-making process regarding the uncertainty introduced by those parameters.[7] The values of the uncertain parameters are represented through a set of **scenarios**. The scenarios are generated using historical data from ENTSO-E.[8]

Model description

The proposed market design is modelled through an optimization problem that seeks to minimize the total operating cost of scheduling energy and reserve in the day-ahead market and the expected cost of deviations in the balancing market. Specifically, the model is formulated as a two-stage stochastic-programming problem where the first stage represents the day-ahead market and the second stage represents the balancing market.

The constraints included in the proposed model are as follows:

- The power balance in the day-ahead and the balancing markets is imposed in each hour and in each node of the network, and in each scenario in the balancing market (scenarios are only considered in the balancing market, not in the day-ahead market);
- Capacity and ramping limits are imposed to the thermal and hydroelectric units. The maximum power output of renewable units, such as wind and solar, is limited by the primary energy available in each hour;
- The power that can be interchanged among countries is also limited;
- The constraints included to represent the storage operation comprise: the energy balance in the storage, the capacity and the charge/discharge

6 http://tyndp.entsoe.eu/

7 Birge J. R., and F. Louveaux (1997), Introduction to stochastic programming, New York: Springer-Verlag.

8 https://transparency.entsoe.eu/

limits of the storage, and the minimum energy level in the storage at the end of the day;

- Minimum upward/downward reserve requirements are imposed based on the projection of the electricity consumption and the renewable power production in the day-ahead;
- The deployed reserves in the balancing market are limited to the scheduled reserves in the day-ahead market.

Due to space limitation the mathematical formulation is not provided, but the proposed model is similar to what presented in related papers.[9],[10]

Numerical results

All the data used in this work were mainly collected from ENTSO-E.[11] The webpages of the system operators of Norway, Switzerland and the UK were also consulted to complete the data.

A list with the main assumptions considered to carry out the numerical analysis follows:

- We assume that the electricity consumption in 2050 will be 25% higher than that of 2016, coherently with the projections of the European Commission;[12]
- The total generating capacity of the system in 2050 is assumed to be 1442.8 GW, being 66% renewable. The percentages per installed technology are: nuclear 6%, coal 3%, CCGT 18%, hydroelectric 12%, onshore wind 30%, offshore wind 1%, solar PV 24%, CSP 0.5%, and biomass 5% (total generating capacity considered for 2016 is 818.4 GW, being 43% renewable);
- The energy storage capacity in each country corresponds to 10% of the average daily electricity consumption in 2016;
- The real-time scenarios were generated applying the forecast error observed during 2016 between the prediction for D-1 provided by ENTSO-E and the actual realization, for each hour and in each country. Therefore, the same demand curve and renewable power availability factors are applied to the generating capacity systems of 2016 and 2050, respectively. Note that demand in 2050 is adjusted, considering the expected demand growth;
- Investment and operating costs are taken from the reports of the International Energy Agency.[13]

Specifically, in this section we analyse the system operation in two different ways:

- First, we consider a representative day of 2016 in terms of net demand. The day is selected over the 366 days of 2016 using a scenario reduction technique that evaluates the net demand, namely the daily electricity consumption minus the wind and solar power production. The resulting representative day is September 2nd. Specifically, we take the demand curve and renewable power availability factors of this day to analyse the EU power system both in 2016 and 2050, taking into account the generating capacity and the demand growth in each year.
- Second, the system operation for the whole year considering the generating capacity of 2050.

The main **results** obtained from this analysis are described below. All the figures in the following compare the results obtained without (left hand) and with (right hand) storage capacity, respectively.

First, we provide the results obtained considering a representative day of the year, namely September 2nd, as indicated above.

Figure 1 depicts the day-ahead energy scheduling in the whole system for that day in 2050. As comparison, Figure 2 represents the day-ahead energy scheduling in the same day, with the generating capacity of 2016. The main results are: first, the energy mix in 2050 will expectedly be less carbon-intense than the current one; second, solar PV units will play a relevant role to attain

9 Domínguez R., A.J. Conejo, and M. Carrión (2014), Operation of a fully renewable electric energy system with CSP plants, Applied Energy, vol. 119, pp. 417-430.

10 Morales J.M., A.J. Conejo, and J. Pérez-Ruiz (2009), Economic valuation of reserves in power systems with high penetration of wind power, IEEE Transaction on Power Systems, vol. 24(2), pp. 900-910.

11 https://transparency.entsoe.eu/

12 https://ec.europa.eu/energy/en/data-analysis/energy-modelling

13 http://www.worldenergyoutlook.org/weomodel/

the emission reduction targets; third, the availability of storage capacity allows a better integration of intermittent renewable production, especially in a RES-based system as that in 2050.

Additionally, Figures 3 and 4 depict the reserve capacity scheduled per technology in the day ahead for the generating system of 2050 and 2016, respectively. Comparing these figures, we observe that higher reserve capacity is required in 2050 than in 2016 because there is more intermittent renewable production. If available, storage units will provide high reserve capacity.

To conclude this first analysis, we provide Figure 5 that depicts the renewable power curtailment in that day in 2050 with (right) and without (left) storage capacity. As expected, comparatively less power production is curtailed if storage capacity is available.

Second, we simulated the system operation for the 365 days of the year considering the generating capacity system of 2050. The results show the system operation with and without storage capacity.

Figure 6 depicts the day-ahead energy scheduling in each month of 2050. These figures show that there is more wind power production in the cold season, whereas in hot season the lack of wind is compensated by solar power production.

Moreover, Figure 7 shows that the reserve capacity requirement is higher in those months with higher wind power production. Biomass and CSP units provide high reserve capacity to the system. If storage units are available, they provide high reserve capacity and make the system more flexible.

On the other hand, Figure 8 provides the mean, minimum and maximum electricity price attained in each month of 2050 with and without considering storage capacity. In the case without storage capacity we find a couple of months with negative minimum prices. However, if storage capacity is available, no negative prices are found, whereas maximum prices are slightly lower during the year.

Finally, Table 1 provides the rate of expected profits in k€/MW attained per technology in each country (note that the blank spaces are for those countries without capacity of that technology). The profits are computed as the difference between the incomes received from providing energy and capacity to the system minus the variable and annualized investment costs. From the results provided in Table 1, we can highlight the good economic results attained by nuclear, hydro, and biomass units, in general. Other units, such as CCGT or offshore wind, get into losses in some countries. In the case of CCGT units this is due to their high operating costs and their low load factor, whereas the high investment costs are the reason of the negative results for offshore wind units.

Conclusions

The main conclusions obtained from this analysis are as follows:

- Jointly **scheduling energy and reserve** capacity in all European countries allows for an efficient integration of the renewable power production, which is a crucial point in the decarbonized energy system expected for 2050;
- Electricity **prices** in the day-ahead market in 2050 will be comparatively lower than the current ones. However, generating units will recover their expenses and are expected to make profits in in every country, except for the CCGT and offshore wind units that may need an uplift;
- The availability of **energy storage** capacity allows for a reduction in operating costs, by providing more flexibility to the system;
- Comparing the **energy mix** in 2016 and 2050 for the electricity consumption projected for 2050, it is observable the large reduction in the **CO_2 emissions**;
- The proposed model allows to jointly clearing energy and reserves in the whole European system in **short computational times**.

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(K€/MW)	NUCL	COAL	CCGT	HRES	HROR	WONS	WOFF	SOPV	SOTH	BIOM
AT	-	68.69	2.42	5.29	70.06	36.99	-	25.76	-	133.53
BE	-	-	0.91	-	19.12	38.86	37.40	27.69	-	187.85
CH	143.50	-	-	23.34	67.89	196.00	-	211.86	-	160.00
CZ	88.67	36.54	0.22	3.06	32.12	26.07	-	15.67	-	105.78
DE	-	48.62	0.18	4.77	78.70	24.22	0.05	15.32	-	122.98
DK	-	66.71	1.28	-	0.00	21.49	-5.40	22.38	-	119.62
EE	-	63.30	-0.10	-	70.00	24.61	-	160.00	-	131.96
ES	-	30.02	-0.09	0.33	59.98	9.88	-	9.56	90.08	58.23
FI	122.27	69.06	-0.07	-	98.63	47.51	53.00	192.00	-	136.13
FR	4.15	3.04	-0.10	0.09	14.57	11.44	-0.38	17.34	-	13.60
HU	109.32	58.60	0.29	3.05	64.03	32.33	-	-0.14	-	123.81
IT	-	34.87	0.09	2.71	81.57	22.06	-	14.18	113.20	79.90
LT	108.59	-	0.00	2.44	53.52	38.96	-	16.29	-	124.21
LU	-	-	3.38	-	14.29	28.55	-	17.54	-	124.03
LV	-	56.71	0.00	-	32.31	33.75	-	175.87	-	127.01
NL	-	90.61	0.69	-	0.00	37.30	45.00	26.46	-	170.53
NR	-	-	0.00	0.64	-0.37	53.06	56.00	-	-	-
PL	93.62	36.66	0.32	4.70	70.36	27.68	-	0.00	-	108.29
PT	-	-	0.00	1.02	28.57	16.53	-	17.78	90.38	58.78
RO	101.38	48.91	-0.03	0.88	76.80	31.86	-	19.27	-	116.47
SE	126.15	75.19	0.02	2.18	-	52.71	-	194.93	-	141.40
SI	90.15	42.40	0.85	-	61.71	-0.29	-	12.73	-	106.95
SK	98.77	42.97	0.00	2.25	76.12	38.02	-	19.45	-	113.07
UK	27.00	19.20	0.45	4.95	-0.37	11.48	-40.45	10.72	-	44.40
EU	**56.50**	**45.08**	**0.29**	**2.38**	**54.03**	**21.32**	**0.30**	**15.35**	**93.51**	**87.45**

Table 1: Rate of profits in k€/MW per technology in each country

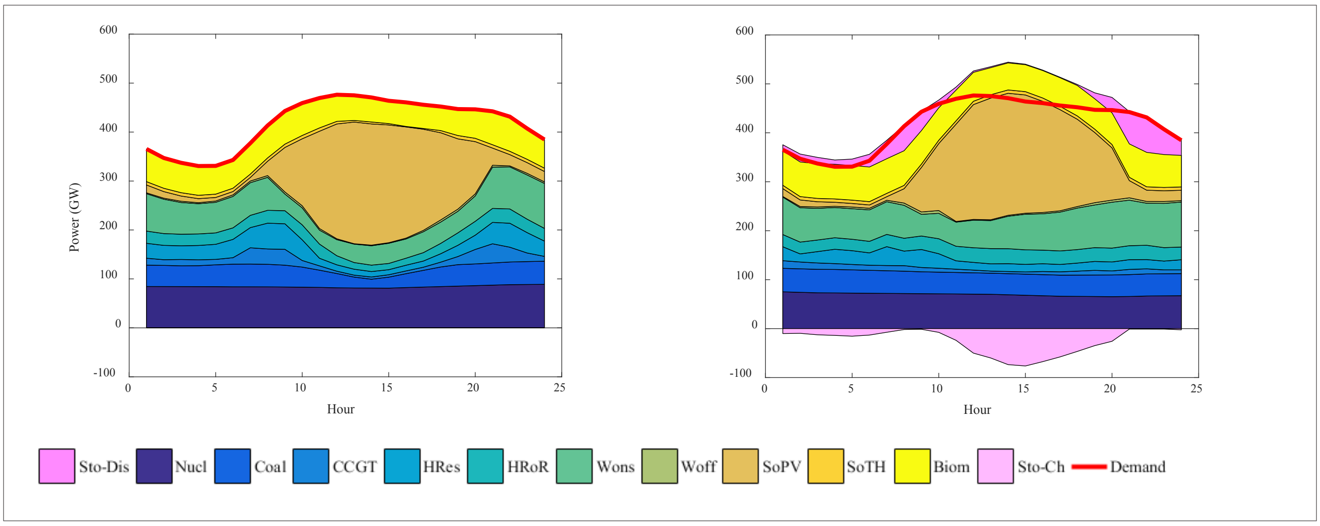


Figure 1: Day-ahead energy scheduling on the 2nd of September of 2050 without (left hand) and with (right hand) storage capacity

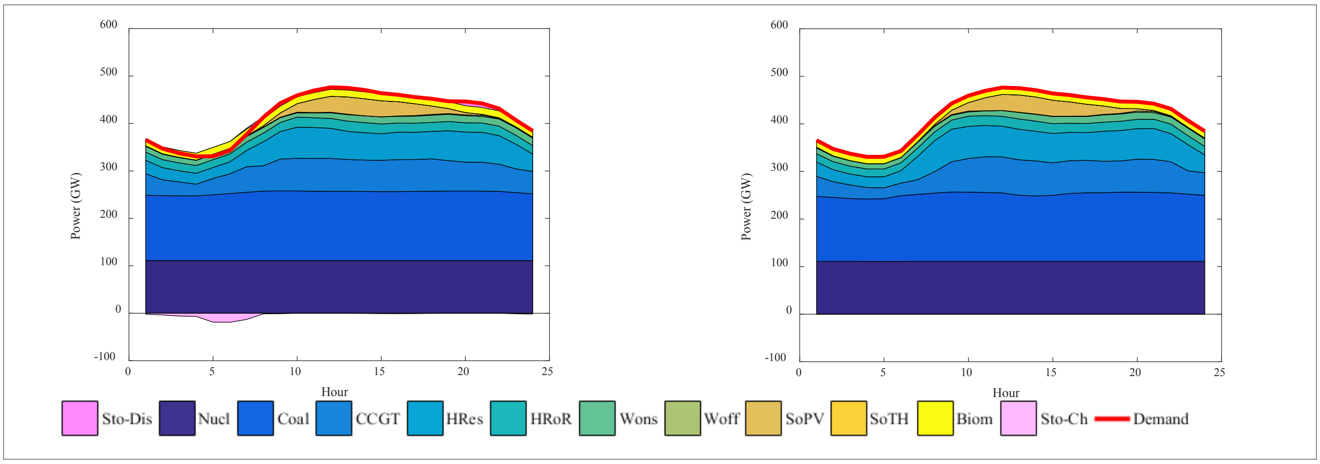


Figure 2: Day-ahead energy scheduling on the 2nd of September of 2016 without (left hand) and with (right hand) storage capacity

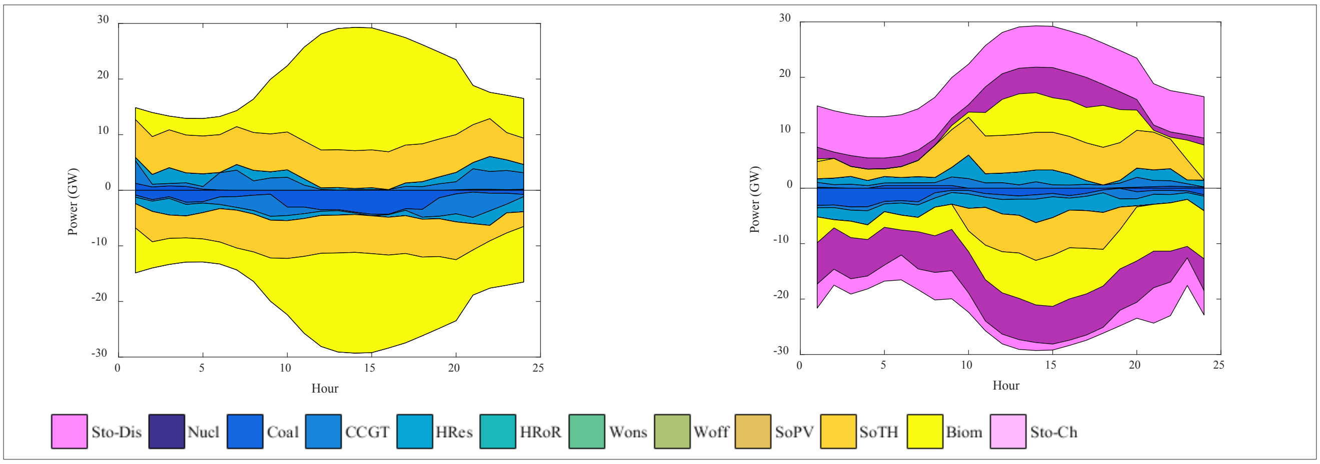


Figure 3: Reserve capacity scheduling on the 2nd of September of 2050 without (left hand) and with (right hand) storage capacity

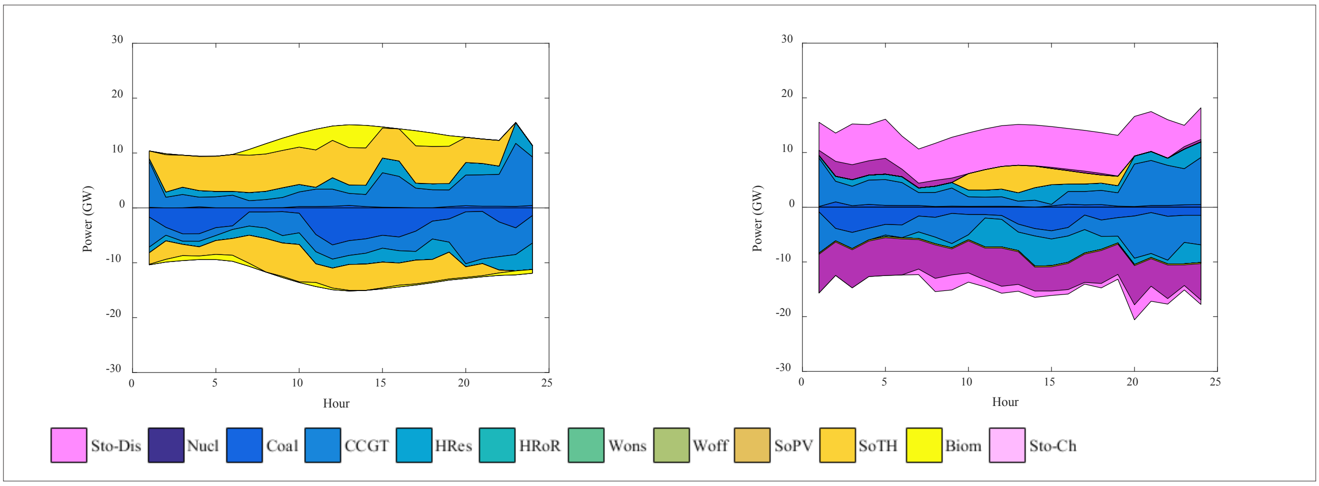


Figure 4: Reserve capacity scheduling on the 2nd of September of 2016 without (left hand) and with (right hand) storage capacity

