Improving the Market for Flexibility in the Electricity Sector

Task Force Report

Chair: Jacques de Jong
Rapporteurs: Arndt Hassel
Jaap Jansen
Christian Egenhofer
Zheng Xu

Improving the Market for Flexibility in the Electricity Sector

Report of a CEPS Task Force

Chair:

Jacques de Jong

Rapporteurs:

Arndt Hassel
Jaap Jansen
Christian Egenhofer
Zheng Xu

Disclaimer

This report is based on discussions in the CEPS Energy Climate House Task Force on Creating a Market Design for Flexibility in EU Electricity Markets. The Task Force met three times between April and September 2017. Task Force participants included senior executives from a broad range of industries – including energy production and supply companies, energy-intensive industries and service companies – and representatives from business associations, non-governmental environmental organisations, research institutes, think tanks and international organisations. A full list of members and speakers appears in the appendix.

Task Force members engaged in extensive debates during the three meetings and submitted comments on earlier drafts of this report. Its contents reflect the general tone and direction of the discussion, but its recommendations do not necessarily represent a full common position among Task Force members, or indeed the views of the institutions with which the members are associated.

ISBN 978-94-6138-641-0

CEPS
Place du Congrès 1, B-1000 Brussels
Tel: 32 (0) 2 229.39.11
e-mail: info@ceps.eu
internet: www.ceps.eu

Table of Contents

EXECUTIVE SUMMARY

1.1 Flexibility and flexibility needs

All decarbonisation scenarios point to the increasing electrification of the energy system. Electricity will gradually play a bigger role in the transport and building sectors, but in order to reach EU climate change targets, the electricity used will need to come increasingly from low carbon sources and especially, but not only, from variable renewable energy sources. Both trends, the electrification of sectors and the need to integrate electricity from variable renewables, mean that there will be a greater need for flexibility in the electricity sector. This need can be met by the flexibilisation of both the generation and consumption side and the storage; the more intensive use of the existing networks; improved cross-border interconnectivity; and the integration of different sectors. The latter might include integrated electricity and gas infrastructure to address seasonal storage, heat storage in combination with electrified heating and the utilisation of electric vehicle batteries. This Task Force has analysed the complex issue of flexibility and the market framework that is best able to provide it. It has identified the following key messages and practical recommendations.

1.2 Key messages and recommendations

Short-term and balancing markets

Efficient EU-wide market integration is the principal and most cost-effective source of flexibility. The biggest potential remains in the intraday (ID) and balancing markets. The harmonisation of market designs is a prerequisite for this integration. The current integration approach attempts to build bridges between nationally diverse markets and is limited.

The existing target model for the intraday timeframe, based on continuous trading, should be swiftly implemented. Harmonised intraday auctions in addition to continuous trading (e.g. an opening and closing auction) could enable more efficient implicit capacity allocation for cross-zonal intraday trading. This calls for consultation with market participants and exchanges to work out a common plan for all coupled bidding zones.

Recommendations:

- The European Commission should work further towards harmonising national short-term and balancing market designs. This should be done by ensuring swift implementation of existing provisions (e.g. continuous trading in the intraday market) and through further provisions towards an efficient target model. Harmonisation should start at the regional level, if necessary.
- The European Commission, member states, power exchanges and transmission system operators (TSOs) should continue to pursue pan-European market coupling of day-ahead markets, especially connecting with Central and Eastern Europe.
- To reward flexibility, design elements should include:
  - Balancing energy auctions which are open to pre-qualified market participants and which take place after the intraday market
  - Marginal balancing energy and imbalance pricing

- Real-time disclosure of the system imbalance and imbalance price allowing for implicit balancing by balancing responsible parties
- EU-wide, harmonised intraday auctions (e.g. opening and closing auctions complementary to continuous trade)
- Long and medium-term balancing capacity auctions only where justified on cost-efficiency grounds
- Harmonised trading schedules of the day-ahead, intraday and balancing markets including common gate closure times and a common time interval (e.g. 15 minutes)
- Harmonised basic trading products based on this interval, with subsidiarity on specific products
- Monitoring by ACER and/or a common guideline on balancing market pre-qualification requirements in order to reduce undue discrimination.

Grid reinforcement and cross-zonal capacity allocation

Grid reinforcement has been on the agenda for decades. The European Commission has proposed mechanisms for improved capacity allocation and bidding zone revision. Cross-zonal price differences (for congested interconnectors) and costs for congestion management (for internally congested bidding zones) are indicators for priority needs. There is a trade-off between grid reinforcement and alleviating congestion by increasing local flexible generation or consumption resources. The core barrier to grid reinforcement is public acceptance by citizens who are affected by the construction of new lines.

Recommendations:

- The capacity allocation mechanism should be optimised to allocate capacity to the ID and balancing markets efficiently, including a market-based price for use of interconnection capacity. This may include additional recalculation steps of available capacity after the DA and ID markets have closed.
- In cases where public acceptance hinders new projects, adapting the concerned price zone(s) to minimise the cost for congestion management should be considered, taking into account past market-based investments.
- The highest priorities for grid reinforcement (i.e. where cross-zonal price differences and costs of congestion management are highest) should receive greater support from ENTSO-E's TYNDP and other EU policies (like the Commission-proposed use of congestion rent for new investment and the 15% interconnection target for 2030).

Aggregation

The role of (and market for) aggregators is bound to grow in the future, with larger (industrial/business) participants as first movers. The development will be aided on the one hand by removing barriers to market access for interested consumers and on the other by the creation of standards and protocols. Based on a level playing field, independent aggregation and aggregation carried out by suppliers should both be possible.

Recommendations:

- The market design should facilitate the contribution of independent aggregators in a non-discriminatory way, i.e. removing market barriers (in all time-frames) without introducing (indirect) subsidies.
- EU-level rules should ensure a level playing-field for aggregators. Member state-level rules for the calculation of aggregators' net generation/consumption balance should be monitored by ACER.

- To enable data exchange and the interoperability of appliances, a common platform, such as one based on the CENELEC work, should accelerate the development of common standards and protocols.

Priority dispatch

Better integrating renewables into the market helps to minimise their impact on flexibility needs. Despite their intermittency, solar and wind power can contribute to flexibility and minimise system cost. The support schemes on which these energy sources depend can be designed to incentivise flexible behaviour. Priority dispatch can be replaced by market-based, non-discriminatory curtailment and redispatch rules without harming renewable generators if fair compensation is ensured for fallback procedures. However, fallback procedures (whenever market-based curtailment fails to solve a grid situation) that do not prioritise renewables may lead to the increasing curtailment of renewables, especially in the absence of other policies that incentivise the system to adapt for high renewables shares.

Recommendations:

- Priority dispatch, should be phased out for new installations, under the condition of non-discriminatory balancing markets, market-based curtailment and fair compensation of fallback (non-market-based) curtailment.
- A prescriptive EU-level guideline that ensures that the compensation for fallback curtailment includes all benefits foregone, differentiating between different generators and customers, should be considered.
- Priority access (a 'last-curtailed'-rule for renewables when market-based curtailment does not solve a grid situation) should be upheld unless other policies facilitate the uptake of high renewables shares and flexibilising existing must-run capacities.
- Emergency (non-market-based) curtailment should be subject to compensation (of benefits foregone) for all plants.

The role of DSOs

Increasingly decentral generation and flexibility provision puts additional challenges to grid operators and particularly to DSOs. They are tasked with integrating a growing number of flexible resources, the resulting flows from which need to be coordinated with other stakeholders and particularly TSOs. For example, aggregation is different from conventional flexibility because it triggers flows in many distributed locations, rather than at a single point in the distribution or transmission grid. There are benefits in sharing flexible reserves between both DSOs and TSOs to increase system-wide cost-efficiency.

Recommendations:

- A mechanism for data exchange between DSOs, TSOs and decentral market participants should be developed, to manage resulting electricity flows and enable efficient, system-wide use of distributed flexible resources. Such a mechanism should take into account the data flows and calculation needs resulting from aggregation.
- Balancing, congestion management and other ancillary services should be regulated to ensure that the required resources are shared efficiently between DSOs and TSOs where possible.

Sectoral integration

It is undisputed that the market is developing stronger links between the heating/cooling, electricity and transport sectors and the different energy carriers used therein (gas/liquid fuel, heat, electricity). This sectoral integration has potential benefits for flexibility, decarbonisation and security of supply. Governments may be inclined to pursue specific options and technological solutions. This risks creating market distortions. Neglecting the challenges that arise from sectoral integration (e.g. seasonal storage for heating) might jeopardise security of supply.

Recommendations:

- In order to adapt policies to the effects and needs of sectoral integration, long-term cross-sectoral energy flows and infrastructure planning (for different scenarios) should be institutionalised, starting with electricity, heating and gas infrastructure.
- The EU and member states should consider integrating cross-sectoral infrastructure planning into National Energy and Climate Plans (as part of the proposed Governance Regulation) and/or in other institutional frameworks.