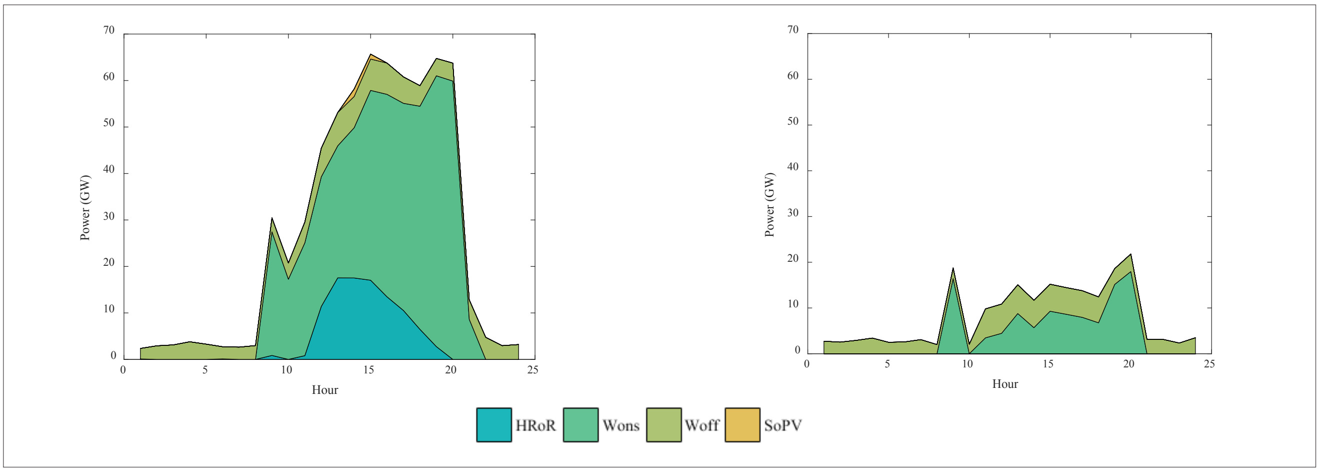


Figure 5: Power spillage on the 2nd of September of 2050 without (left hand) and with (right hand) storage capacity

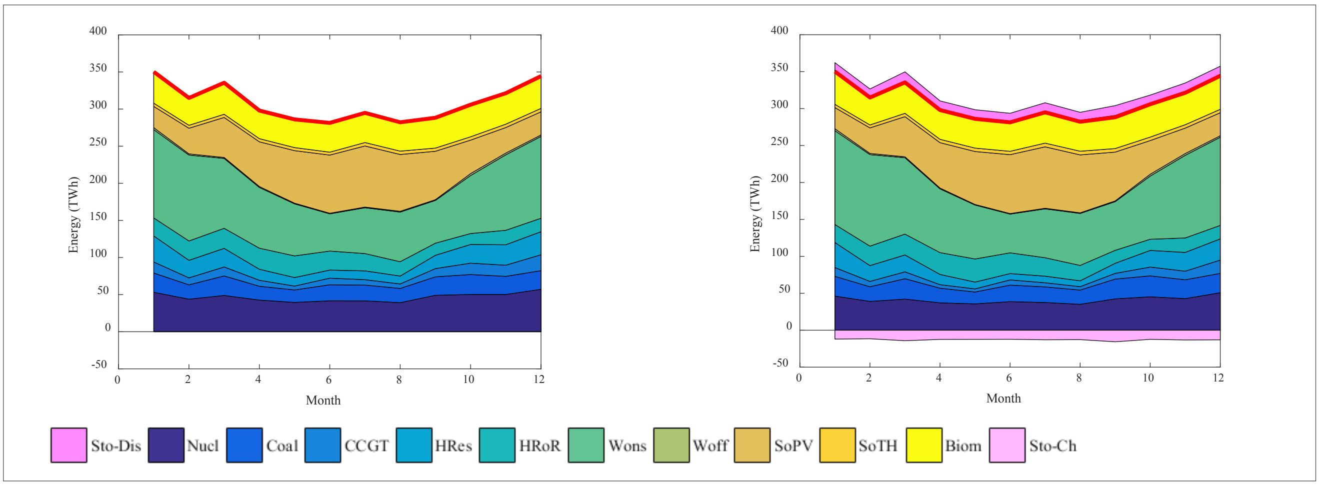


Figure 6: Monthly day-ahead energy scheduling in 2050 without (left hand) and with (right hand) storage capacity

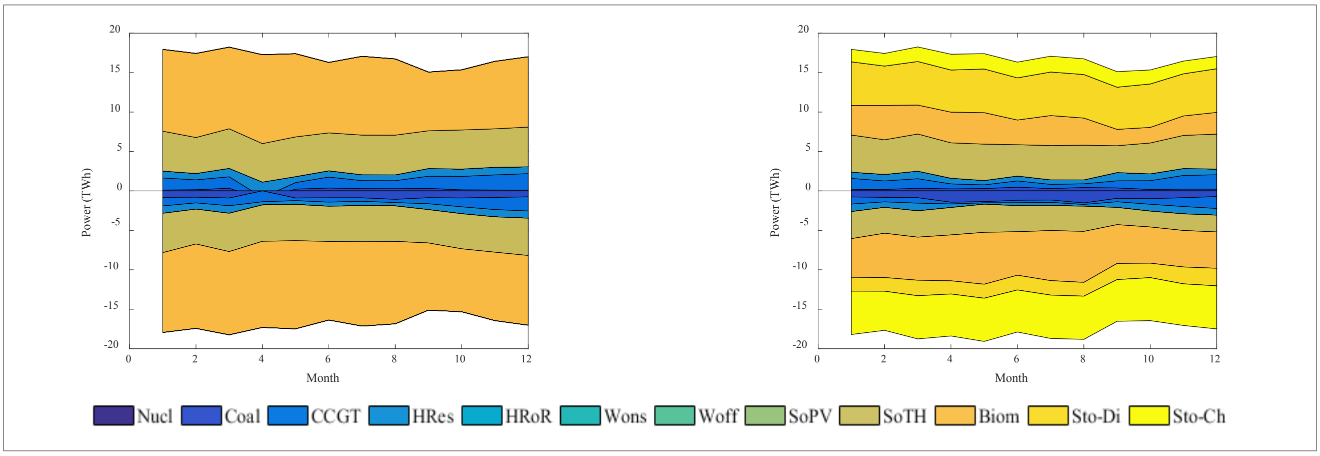


Figure 7: Monthly day-ahead reserve capacity scheduling in 2050 without (left hand) and with (right hand) storage capacity

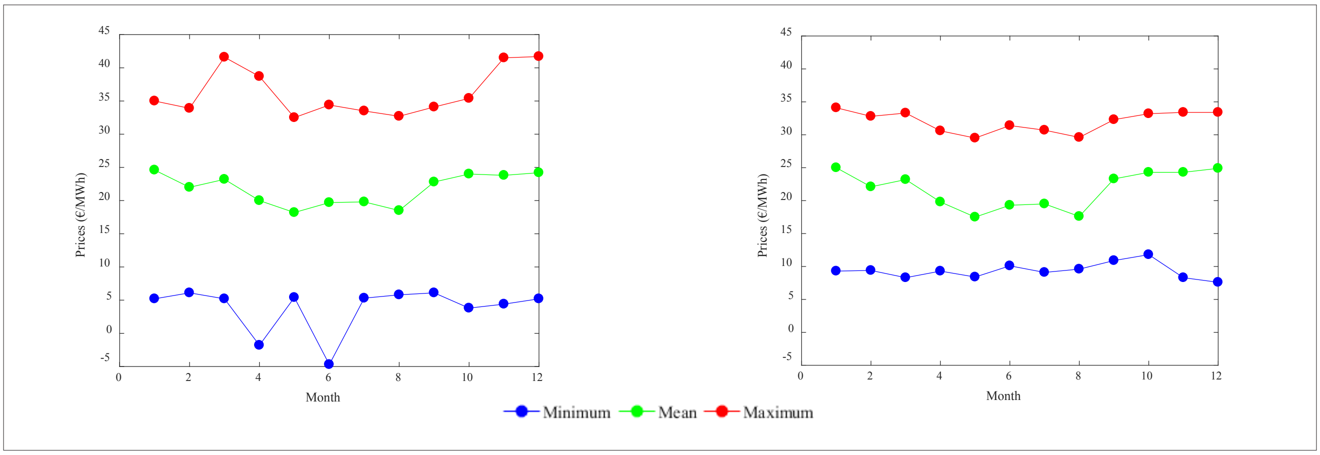


Figure 8: Monthly mean, minimum and maximum prices in 2050 without (left hand) and with (right hand) storage capacity

ELECTRICITY MARKET REDESIGN – FROM A DISTORTED SHORT-RUN TO A COMPETITIVE LONG-RUN MARGINAL PRICE-SETTING MECHANISM

Christian Grenz

Introduction

Over almost two decades of electricity market liberalisation – a market price-setting mechanism based on short run marginal costs (SRMC) – has delivered a competitive and economically viable electricity supply. However, given the steadily growing share of renewable energy sources (RES) with near-zero SRMC, it is most unlikely that the profit contribution would be sufficient to investors in long-term capital-intensive projects as those in the electricity sector usually are. A delivery of efficient and effective outcomes would not be ensured.[1]

Investors in long-term capital-intensive projects require predictable revenues for any sort of credit rating stability and thus in order to be willing to invest for modest returns. Business models based on unpredictable future market prices would be high risk, and therefore would either involve risk-adjusted capital cost or be unable to obtain financing. Adequate revenue stabilisation mechanisms (RSMs), no matter if public or private, would contribute to low capital costs and so to an economically viable and environmentally friendly market design.[2]

On the other hand, competitive prices in line with the market are essential to stimulate investment in flexibility, efficiency and system integration, including digital platforms and cross-sector interactions. However, the out-of-market payments from support schemes for RES and backup capacity sources (BCS) have already achieved a critical level in most European markets. For example, in Germany, the out-of-market payments for electricity generation have reached a share of almost 65 per cent. In the year 2016, market-oriented remuneration has decreased to ca. EUR 15 billion[3] and non-market remuneration has increased to ca. EUR 30 billion.[4]

If policymakers really want to reverse the trend, it is crucial to define and analyse the design errors in the existing mechanisms and to take a targeted approach to the issue. Should Europe fail to resolve this issue, not only will the large-scale market distortions and massive redistribution effects in evidence today persist and make further market intervention inevitable, but they will also sprawl into other energy sectors such as heating, cooling and transportation.

Method

In my study, I investigate: (i) the properties of the existing market price-setting mechanism and the impact from near-zero SRMCs of RES; (ii) the investment conditions, the perception of risk and reward and the impact of risk adjustments on

1 A RES supply curve based on SRMC would be too flat to deliver the necessary producer surplus (missing money problem).

2 Investment in long-term capital-intensive projects is very risk sensitive with capital costs being one of the largest contributors to the long-term marginal cost (LRMC). The predictability of cash flow determines the risk premium and amortisation period. For example, refinancing of a newly built gas-fired power plant (CCGT) based on scarcity pricing would require an average price spike of not less than 420 EUR/MWh at 1,000 full load hours (FLHs) per annum or 7,450 EUR/MWh at 50 FLHs p.a. This in turn can significantly increase the overall electricity cost and endanger the economic viability of the system. In an integrated European electricity market with an average peak load of 500 GW, the additional cost could rise to almost EUR 125 billion p.a.

3 Approximately 500 TWh times the average market price of 30 EUR/MWh.

4 EUR 25 billion for generated electricity under the Renewable Energies Law, EUR 1.5 billion in form of capacity payments under the Cogeneration Act and ca. EUR 3.5 billion for capacity reserves and other cost associated with security of supply.

capital cost; (iii) the balancing effects of potential cross-border and cross-sector interactions; (iv) the options of intensifying market-driven stimulation of ongoing flexibility and efficiency enhancements; and (v) the avoidance of distortion in competition and unintended distribution effects. The LRMC is one of the primary metrics, and strengthening efficiency and the effectiveness of market mechanisms the primary objective.

Results

For less regulated, highly flexible and economically viable decarbonized markets, the out-of-market payments have to be embedded into the market price-setting mechanism and the mechanism basis itself has to be transformed from one grounded on SRMC to one based on LRMC. The key characteristics of an efficient and effective redesign are: (i) tailored LRMC based capacity auctions for a certain number of FLH in predefined time periods and for specific backup requirements; (ii) the right and obligation to deliver for the contracted capacity in all markets; (iii) an index-based remuneration mechanism for BCS; and, most importantly, (iv) the reduction of the contracted remuneration in the amount of the FLHs fed into the grid.

Framework for investment in renewable energy

Markets today are in principle characterised by RSMs for all electricity generated in a specific number of years, whereby the publicly guaranteed remuneration is paid independently of demand and outside of the market price-setting mechanism.[5] These out-of-market payments have formed the basis for the RES deployment in the last two decades. European legislation adopted in 2009 has accelerated this development. Meanwhile, the market share of RES and therewith the level of out-of-market payments has made further market intervention necessary such as capacity remuneration mechanisms (CRMs) for BCS, prohibition on decommissioning of BCS and a controlling regulatory system of penalties, levies and taxes.

5 The most common are: feed in tariffs, contracts for difference and renewable obligation certificates.

In the context of a sustainable and market-oriented design for clean, cheap and reliable energy, the following two questions have to be addressed:

1. How can the RES targets be achieved without withdrawing the basis for investment in renewable energy? Or in other words, how can the out-of-market payments of today be embedded in a competitive market-price setting mechanism of tomorrow?
2. How can RES be integrated in the system and market-driven price signals for flexibility features be achieved? Or in other words, how can the full diversity of system flexibility and cross-sector interaction be unlocked without additional regulatory intervention in the market?

When answering these questions, it is essential to bear in mind that long-term RSMs are the basis for ongoing investment. However, it does not mean that the guaranteed remuneration has to be provided independently of demand and for all electricity generated. A more market-oriented approach, for example guaranteed remuneration for a certain number of FLHs in predefined time periods, would also work as basis for RES investment and would, in addition, provide a sound basis for a truly integrated system.

Appropriate adjustments of RSMs are shown in Figure 1 below. The design elements which need to be changed are highlighted in red and green. For example, in the case of a Power Purchase Agreement (PPA), a floor price is guaranteed for a certain number of FLH in pre-defined time periods, rather than for all electricity generated at any time and independent from the demand.[6]

In today markets, the RES investors contracted offer the electricity generated for the lowest price possible in order to secure a power off-take contract and, in turn, the remuneration guaranteed.[7] The negative impact on

6 The Netherlands have already adopted a ceiling in the RSMs for RES (SDE: Stimulering Duurzame Energieproductie)

7 For example, in Germany the lowest bidding price is minus 500 EUR/MWh. When negative market prices occur, the contracted supplier pays the negative price to the power off-taker, receiving in return the difference with the guaranteed auction price. In a future with more and more time periods with a surplus of RES supply, market based clearing will become critical.

the electricity market prices as well as the increase in the out-of-market payments needs to be stopped and mitigated. In the proposed redesign, the guaranteed remuneration will be reduced by the amount of the FLHs fed into the grid. Given the fact that investors who have been awarded a RSM contract have the right and the obligation to deliver for the contracted capacity in predefined time periods, the bid price will be equal to or higher than the contracted auction price.[8] As a result, the out-of-market payments for RES will be embedded in the market price setting mechanism and public funding from support schemes for RES will most likely be reduced to zero.[9] Investors will be compensated from public funds only in cases where the FLHs bid are higher and the FLHs generated are lower than the FLHs contracted.

There are many reasons why it is becoming increasing important to integrate the growing share of fluctuating RES into the system. A market-driven price signals approach is shown in Figure 2 above. The idea of drawing up this approach is the fact that private investors are mostly profit oriented and strive to make their investments and operations more efficient and cost-competitive. In two or more simultaneous tailored auctions with different pre-defined time periods[10] and corresponding auction prices, the investors will be incentivized and rewarded for investments in flexibility features. The price differences between the auctions will provide strong market-driven price signals for system flexibility and cross-sector interaction. For example, if the cost of flexibility borne by the investor is lower or the expected revenue from cross-sector interactions is higher than a previous price difference of 50 EUR/MWh between auction 1 and auction 2, the investor will most likely opt for participation in auction 2. Conversely, this means that investors with higher opportunity cost or lower profit opportunities in cross-sector markets may stay with auction 1 and be exposed to increasing price pressure and lower profit margins.

The proposed mechanism would primarily provide market-driven price signals for innovations and new business concepts in short-term flexibility features such as demand response, storage systems and platform solutions as well as cross-sector revenues from electricity heating and cooling, e-mobility and a conversion into other forms of energy. The price difference would reflect the real cost of system flexibility and stimulate a technology-neutral and market-oriented competition. The regulator acquires an efficient management tool to optimize the electricity supply from RES in line with market developments, and thus can allocate resources in an economically viable and highly efficient manner. An uncontrolled sharp rise in downtime costs in critical time periods with a surplus of supply can be better monitored, stopped or minimized.

Framework for investment in backup capacity

Across Europe, electricity markets are in principle designed as energy only markets (EOM). However, a massive increase in out-of-market payments for RES has had a profound and destructive impact on the economics of conventional power plants, which still form the bulk of indispensable BCS. The sum of (i) distorted low market prices, (ii) a continuously shrinking residual load and (iii) an increase in operating and maintenance costs will most likely keep the amount of missing money at an unacceptably high level. Without CRMs, which have now been implemented in most of the larger European electricity markets, security of supply would already be at risk.[11]

Aside from the fact that implementing different forms

8 For example, the auction price for a wind farm with installed capacity of 100 MW is 40 EUR/MWh for 3.000 FLH p.a. The guaranteed remuneration would be EUR 12 million p.a. In the event that the electricity generated by the wind farm is exactly 300 GWh p.a., offered for a lower price and contracted for 30 EUR/MWh in average, the remuneration would be EUR 9 million p.a. only. In order to secure the EUR 12 million p.a., the RES investor will offer the electricity generated for an average price equal to or higher than 40 EUR/MWh only.

9 The generated FLHs should be in principle higher than the contracted FLHs.

10 Based on the demand in specific time periods, e.g. per year at any time, per month and per week for a particular mix of on and off-peak periods or for low and high seasons.

11 For example: price-based CRMs in Germany since 2002 (other large markets are Spain and Italy), capacity-based CRMs in UK since 2014 (capacity auction) and in France since 2016 (capacity obligation). Strategic reserves exist in at least eight markets (inter alia in Germany, UK, Italy and Poland). In Germany, the price-based CRM for cogeneration power plants alone has increased three-fold to EUR 1.5 billion in 2016.

of CRMs runs the risk of fragmenting the European internal market for electricity, existing CRMs all have the same serious design error: they are independent of market developments and do not incorporate operational efficiency and flexibility. However, in a decarbonised, RES dominated future, it will become even more important to unlock the full diversity of flexibility in BCS and to value the flexibility features in line with market trends. The main questions to be addressed are as follows:

1. How can the design errors in existing CRMs be fixed and market-driven price signals for flexibility and cross-sector interaction achieved? Or in other words, how can transparent, innovative and highly competitive markets be set up?
2. In interconnected markets with different regulatory frameworks, how can undesirable distortion of competition and distribution effects be mitigated or even avoided? Or in other words, how can maximum long-term compatibility be achieved amongst European markets and in cross-sector interactions?
3. How can the out-of-market payments of today be embedded in a competitive market-price setting mechanism of tomorrow?

Given the key drivers in the energy sector of the future (decarbonisation, decentralisation and digitalisation) and the increasing complexity of markets, a market-oriented solution seems to be impossible at first glance. However, with a closer look at market mechanisms and more thorough analysis of the underlying changes, it is possible for a sustainable solution to emerge.

First and foremost, capacity payments must be linked to market developments and embedded in the market price-setting mechanism. For a competitive and market-consistent mechanism, auctions should be tailored in line with the characteristics of the diverse BCS and capacity remuneration should be index-based and be reduced by self-dispatched capacity.

Figure 3 below shows appropriate adjustments of a capacity-based CRM such as in the United Kingdom. The design elements which need to be changed are highlighted in red and green. For example, in the PPA a floor price is guaranteed for a certain number of FLH rather than for installed firm capacity. This adjustment in conjunction with an index-based SRMC reference is of utmost importance. Strong investment incentives in operational efficiency and flexibility are given when the guaranteed remuneration is based on a capacity payment per megawatt hour (EUR/MWh).[12]

It will be possible to mitigate negative distribution effects and undesired distortion of competition through the same redesign of revenue recognition as described in the framework for investment in RES above. The reduction of contracted capacity payments by the amount of the FLHs fed into the grid, provides a strong incentive to participate in the electricity markets for a price equal to or higher than the investors own SRMC plus the auction price. The negative impact of windfall profits may be avoided and the highest possible level of long-term compatibility amongst European markets and in cross-sector interactions will have been achieved.

The introduction of an index-based SRMC reference overcomes the parallel world of EOM and CRM and thus the independency of capacity payments from market developments which has been the subject of criticism. The most suitable index is most likely the well-known clean spark spread (CSS). The CSS represents the profit contribution on electricity generated and is calculated as following:

CSS (market) = reference price for electricity – (reference price for gas + reference price for CO_2-certificate)η

The reference price indices must be transparent to all market participants. The most suitable publicly available price indices for the European electricity markets seem to be Phelix for electricity, NCG for gas and EU-ETS for CO_2-certificates. Reference efficiency in the nominal output point should be given for the gross calorific value and be close to 55 per cent. Reference efficiency rather than minimum efficiency

12 The unintended outcome in the first capacity auctions in the UK is caused by this reason. The auction is designed for cheap installed capacity. As a result, successful new capacity was primarily from relatively inefficient and cheap small-scale engines. Almost no new capacity from highly efficient large-scale gas fired power plants could secure a contract.

enables auctions to run on a technology-open basis and avoids discriminatory treatments.[13]

Reference efficiency in conjunction with reference price indices for electricity, fuel cost and carbon allowances would have a positive side effect: it would ensure the price for ancillary services called by the system operator were calculated in a simple and transparent manner, and facilitate low administration burden and costs. The complicated and lengthy calculations typical at present would be avoided.

As shown in figure 4 above, two or more simultaneous tailored auctions are envisaged to address specific needs, to unlock the full diversity of flexibility features and to avoid discriminatory treatment.[14] Given the fact that self-dispatched capacity will reduce remuneration under secured contracts and cross-sector revenues will not, profit-oriented investors will have a strong incentive to reduce the more inefficient start-up, shutdown and part-load time periods and to optimize the load sequence operation in line with cross-sector interactions. Both incentives would most likely contribute significantly to a reduction of unintended must-run capacities and thus to overall system flexibility. In addition, there is a strong incentive for the investors to optimize their own fuel costs.[15]

The bidding process should preferably be arranged in two phases. In the first phase, bids have to include firm capacity plus a price in EUR/MWh for a given number of FLH p.a.[16] Based on the outcome in each of the tailored auctions, the regulator can optimize the BCS portfolio by pre-qualifying the bidders for the second phase in line with security of supply requirements and the most efficient allocation of resources. Price caps and tendered capacities in the second and final phase are determined by the aggregate bid curves in the first bidding phase.[17]

The bidding prices would be based on self-determined LRMC in EUR/MWh and primarily be a function of the following key-metrics:

> CSS (auction) = f (capex, financing structure, perception of risk and reward, capital cost, provision cost, contracted term, contracted performance hours, reference efficiency and reference price of fuel cost, own efficiency and flexibility, own fuel cost, cross-sector revenues and market outlook)

Contracted investors' revenue will be the sum of self-dispatched electricity generated, ancillary services called by the system operator, capacity payments for unused contracted capacity and cross-sector revenues. Revenue from ancillary services is calculated as following:

> Revenue (ancillary services) = contracted firm capacity x called FLH x (CSS (auction) – CSS (market)η)
>
> with: CSS (auction) < CSS (market)η:
> Revenue = market price
>
> CSS (auction) > CSS (market) η:
> Revenue = market price + (CSS(auction) – CSS(market)η)

The revenue from unused contracted capacity is calculated as following:

> Revenue (unused capacity) = contracted firm capacity x unused FLH x CSS (auction)

For a better understanding of the index-based remuneration mechanism, a sample calculation for a contracted investor is shown in figure 5 below. The contracted bidding price reflects the self-determined annual fixed cost of electricity divided by the number

13 Minimum efficiency as a pre-qualification criterion was inter alia criticized in the Belgian capacity auction mechanism.

14 Everybody can take part and multiple bids are allowed.

15 For example: they can increase profit through fuel mix optimization, structuring costs and use of hedging instruments; it would be possible to reduce fuel costs significantly by entering into bilateral agreements.

16 Process as applied in the PJM-RPM, multiple bids allowed.

17 This will prevent distortion due to administratively fixed price caps and demand curves. A highly competitive and transparent tendering process will be achieved.

of contracted performance hours. In the example given, an investor would have a strong incentive to participate in electricity markets for a price equal to or higher than his own SRMC plus 50 EUR/MWh, which together make up his LRMC.

and the allocated resources from the public purse for investment in renewable energy will be reduced to zero. A sustainable and highly competitive design for clean energy and flexibility to meet changing system requirements will finally be achieved.

Conclusions

The proposed redesign can easily be adopted by existing RSMs for RES and BCS. At the beginning of the development process, certain parts of the BCS may work as strategic reserves during critical time periods. As development is being completed, the overall market price-setting mechanism will be grounded on a competitive LRMC-based rather than a distorted SRMC-based merit order. A predictable revenue as required for investment in long-term capital-intensive projects on modest return expectation and a delivery of efficient and effective outcomes will have been ensured. The re-regulation trend will be reversed