1. INTRODUCTION: WHY AND HOW

The European Council conclusions of October 2014, pledging to reach at least 27% renewables by 2030, and the European Commission's 'Clean Energy for All Europeans' proposals of November 2016 will require additional and increasing flexibility in the European power system. Reaching 27% renewables by 2030 will translate into a share of at least 45% of renewable electricity. By 2050, according to the European Commission's 'Energy Roadmap 2050', renewable energy would contribute between 64-96% to the electricity mix.

Most renewable electricity can be expected to come from intermittent sources (wind and solar power). Accommodating such high shares of intermittent renewables will require flexible resources – generation and consumption – and infrastructure, as has been continuously highlighted by the European Commission. This will include different types of 'flexibility needs' for different purposes. Matching generation and consumption at every point in time is the most basic need. Others include congestion management, voltage control, daily, weekly and seasonal flexibility, plus strategic reserves.

Flexible resources (with varying degrees of flexibility) can include generation (e.g. hydro, gas, certain nuclear, renewables, certain coal), consumption (demand response, e.g. power-to-heat, interruptible loads, facilitated by digital infrastructure), - as well as electricity storage (e.g. pumped storage, batteries and other storage technologies). Infrastructure enabling flexibility can include transmission and distribution capacity as well as information and communication technology (ICT, e.g. smart meters).

In a well-functioning market, flexibility has a value. The adequate functioning of electricity markets, especially an undistorted market for flexibility, facilitates market-driven investment and the efficient utilisation of flexible resources and infrastructure. The European Commission's aim is thus to ensure and if necessary improve the working of the market, notably short-term markets, in particular intraday. Balancing and reserve power mechanisms are another focus.

This CEPS Energy Climate House (ECH) Task Force Report i) takes stock of the market regarding flexibility, including the proposals under the Clean Energy for All Europeans package, ii) briefly reviews the current and future options, and iii) identifies workable and practical proposals for the way forward. An Executive Summary and Recommendations completes the Report.

Annex 1 provides an overview of flexibility technology options. Annex 2 contains a glossary of abbreviations and technical terms. Annex 3 lists all Task Force members and speakers.

2. FLEXIBILITY OPTIONS

This chapter introduces the flexibility options that can be addressed by EU policy. They include flexible resources, (i.e. flexible generation, consumption and storage technologies), options relating to the grid (i.e. grid reinforcement and optimisation of its use) and policy options relating to market design and market integration.

2.1 Flexible resources

Flexible generation and consumption technologies provide physical flexibility to the electricity system. Electricity storage technologies can carry out both functions. For each of the three categories, many technology options are capable of providing varying degrees of flexibility.

A key challenge lies in creating a market and policy framework that enables efficient and adequate investment into flexible resources. This is especially important for long-term security of supply. On the generation side, both investment in new flexible generation or storage installations and in retrofits that render existing installations (like coal or nuclear power plants, but also PV and wind power) more flexible, is possible. Developing consumption side flexibility necessitates investment into ICT (which enables existing resources) or into storage installations.

Efficient investments in the electricity sector are helped by long-term price signals.[1] These price signals are most efficient if they emerge from the market itself. The European electricity market currently includes a lack of liquidity in forward markets and a decline of wholesale prices. The underlying causes include overcapacity (resulting *inter alia* from policy-driven additions of renewable capacity and reduced consumption), declining fossil-fuel prices, depressed ETS prices and market distortions such as exit barriers, price caps and regulated prices.

The Clean Energy package proposed by the European Commission intends to improve the design of the market to improve price signals and enable market-driven investment (also known as 'resource adequacy').

Annex 1 includes characterisations of relevant flexible generation and consumption technologies. The following sections provide a summary.

2.1.1 Flexible generation

Flexible generation technologies can include thermal power plants based on natural gas (turbine and combustion engine-based), hydro power, biogas, biomass, coal, nuclear, solar thermal, geothermal, but also wind and PV power (with limitations).

Technologies vary in their degrees of flexibility, typical grid level (centralised vs. decentralised), economic potential, limiting conditions and climate-related and environmental factors. Typical parameters to characterise an installation's level of flexibility include minimum load (lowest percentage of full load to which it can be throttled), ramp rate (time needed to increase or decrease generation output), and start-up-time (duration between cold-start and generation).

In the future, the levelised cost of electricity by flexible generation sources will be significantly impacted by lower full load hours, recurrent partial load operation and a higher

[1] F. Genoese, E. Drabik and C. Egenhofer (2016), "The EU power sector needs long-term price signals".

amount of start-stop cycles. This can be expected to impact the profitability of both conventional and new generation technologies.[2]

While the power sector is probably the most cost-efficient energy sector to reach a carbon-free state, existing carbon-emitting flexibility assets provide an important trade-off between flexibility and emission in the medium term. They might take reserve functions in the long term and can technologically transition to low-carbon fuels.

Many low-carbon (renewable) options depend on support schemes to be competitive and operate primarily to reach the decarbonisation objective and only secondarily to provide flexibility. This situation might change with further cost reductions of renewable technologies and with better market access, e.g. to balancing markets.

2.1.2 *Flexible consumption*

Flexible electricity consumption, also known as demand response, plays a role historically and today, but constitutes a considerable unused potential. The aluminium industry is a prominent example for existing players in demand response, which are mostly in the industrial sector.[3] A large theoretical potential of flexible demand resources in the household, business and industrial sectors could be unlocked by further developing the necessities (standardisation of IT infrastructure and data exchange, market platform, regulatory framework) for their market participation. This could include both implicit demand response, i.e. dynamic pricing schemes for end-consumers, and explicit demand response (e.g. direct wholesale market participation or through aggregation).

Reportedly, 29% of total EU electricity consumption (52 GW in capacity) qualifies for demand response, technically.[4] Most of this potential would consist of small-scale, decentralised installations, i.e. in the kW to low MW scale.[5] Table 2.1 shows a list of processes with demand response potential by sector.

Table 2.1 Processes with demand response potential

Industry	Tertiary	Residential
Iron & steel [I&S]	Commercial refrigeration [CR]	Refrigerators & freezers [R&F]
Non-ferrous metals [NFM]	Air-conditioning [AC]	Washing machines [WM]
Chemical & petrochemical [C&P]	Space & water heating [SWH]	Dishwashers [DW]
Non-metallic minerals [NMM]	Ventilation [VE]	Air-conditioning [AC]
Paper, pulp & print [PPP]		Water heaters [WH]
Wood & wood products [W&W]		Heating systems & electric boilers [HSEB]

Source: SiaPartners (2014), "Demand Response: A Study of its Potential in Europe".

[2] C. Perez Linkenheil, I. Küchle, T. Kurth and F. Huneke (2017), "Flexibility needs and options for Europe's future electricity system", study by Energy Brainpool for EUGINE.

[3] Alcoa participate in the ancillary services market. Their aluminium factories in Indiana and New York have been integrated with regional grid operators to provide overall 125 MW DR capacity. In the past nine years, this capacity could be cleared in the market almost every day. Source: presentation by Álvaro Dorado Baselga, Vice President Energy Europe, Alcoa in the second Task Force meeting, 31st May 2017.

[4] SiaPartners (2014), "Demand Response – A Study of its Potential in Europe".

[5] Reportedly, it is distributed relatively evenly across the three sectors (residential 42%, industrial 31%, business 27%).

To date, the IT infrastructure necessary for decentralised consumption resources to access the market (smart metering) is still not deployed widely. Current and future cost reductions due to technological progress and scale effects in IT hardware and digital information exchange will be significant factors. As will regulatory frameworks, including the possible future evolution from the current aggregator model to decentralised markets or blockchain technology.

In many ways, flexible consumption relates to sectoral integration as it includes technologies such as power-to-heat and power-to-gas/liquid, which are interfaces between the electricity, heating and transport sectors.

Aggregation has an important function as enabler for decentralised consumption flexibility.

2.1.3 Electricity storage

Electricity storage can both consume and generate[6] electricity flexibly. Alongside pumped-hydro storage (see section 2.1.1), which is by far the most widely deployed technology, others are emerging.

According to an IEA report,[7] out of 3.4 GW non-hydro storage capacities deployed in 2016, 53% were battery solutions, with lithium ion batteries contributing much more than other battery technologies (lead acid, redox-flow, nickel-cadmium, and sodium-sulphur). Flywheels and compressed air energy storage (CAES) contributed 28% and 19% respectively. Most projects were launched or coordinated by grid operators, either to meet specific ancillary services needs or as demonstration plants, i.e. not based on price signals in wholesale markets.

Battery electric vehicles hold a potential for flexibility provision. In the Netherlands, an operator of electric vehicle charging stations started participating in the balancing market in January 2016.[8]

2.2 Grid

2.2.1 Grid reinforcement

Since the European grids are currently adapted to power plants, many of which will be replaced by renewable generation in different geographical locations, the problem of grid congestions can be expected to grow, along with the costs for the end-consumer.