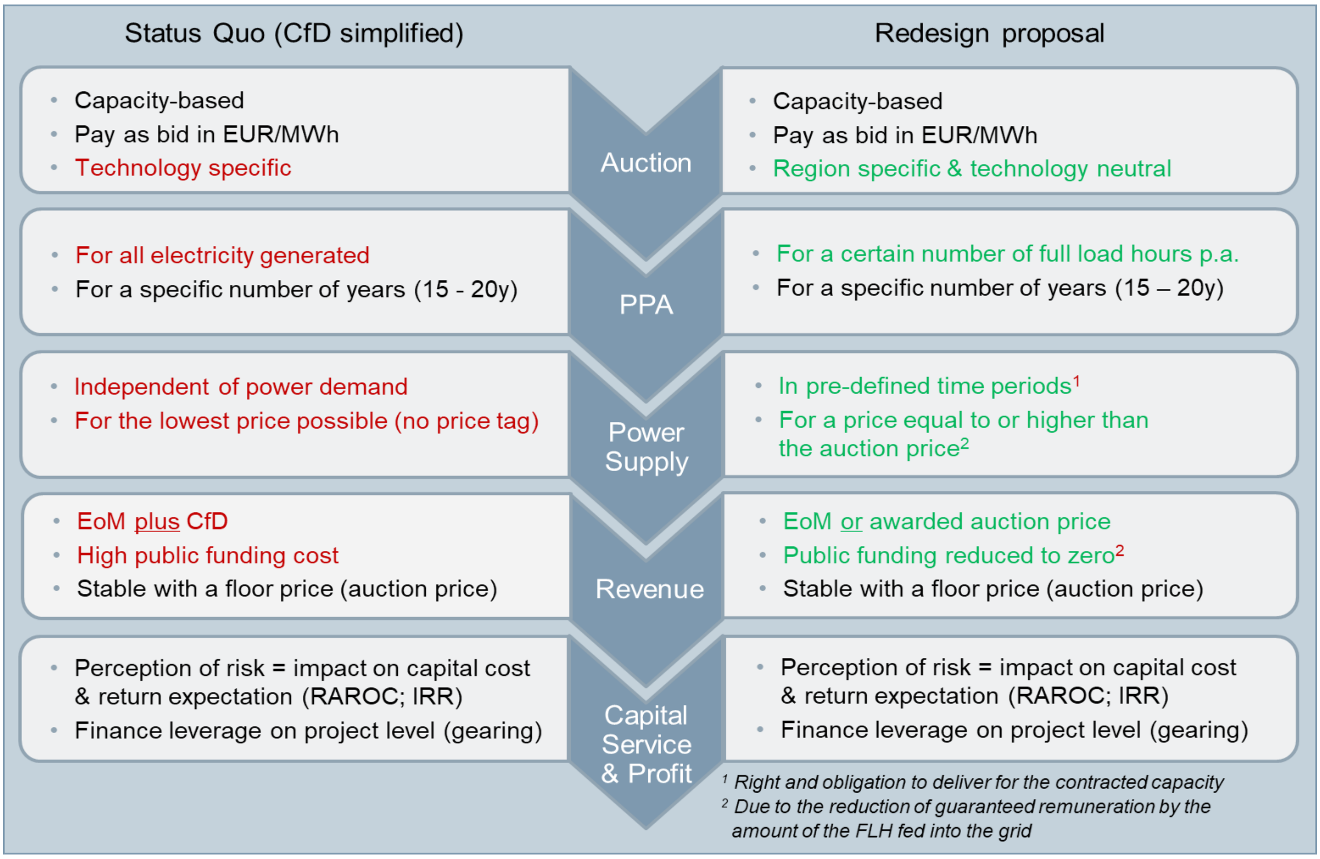


Figure 1: RSM for RES – status quo versus redesign proposal

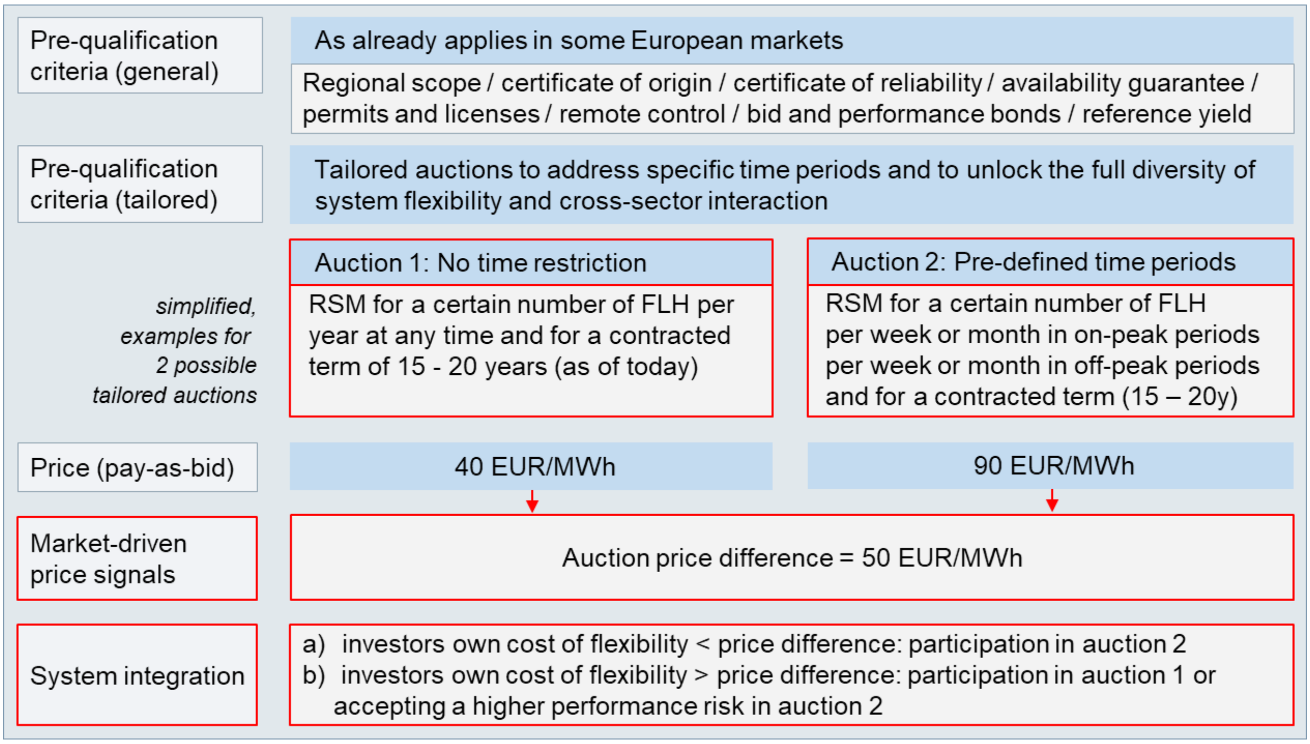


Figure 2: RES system integration by market-driven price signals

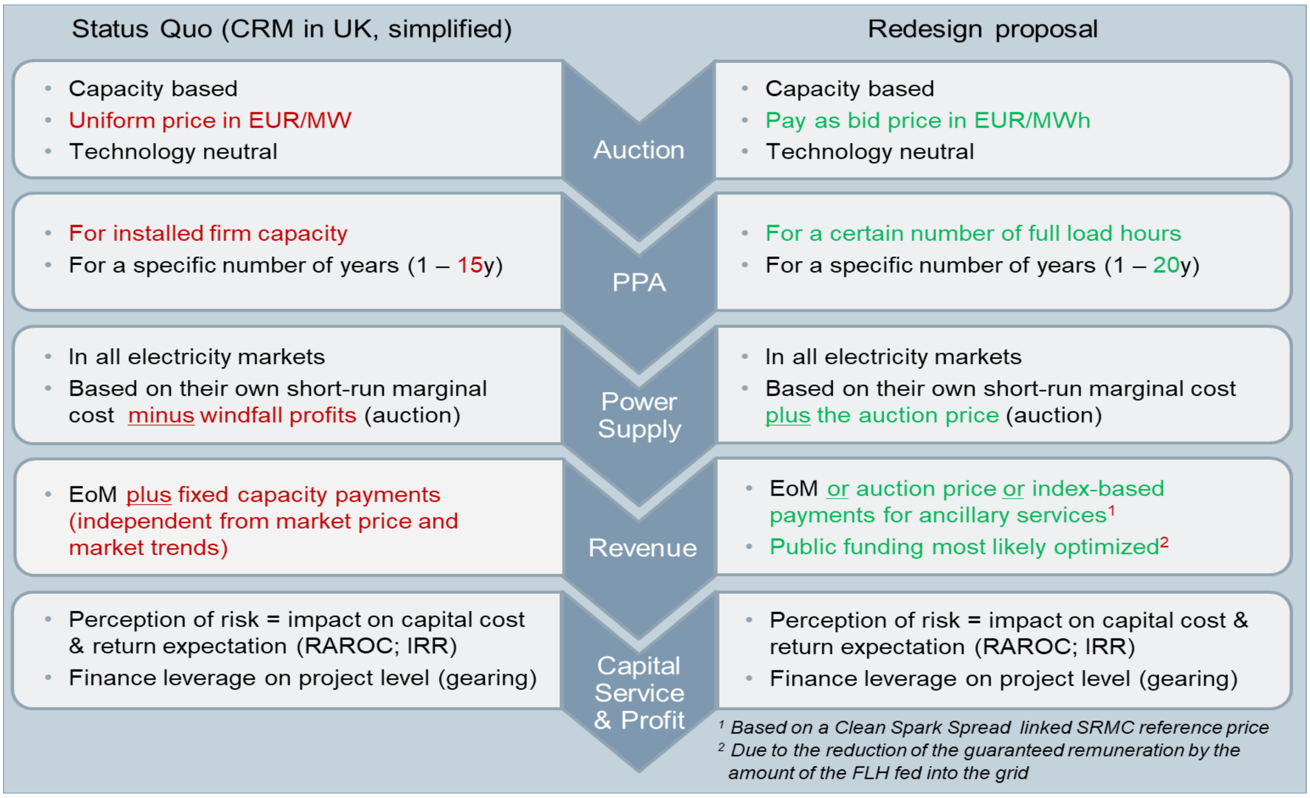
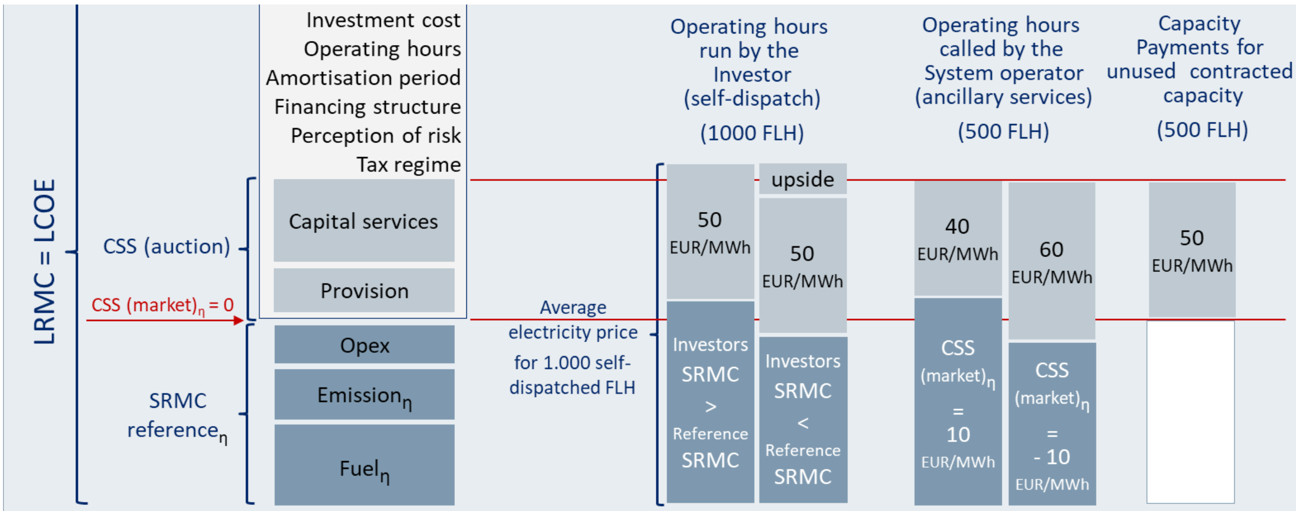


Figure 3: RSM for BCS - status quo versus redesign proposal

Pre-qualification criteria	Targeted flexibility
For short time periods (example for auction 1)	**Capacity with limited performance and warranty periods**
Minimum capacity: 1 MW Response time: < 30 minutes Performance period: max. 2 hours Performance hours: up to 500 hours p.a. Lead time: up to 1 year Contract term: up to 3 years	*Strong competition can in principle be expected between small-scale engines and turbines, hydro plants, demand response, storage solutions, trading platforms, private and industry prosumers and virtual power plants.*
For long time periods (example for auction 2)	**Capacity with unlimited performance and warranty periods and a long economic lifetime[1]**
Minimum capacity: 10 MW Response time: < 1 hour Performance period: unlimited Performance hours: up to 2000 hours p.a. Lead-time: up to 3 years Contract term: up to 20 years	*Strong competition can in principle be expected between hydro plants and large-scale turbines with high efficiency, short response time and cross-sector business models (e.g. cogeneration).*
For long time periods (example for auction 3)	**Capacity with low capital service and a short lead time[2]**
Minimum capacity: 10 MW Response time: < 4 hour Performance period: unlimited Performance hours: up to 4000 hours p.a. Lead-time: 1 year Contract term: 2 years	*Strong competition can in principle be expected between fully or partially written-off power plants with low SRMC and cross-sector revenues. The response time can be reduced over time in accordance with the portfolio mix.*

[1] Performance hours can be progressively reduced over the years in line with the expected BCS needs.
[2] Targeted capacity can be reduced in line with market changes and development in the other auctions.

Figure 4: Pre-qualification criteria and targeted BCS flexibility



Assumption	
Contracted firm capacity:	300 MW
Contracted performance hours:	2000 FLH
Contracted price (CSS (auction)):	50 EUR/MWh
Weighted average CSS (market)$_\eta$:	10 EUR/MWh
Operating hours run by the Investor:	1000 FLH
Ancillary services (system operator):	500 FLH
Unused firm capacity:	500 FLH

Revenue floor p.a.: 300 MW x 2000 FLH x 50 EUR/MWh = EUR 30 million

Revenue	
Operating hours:	300.000 MWh x (Investors SRMC + 50 EUR/MWh)
Ancillary services:	150.000 MWh x (50 EUR/MWh – 10 EUR/MWh)
Capacity payments:	150.000 MWh x 50 EUR/MWh = EUR 7.5 million
Gross sector-revenues:	(no impact on capacity payments)

Figure 5: Sample calculation for an index-based remuneration mechanism

SESSION 3

SECURITY OF SUPPLY – A CONSUMER'S CHOICE

Moderated by
Peter Fraser, IEA

SECURITY OF SUPPLY – A CONSUMER'S CHOICE

Peter Fraser

Highlights

The four papers we discussed during the parallel session advocated two complementary strategies. Two of the papers rely on the demand side, i.e. consumer participation, to ensure security of supply, while the second pair aim to address the supply side to guarantee that both intermittent and flexible resources are adequately compensated. Of the first two papers, the most straightforward approach was advocated by Doorman and de Vries. They proposed that each consumer nominate their preferred level of guaranteed peak capacity (subject to a minimum default level), while the utility provides load limiters to prevent the customer from exceeding that capacity during a peak event. Physically restricting demand of individual customers decreases the risk of inadequate supply and reflects the individual consumer preference. Winzer and Borggrefe advocated a similar but more sophisticated approach, where each customer would ultimately be expressing his own 'demand curve' and would be required to limit consumption to different levels subject to different prices. One important contrast between the two approaches is that the one proposed by Doorman relies on a capacity allocation based on annual peak demand and a TSO decision when the event is triggered. On the contrary, Winzer and Borggrefe (and the other two papers discussed below) rely on scarcity pricing to 'scare people' and get them to change their behaviour. Technology is going to make this task easier for consumers to implement.

The other two papers aim to change how generators are compensated to ensure that both intermittent resources and flexible resources can be adequately compensated through two separate markets. Keay and Robinson propose that variable renewables would essentially offer power into a 'when available' market and be paid based on a regulated price. Customers would buy the additional power they may need from an 'on demand' market which would have power sold by flexible resources. The key element of the proposal is to avoid price contamination of the flexible resource market by the inflexible resource market. Higher prices for the former would encourage investment and send price signals to end users to curb consumption during peaks. The Climate Policy Initiative proposal presented by Felicity Carus was, on the contrary, focussed primarily on how to procure renewable kWh at the lowest cost (i.e., to avoid exposing generation from renewables to the market conditions since this fact would put them at risk of being curtailed and increase their cost of capital), while having all other flexible generation units exposed to a PJM style market (nodal pricing and ancillary service market but no capacity market). Both proposals rely on scarcity pricing to encourage consumers to cut demand.

AN ELECTRICITY MARKET DESIGN BASED ON CONSUMER DEMAND FOR CAPACITY

Gerard Doorman and Laurens de Vries

Introduction

It is generally assumed that solar and wind energy (vRES) will play a large role in a low-carbon power system, but with them security of supply remains a major challenge. Short periods of supply shortage can be met with storage or by shifting demand, but the key challenge for a low-carbon electricity system is how to provide sufficient electricity during periods when wind and solar generation are incapable to meet demand. Market parties may provide part of the required flexibility, in the form of demand response, storage and flexible generation options such as biomass. However, there will be from time to time larger shortages, like for instance periods in winter of more than a week without wind, limited solar generation and high heat demand. The risk of investing in facilities that are used once per year or less is too high for market parties, if they need to recover their investment only from the (very) high energy prices that occur when their generation is needed.

In addition, it will also be difficult for vRES to recover their costs, as they tend to produce when prices are low, but not when they are high (Aghaie, 2017; Hirth, 2014). They, too, face high investment risk, as they are capital-intensive and their revenues are highly sensitive to weather and to changes in demand and supply (such as higher than expected investment in generation).

Therefore, we argue that an *Energy-Only* market will not provide incentives to invest in either vRES or necessary flexible capacity. The market design must therefore hedge risks for variable and controllable generation (including storage), for generators and consumers alike.

Therefore, we propose a system that is based on two pillars:

- *Capacity Subscriptions* to ensure that demand can be limited to available generation when necessary (Section 2);
- *Tenders* for variable renewable energy in combination with a level playing field for decentralised generation (Section 3).

Capacity Subscription has a number of advantages:

- Consumers pay directly for the scarce resource, i.e. generation capacity;
- System adequacy moves in the direction of a private good;
- Consumers do not face extreme price spikes in the energy market;
- Demand flexibility is internalized in the consumers' decisions;
- Demand is controlled by the consumer in real time and physical shortages are avoided;
- Producers are remunerated by selling capacity and not dependent on rare scarcity prices;
- The price and quantity of capacity are both market based.

As indicated above, we do not believe that vRES will be able to recover their costs in the energy-only market. We therefore propose tenders for vRES, which recently have been quite successful for several places in Northern Europe. Should vRES become able to recover their costs only from energy sales in the long run, tender bid prices will drop to zero and the tenders will phase themselves out.

The essentials of capacity subscription

With *Capacity Subscription* (Doorman, 2005: Doorman and Botterud, 2008; Margellos and Oren, 2016) consumers buy the amount of generation capacity they are going to need during system scarcity periods. They buy capacity subscriptions from providers of firm capacity (generation and storage). When a consumer buys a capacity subscription of, say, 4 kW, he is guaranteed that he can consume electricity up to this capacity level under all conditions. When the energy market is short of generation capacity, e.g. during a period without much solar and wind energy, the TSO activates so-called *Load Limiting Devices* (LLDs) that are installed at each consumer site. Thus, consumers must restrict their consumption to the levels that they contracted. In return they have the certainty that this capacity is available. When there is no shortage of generation capacity – most of the time – consumption is unrestricted.

Risk reduction for consumers and generation

Because physical shortages are avoided, scarcity prices do not occur. A capacity subscription may therefore be considered as a sort of physical option contract: by paying for the capacity subscription, a consumer obtains the right to consume electricity at a contracted price at any time, avoiding scarcity prices. For generation companies, the benefits are that the demand for reliable capacity is made explicit and that the payments are spread out over time. In fact, this system turns reliable capacity into a product with a steady remuneration.

Consumers

Crucial questions for consumers include how much capacity they need, when they need it, how it coincides with system scarcity and if they have alternative means to reduce their need for capacity.

Based on available data and forecasts, apps and web sites can be developed to support consumers to make choices that match their preferences. Moreover, in a system with widespread use of *Capacity Subscription*, there will be a strong demand for such solutions, typically incentivizing their development.

Demand flexibility

A compelling feature of *Capacity Subscription* is that it creates incentives to keep demand below the subscribed capacity and to develop the technology for this purpose. If *Capacity Subscription* is widely used, millions of consumers will be interested to control their demand, creating opportunities for companies to develop and sell solutions.

Capacity subscription turns reliability into a private good

Ensuring system adequacy by having sufficient generation capacity is the way consumers' preferences for uninterrupted supply normally are satisfied. Obviously, in this setting system adequacy has strong common good characteristics. With *Capacity Subscription*, consumers weigh the cost of capacity against their preferences for unlimited supply. If the price of capacity is high, industrial consumers will over time redesign their production processes to be able to reduce their need for capacity. Households and services will similarly have incentives to look at ways to reduce demand when necessary. *Capacity Subscription* thus has the unique feature that it reveals the need for capacity in the market, based on consumers' preferences for uninterrupted supply, which internalizes system adequacy in the market: the generation part of system adequacy becomes a private good.

Capacity supply

The main capacity suppliers are the generators. They can sell the capacity they expect to have available during periods of system scarcity. When a scarcity event occurs, generators need to demonstrate their availability by bidding in the relevant markets, day-ahead, intraday and balancing. There needs to be a significant penalty for non-compliance to avoid gaming.

Activation of the LLDs and the role of the TSO

The main role of *Capacity Subscription* is to ensure the balance between demand and supply at system level. In this context, the TSO is the obvious entity in charge of activating the LLDs. While actual activation will only happen close to real-time, the TSO issues advance warnings before the day-ahead market clearing and subsequently throughout the day until (close to) real-time. Consumers need to be "notified" in advance in order to be prepared.

Capacity auctions

Annual auctions are the primary market place. The auctions need to be held well in advance of the season when residual demand (demand minus vRES production) peaks. There is no lead time, i.e. only existing capacity can participate. However, owners of new plants know that, once a plant is commissioned, it will receive revenues from selling capacity. Additional auctions will be needed to address changes in supply and demand of capacity, but this may also be solved through continuous trade. Participation in auctions or continuous trade in capacity is not relevant for small consumers – instead they could buy capacity from a retailer, much in the same way as they buy energy today. Retailers will then buy capacity on behalf of small consumers.

Simplified solution for small consumers

Household consumers can be provided with a default capacity subscription that is based on their peak capacity usage recorded during the previous year, without the physical limitation. There would be no immediate penalty for exceeding the capacity level, but in this case, the next years' capacity subscription would be based on their new consumption peak. This way, consumers do not need to think about buying capacity subscription while they still have a strong incentive for reducing their contribution to the system consumption peak. Consumers who want to reduce their cost can opt into the system by buying a capacity subscription and committing to that level of peak consumption.

Variable renewable energy

We distinguish between three different categories of renewable energy technologies: large-scale variable renewable energy, behind-the-meter variable renewable energy, and controllable renewable energy. Large-scale variable renewable energy, such as wind parks and large solar plants, should be subject to competition in order to bring their costs down. The same is true of small-scale variable renewable energy generators, but a market with a large number of small generators, often owned by households, needs to be organized differently. Controllable RES can sell capacity under the *Capacity Subscription* scheme in competition with other providers of reliable capacity.

Tenders for large-scale vRES

Auctions (tenders) for renewable energy balance effectiveness with cost-efficiency. In such tenders renewable energy projects are able to obtain subsidies equal to the difference between their average cost and the market price (Del Río and Linares, 2014). The subsidies are awarded to the projects that demand the least subsidy per unit of electricity. Investor risk related to auction process can be reduced, e.g. if the government selects the site and publishes information about wind speed, sea bottom conditions etc. In addition, successful bids may receive the necessary permits and a grid connection. Should the renewable energy generators begin to earn back their investments in the market, the prices set by the tenders are will go to zero and the auctions will phase themselves out.

Financing the tenders

We propose to pass the costs of the tenders as a per-kWh charge to consumers. Wholesale prices will continue to be determined by the marginal cost of generation, which is important for economic efficiency. Although it may drop to zero in case of excess supply of variable renewable energy sources, the wholesale price of electricity ensures that incentives to curtail excessive vRES production and to invest in storage facilities remain in place. At the same time, a levy on final energy consumption for recovering the cost of the tenders has the interesting property of providing a balanced incentive for self-generation, as we will discuss below.

Small-scale variable renewable energy

Small-scale (behind-the-meter) renewable energy generation is usually remunerated in a way that is clearly not sustainable in the long term, namely through annual net metering. There are several problematic aspects with this:

- It ignores **the time value of electricity**, i.e. the prosumer implicitly pays/receives the same price regardless of system conditions;
- Households **avoid taxes and levies** and in many cases also **network charges**. This is an implicit subsidy that may be unreasonably high and may lead to grid defection;
- **Equity**. This approach is in reality a subsidy to those who can invest in small-scale vRES from those that cannot, e.g. because they have no available area for PV or lack financial resources.

Distributed generation should be exposed to real-time prices

Consumers who generate some of their own electricity (so called prosumers) should buy and sell at the prevailing real-time wholesale price. This will also provide better incentives for demand response and storage and for curtailing vRES generation when there is excess supply.

Most surcharges on electricity are undesirable in a low-carbon system

Most of the taxes, levies and energy charges (the second bullet point mentioned above) can and should be removed in a sustainable energy system. Grid charges should be (peak) capacity-based and not energy related, as the network costs largely consist of capital costs. When electricity is generated (mostly) sustainably, it is no longer necessary to charge a 'sin tax' on electricity.

Remaining charges stimulate distributed generation

The remaining charges are the renewable energy levy, i.e. the financial source for the tenders for large-scale vRES, and the VAT. When consumers generate their own electricity at the moment that they consume it, they avoid these charges. Avoidance of the VAT creates a small economic distortion to the advantage of distributed generation. Avoidance of the renewable energy levy, on the other hand, provides a benefit for self-generated renewable energy that is equal (per kWh) to the tender payments for large-scale vRES, resulting in a level playing field for large-scale and behind-the-meter vRES, without the need for additional policy instruments.

Hourly settlement of prosumers reduces equity problems

Settlement at the real-time wholesale price also reduces the equity problem. One problem with annual net metering is that *all* local production is subtracted from demand. Net demand may become quite small and as a result prosumers may end up not contributing to large scale vRES, even though they significantly profit from it (i.e. in those hours when their own production is lower than their demand). Hourly netting significantly reduces this problem, as prosumers will then pay the full price for all energy they use from the grid.

Conclusions

Economic efficiency, risk reduction and security

We propose a combination of *Capacity Subscription*, tenders for large-scale variable energy and a remuneration system for vRES that creates a level playing field for generation behind the meter. A unique feature of *Capacity Subscription* is that demand for capacity is based on the individual consumers' preferences for uninterrupted supply. Based on this demand, providers are ensured a market-based revenue for their capacity and consumers are certain that they have access to the electricity they need at affordable prices. This market design combines economic efficiency with a significant reduction of risk for both consumers and generation companies and guarantees security of supply.

Consumer payments

In our market design consumers make the following payments:

- A monthly payment for their capacity subscription;
- A payment per unit of electricity that they consume that is equal to the real-time wholesale price of electricity plus a surcharge for large-scale variable renewable energy and VAT;
- A grid fee, which we recommend is mainly based on capacity. The subscribed capacity is a natural basis for the grid fee.

The capacity subscriptions pay for the controllable generation capacity that will serve load when there is not enough vRES. Real-time electricity prices cover the variable cost of generation. The renewable energy levy pays for the tenders for large-scale vRES. Small-scale vRES units earn their cost from the avoided cost of buying electricity from the market (with renewable energy levy added to the market price). Grid tariffs are mainly based on capacity (a combination with the subscribed capacity should be considered).

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POWER TO THE PEOPLE – CREATING MARKETS FOR SUPPLY SECURITY BASED ON CONSUMER CHOICE

Christian Winzer and Frieder Borggrefe

Introduction

As a result of increasing renewables penetration in the European electricity mix, the average utilization rate of dispatchable plants will continue to decline. At the same time, during a few hours per year, or longer time periods every couple of years, intermittent renewables may produce very little, while demand may be high. In order to provide a similar level of supply security as today, there will be a need for significant amounts of back-up capacity. Thus, the total cost of the energy system will increasingly depend on the *amount* and the *firmness* of capacity that is required by consumers, rather than the amount of energy they consume.

However, current supply contracts and grid usage tariffs often do not charge end-consumers for the amount of capacity they require. This is particularly problematic in light of an increasing number of customers with electric vehicles, using their grid connection capacity to the technical limits.

Besides, the required firmness of non-interruptible contracts is usually derived from value of lost load (VOLL) estimates, rather than from contractually agreed compensations for emergency curtailments. However, curtailment cost estimates based on stated preferences are a very imprecise indicator of the true curtailment cost. Since, the curtailment of consumers from the grid will not always lead to a black-out, as consumers may have decentralised back-up supplies, curtailment costs will vary strongly, both between consumer groups (e.g. between consumers with and without back-up supply) and across time (e.g. depending on the purpose for which the electricity is used or the charging level of home batteries).

As a result of the uncertainty about true curtailment costs, existing administrative approaches to supply security will be very inefficient. At the same time, falling cost of information technology will enable smarter demand side management approaches and tariff schemes, such as the ones suggested in this contribution, to thrive.

Shortcomings of the Winter Package

The Winter Package presented by the European Commission in late 2016 claims to offer a "new deal for consumers". However, it continues to foresee a largely administrative approach to supply security. According to it, both the price caps in wholesale markets and the procurement targets of capacity mechanisms should be based on regulatory estimates of a constant, single value of lost load (EC, 2017a, Article 10 and 19), rather than on contracted curtailment costs. During simultaneous scarcity situations, the dispatch should follow administrative regional load shedding plans (EC, 2017b, Article 12) and investment incentives in transmission and distribution grid infrastructure may continue to be based on administrative reliability targets.

As a result, market arrangements will lead to an inefficient dispatch during scarcities as well as distorted investment incentives, falling short of the promise to place the consumer at the centre of the decision process. Concerns about market power and excessive risks, will exert pressure on politicians to keep price caps low. At the same time, the fear of occasional outages will prompt them to overinvest in capacity and overestimate reliability targets for grid operators (Newbery, 2016).

Overview of suggested arrangements

In line with the requirements in (EC, 2017a, Article 12) and (EC, 2017b, Article 15), we propose to tackle the

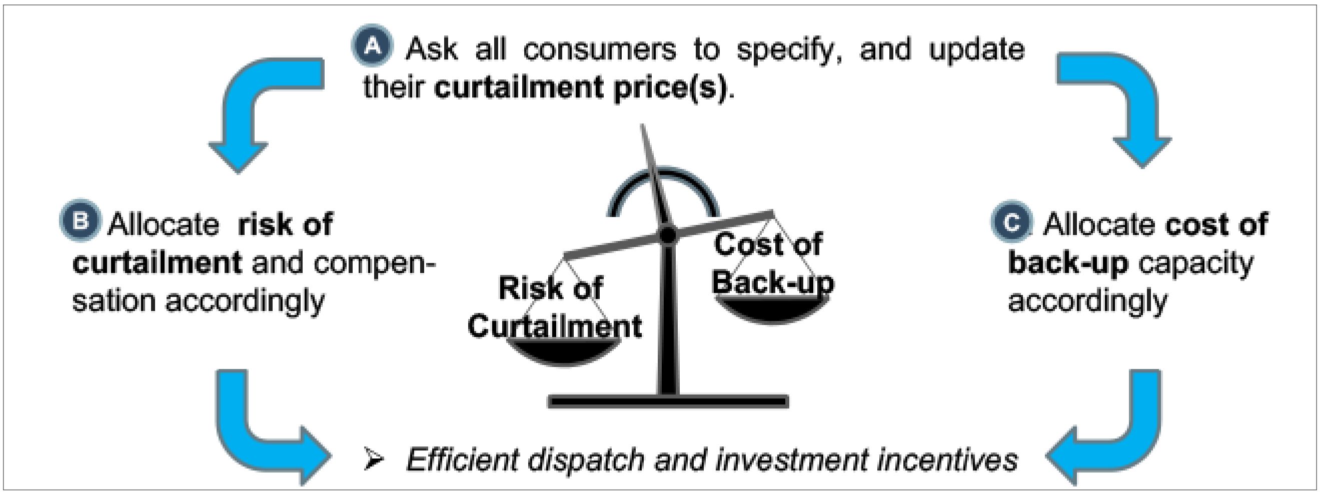

Figure 1: Overview of suggested market arrangements

problem at its root by asking each consumer to select and pay for his individually preferred reliability level, as well as compensating consumers for grid curtailments. This could be achieved through the following steps:

- A. Ask all consumers to specify their curtailment price curve;
- B. Allocate curtailment risks and compensations accordingly;
- C. Allocate cost of all back-up capacity accordingly.

As illustrated in figure 1, consumers who specify a high curtailment price, would receive a higher compensation during the hours when they need to be curtailed. As system operators aim to minimize the cost of curtailments, consumers with a high curtailment price would thus be curtailed less often, and benefit from a lower curtailment risk. In return, they would be asked to pay a higher share of the cost for the back-up grid, generation and storage capacity. This would allow each consumer to trade-off the benefits of a higher reliability level against the associated cost and select the reliability level which best suits his individual needs at different points in time. Today's administrative approach to supply security would thus be replaced with an approach based on consumer choice.

In section 4, we provide further design details for each of the above mentioned steps. Section 5 describes how a smooth transition could be achieved from today's situation characterised by an incomplete smart-meter roll-out and centralized capacity mechanisms. In section 6 we summarize the expected impacts and questions for future research. Further details on several of these topics can be found in our forthcoming research paper.[1]

Design details

Ask all consumers to specify their curtailment price curve

Each consumer could select his desired level of supply security by specifying the required amount and firmness of capacity that he requires. As displayed in Figure 2, depending on his needs, a consumer could for example:

- A.Specify a single curtailment price, which is valid for his total grid connection capacity;
- B. Specify a very high curtailment price for the required amount of "firm" capacity and a lower curtailment price for the rest of his grid connection capacity;
- C. Distinguish several tranches of consumption with decreasing curtailment prices.

Consumers who want could further differentiate their curtailment price based on the time of the day, week or year, the advanced notice that is given to them, etc.

As a starting point, regulators will need to define a

1 Available at SSRN: https://ssrn.com/abstract=2956590.

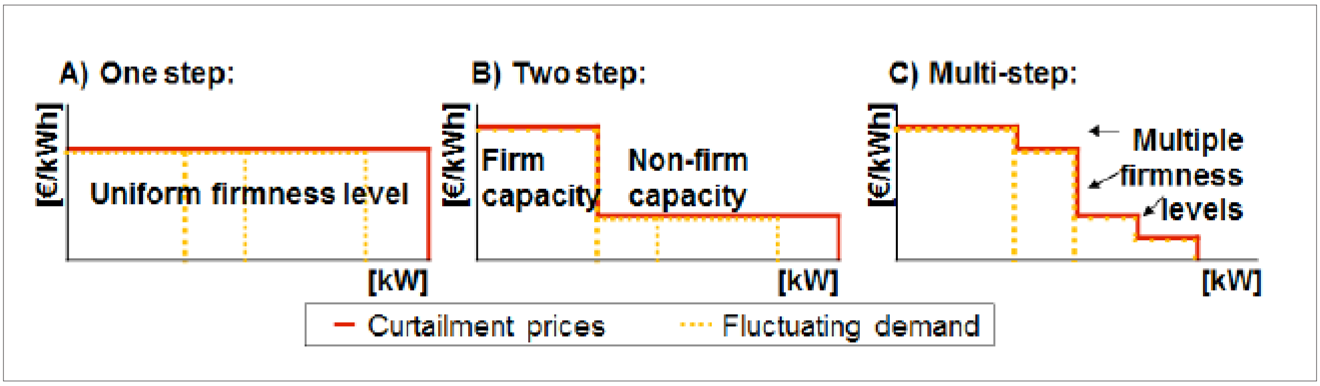

Figure 2: Curtailment price curves

default tariff for consumers. This could be a tariff such as (B), where the amount of firm capacity corresponds to a consumer's share of the capacity mechanism procurement target (as suggested by Doorman, 2005), and the curtailment price for the remaining non-firm capacity corresponds to today's spot market price cap. Consumers could then be given the choice to select a different tariff, or remain in the default tariff, if they do not wish to actively engage in the market.

In order to allow for a transparent comparison between different suppliers, it could further be helpful if regulators pre-specify a limited number of "**standard tariff options**" that have to be offered by each supplier.

To anticipate the cost and risk of different curtailment prices, consumers should finally be provided with **additional information**, such as the curtailment frequency and duration, monthly electricity cost, maximum hourly bill, etc. that would have resulted from different curtailment prices applied to their historical demand profile (if available) or an average load profile.

Allocate curtailment risks and compensations

Curtailment price curves should be offered in the balancing energy market. Whenever load shedding is required as a last resort measure to balance demand and supply, the imbalance price should thus rise to the marginal curtailment price.[2] Load-limiting devices or smart meters should restrict the consumption of each household to the amount of capacity for which a curtailment price above the current balancing energy price have been specified. This would ensure that scarcity prices reflect the true value of energy. At the same time, the "firmer" consumption tranches with a higher curtailment price would be protected against rotating outages.

During curtailments, the **compensation** for the explicit demand response which consumers provide through their curtailment price curve should be fairly distributed between suppliers and consumers (or aggregators). Consumers (or the aggregators, to whom consumers sell their demand response) should receive the difference between the market price and their supply price, while suppliers should continue to receive the same supply price and retain the same balancing responsibility as if their consumers were not curtailed.[3] Figure 3 illustrates the resulting distribution of revenues for the stylized cases of A) a consumer with a fixed supply price, and B) a consumer who is supplied at the real-time, imbalance price. In both cases, consumers will be curtailed when the market price rises above their curtailment price.

In case of a fixed price contract (A), suppliers will typically continue to deliver the energy which they have purchased for their consumers in forward markets. Consumers would thus purchase the energy from their supplier at the fixed supply price (dark blue area) and resell it at the imbalance price. The net compensation of the consumers would thus be equal to the difference

2 Subject to an implementation of Article 30 literal 1.a of the Electricity Balancing Guideline, which foresees marginal balancing energy prices.

3 Following the concept of 'unbundled transactions' suggested by (Hogan, 2009)

between market prices and their fixed supply price (dark green area).

In case of a contract indexed to the imbalance price (B), suppliers may or may not purchase the energy for their consumers in advance. In any case, consumers would not receive any compensation for their curtailment as the market price equals the supply price which they have contracted. Suppliers would continue to receive the supply price which they agreed with consumers (dark blue area). But they would also be responsible to balance the amount of energy which their consumers would have consumed if they had not been curtailed. If they have not purchased this energy in advance, their net compensation would thus also be zero, as the dark blue area would be cancelled out by imbalance payments.

Curtailment cost of most consumers will vary strongly across time. Consumers should thus be free to **adjust** curtailment prices at any time by:

- Offering *implicit demand response* and restricting or shifting their consumption at prices below their curtailment price curve;
- Updating their curtailment price curve, which will be used to trigger their *explicit demand response* as well as to allocate costs of back-up capacity.

As the penetration of smart devices increases, these adjustments could even be automated, so as to further reduce the transaction costs for consumers. In order to avoid opportunistic behaviour, the conditions and prices of these switching decisions need to be designed appropriately. For example, the cost for setting a higher curtailment price could be indexed to the cost of buying or selling equivalent yearly option contracts.

Allocate cost of back-up capacity

Avoiding curtailments comes at a cost. As mentioned in (Winzer, 2012) the continuity of supplies can be influenced by a number of different risks. Some of these risks are displayed along the horizontal axis in Figure 4. Each actor – including consumers – can take actions which directly mitigate risks by reducing their likelihood of occurrence (see the dark blue boxes in Figure 4). In addition to that, some of the actions may indirectly mitigate other risks along the supply chain by reducing their impact. For example, if consumers or their suppliers reduce the cost of grid curtailments, through a behaviour change or back-up technologies such as home batteries or PV panels, this would indirectly mitigate any of the other risk sources listed further to the left in the graph. Generally speaking, the closer to the consumer mitigation measures are located, the more risks can be mitigated through them.

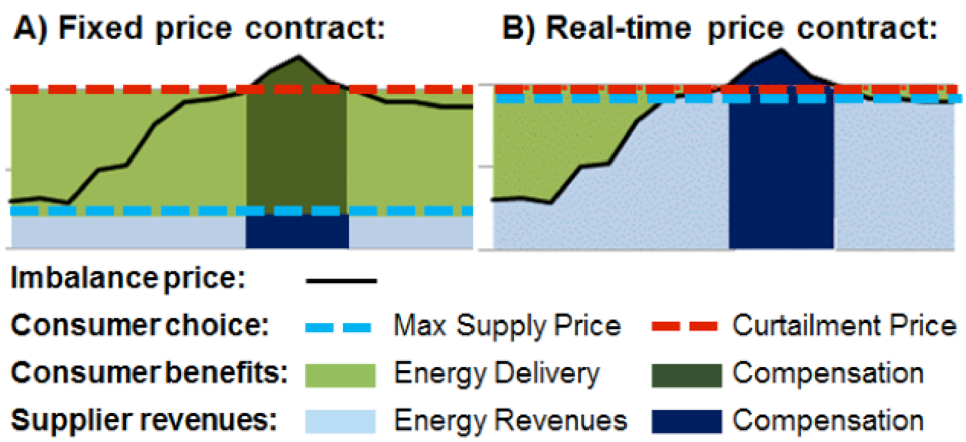

Figure 3: Sharing of curtailment compensations

The share of costs for the back-up grid and generation capacity which is allocated to each consumer (or any other actor along the supply chain) should correspond to the level of "insurance" each consumer wishes to contract from the rest of the system. Consumers who chose a very low curtailment price or a low volume of capacity should pay a low share of costs, while consumers selecting a higher curtailment price or a higher volume of capacity should pay a higher share of costs for back-up capacity (for example see Oren and Doucet, 1990; and Wilson, 1997). The selected curtailment price curves would thus act as an "interface" which would enable each player along the supply chain to trade-off the cost of his own mitigation measures against the cost of transferring risks to other actors along the supply chain who may be better placed to mitigate them.

In order to achieve this, some of the **contracts** which are used to transfer costs and risks across the supply chain would need to be adapted. For instance, supply contracts between consumers and their suppliers, as well as grid usage contracts with DSOs and TSOs should compensate grid curtailments at the respective curtailment price. In addition to that, grid usage tariffs should ensure that the share of the costs which is borne by a connected party does not only depend on the volume of contracted capacity (or on peak demand), but also on the selected curtailment price(s), which may be different for consumers with identical peak demand. In order to prevent an opportunistic switching of curtailment prices, the cost allocation should also take into account the point in time and duration during which different curtailment prices have been selected.