New transmission and distribution infrastructure reduces the need for flexible resources to compensate for grid congestions. Moreover, expanding cross-border transmission capacity to higher levels is a prerequisite to further integrate European markets, which in turn reduces the overall need for flexible resources (see option 1). The practice of redispatch means that a reserve of flexible resources is kept idle and can be activated in the event of grid congestion. Another form of congestion management is counter-trading, where TSOs procure remedial generation through the market.

2.2.2 Better use of the grid

There is a potential to achieve higher flexibility by optimising the use of the grid. Firstly, better representation of grid constraints in market prices can lead to grid-friendly investment decisions in new flexible resources. Secondly, better planning of grid operation, enabled by more and better data, can reduce the need for hedging uncertainties by blocking safety margins in the grid and keeping flexible resources in reserve (for congestion management).

---

[6] To the extent that energy has been consumed before.

[7] International Energy Agency (2017), "Tracking Clean Energy Progress: 2017".

[8] The New Motion aggregates 19,000 electric vehicle charging stations, see TenneT (2016), "Market Review 2016".

By improving the representation of grid constraints in the market design, price signals can better incentivise consumers and generators to act flexibly and to the system's benefit, both in short-term dispatch and long-term investment (including renewables). Locational price signals would lead to higher revenues in areas where (structural) congestion leads to local shortage, while providing lower revenue in areas with local surplus. A transition to more granular price zones (as proposed by the European Commission) would achieve this.[9]

Another mechanism with similar effects is a dynamic grid charge which varies over time according to the level of stress in the grid. Progress in this area necessitates decentralised IT infrastructure (smart metering). The feasibility of this approach is currently being demonstrated in France.[10]

Better use of the grid can also be achieved by more accurately predicting electricity flows through better data availability. Monitoring and planning of grid operation involves production and consumption schedules of wholesale market participants on the TSO side, but most consumption and decentralised production is based on predictions that are subject to a considerable margin of error.[11] The complexity of these predictions increases as more and more decentralised production units are built. Actual grid flows always diverge from planned flows, causing inefficiencies because i) grid capacities must be reduced by a margin of safety and ii) transactions that would benefit the system can be omitted because of false assumptions during the time of trade.

Evolving IT infrastructure, computational abilities and big data are key enablers for optimising the grid and thereby reducing future flexibility needs.

2.3 Market

This section gives an overview of how the market design can address the flexibility challenge, both by improving the design of individual markets and by integrating them.

2.3.1 Cross-border market integration

Further cross-border integrating of the EU's electricity markets will reduce the overall volatility of consumption and intermittent generation through what is referred to as a 'geographical smoothing effect'. By nature, peaks and troughs in two geographically separate electricity systems are to some degree decorellated (i.e. do not always occur at the same time). A peak in one system is often balanced out by a trough in the other. The degree of decorellation is affected by differences in the (renewable) technology mix as well as weather (including water flow) and consumption patterns in the two systems. The higher the degree of decorrelation, the lower the combined system volatility and the lower the need for flexible resources.

In addition, the total capacity of flexible resources necessary to operate the combined system is lower (in both relative and absolute terms) than for a single system. Balancing reserves can therefore be shared, resulting in significant cost reduction. A study published by Agora Energiewende,[12] for example, confirms the considerable potential for reducing flexibility needs by pan-EU integration, both in terms of annual peaks and troughs (which determine needed reserve

---

[9] An important precondition for investment based on locational price signals is that these price signals translate into the forward market, which is an unsolved issue the Commission's proposal tries to address.

[10] Since August 2017, customers connected to the 20 kV level can opt for a dynamic grid charge.

[11] This includes predicting the output from intermittent renewables (weather forecasts) and demand (based on consumption profiles). Moreover, computational capacities limit the resolution of grid modelling and the structure of large portions of the grid (particularly on the low voltage level) is merely approximated.

[12] Fraunhofer IWES (2015), "The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region", analysis on behalf of Agora Energiewende.

capacity) and day-to-day volatilities (which determine total flexible energy needed to be dispatched). This potential emerges due to EU territory being geographically, climatically and technologically diverse.

For decades, European countries' electricity systems have been continuously connected by physical interconnection capacities and EU internal market policy. While trade is integrated EU-wide in the day-ahead timeframe, cross-border pooling of TSO-procured flexibility (various reserves, including for balancing and redispatch) is not conclusively implemented and cross-border intraday trade has not reached its full potential.

The integration of balancing markets is achieved in three steps. Firstly, imbalance netting (combining simultaneous surpluses and shortfalls among TSOs) reduces the need for balancing energy to be covered by flexible resources. Secondly, sharing reserves then reduces the need for reserve capacity. Lastly, a common market platform for both balancing energy and balancing capacity encourages competition and achieves maximum efficiency and social benefit.

So far, 19 countries, including Norway and Switzerland, participate in the coupled day-ahead market. Some progress has been reached regarding market coupling of ID markets, especially in the Nordic region and within the SWE region. However, utilisation of available cross-border capacities is low in most cases.[13] One way to address this would be full implementation of the CACM (Capacity Allocation and Congestion Management) Regulation and the upcoming network code on electricity balancing, for example. Cross-border exchanges in the balancing market are growing, but remain limited. One key reason that hampers swifter integration is the divergence of balancing market design among member states, rendering the markets incompatible for closer cooperation. In March 2017, an Electricity Balancing Guideline received a positive vote in comitology and should lead to future improvements in cross-border balancing.

The allocation of cross-border transmission capacity[14] to the various market timeframes (including balancing by TSOs) is an important parameter for market integration, and one that should be improved. The objective is to maximise the value of the interconnector capacity. Short-term cross-border transactions should be considered to enable efficient cross-border exchange of flexibility.

2.3.2 *Changes to adapt market design*

Efficient market design will find market solutions for the dispatch of flexibility, while reducing the need for TSO-procured reserves. Ultimately, market design should enable price signals for investment in the required flexible resources.

Many elements can enhance flexibility through efficient market design. This includes shorter trading intervals closer to real-time (temporal resolution), optimised price zones or locational pricing (geographical resolution), removal or improvement of regulatory price restrictions (price caps) and more efficient bidding mechanisms in the intraday market (e.g. opening and closing intraday auctions complementary to continuous trading). Market integration will require the harmonisation of these parameters.

The market design should ensure that all market participants capable of providing flexibility have access to the market. For example, there is potential for variable generation sources such as PV and wind turbines to be operated more flexibly. This means that when their primary resource (sun/wind) is available, the operator can decide to operate or not. Curtailment of renewables, i.e. a flexible production stop, can, under certain circumstances, be a cost-effective option, including when appropriate compensation is ensured. The same is true for the opposite, i.e. intermittent renewables acting as a reserve within a certain timeframe where the availability of wind or sunshine is reasonably certain.

---

[13] ACER (2016), "ACER Market Monitoring Report 2015 - KEY INSIGHTS AND RECOMMENDATIONS".

[14] This allocation currently gives priority to day-ahead or earlier transactions.

Market design must ensure that the market gives price signals for investment in flexibility. This is best achieved in a market that is free of distortion, such as regulated prices, exit barriers, price caps and undue subsidies. Such distortions endanger long-term market functioning by limiting market participants' ability to obtain sufficient remuneration from the market. While such distortions are not the only factor, they have added to the continuous price decline of European wholesale markets in recent years.

3. MARKET DESIGN PROPOSALS UNDER THE 'CLEAN ENERGY FOR ALL EUROPEANS' PACKAGE

In the proposed revisions for the Electricity Market Regulation[15] and Directive,[16] the European Commission proposes a number of provisions relating to flexibility. Table 3.1 gives an overview of the provisions and flexibility options they address. Sections 4.1 and 4.2 explain the concrete proposals.

Table 3.1 Overview of provisions for flexibility options

Proposal	**Provisions**	**Cross-border market integration**	**Improved Market Design**	**Grid reinforce-ment**	**Better Use of the Grid**	**Flexible Resource (including generation, consumption and storage)s**
Proposed Electricity Market Regulation (COM(2016) 861 final)	Capacity Mechanism rules (A18-24)	X	X			X
	No discrimination in network charges (A16)					X
	ENTSO-E counterpart for DSOs (A49-53)				X	X
	Re-evaluation of bidding zones (A13)				X	
	Optimised use of interconnectors (A14-15)	X	X		X	
	Congestion income for investment into new interconnectors (A17)	X		X		
	Balancing capacity procured by ROCs (A32-35)	X				
	Harmonisation of balancing market design (A5,7)	X	X			X
	Removing price caps in the wholesale market (A9-10)		X			X
	Cross-border curtailment and redispatch (A12)	X			X	

[15] COM(2016) 861 final.

[16] COM(2016) 864 final

Proposed Electricity Market Directive (COM(2016) 864 final)	Right for customers to prosume, to a dynamic price contract and to participate in aggregation (A11, 13, 15, 17)					X
	Smart metering obligation and customer right to smart meter (A19-21)					X
	Role of DSO as neutral market facilitator (A30-36)		X		X	X

Many provisions addressing flexible resources (last column) focus on enabling decentralised sources.