Transitional Arrangements

Allow consumers to vote on average reliability levels

Consumers without smart meters or load-limiting devices that allow their individual disconnection from

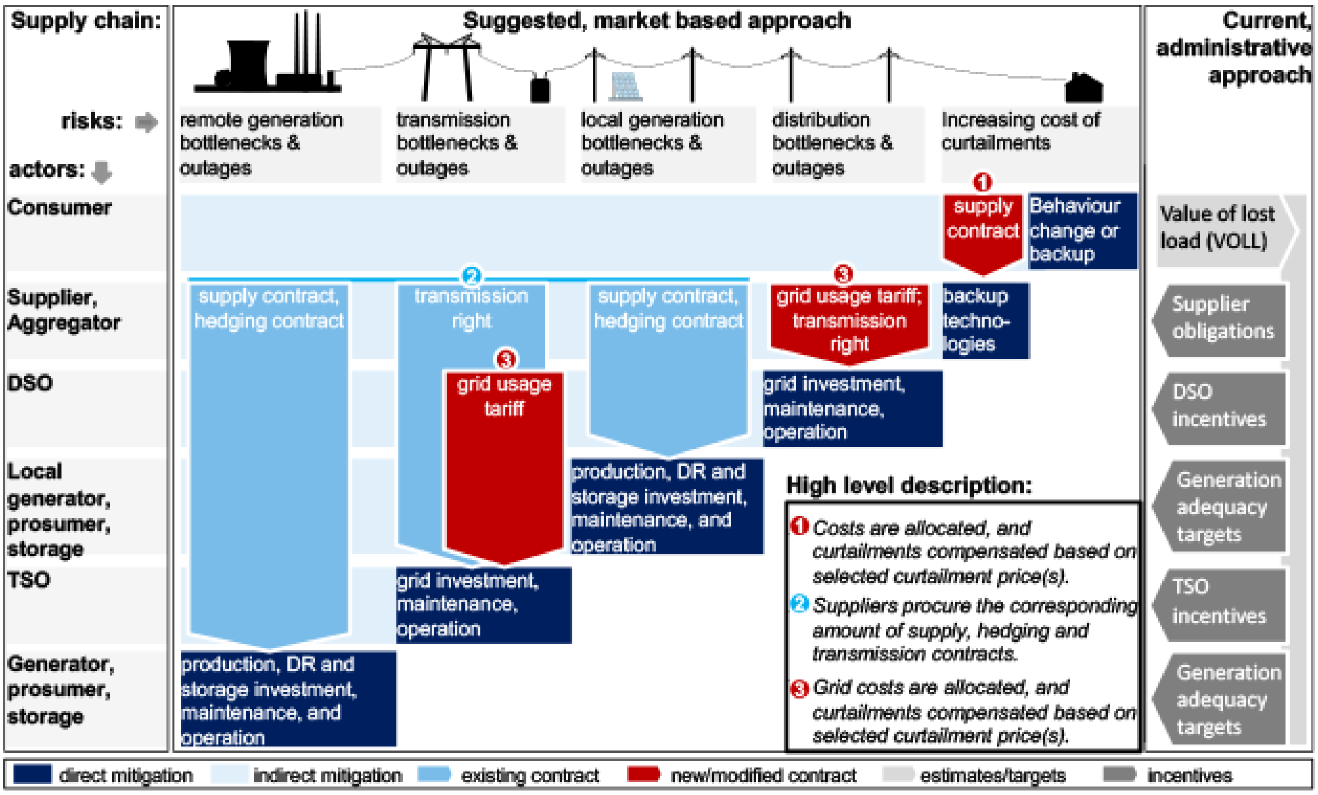

Figure 4: Market based approach vs. administrative approach to ensure security of supply

the grid effectively share the same reliability level with all other consumers connected to the same grid segment. As a transitional measure, these users could be allowed to indicate their preferred reliability level as part of their supply contract. However, they would receive (and pay for) the weighted average reliability level of the distribution grid section, to which they are connected.

Consumers who are not satisfied with the average curtailment risk of their neighbourhood, could install a smart meter or a load limiting device in order to select and pay for a lower, individual reliability level, or install back-up batteries and supplies in order to reduce their cost of grid curtailments or both. The resulting demand pull for smart technologies could allow for a more efficient roll-out than today's blanket roll-out of smart meters.

Allow consumers to opt out of capacity mechanisms

Countries with a capacity mechanism, could foster a transition towards a consumer based valuation of supply security, by allowing (groups of) consumers who can be individually disconnected, to opt out of the capacity mechanism. As a prerequisite to that, each consumer would need to bear the share of the capacity mechanism cost, which corresponds to the capacity that is procured "on his behalf". Consumers who opt out of the capacity mechanism should then be exempted from the capacity payment and not considered in future procurement auctions. In return, if demand at the maximum curtailment price exceeds supply during one of the capacity mechanism delivery periods, the consumers who opted out of the capacity mechanisms should be curtailed first, before the remaining customers are curtailed.

In order to prevent opportunistic behaviour, the rules for switching in and out of the capacity mechanism need to be designed appropriately. Most likely, this would include secondary trading of the insurance provided by capacity mechanisms.

Conclusions and next steps

We expect that an implementation of our propositions would solve the missing money problem that has been identified already by Stoft in 2002. As displayed in Figure 5, the suggested market design would:

- *Improve consumer participation and innovation*

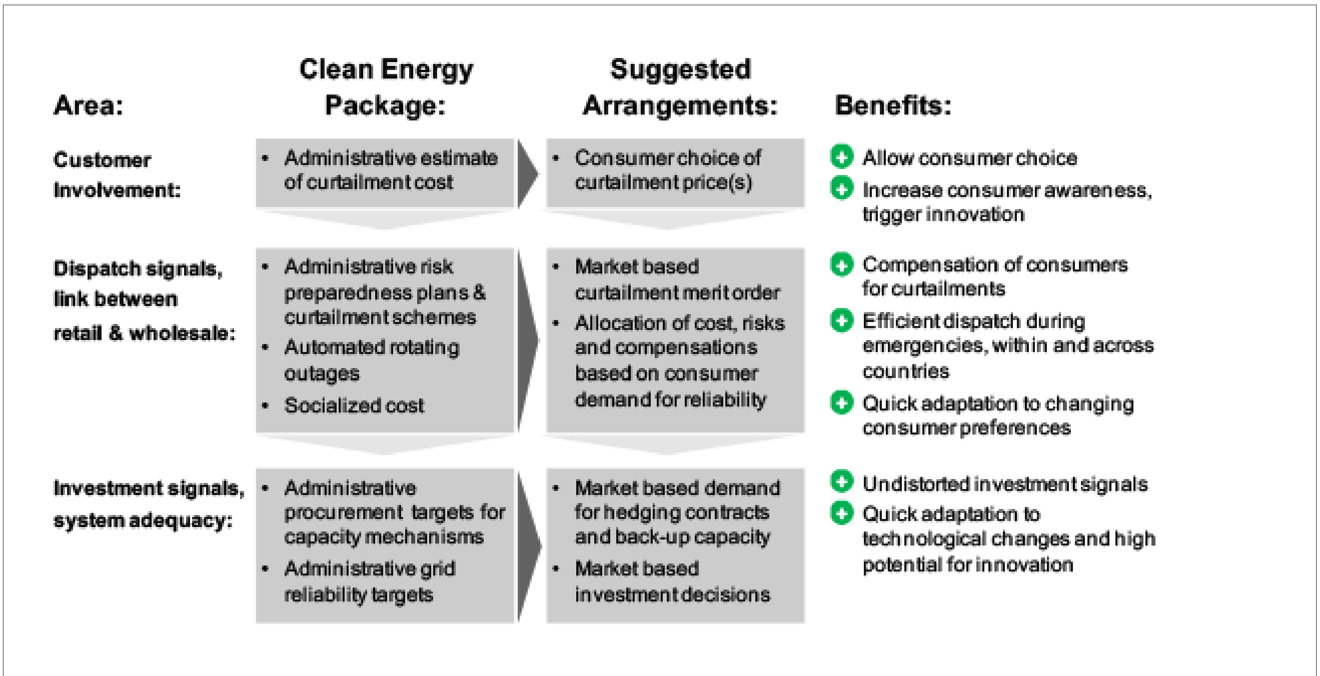

Figure 5: Expected benefits of the suggested arrangements

incentives, as explicit decisions by consumers would increase their awareness about the cost-benefits of different supply security levels. This could lead consumers to explore alternative back-up technologies, investments into smart meters and demand side management measures as well as behavioural change, triggering a wave of innovation;

- *Improve dispatch during emergencies*, as consumers set the curtailment price for different tranches of their consumption. Curtailments within and across countries could thus be distributed in a way that minimizes curtailment cost, for example through partial load shedding, rather than based on administrative risk preparedness plans and rotating outages;
- *Improve hedging and investment incentives*, as sufficiently high prices in the wholesale and real-time markets would create a natural demand for hedging contracts. This could remove the need for administrative reliability targets and capacity mechanisms which are prone to over-investment.

In order to provide a safe passage towards the suggested market design, further research should explore critical issues such as the transaction cost of the suggested arrangements, the appropriate design of supply contracts, grid usage tariffs and, more generally speaking, contracting structures for efficient risk transfer, arrangements to prevent opportunistic switching as well as redistributional impacts and potential compensation schemes. Eventually, the design and impacts of consumer interactions should be tested through field trials in order to obtain a more detailed estimate of the potential cost, benefits and crucial design parameters of the proposed market design.

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MARKET DESIGN FOR A DECARBONISED ELECTRICITY MARKET: THE 'TWO-MARKET' APPROACH

Malcolm Keay and David Robinson

Introduction

Our starting point is that current energy-only electricity markets are broken,[1] especially in power systems with high penetration of intermittent renewables. Energy-only markets are designed to discriminate between sources with different short-run marginal costs (SRMC); by selecting the lowest cost plants they should lead to both short and long-run efficiency.[2] However, this design is based on the assumption of dispatchable plants with varying marginal costs, an assumption which will no longer hold good in the decarbonised market of the future if, as seems inevitable, it will be dominated by intermittent plants with low or zero SRMC. In such circumstances, energy-only markets cannot remunerate investment and may not be able to provide effective signals for operation or for consumers. Furthermore, there is no exit strategy – as long as plants with near-zero SRMC dominate, they need support from outside the wholesale market, but their presence in the market creates 'pecuniary externalities' which distort that market and lead to a need for support for conventional plants via capacity payments and the like.[3] In this situation there are no market signals to optimise the system – the quantity and type of renewable plants are determined by the nature of the support schemes, while conventional plants are needed essentially as a residual to balance the system, in a quantity (and often of a type) determined by government decisions. In other words, markets are increasingly growing less effective in performing their essential functions – remunerating investment, providing for efficient operation, giving useful signals for consumers, optimising the generation mix – and are not sustainable without support. Proposed reforms that focus on just one of the challenges – for instance capacity markets to remunerate fixed costs – do not deal with the other problems and entail the risk of introducing further distortions.

Concept

The two-market solution addresses these issues by creating separate markets for different sorts of power ('on demand' and 'as available') at both producer and consumer ends. For producers, dispatchable plants would operate in the 'on demand' or flexible market, be dispatched according to merit order when needed and paid on broadly the same basis as at present. Intermittent plants would participate in the 'as available' market; in principle, they would operate as available and, at least initially, be paid a price reflecting the levelised cost of electricity from the particular source in question (with the price normally set via auctions at the investment stage). This is not in itself very different from the current Feed-In Tariff (FiT) auction arrangements which are used in a number of EU countries; however, the idea is that the differing costs and operation of 'as available' and 'on demand' sources would also be reflected in the retail market. Consumers would be able to select 'on demand' or 'as available' power (for which they would normally have separate meter readings) or combinations of the two sources. Initially – as at present – it is likely that price support (or public financing of some renewable costs) would be needed either at producer or consumer level to make the 'as available' offer attractive to consumers,

1 See, inter alia, Keay M., J. Rhys, and D. Robinson (2014), Electricity Markets and Pricing for the Distributed Generation Era, in *Distributed Generation and its Implications for the Utility Industry*", Sioshansi F. (ed.), Elsevier, and Keay M (2016), Electricity markets are broken – can they be fixed?, *OIES Paper*: EL 17, January 2016.

2 Recognising that prices will need to exceed SRMC at times to recover fixed costs.

3 See the discussion of "pecuniary externalities" in the study *Nuclear Energy and Renewables*, OECD/NEA Paris 2012, pp. 34-37.

but over time, as carbon prices increase and renewable costs fall, the support could be removed, creating a potential exit strategy.

The design is shown schematically in Chart 1.

Design objectives

The design proposed in this contribution aims to:

- Provide signals for investment in both markets and, in the long-run, enable investments in renewables and conventional plants to be remunerated solely from the market;
- Provide efficient signals for operation in the 'on demand' market and encourage consumers to maximise their use of 'as available' power (consumers would now have an understandable and effective choice, along with price incentives, to use this power; markets for demand response, on-site storage, distributed generation and the supply chain that supports these and other services, would develop in response to their preferences);
- Provide meaningful signals for consumers – in effect security would be privatised and consumers would be able to decide for themselves how far they were prepared to pay for secure supplies (system stability is a slightly different matter and would still be subject to system operator control). It would be possible for consumers effectively to use their own Value of Lost Load (VOLL) assessments in deciding whether to access the 'on demand' market;
- Provide scope for incorporating distributed resources, and network and transmission costs, using the same general principles;
- By these means, provide for overall system

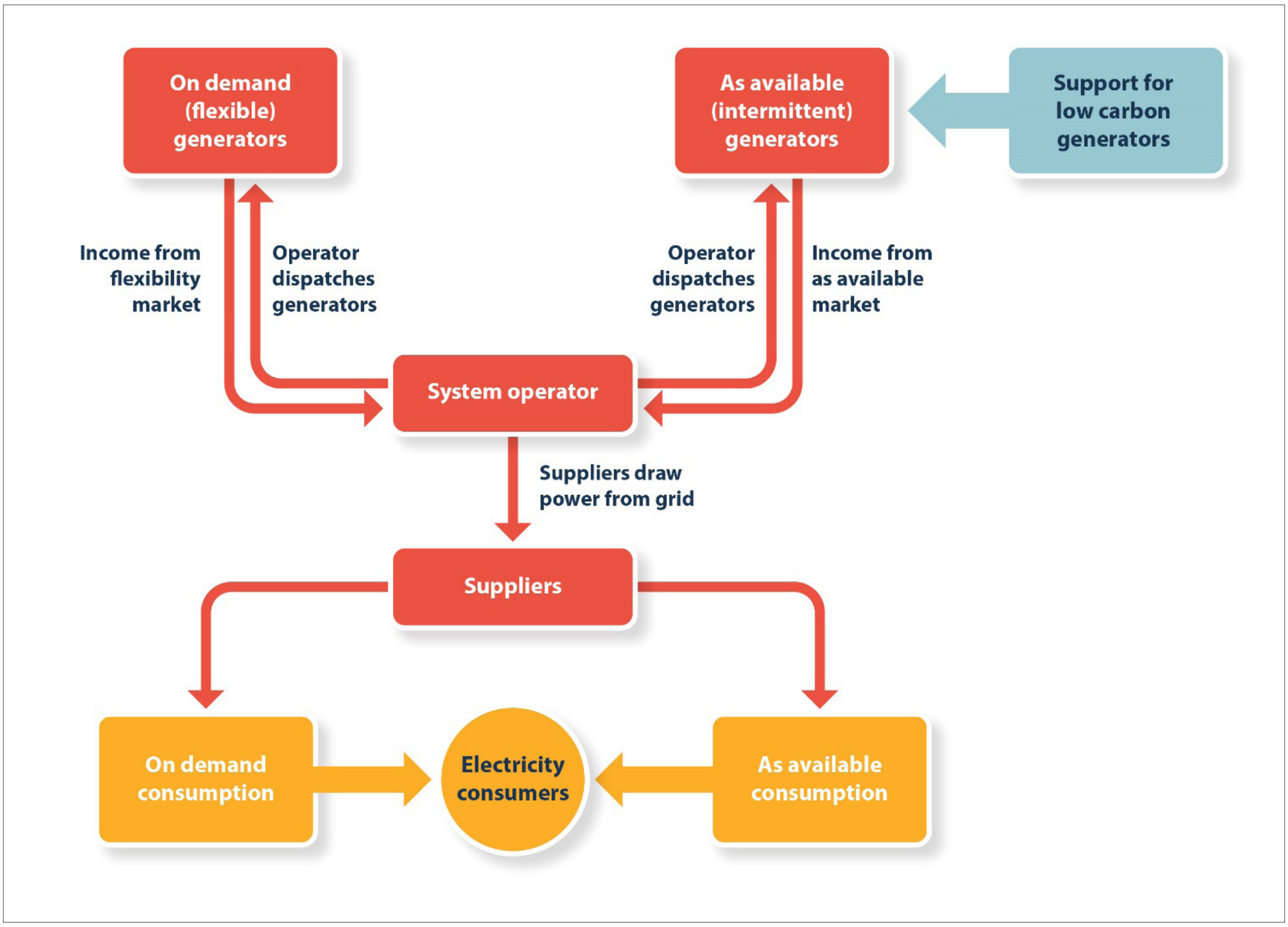

Figure 1: Schematic of two-market design

optimisation on the basis of consumer preferences;

- Provide an exit strategy – the support shown in the schematic above could be removed over time; intermittent generators would be able to remunerate their investments from the market once it had developed sufficiently to be understood and used by consumers;
- Deal with the problem of 'pecuniary externalities' by keeping the markets separate, at least in commercial terms, thereby providing investment signals and the prospect of fixed price recovery for flexible generation.

Methodology

The proposals presented here are based on a qualitative approach, rather than modelling – in the view of the authors it is not possible to undertake meaningful modelling at this stage, since we do not have adequate information about consumer preferences or likely technological developments. We are not therefore in a position to assess how to optimise the overall welfare impacts.

In essence, the design is a large-scale effort to *reveal* consumer preferences and support the development of a supply chain that would respond to those preferences. The authors believe there is insufficient evidence available from current market structures on *revealed* consumer preferences and that the alternative of relying on *stated* consumer preferences that are incorporated into existing markets, e.g. via capacity mechanisms and centrally determined VOLLs, is liable only to introduce and rigidify distortions.

Implementation

A two-market approach could in practice take many forms. However, we would suggest that four underlying principles are essential to the concept as presented here.

At wholesale level:

- **Economic separation** of markets so that intermittent low and zero marginal cost plants which receive support from non-market sources do not create 'pecuniary externalities' for flexible plants with significant marginal costs;
- **Price signals** in both markets which are capable of remunerating investment and guiding operation.

At retail level:

- **Separation** of the consumer offer as between 'as available' and 'on demand' options;
- **Cost pass-through** from the two wholesale markets via the two separate offers respectively.

Within these broad guidelines a number of detailed design options are available. Some are explored in more detail in a fuller paper by the present authors;[4] it sets out ways in which the two markets could be separated in commercial terms, while retaining a unified overall electricity supply structure; and how incentives could be created for suppliers to balance supply and demand in each market, and thereby encourage the development of a flexible and self-sustaining consumer market for intermittent power.

Transition and the longer term

The two-market approach is designed to a large extent as a transitional measure in the sense of being a process of discovery – it will take time to set up the systems, hardware and consumer understanding for a fully self-sustaining low-carbon power supply. In particular, it will take time to delineate the demand side resource potential and it will require systems to be in place that make it simple and practical for consumers to engage with it. Therefore, it is difficult to be definitive about the long-run.

Uncertainty also applies to technology on the supply side: it is in theory possible that in the long-run most plants will be primarily based on fixed costs. In the view of the authors, that outcome is unlikely. It is almost certainly always going to be cheaper, for straightforward economic reasons, to provide flexibility via plants that have a relatively high marginal/fixed cost ratio, like fossil or biomass combustion plants – or have a significant opportunity cost because of the

4 https://www.oxfordenergy.org/publications/decarbonised-electricity-system-future-two-market-approach/.

storability of their power source, like hydro – rather than via plants whose costs are almost entirely fixed. However, should the situation arise where all plants were essentially based on fixed costs, it would in principle still be possible to apply the overall two-market approach, with prices in the flexibility market reflecting scarcity or congestion. Clearly, prices could in theory rise to very high levels on this scenario, but the aim is by that time to have created a capacity for self-supply or demand management amongst consumers which would at least mitigate the consequences (or, in the view of the authors, mean that the scenario itself was very unlikely – i.e. short-term demand response is likely to be more economic than short-term use of generation sources whose costs are entirely fixed).

With these caveats, it would be the authors' expectation that in the long-run, government intervention in the electricity market could be reduced to setting the overall framework conditions. Policy intervention would continue to be needed in order to incorporate the carbon externality and ensure that carbon targets were met. However, this could be done either by a carbon price or (the authors' preference) through tradable carbon intensity targets;[5] the use of one of these options would get away from the need to support particular technologies or sources (like storage or demand response) and allow markets to select the lowest cost options. In other respects, the market should be self-sustaining. Over time, the consumer trade-off between security and price should be well-established, and market prices should be capable of signalling the need for investment in different power sources, including consumer-side sources such as in-house storage and consumer demand management.

Conclusions

Electricity markets are broken; they no longer fulfil their primary functions of providing appropriate signals for producers and consumers. The problem arises from a combination of changes in technology (from predominantly marginal cost plants to predominantly capital cost plants) and of policy (support for intermittent renewable plants) which undermine traditional market structures. In the view of the authors, markets will require fundamental reform to resolve the problem. Existing market structures are inevitably leading to greater central intervention – support for renewables and the creation of capacity markets. There needs to be a shift in emphasis which will enable consumer preferences to be expressed clearly and drive overall market development. The reforms needed will require not just a change in market design but also in consumer attitudes to electricity – this will necessitate a relatively simple and comprehensible basic offer at consumer level.

Against this background the authors propose a new approach to market design which will enable intermittent renewable sources to be accommodated; maintain overall system reliability while enabling consumers to put a value on their own supply security; provide clear signals to generators for investment and operation; and provide an 'exit strategy' allowing government intervention to be limited in the long-run to the setting of framework conditions only. In the view of the authors, no other proposal put forward to date can meet all these objectives.

Fundamental changes are under way in electricity – the aim should be to let consumers drive the process rather than central decision-makers. The two-market design aspires to open the way for them to do so.

5 See Buchan D., and Keay M (2016), *Europe's Long Energy Journey: towards an energy union? Annex 2*, Oxford University Press, pp. 199-209.

MARKETS REIMAGINED TO FINANCE FLEXIBLE, LOW-CARBON AND LOW-COST ELECTRICITY SYSTEMS

David Nelson and Brendan Pierpont

Introduction[1]

CPI-EF carried out an analysis for the Energy Transitions Commission (ETC) which found that by 2030 a grid powered by the sun and wind could be cheaper than building a new system based on gas, including costs for flexibility and backup (Figure 1).[2] The study also found that most regions have enough flexible capacity to reach or exceed 30% variable renewable energy in their generation mix without the need for further investment.

Decarbonisation of the grid at low cost is a massive prize and one that could be winnable within just a few years thanks to dramatic technology cost declines. But this future is by no means assured. As we see in today's wholesale market, signals to incentivize new investments to get to high shares of variable renewable energy are being eroded by low or negative electricity pricing.

Our work with the ETC has brought us to a level of new understanding about what needs to be done to create markets that send the right signals to ensure efficient operations in a low-carbon system and to incentivise the development of more flexible capacity, the cornerstone of the future renewable-based grid.

So far, we have identified three interlinked key challenges, mostly around financing and incentives, that could block or unlock the pathway to this future:

Finance (mainly for new generation supply)

- **Risk allocation** – Market mechanisms should allocate risk appropriately, and not create risks for investors to manage, unless investors are a low cost path for mitigating them.
- **Investors** – Markets need to attract investors whose risk and reward position is aligned with the asset fundamentals.
- **Financial vehicles** – Financing instruments need to adjust to match the needs of optimum investors.

Incentives (mainly for system flexibility)

- **Capacity to deliver flexibility** – Encourage market participants to offer more storage, demand response, and flexible generation.
- **Technology development** – To lower the cost and improve the performance of emerging technologies and processes.
- **Dispatch of flexibility resources** – Balancing flexibility needs, including short-term versus long-term flexibility, and locational flexibility (e.g., distributed versus wholesale).

Transition (for everything)

- **The technology learning curve** – Brings down the cost of new technology through replicable deployment, scale and technological improvements.
- **Market rollout and development of new types of energy businesses** – Drives innovation and competition to provide energy services at the lowest cost and highest quality.
- **New investors** – Lowers the cost of capital for the sector by aligning investor and electricity market needs.

1 This brief presents concepts that are outlined in more detail in Nelson D., B. Pierpont (2017), *Markets for Low Carbon, Low Cost Electricity Systems*, CPI Energy Finance, October 2017.

2 Pierpont B., D. Nelson, A. Goggins, and D. Posner (2017), *Flexibility: the path to low-carbon, low-cost electricity grids*, CPI-EF, April, available at https://climatepolicyinitiative.org/publication/flexibility-path-low-carbon-low-cost-electricity-grids/.

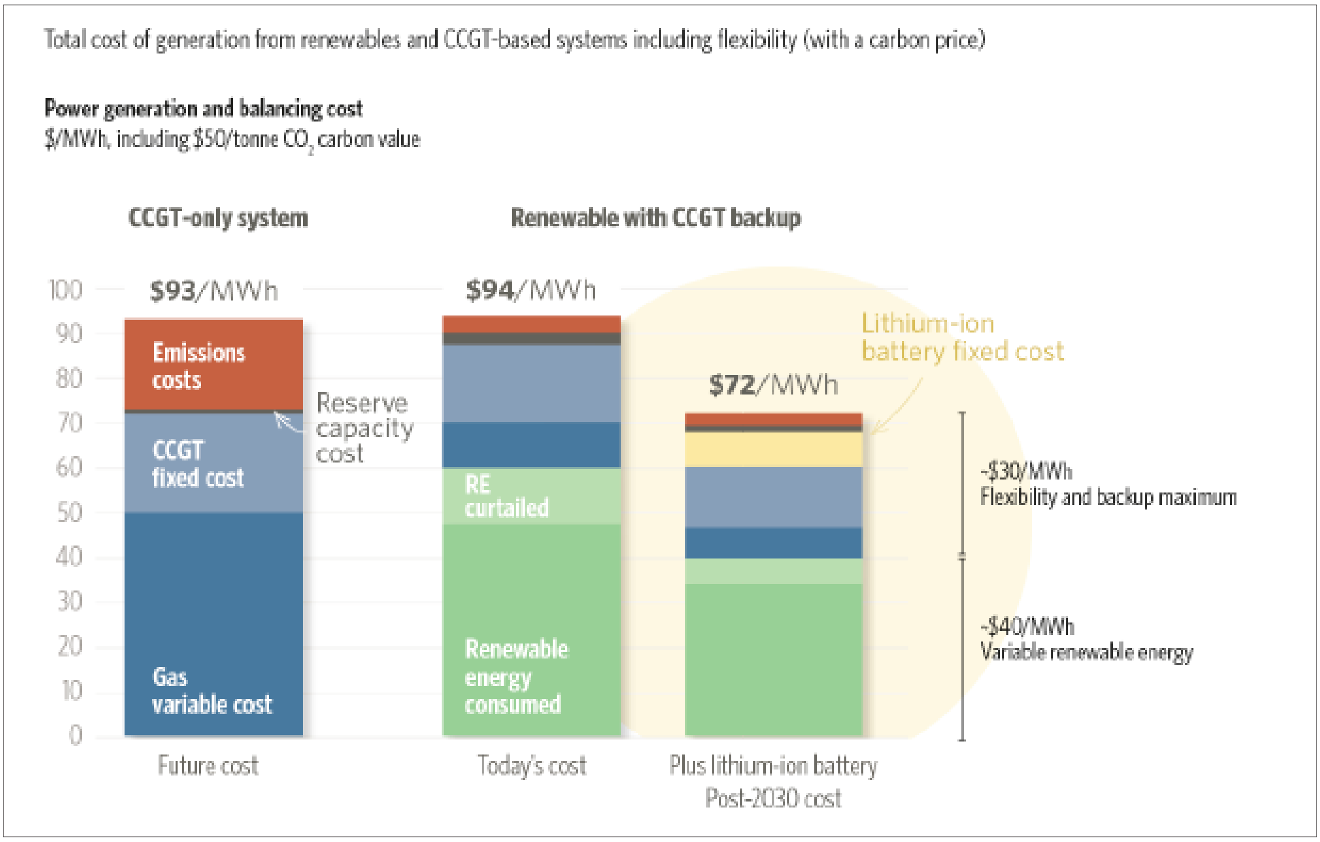

Figure 1: By 2030, an electricity system run on renewables could be cheaper than a gas-based system

Wholesale market that is no longer whole

Existing electricity market designs usually allocate risks to market participants who are not able to manage them efficiently, and in so doing they raise the cost of finance and energy significantly. In today's markets, the more renewables we put on the system, the less valuable all generation assets become and the resulting low or even negative wholesale prices send market signals to investors that electricity generation is a risky business.

Today's electricity markets set prices based on the variable costs of the "marginal" power plant. In other words, we stack all of the power plants in a system from the lowest to the highest variable cost, and the last plant that has to turn on to meet demand in a given hour sets the clearing price for the whole market (Figure 2).

Retaining this model in a high-renewables scenario will create some significant issues. First of all, fuel price risk is passed to those who do not burn fuel. In addition, wind and solar power plants have little control over when they produce power, so they cannot necessarily generate electricity in response to changing prices. Curtailment policies that place the financial risk entirely on renewable energy suppliers can also lead to dramatic increases in the cost of capital and cost of energy from these plants.[3] We are left with a market that will produce higher total costs even in spite of low wholesale prices.

Structuring a new electricity market

A new market design needs to address several issues at once. It should create a stable environment for the low-cost financing of long-term capital intensive energy

3 Nelson D., M. Huxham, S. Muench and B. O'Connell (2016), *Policy and Investment in German renewable energy*, CPI, April, available at https://climatepolicyinitiative.org/publication/policy-investment-german-renewables/.

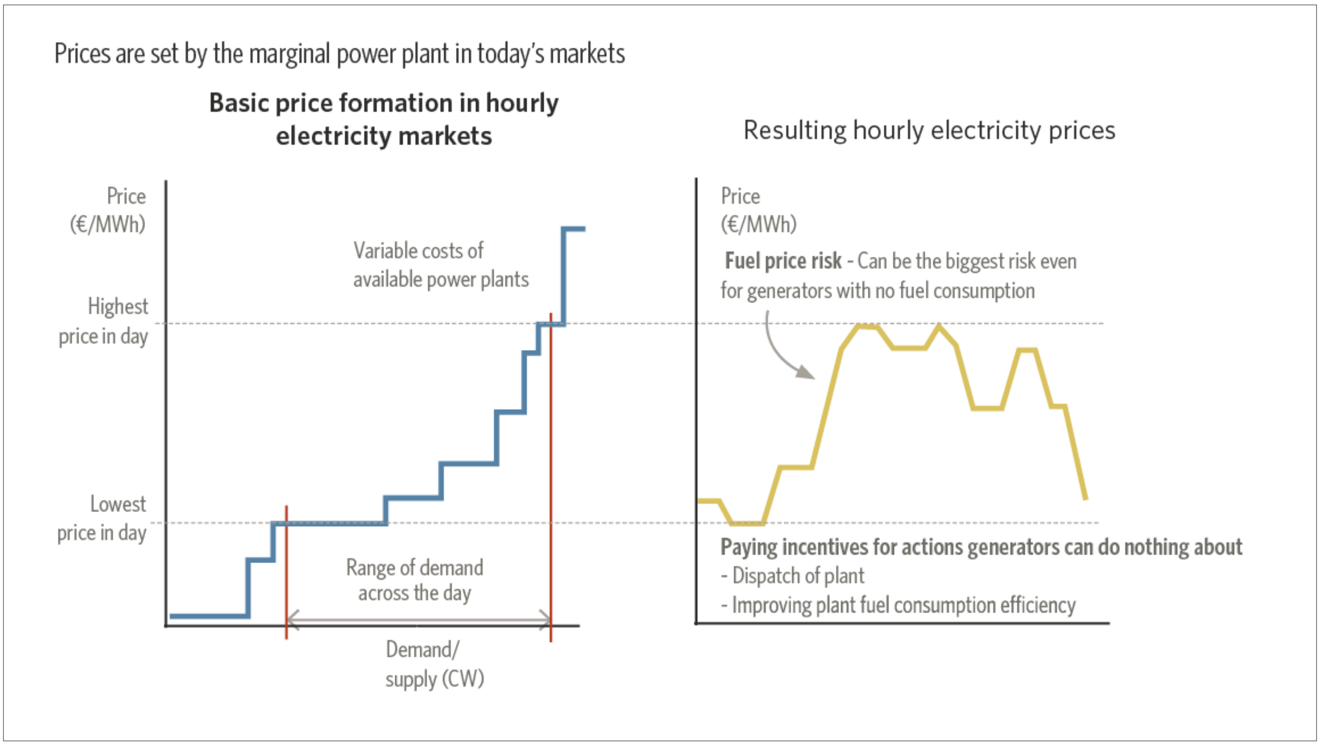

Figure 2: Current market models

generation. But at the same time, it should concentrate the price signals and risks associated with delivering power when and where it is needed with those assets best suited to respond to and manage those risks.

One approach to meeting these goals would be to split the market into two parts (Table 1):

- An **energy market**: a market for trading electricity as a commodity, independent of time and location, that relies on auctions for long-term energy contracts to enable long-term low-cost financing of capital intensive energy resources.
- A **delivery market**: a market for the delivery of energy when and where it is needed to meet demand and ensure reliability. This market would concentrate incentives for flexibility on the subset of market actors that is best suited to manage those risks.

This market design concept is intended as a starting point for a discussion about the major challenges facing today's electricity markets that will enable us to focus on the right solutions.

The combination of these markets could lead to lower financing costs for long-term capital intensive power plants, like wind and solar, as many of the key risks facing these assets would be transferred into the delivery market. At the same time, sharpened market signals for flexibility would provide a strong economic incentive to flexible power plants, battery energy storage and demand-side flexibility providers (Figure 3).

In addition, a variety of electricity system services – ancillary services such as short-term reserves and frequency control – would continue to be needed and could rely on market mechanisms similar to those we have in place today.