Interestingly, grid reinforcement receives little attention in the two analysed proposals and the Clean Energy for All Europeans package. Major policies for grid expansion were adopted in 2009 and are yet to be analysed for effectiveness.

3.1 Provisions in the proposed Electricity Market Regulation

Articles 18-24 tighten member states' freedom to devise capacity mechanisms. Capacity mechanisms would only be allowed where a European resource adequacy assessment has identified an adequacy concern. The proposal would oblige member states to allow cross-border participation (where possible). If adopted, the rules would affect the operation of existing mechanisms, potentially leading to necessary reforms for some of them.

Articles 49-53 propose an ENTSO-E counterpart for DSOs. Tasks would include the coordination of grid planning with TSOs and the development of demand response and smart grids. The new entity would be involved in drafting relevant new network codes and guidelines, similar to the current role of ENTSO-E.

Article 13 calls for a re-evaluation of bidding zones (or price zones). Bidding zones that contain structural congestions (i.e. transmission lines that are congested on a regular basis) would be revised by the European Commission based on a bidding zone review procedure[17] and a recommendation given by the affected TSOs.

Articles 14 and 15 provide a number of new rules to optimise the use of cross-border interconnectors. This includes a penalty for non-use of committed transmission capacity, pressure on TSOs to engage more actively in cross-border redispatch and counter-trading, and improved allocation of capacity across timeframes (including balancing).

Article 17 would tie congestion income to use for the operation of existing interconnectors and investment in new ones, based on a new methodology to be developed by ACER.

Articles 32-35 propose the establishment of regional operational centres (ROCs), which would coordinate tasks of regional relevance, including procurement of balancing capacities and coordinated capacity calculation for interconnectors.

Article 4 provides existing and new small-scale renewable generation an exemption from balancing responsibility.

[17] This procedure is defined in the already adopted regulation on capacity allocation and congestion management (COMMISSION REGULATION (EU) 2015/1222).

Article 5 would provide new common rules for balancing market design. Imbalances would need to be settled at marginal cost and real-time information on the balancing state and imbalance price would need to be published by TSOs.[18] Access to the balancing market for all market participants would be enshrined. Moreover, balancing energy auctions would need to be held after gate closure in the intraday market. The required balancing capacity would be procured regionally, separately for upward and downward capacity and would be contracted for a maximum period of one day.

Article 7 would set a mandatory imbalance settlement period and (minimum) time interval for market trading at 15 minutes by January 2025 for all EU member states.

Articles 9 and 10 would eliminate price limits in the wholesale market unless they represent the value of lost load (which is to be defined ex ante for each bidding zone).[19] Derogation would still be possible[20] for two more years. Moreover, if price limits (or value of lost load) are reached, they would have to be raised the following day.

Article 11 provides new limits for the priority dispatch of renewable energy, cogeneration and innovative technologies and a foundation. For the two former categories, priority dispatch is limited to installations smaller than 500kW.[21] Existing installations are exempt.

Article 12 states that market-based mechanisms have to be applied for curtailment and redispatch (including for cross-border transactions) and that compensation mechanisms should be put in place when fallback (non-market-based) procedures are used. For grid planning, a limit for the maximum amount of renewable energy and cogeneration to be curtailed is set at 5%.

3.2 Provisions in the proposed Electricity Market Directive

Articles 13 and 15 would entitle final customers to participate in the market both as generators and consumers and to engage with aggregators without the consent of their respective suppliers.

Article 17 exempts aggregators from compensation to suppliers, but gives member states the right to choose whether aggregators must compensate suppliers specifically for imbalances caused.

Articles 19-21 would oblige member states to implement smart metering, if a cost-benefit assessment defined by the European Commission were positive. Independent of the assessment, final customers would be entitled to have a smart meter installed at reasonable cost.

Article 11 would entitle final customers to a dynamic price contract.[22]

Articles 30-36 assign distribution system operators (DSOs) the role of neutral market facilitators for local ancillary services. DSOs would only be allowed to operate storage or EV recharging points if no other market option were available. Member states would need to enable non-discriminatory access to data from smart meters.

---

[18] This would give a stronger price signal for market actors to counteract the system's imbalance in real time.

[19] For negative prices, a limit can be set at €2000 per MWh.

[20] Based on Articles 41 and 54 of REGULATION (EU) 2015/1222.

[21] This limit is reduced over time and with increasing burden on the grid.

[22] Such a contract would allow customers to consume more flexibly based on changing prices throughout the day. See section 2.1.2.

4. Priority Areas

This Task Force has identified a number of priority topics that have emerged during debates at meetings and general EU policy discussions, e.g. in the European Parliament and the European Council. They are grouped into market design issues, which in this report describe a number of fundamental points and various other topics, summarised under 'other options'.

4.1 Market design

We focus here on three interrelated priority issues to unlock potential flexibility through proposed targeted reforms of electricity market design. These priorities were identified as being important controversial issues in the ongoing legislative process.

The proposed reforms seek to enable new entrants to offer flexibility services and will capitalise on the benefits of market-widening through inter-zonal market integration. The first priority issue is that national market designs will be aligned to a highly efficient pan-European target model. This is a prerequisite for efficient cross-border market integration, i.e. the second priority issue that calls for efficient harmonised solutions for the determination of bidding zone areas and the allocation of available interconnection capacity. The third priority is to enable a regulatory environment for the aggregation of potential flexibility services by small market participants.

4.1.1 Harmonising the design of short-term and real-time markets

In many member states significant progress has been made to align the market design of day-ahead markets. Notably in the Nordic countries and member states in the Central Western Europe (CWE) electricity market area, day-ahead and intraday markets based on bilateral trading, as distinct from a mandatory power pool model in Spain, for example. Another example is the Flow-Based Market Coupling (FBMC) project in 2015 (see Box 4.1). Cross-border day-ahead trading proceeds through an implicit day-ahead allocation mechanism where market participants bid simultaneously for the energy and availability of interconnector capacity. When the interconnectors between two countries (price zones) are congested the congestion fee per MWh is equal to the price difference between the two zones, which is just large enough for all transactions to be accommodated by the available capacity. The algorithm used for the FBMC project ensures a much better use of available cross-border transmission capacity than before this project went live. Recently, also the intraday market design of many member states is, *grosso modo,* converging. A similar integration of intraday markets will increase flexibility and help the integration of electricity from intermittent renewable sources. This would be helped by the further harmonisation of intraday market design among member states (gate opening time, gate closure time close to delivery time; trading time units etc.), based on a revisited target model that takes into account possible benefits from auctions. Auctions (e.g. an opening and closing auction) may enhance market efficiency complementarily to continuous trading by offering additional market design elements (price discovery, cross-zonal capacity pricing, energy pricing options).[23]

[23] Neuhoff et al. (2015); CE Delft and Microeconomix (2016).

Box 4.1 Successes of the day-ahead market

Day-ahead markets are based on auctions around 12:00h the day before for delivery in unit trading periods (60 or 30 minutes) the following day. Intraday markets are still at a fledgling stage based on continuous trading, partly using the central trading platforms of power exchanges. The most liquid intraday markets are provided by EPEX Spot and Nord Pool Spot. On top of continuous trading, EPEX Spot organises day-ahead auctions on 15:00h for delivery in 96 distinct Programme Trading Units (PTUs of 15 minutes) the next day. The gate closure of EPEX Spot is 30 minutes before delivery time as against 20 minutes before delivery time for Nord Pool Spot. A successful integration project of national DA markets is the Flow-Based Market Coupling project, to date involving 17 out of 28 member states, as well as Norway and Switzerland. This project allows for progress in the market efficiency of power markets in the cooperating countries, with significant improvements in the efficient use of interconnectors.

The fully fledged integration of national balancing markets, however, is still a remote prospect.[24] The harmonisation of the currently widely fragmented national balancing markets is a very complex process. It may be time-consuming to reach a pan-European consensus on a detailed, highly efficient target model for balancing markets and operational balancing philosophies, and to subsequently implement them. Meanwhile, various regional initiatives exist on cross-border balancing cooperation. In the Nordic region TSOs cooperate in the realisation of a Common Merit Order List (CMOL) for balancing energy, whereas reserve capacities are acquired per individual control area. Dutch TSO TenneT BV and Swiss TSO Swissgrid participate in the German FCR joint tendering procedure for, respectively, 35MW and 25 MW of Dutch and Swiss FRR demand. The tender is open for German and prequalified Dutch and Swiss bidders. As from 1 August 2016 and early 2017, respectively, Belgium TSO Elia and French TSO RTE joined this cross-border activity as well.[25]

Box 4.2 Introduction to the balancing market

A balancing market encompasses the entirety of institutional, commercial and operational arrangements that establish a market-based management of balancing. TSOs are responsible for maintaining the system frequency within a predefined stability range (around 50 Hz in the synchronous area of Central Europe), balancing supply and demand in their respective control areas and ensuring resource adequacy in longer timeframes at the lowest cost for system users (generators and consumers). Each TSO acts as a single buyer in his control area, buying specified balancing services (products) from balancing service providers (BSPs). BSPs are pre-qualified by the TSO on their ability to deliver specific balancing services. The balancing market consists of a market for balancing (reserve) capacity and a market for balancing energy. BSPs offering balancing capacity bring out a bid for availability of a certain level (kW) of reserve capacity for an agreed duration in combination with a price bid for balancing energy upon activation by the TSO. To date, in most member states, BSPs contracted for delivery of balancing capacity are allowed to update their balancing energy bid. Moreover, in several member states non-contracted BSPs can submit balancing energy bids close to delivery time without receiving availability compensation.

The size of the most flexible reserves, Frequency Containment Reserves (FCR) with full activation within 30 seconds, is determined by a UCTE (i.e. present-day ENTSO-E) agreement on a certain pro rata allocation of 3000 MW among the pertinent control areas of the synchronous area of Central Europe. The contracted FCR units will provide automatic positive (negative) balancing services when the frequency deviates negatively (positively) from the nominal value of 50 Hz in order to re-stabilise the frequency. In such a frequency deviation event the TSO will immediately activate contracted Frequency Restoration Reserve units, with a maximum full activation time of 15 minutes, to relieve the FCR units and to bring back the system frequency to its nominal value as well as to minimise the

[24] See Box 4.2 for a brief introduction to the balancing market.

[25] TenneT (2017), "Market Review 2016", Arnhem, March.

Area Control Error. Most FRR units are activated automatically by the TSO (FRR_a), some are activated manually (FRR_m) by the installation owned after a telephone call by the TSO. When necessary or financially more attractive, the least flexible reserves, i.e. the Replacement Reserves with an activation time up to several hours, will be activated to replace – if and when possible – the FCR units until the frequency has stabilised at its nominal setpoint and system balance has stabilised.

Since the market liberalisation started in the 1990s, TSOs in each member state dealt with balancing consumption and generation and supply reliability in their respective control areas by introducing national balancing mechanisms with widely diverging features along a long list of design parameters. Only recently has attention been paid by organisations such as UCTE / ENTSO-E and ACER to developing guidelines and a network code for electricity balancing, aimed at converging national balancing arrangements to a cost-efficient, harmonised target model. Major efforts are needed to harmonise the designs of the national balancing markets to enable cross-border exchanges of balancing energy and joint procurement of balancing capacity. This, in turn, will bring high cost savings and improve supply security, including risk preparedness.

Another example is the inter-TSO cooperation between the four German TSOs, building on the same design of balancing markets, which was stipulated by the German regulator. According to Consentec (2014), this cooperation encompasses i) the cost-optimised deployment of FRR and RR using common merit order lists; ii) a joint dimensioning procedure of the control reserve of areas involved,[26] iii) a joint tendering procedure, enabling partly or entirely common tendering of control reserve. This means that balancing reserves in a certain control area can be deployed by any one of the four TSOs, as long as technical restrictions are observed.

National electricity markets were originally designed under circumstances different from today's in terms of market actors, available generation and storage technologies, demand response, as well as different energy and climate objectives. Therefore, many market design elements must now be updated to the new circumstances. Such elements include the resolution of the trading time units, the minimum size of electricity products, the duration of availability periods and activation periods of balancing capacity products and the symmetry of balancing requirements. Progress would be to base reforms in national electricity market designs on a set of over-arching design principles, including the following three principles:

1. *Consistent configuration of sequential market segments*. Day-ahead, intraday and real-time markets are best designed in a mutually consistent way, facilitating good market functioning[27] (Smeers, 2008; van der Welle, 2016; CE Delft and Microeconomix, 2016)
2. *Inclusiveness*: All market participants, large and small ones, and technologies can compete in all market segments on a non-discriminatory basis (including distributed resources and intermittent renewables)
3. *Appropriate price determination and timely price discovery.* Timely discovery of prices of electricity products that closely reflect their real value including their inherent value of flexibility.

The first principle follows from the observation that day-ahead, intraday and real-time are just different steps of a single trading process (Smeers, 2008). The trading process ends with delivery in real time based on transactions concluded before real time. After market participants have submitted to the TSO, their respective final (net power injection or withdrawal) positions, the TSO has to balance on a second-by second basis aggregate power injections and withdrawals in his control area[28] and maintain the system frequency within a narrow stability range. Hence, the

[26] This procedure enables portfolio effects to be taken into account, which reduces the demand for control reserve in case of forecast failures and enables the network integration of variable renewables at lower pan-German costs.

[27] We focus on short-term timeframes, but the forward market will have to adapt to this principle as well.

[28] That is, the TSO must continually minimise his area control error.

balancing energy market is the residual real-time market with the most flexible, and therefore scarce and expensive, balancing energy providers on the supply side. At the same time, the balancing energy price tends to show the highest price volatility. Due to these reasons, the balancing energy market may provide the best flexibility-inclusive price signal to traders in preceding market segments (ID, DA). DA market participants (or their delegated balance responsible parties) have to submit schedules of their planned net injections or withdrawals to the TSO based on their day-ahead electricity transactions. In the intraday market, market participants have the chance to rebalance their portfolio close to real time their net injections/withdrawals in line with their final schedules. Market participants that have the possibility to operate in two or even three of these markets will seek to optimise their transactions through arbitraging.

In the Clean Energy package, the European Commission proposes some important first steps to meet this requirement, e.g. the proposal to harmonise the programme time unit (PTU),[29] to 15 minutes across the EU. This duration is equal to the shortest PTU applied in the EU to date and dominates across member states in the CWE area. A shorter PTU helps TSOs and market participants to control the balancing process and their imbalance positions, particularly as generation and consumption become more volatile (steeper ramps, larger forecast errors etc.). Another important element would be to harmonise market time units in DA and ID markets in line with the proposed harmonisation of the PTU, i.e. to 15 minutes.[30] A third element would be the harmonisation of the duration of all basic products in DA, ID and in real time, i.e. to 15 minutes in all market segments.[31] These reforms would remove entry hurdles for many technologies to become active in the balancing market.

The possibility of multi-part bids was mentioned in the Task Force and continues to be play a role in debates on future market design. In combination with developed algorithms, such bids can take into account additional parameters like ramping rates and minimum load for clearing the market.[32]

The second principle seeks a level-playing-field in electricity market design for all market players and technologies. In fact, harmonising the duration of basic products in all electricity market segments to a relatively high-resolution (15 minutes) period is consistent with both the first and the second principle. Other applications of this principle include:

- Reduced capacity size requirements as prequalification of market participants for the provision of balancing services.
- Shorter lead times for reserve capacity auctions. From a grid operation perspective, long lead times increase the certainty to have sufficient capacity at hand to address very adverse security contingency scenarios. From a cost perspective, long lead times can be inefficient, because they tend to result in higher bids (due to opportunity cost considerations by the bidders) and can exclude certain market players.[33] On the other hand, a cost-efficient reserve might include a portion of long-term contracts or a secondary market for hedging financial risks. Taking this into account, a large efficiency potential for reducing lead times likely remains.

[29] Also referred to as imbalance settlement period.

[30] For example, a common PTU will reduce "schedule lags" during the morning and evening ramps starting out from a situation of hourly day-ahead trading and 15-minutes PTUs in BE markets. See L. Hirth and I. Ziegenhagen (2015), "Balancing Power and Variable Renewables: Three Links", paper submitted to Renewable & Sustainable Energy Reviews, Berlin, March.

[31] Some stakeholders do not see this as necessary.

[32] K. Neuhoff, N. Ritter, A. Salah Abou El-Enien and P. Vassilopoulos (2016), "Intraday Markets for Power: Discretizing the Continuous Trading?", DIW Discussion paper No. 1544, Berlin.

[33] For these reasons, and due to pressure from energy regulators, a tendency towards shortening forward periods of reserve capacity auctions is noticable, e.g. in Germany and the Netherlands.

- Separate procurement of upward and downward balancing capacity would lower entry barriers e.g. for wind power. Currently existing requirements for symmetric capacity provision, which require participants to be capable of increasing and decreasing their output at any given time, cannot be complied with by renewable generators and can constitute an undue distortion.
- Removing barriers to market-based aggregation services would enable e.g. participation of retail-level demand response
- Balancing energy auctions open to prequalified market players outside the balancing capacity reserve

Applications of the third principle relate to pricing, PTU regulation, availability of market information and intraday auctions.

4.2 Price zone revision, capacity allocation and congestion rents

Price zone revision

The European Commission's proposals include plans to adapt price zones to remove structural congestion in transmission grids. This includes an *ad hoc* revision of all price zones based on a defined procedure[34] as well as continuous revisions in the future. The proposal could lead to a number of bidding zones being split, effectively increasing the number of zones.

A nodal pricing system, i.e. a system with very high granularity of price zones, has been deemed the most efficient market model by a number of studies.[35] One underlying reason is a high resolution of locational price signals which can lead to efficient dispatch and investment. In principle, better locational price signals can be facilitated not just by decreasing the size of bidding zones, but also by implementing dynamic grid charges.