The long-term energy market

The long-term energy market could be constructed as follows:

- Each year, the system operator or electricity retailers would construct a long-term forecast of the energy needs to determine how much contracted energy the market would need to procure;
- Based on this long-term forecast, a certain portion of that energy need would be auctioned, where the lowest-cost bidder(s) would receive long-term

	ENERGY MARKET	DELIVERY MARKET
Price formation	Based on long-run, levelized costs	Based on short-run locational costs and scarcity value
Risk	Low, primarily credit and counterparty risks	High, including fuel price, availability, storage levels, etc.
Time frame	Annual rolling auctions for delivery 1-3 years ahead, with long-term contracts	Day-ahead and real-time markets, potentially some longer-term contracts for reliability and resource adequacy
Objective	Minimize financing cost for bulk of kWh	Minimize operating cost for flexible resources and encourage consumer flexibility

Table 1: Characteristics of the energy and delivery markets

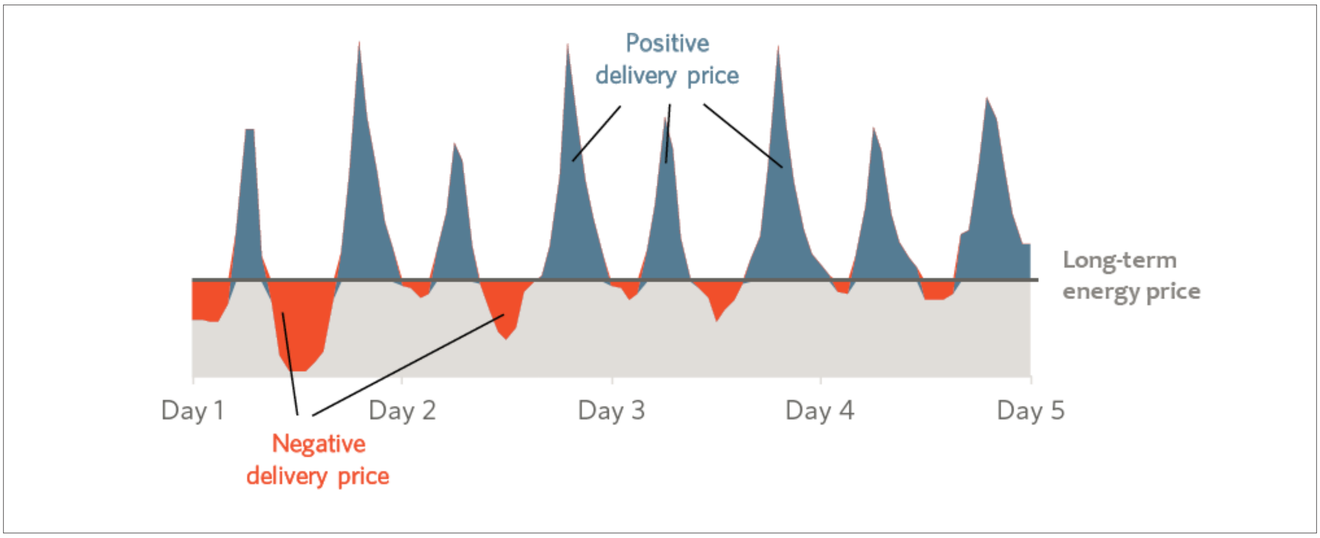

Figure 3: Long-term energy prices are stable while delivery prices vary significantly

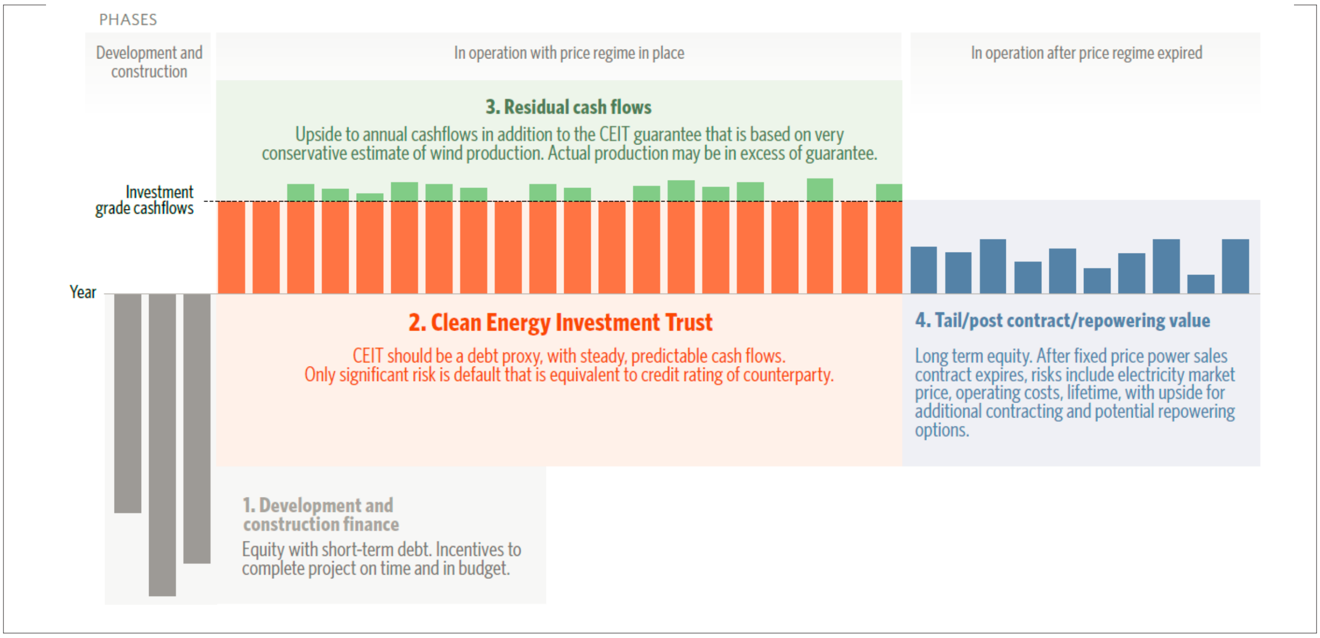

Figure 4: Clean Energy Investment Trust unbundles cash flows for different types of investor

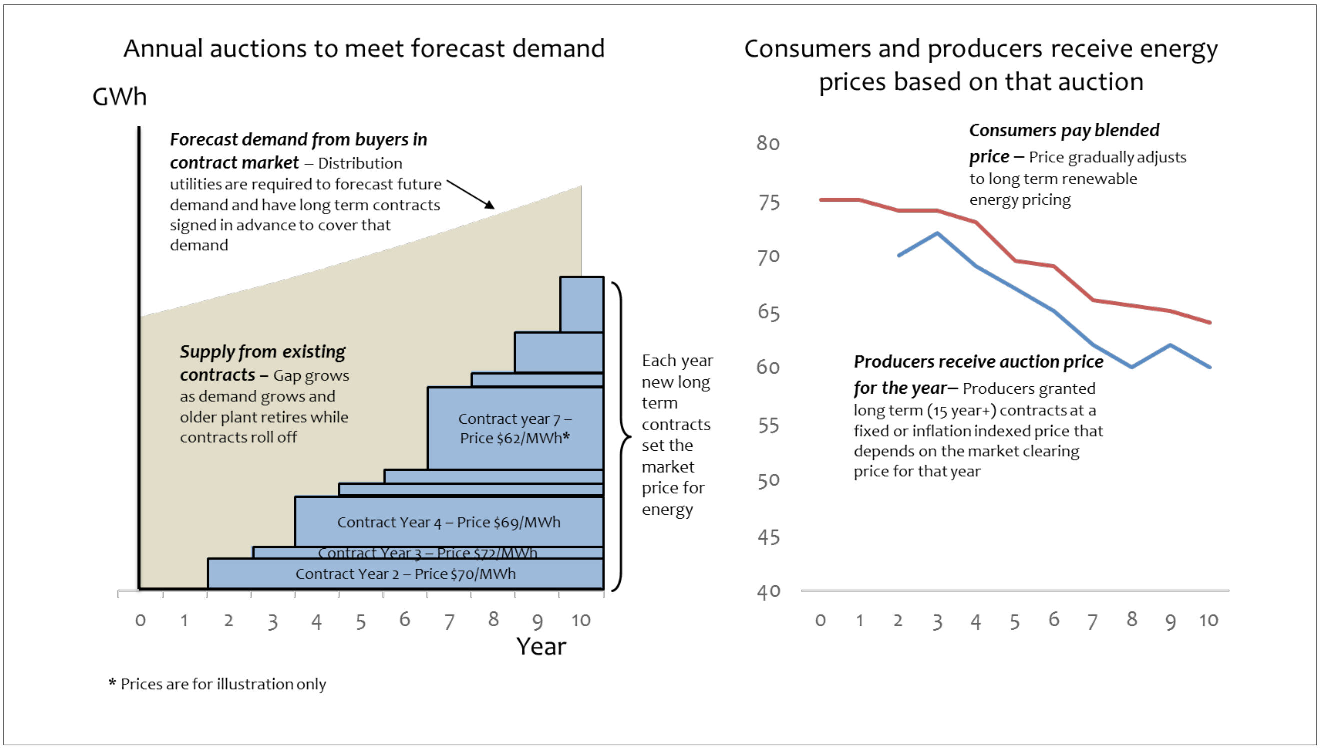

Figure 5: The auction based Brazilian electricity market

contracts to supply electricity at a fixed price, with delivery starting in one to three years to allow time for construction of new plants;

- As old contracts expire and demand estimates change each year, the amount of energy procured through these long-term energy auctions could be adjusted;
- While long-term contracted energy resources would be paid the clearing price for their auction (or in some cases may be paid as they bid), consumers and non-contracted energy suppliers (e.g. those that provide energy while participating in the delivery market) would receive a blended price, reflecting the weighted average price across all contracted energy in a given year.

This market design could enable financial innovation to further reduce costs. In many ways, renewable energy investments look a lot like a bond, with a large fixed investment up front followed by many years of steady cash flows thereafter. At CPI-EF we have been working with institutional investors to design a new investment vehicle that could lower the cost of energy from wind by 15-17 per cent. This Clean Energy Investment Trust (CEIT) structures cash flows from a portfolio of renewable energy projects to create a bond-like product which will appeal to pension funds and insurance companies looking to match their long-term liabilities with investment grade returns.[4]

The energy market would provide a predictable, low risk stream of cash flows to projects under long-term contract. This would enable financial instruments like the CEIT, which are designed for bond-like liability hedging and debt investors. Thus, the energy market does not include curtailment risk, etc., except for at the initial bidding, when these projects can make decisions that mitigate this risk.

Drawing on experience with long-term energy auctions in Brazil

Auction mechanisms have been used for decades to

4 Varadarajan U., et al. (2017), *Mobilising low-cost institutional investment in renewable energy*, CPI-EF, August, available at https://climatepolicyinitiative.org/publication/clean-energy-investment-trust-financial-innovation-renewables/ .

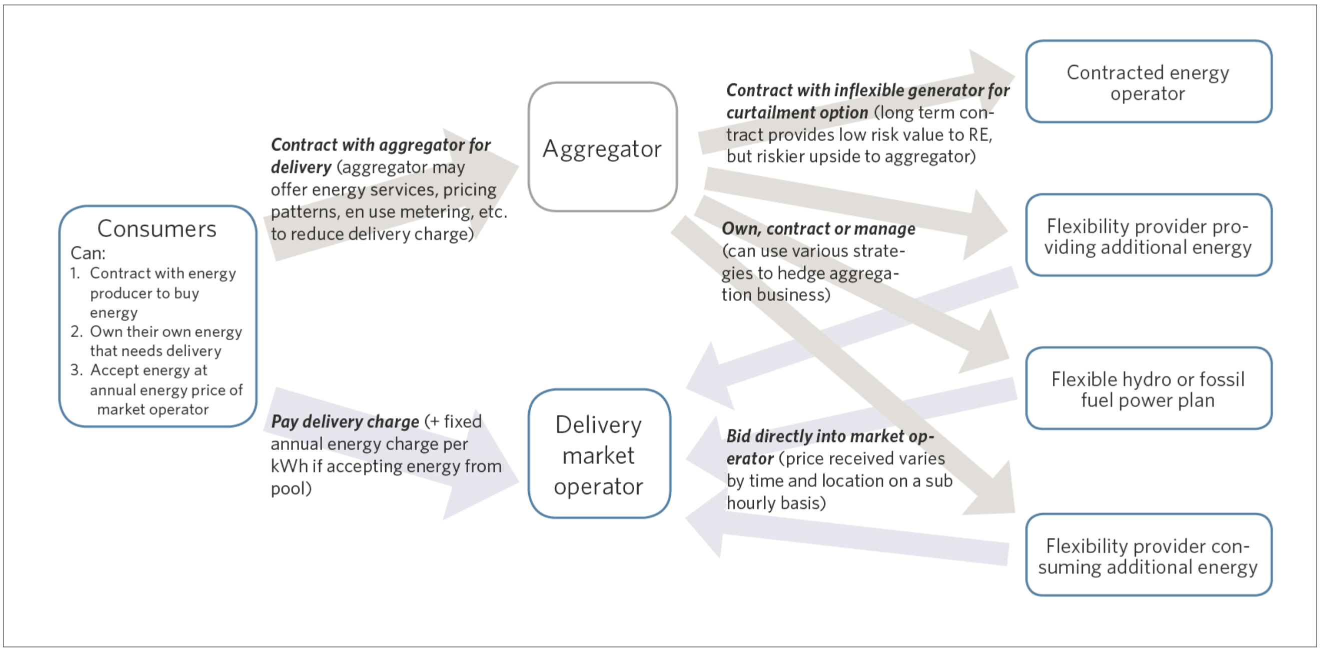

Figure 6: Delivery market pays to deliver energy purchased to a specific time and place

procure electricity. Auctions are common in renewable energy procurement as a tool for price discovery for long-term renewable energy contracts (for example, California's Renewable Auction Mechanism). In addition, most renewable energy tenders and requests for offers for bilateral contracts strongly resemble auctions.

However, Brazil's electricity market structure puts auctions for long-term energy contracts right at the centre.[5] Each year, a certain amount of new and existing generation is procured through long-term contracts (typically 15-30 years with a three to five year lead time), while existing plants that are not currently contracted typically bid to supply shorter-term contracts with immediate to short lead times.

Brazil's long-term energy auction system has led to low costs and facilitated investment in new hydro generation. However, the system is not without its challenges, particularly exclusion of technologies other than hydro from auctions, potential gaming of hydroelectric production estimates, and crowding out of private generation investments by low cost publicly funded projects.

The delivery market

Once kWh have been contracted in the long-term energy market, there will be greater certainty and less risk for contracted energy resources. Nevertheless, the electricity system still needs to ensure that electricity is delivered at the time and location where it is needed, instantaneously.

The delivery market would be designed to meet the difference between expected generation from the long-term energy market and real-time electricity demand at each location in the grid, by providing robust market signals for flexibility. This market would provide short-term price signals, based on day-ahead or near real-time markets. It would also provide locational price signals, differentiating the value of delivery services between locations on the grid. It would have several layers (Figure 6):

- First, flexibility resources – those that can generate, hold back generation, consume, or store and shift electricity – would be able to bid directly into

5 As described by Maurer L., and L. Barroso (2011), *Electricity Auctions: An Overview of Efficient Practices*, The World Bank; and by Moreno R., et al. (2010), Auction approaches of long term contracts to ensure generation investment in electricity markets: Lessons from the Brazilian and Chilean experiences, *Energy Policy*, 38 (10), pp. 5758-5769.

a delivery market. Ideally, this delivery market would be open to a wide range of technologies, and would aim to minimize the cost of matching supply with demand at a particular place and point in time;

- Second, those same flexibility resources could be owned and/or operated by businesses that manage a portfolio of assets, much in the way an independent power producer or power trader might today. By managing a diversified portfolio of flexibility resources these businesses would have the incentive to manage flexibility risks and compete to keep costs low;
- Finally, consumers could play several roles in the delivery market. They could contract with an aggregator who manages delivery costs on their behalf (like today's retailers), or purchase delivery services directly from the market and potentially use automated demand side flexibility technologies to manage their own exposure to delivery market risks.

Concentrating flexibility risks in a flexible market

In today's power markets, most participants are either directly or indirectly exposed to volatile electricity prices. For flexible generators that can respond quickly to changing grid conditions, these prices are effective signals for driving flexible operations. But for some resources – namely capital intensive renewables – these volatile prices introduce risk that the resources have little ability to manage.

By partitioning the market into an energy and a delivery market, the volatile price signals for flexibility would be concentrated in the delivery market, where more flexible resources would have stronger signals to respond.

In addition, this new market model would separate the value of the commodity (kWh) from the value of the delivery and flexibility services. In doing so, it would allow consumers (and aggregators acting on consumers' behalf) to see a clear market signal for the value of firm delivery of electricity to a particular point in space and time.

Much like the PJM market or other locational marginal price based systems, the delivery market could use the concept of locational marginal pricing for delivery services. The key difference would be that rather than bidding to supply energy to meet demand at a given point in time and space, the delivery market would clear the difference between demand and production from contracted generators in the energy market, which in some cases could be negative. This, of course, would send strong signals for energy storage, demand shifting and the efficient use of transmission.

Conclusions

Overall, this two-market model builds on the success of current electricity market models, while fixing the areas where these models are distorting investment decisions and risk allocation for a low-carbon electricity industry. It also redefines the concept of a market price for energy to reflect the reality of low carbon energy as the source of significant new capacity.

We believe that the key benefits are possible both in the energy market and in the delivery market. By unbundling the delivery and the commodity, the energy market will be able to reduce the risks for power producers, lowering their cost of capital. In such a market, long-term contracts and load differentiation charges will provide appropriate incentives to generators. The cost of low-carbon electricity will fall as the delivery risk is concentrated on those who can absorb and optimize that risk. The delivery market will expand the range of actors participating in the supply of flexibility and other ancillary services, but only flexible generation, consumers and storage are likely to benefit. The base price for delivery markets could be near zero, with prices swinging from positive to negative depending on congestion which provides a clear signal of the value of flexibility to market participants. Traders could also harness curtailment of non-dispatchable generation by bidding curtailment of contracted energy supply into the delivery market as a potential additional (but riskier) source of value on top of a long-term contract for energy.

AUTHORS

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