Increasing the number of bidding zones would affect many aspects of the electricity markets, including market efficiency, investment signals, distributional impacts (winners and losers), liquidity, issues of market power and costs of transitioning to the new structure.[36]

Arguments for and against increasing the number of price zones (along structurally congested lines) include:

Pros	**Cons**
• Better price signals for generation/consumption • Better price signals for investment in new capacity (including renewables and flexibility) • Lower cost for congestion management • Congestion rent as price signal for investment in grid capacity • Nodal pricing could be approached over time	• Distributional effects would disrupt the market (creating winners and losers) • Continued changes of pricing zones will create additional investment uncertainty. • Lower market liquidity would increase risk for abuse of market power • (Lack of structural congestion in complex markets would limit relevance of the approach)

[34] See Article 32 of Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

[35] K. Neuhoff, B. Hobbs and D. Newbery (2014), "Congestion Management in European Power Networks - Criteria to Assess the Available Options".

[36] Ofgem (2014), "Bidding Zones Literature Review".

As ACER data has repeatedly shown,[37] costs arising from congestions within price zones, including those for redispatch/counter-trading as well as unplanned flows and loop flows are significant. They can be expected to rise further, as the impact of geographically changing feed-in of intermittent renewables further increases in the coming decades. As the short-term cost of changing price zones could potentially offset long-term benefits, case-by-case analyses of short-term cost and long-term benefits might be required to assess the merits of changes in price zone make-up. At the same time, procedures and time-frame for the changes should take into account the needs of market participants. There is also a risk of market distortions resulting from liquidity issues and abuse of market power.

Cross-border capacity allocation for the intraday and balancing markets

To unlock the flexibility potential from market integration (see section 2.1.1), cross-border transmission capacity has to be made available in the intraday and balancing timeframes when efficient. As data collected by ACER shows,[38] past legislation has improved the capacity allocation in the day-ahead timeframe, leaving intraday and balancing much more inefficient[39].

A mechanism for optimising the allocation of capacity across the different timeframes could address this. Such a mechanism would depend on a sufficiently harmonised market design (i.e. an applied target model) and its concrete features. One study[40] suggests that capacity options should be applied in the day-ahead market in order to return unused capacity available to the intraday and balancing energy market. Similarly, a recalculation step for available capacity could be carried out before both timeframes. Another study suggests that in the mid-term, capacity allocation for balancing capacity and day-ahead market could be co-optimised in a single algorithm.[41]

Facilitating optimal grid reinforcement

Grid-reinforcement is the flexibility option least addressed in the European Commission's proposal, with only one relevant provision. The draft report by the ITRE Committee suggests removing this provision, which would limit congestion rents obtained by TSOs to be used for new investments into the grid.

Lack of market-based signals for investment into grid capacity is an important shortcoming in the economics of electricity grids. Internal congestions are compensated by redispatch and counter-trade (the cost for which are socialised) and system-beneficial investments are not appropriately incentivised.

Congestion rent as well as cost of congestion management within bidding zones are indicators that imply a continuing potential for new transmission lines which are both optimal with regard to social welfare and serving the increasing flexibility needs. This applies for both bidding zone borders between and within member states. If price zones run along structurally congested lines (as proposed by the European Commission), price differentials between bidding zones generate a congestion rent, which is, in theory, a price signal for grid investment. However, congestion rent only measures the present level of congestion, while investment in new transmission capacity depends on long-term economic situations (10-15 years). A present congestion rent can be reduced much quicker (but less efficiently) by installing flexible generation on the good side of the congestion.

---

[37] ACER/CEER (2016), "Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015 September 2016".

[38] ACER (2016), "ACER Market Monitoring Report 2015 - KEY INSIGHTS AND RECOMMENDATIONS".

[39] Efficiencies of day-ahead, intraday and balancing allocation is 84%, 54% and 10% respectively.

[40] A. van der Welle (2016), "Required adjustments of electricity market design for a more flexible energy system in the short term".

[41] THEMA (2014), "Reservation of cross-zonal capacity for balancing services".

Additionally, the main problem for grid investment is often not a question of finance, but of local acceptance for steel towers. Existing EU policies for grid reinforcement include (since 2009) planning by ENTSO-E[42] as well as access to EU co-funding of interconnectors as "Projects of Common Interest". As these measures are already being implemented, the "Clean Energy for All Europeans" package does not focus on reform of these approaches.

4.2.1 *Aggregation*

The European Commission proposal has given aggregation a prominent position, aiming to facilitate this future role as enabling decentralised flexibility and demand response. A number of stakeholders have criticised these provisions, arguing for a level playing field and against special privileges for aggregators.[43] In the European Parliament's report, amendments to the proposals modify rules for aggregation.[44]

The controversy revolves around compensation to be paid by aggregators to electricity suppliers and the negative implications of aggregating demand from customers without informing their suppliers. On the one hand, independent aggregators can unduly benefit from (indirectly) selling energy procured by the supplier. On the other, influencing customers' consumption behaviour often leads to unforeseen imbalance costs for suppliers, due to a different load curve from the one used by the supplier for sourcing its electricity.

Compensation for sourcing energy

When aggregators act as sellers in the wholesale or balancing market, the energy sold is indirectly sourced from suppliers' energy meant to be delivered to consumers. As consumers neither consume nor pay for this energy based on the retail price, suppliers are not remunerated for it. Instead, the aggregators receive remuneration for the same energy from the wholesale or balancing market. Since they sell energy they have not procured, aggregators should pay compensation for the energy concerned and assume balancing responsibility. Otherwise, they would benefit from an indirect subsidy, since the cost of procuring energy would be socialised among all customers of the supplier, risking negative social welfare effects.

In France, there is a rule for payments from aggregators to suppliers for the energy resold. This rule has been upheld in court after being challenged by aggregators. France's aggregation market has now developed mainly for larger consumers (which can aggregate higher volumes at similar cost) and less for smaller consumers (like households). Given the decreasing cost for the needed ICT and improvements in standardisation, market penetration is increasingly likely to reach smaller customers.

Removing barriers for aggregation

In many European markets, including day-ahead, intraday (plus other wholesale segments) and balancing markets, there are still considerable barriers for aggregation. Regulatory arrangements to facilitate participation in all market segments currently only exist in France.[45] An initial priority would therefore be to adopt such arrangements to enable participation of aggregation, based on the principle of non-discrimination, in all wholesale and balancing market segments.

---

[42] ENTSO-E's Ten-Year Network Development Plan (TYNDP) assesses transmission grid expansion needs for reaching EU policy objectives based on cost-benefit analysis. According to the TYNDP 2016, currently planned transmission grid reinforcement would cost 1-2€/MWh (as a surcharge on each MWh of electricity consumed in the EU) while reducing wholesale prices by 1-5€/MWh.

[43] H. Ziegler, T. Mennel and C. Hülsen (2017), "Demand Response Activation by Independent Aggregators As Proposed in the Draft Electricity Directive".

[44] See Amendment 17&18 of European Parliament Draft Report 2016/0380(COD).

[45] CE Delft and Microeconomix (2016), "Refining ShortTerm Electricity Markets to Enhance Flexibility", study on behalf of Agora Energiewende.

The state-aid guidelines provide rules for the treatment of demand response in relation to capacity remuneration mechanisms and take the role of ensuring non-discriminatory treatment of aggregation (as a form of demand response).

Independent Aggregators

Aggregation is a service that pools demand response load and directly trades in the energy market on behalf of retail customers. This service enables retail customers to overcome barriers to entering the wholesale and balancing markets. Aggregation can be carried out both by independent aggregators, as well as by retail suppliers (which may themselves procure their energy in the wholesale market and/or produce their own electricity). Based on a level playing field, independent aggregation and aggregation by suppliers should both be possible.

Balancing Compensation

That all market participants should bear a financial responsibility for adhering to their scheduled generation and consumption is uncontroversial. When aggregators are market participants (both in wholesale markets, balancing markets or ancillary services), they should bear this financial responsibility, i.e. to face imbalance charges if ex post analysis shows that there was a deviation from the aggregator's submitted schedule in a given time interval.

A different issue is compensation from aggregators to suppliers when the latter face imbalances that were caused by the aggregator. Since aggregators incentivise contracted consumers to change their consumption behaviour, suppliers will likely face increasingly uncertain load curves and therefore increasing imbalance costs. The European Commission's proposal grants member states the option to enforce compensation from aggregators to suppliers in this case.

4.3 Other Options

4.3.1 Priority dispatch and curtailing

Support schemes and other policies benefiting renewable energy sources are currently justified by the decarbonisation policy objective. Ideally, they would also be designed to minimise market distortions and provide maximum incentive to efficiently integrate into the electricity system. Inversely, changes to the market design should facilitate integration of renewables into the market.

Currently, renewable generation (and high-efficiency cogeneration) is subject to priority dispatch, i.e. these sources are curtailed last and only if their output is a threat to the system's stability and cannot be compensated otherwise. The European Commission's proposed new Electricity Market Regulation limits priority dispatch to existing as well as small new installations (see section 2.2). The proposal includes new rules that call for market-based curtailment (to be the new non-discriminatory norm for curtailment procedures). It specifies that in emergency deviations from this rule, cogeneration and renewables are meant to be curtailed last. Moreover, in such cases all plants would be compensated.

The priority access rule, which gives renewables the benefit of being the last technology curtailed, can lead to a higher system cost, since renewables are often the most efficient curtailment option. However, given the long-term perspective of a growing share of renewables feeding into the grid, provisions are needed that incentivise system operators to accommodate these renewables. In the absence of other policies, eliminating priority access may lead to the increasing curtailment of renewables. Moreover, other market participants (including inflexible 'must-run') capacities would lack the pressure to optimise their flexibility potential.

Removing the priority access benefit for renewables might hamper the evolution of the electricity system, at least in the absence of other policies incentivising system operators to integrate higher shares of renewables.

WindEurope argues that the removal of priority dispatch for new installations should be accompanied by provisions to ensure that renewables have access to all market segments (including balancing and congestion management). Moreover, WindEurope favours the inclusion of feed-in premiums or certificates in downward balancing energy prices (opportunity cost considerations). One important underlying reason is that the renewables' support scheme-based remuneration is tied to the actual output of the plants. Thus, deliberate non-generation would result in reduced revenue. However, with the evolution of support scheme design,[46] participating in negative balancing should become increasingly feasible for renewable installations.

In some member states, wind generators already participate in balancing markets as downward regulation[47] and there is at least one case of upward regulation (in Spain).[48] In most markets progress is still needed. Indeed, separate markets for upward and downward balancing lead to lower entry hurdles for variable renewables.

In any case, curtailment, redispatch and other decisions taken by the TSO in real time should be subject to increased transparency. This would give market participants better information on what to expect in certain situations and incentivise TSOs to act responsibly.

4.3.2 *Role of DSOs*

By far most of the new renewables-based generation capacity is and will continue to be connected to the distribution grid. In some member states more than 90% of electricity produced by wind and solar is integrated at Distribution System Operators (DSOs) level. Flexibility (e.g. by demand response, electricity storage and decentralised generation) provided at the DSO level to both the DSO and TSO level adds to this challenge, particularly when aggregated.

To date, TSOs have carried the main responsibility for keeping the electricity system in balance. DSOs, on the other hand, have largely focused on maintaining and operating the distribution grid, as well as collecting metering data from the consumer side.

The changes outlined above are likely to require new roles and responsibilities for DSOs. It is likely that additional data on consumption patterns and electricity prices have to be interchanged between the DSOs, TSOs and the wholesale/retail market agents. For example, in the case of aggregation, the actual feed-in or consumption impact from the aggregators' actions has to be calculated, by comparing the load curves of their customers to a hypothetical reference curve. EU-level rules should ensure a level playing-field for aggregators. Member state-level rules for the calculation of aggregators' net generation/consumption balance should be monitored by ACER. In addition, DSOs need data access to the actions of aggregators to actively and securely manage their system operation.

While aggregation of customers at the DSO level constitutes a substantial flexibility source, it increases complexity of grid operation. Sudden changes of load might cause new problems in the distribution grid, as might flows intended for the TSO level balancing. Operation without pre-notice may cause unexpected congestion at different levels of the grid.

Better cooperation between TSOs and DSOs would increase operational security and system-wide cost-efficiency. This should include communication standards, coordinated calculation/operation of grid capacities, a shared pool of flexibility reserves and network planning.

Another issue is the technical need for sufficient grid resilience and flexible resources accessible to DSOs in order to fulfil their role as neutral market facilitators. Generally, DSOs and TSOs should only own or operate assets that are needed for secure system operation to ensure their independence from the market.

---

[46] In Denmark, support is granted for a certain number of full load hours, so that generators are incentivised to provide flexibility in the market.

[47] WindEurope (2016), "WindEurope views on curtailment of wind power and its link to priority dispatch".

[48]See https://www.acciona.com/news/acciona-energia-pioneer-providing-electric-power-system-adjustment-only-using-wind-power/.

Lastly, variable tariffs could be a tool to avoid inefficient investment in hardware and to ensure that network costs are covered.

4.3.3 *Sectoral integration*

The market is developing stronger links between the heating/cooling, electricity and transport sectors and the different energy carriers used therein (gas/liquid fuel, heat, electricity). This sectoral integration has potential benefits for flexibility, decarbonisation and security of supply, but also challenges.

An open question is about the roles of governments, which may be inclined to pursue specific options. This risks creating market distortions. That the market framework should be developed in such a way that consumers will be able to optimise their use of different energy sources is undisputed.

Sectoral integration offers flexibility by allowing the optimal use of various energy carriers and infrastructures. It can also provide storage solutions for heating and cooling, both in the short term and seasonally, which is a challenge arising from increasing electrification. Solutions exist in power-to-X technologies, e.g. power-to-gas and power-to-heat (see Annex 1).

Power-to-gas refers to a group of technologies aimed at converting electricity to hydrogen and/or carbon-based fuels. The process of electrolysis consumes power to generate hydrogen from water. This hydrogen can then be stored, used in direct hydrogen applications (for industrial production or energetic conversion, e.g. in fuel cells) or used to synthesise substitute natural gas and transport fuel.

Since heat can be stored and used at a different point in time (with losses), electric heating can be operated flexibly if a thermal storage tank is available. Technologies include conventional electric heaters and heat pumps, as well as hybrid heat pumps. The same concept holds true for electric cooling.

Electric heating and cooling is widely applied in households, businesses and industrial processes. While some companies already provide balancing services to the grid (see demand response section), a large potential on the business and household scale could be unlocked by making electric heating and cooling installations more flexible and by providing access to a market platform or aggregation.

Electrification

Increasing electrification of the heating sectors faces the challenge of seasonal storage for heating. The heating sector currently relies on natural gas as a medium that is stored seasonally. PV and wind power would not be able to provide the same amount of supply security in winter months, particularly in cold winters. Unless accounted for, this is a potential crisis factor.

Box 4.3 Electrification

Energy is consumed in three end-use sectors: buildings (for heating and cooling), transport and industry. Increasing generation of solar and wind power will lead to excess electricity when the sun is shining and the wind is blowing. At these points in time, electricity will be inexpensive on wholesale markets and therefore increasingly used to generate heat in buildings and industry. Electricity in transport is another important avenue. Electricity is already used largely in trains and trams, but is likely increase to electric bicycles, motor cycles and cars. As more consumers use electric vehicles, the need for smart charging adapted to wholesale power prices and the provision of vehicle-to-grid (V2G) flexibility will grow.

REFERENCES

ACER (2016), "ACER Market Monitoring Report 2015 - KEY INSIGHTS AND RECOMMENDATIONS".

ACER/CEER (2016), "Annual report on the Results of Monitoring the Internal Electricity Markets in 2015".

Agora Energiewende (2017), "Flexibility in thermal power plants – With a focus on existing coal-fired power plants".

Apt, J. and P. Jaramillo (2014), "Variable Renewable Energy and the Electricity Grid".

Bertuccioli, L., A. Chan, D. Hart, F. Lehner, B. Madden and E. Standen (2014), "Study on development of water electrolysis in the EU".

CE Delft and Microeconomix (2016), "Refining Short-Term Electricity Markets to Enhance Flexibility", study on behalf of Agora Energiewende.

Elmegaard, B. and W. Brix (2011), "Efficiency of Compressed Air Energy Storage".

Eurelectric (2011), "Hydro in Europe, Powering Renewables".

European Commission (2017a), "Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in energy (recast)", COM(2016) 864 final/2.

European Commission (2017b), "Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity", COM(2016) 861 final/2.

Fraunhofer IWES (2015), "The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region", analysis on behalf of Agora Energiewende.

Genoese, F., E. Drabik and C. Egenhofer (2016), "The EU power sector needs long-term price signals".

Götz, M. et al. (2015), "Renewable Power-to-Gas: A technological and economic review".

Hirth, L. and I. Ziegenhagen (2015), "Balancing Power and Variable Renewables: Three Links", *Renewable & Sustainable Energy Reviews*, Berlin, March.

IEA (2012), "Technology Roadmap Hydropower".

International Energy Agency (2017), "Tracking Clean Energy Progress: 2017".

Luo, X., J. Wang, M. Dooner and J. Clarke (2015), "Overview of current development in electrical energy storage technologies and the application potential in power system operation".

Neuhoff, K., B. Hobbs and D. Newbery (2014), "Congestion Management in European Power Networks - Criteria to Assess the Available Options".

Ofgem (2014), "Bidding Zones Literature Review".

Perez Linkenheil, C., I. Küchle, T. Kurth and F. Huneke (2017), "Flexibility needs and options for Europe's future electricity system", study by Energy Brainpool for EUGINE.

REN21 (2017), "2017 Global Status Report".

SiaPartners (2014), "Demand Response – A Study of its Potential in Europe".

Smeers, Y. (2008), "Study on the general design of electricity market mechanisms close to real time".

Smolinka, T. et al. (2011), "Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien".

TenneT (2014), "Market Review 2014 H1", Arnhem, September.

TenneT (2017), "Market Review 2016", Arnhem, March.

THEMA (2014), "Reservation of cross-zonal capacity for balancing services".

van der Welle, A. (2016), "Required adjustments of electricity market design for a more flexible energy system in the short term".

WindEurope (2016), "WindEurope views on curtailment of wind power and its link to priority dispatch".

Ziegler, H., T. Mennel and C. Hülsen (2017), "Demand Response Activation by Independent Aggregators As Proposed in the Draft Electricity Directive".

REVIEWED LITERATURE

ACER (2015), "Annex II to Recommendations of the Agency for the Cooperation of Energy regulators No 03/2015 0f 20 July 2015 on the network Code on Electricity Balancing".

Baker, P. (2016), "Benefiting Customers While Compensating Suppliers: Getting Supplier Compensation Right", Regulatory Assistance Project Policy Brief.

Booz & Company (2011), "Physical and financial transmission rights for cross-border trade".

Borggrefe, F. and K. Neuhoff (2011), "Balancing and Intraday Market Design: Options for Wind Integration".

CEER (2016), "Principles for valuation of flexibility - Position Paper. Flexibility Task force".

Chaves-Avila, J.P, R.A. Hakvoort and A. Ramos (2014), "The Impact of European balancing rules on wind power economics and on short-term bidding strategies", *Energy Policy*, Vol. 68 (2014), pp. 383-393.

Consentec (2014), "Description of load-frequency control concept and market for control reserves".

de Heer, H., M. van der Laan et al. (undated), "USEF: Workstream on aggregator implementation models", USEF Aggregator Workstream final report C&I segment.

Erbach, G. (2016), "Understanding electricity markets in the EU. Briefing", European Parliamentary Research Service.

ERGEG (2008),"Firmness of nominated transmission capacity", Report E08-EFG-29-05.

Hirth, L. and I. Ziegenhagen (2013), "Control Power and Variable Renewables: A Glimpse at German Data", paper submitted to the 10th International Conference on the European Energy Market, Stockholm.

Mott MacDonald/SWECO (2013), "Impact Assessment on European Balancing Market".

Neuhoff, K., B.F. Hobbs and D. Newberry (2011), "Congestion Management in European Power Networks; Criteria to Assess the Available Options".

Neuhoff, K., C. Battle, G. Brunekreeft, C. Vasilaikos Konstantinidis, C. Nabe, G. Oggioni, P. Rodilla, S. Schwenen, T. Siewierski and G. Strbac (2015), "Flexible Short-term Power Trading: Gathering Experience in EU Countries".

Neuhoff, K., N. Ritter, A. Salah Abou El-Enien and P. Vassilopoulos (2016), "Intraday Markets for Power: Discretizing the Continuous Trading?".

PJM Interconnection (2017), "Demand Response Strategy".

Pöyry (2011), "The challenges of intermittency in North West European power markets".

Pöyry (2014), "Revealing the value of flexibility. How can flexible capacity be rewarded in the electricity markets of the future?".

SGTF-EG3 (2015), "Regulatory recommendations for the Deployment of Flexibility", Report of the Expert Group 3 of the Smart Grids Task Force.

Slot, T. and H. Dijk (2015), "Options for future Electricity System Operation", Ecorys-DNV_GL-ECN report commissioned by EC DG ENER.

TenneT (2011), "Imbalance management TenneT".

van der Veen, R. and R. Hakvoort (2016), "The electricity balancing market: exploring the design challenge", *Utilities Policy*, Vol. 43, pp. 186-194.

van der Welle, A. (2017), "Required adjustments of electricity market design for a more flexible energy system in the short term".

Ziegler, H., T. Mennel and C. Hülsen (2017), "Short study on Demand response Activation by Independent Aggregators as Proposed in the Draft Electricity Directive", DNV-GL report on behalf of EURELECTRIC.

ANNEX 1: OVERVIEW OF FLEXIBLE GENERATION, CONSUMPTION AND STORAGE TECHNOLOGIES

A.1 *Flexible generation*

Parameters characterising a generation technology's level of flexibility include:

- Minimum load (the lowest percentage of nominal output to which a plant's production can be reduced and operated economically)
- Ramp rate (the speed with which a plant can increase or decrease its production)
- Start-up time (the time needed for a plant to change from idle state to production; differs between hot and cold idle state)

For each technology, these parameters exist in different ranges and can depend on the specific case of each installation. Production units can be specifically engineered and operated with higher flexibility, which however increases investment and/or production cost. Existing plants can be retrofitted for improved flexibility.

Thermal power plants

Thermal power plants, including electricity generation from natural gas, hard coal, lignite, biomass and nuclear, are able to provide flexibility to varying degrees.[49] The table below shows typical parameters for different technologies.[50]

	OCGT	CCGT	Hard coal	Lignite	Engine power plants	
Minimum load	40–50%	40–50%	25–40%	50–60%	Close to zero	Commonly used
Average ramp rate (per minute)	8–12%	2–4%	1.5–4%	1–2%	20% - 50%	
Start-up time	5–11 min	60 min - 4 h	2.5–10 h	4–10 h	2-5 min	
Minimum load	20–50%	20–40%	25–40%	35–50%	Close to zero	State of the art
Average ramp rate (per minute)	10–15%	4–8%	3–6%	2–6h%	50%	
Start-up time	5–10 min	30 min - 3h	80 min - 6 h	1.25 – 8 h	2 min	

Natural gas-fired plants, which exist based on gas turbines and combustion engines, are the most flexible. Open-cycle gas turbines (OCGT) and engines are more flexible than combined-cycle plants, while the latter are more efficient.

Biogas plants have similar flexibility to natural gas plants, but are typically smaller and more decentralised.[51]

CCGT, hard coal and lignite plants have considerable flexibility potentials to be gained by state-of-the-art technologies (see table above). A drawback can be increased strain on components, increasing the lifetime of components and thus the cost of operation.[52]

[49] Renewable thermal power plant technologies separately discussed.

[50] Source: EUGINE and Agora Energiewende (2017), "Flexibility in thermal power plants – With a focus on existing coal-fired power plants".

[51] The aggregator Next Kraftwerke facilitates participation of biogas plants in the German balancing market.

[52] Agora Energiewende (2017), "Flexibility in thermal power plants – With a focus on existing coal-fired power plants".

Nuclear power capacities have been shown to possess a technical flexibility potential in France.[53] The ramping rate is comparable to coal-fired power plants, while the start-up time can be up to 2 days (compared to 3-6 hours for coal plants).[54]

Renewable thermal power plant technologies, i.e. geothermal and solar thermal electricity generation can be operated flexibly. A number of existing solar thermal plants operate heat storage, which enables generation during night time.

The large number of existing thermal power plants across the EU and the option to retrofit hold a very large flexibility potential. While hard coal and lignite plants are under pressure due to decarbonisation policies, they may be a viable flexibility option for the mid-term. Absolute emissions could be reduced due to lower production time being necessary for flexible operation.

Hydro power

Hydro power is divided into three technology categories: run-of-river plants, reservoir plants and pumped-storage plants. Each possesses different flexibility characteristics. Importantly, pumped storage can provide both flexible generation and consumption. Reservoir hydropower is restricted to generation flexibility. Run-of-river plants hydropower can only provide limited short-term flexibility.

According to an IEA report,[55] only 47% of the technical hydro potential in Europe is currently used, suggesting considerable unused potential. However, the economically feasible potential can be considered to be significantly lower. The report expects 61GW of new capacity by 2050.

Start-up time and ramping rates are normally lower for hydro power than for gas turbines,[56] but can be subject to environmental restrictions.

The availability of flexibility from hydro plants is limited by their availability of water, which depends on the size of reservoirs, amount of water inflow (daily, monthly, seasonally varied) and reserved safety margins. Many units need to be operated cooperatively with other stations in the same river system.

Type	Characteristics
Run-of-river Hydro Power	• Little or no storage capacity • The generation profile depends on the available water flow • Some short-term flexibility possible
Pumped-Storage Hydro Power	• Water is cycled between a lower and upper reservoir. • Electricity storage, acts like a battery • 70-80% roundtrip efficiency[57]
Reservoir Hydro Power	• A dam is used to store water in a reservoir • Can generate flexibly within technical and regulatory limits • Can provide seasonal flexibility

[53] Within one week the total nuclear output has been observed to vary by up to 17GW (27% of 63GW installed capacity).

[54] Fraunhofer IWES (2015): "The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende".

[55] IEA (2012), "Technology Roadmap Hydropower".

[56] Ramping rates can be 40% of nominal output per minute (VGB/EURELECTRIC study on technical flexibility of power plants (Eurelectric: Hydro in Europe, Powering Renewables, 2011).

[57] IEA Hydropower Technology Roadmap: Hydropower.

A.2 Flexible consumption/energy storage

Any given imbalance in the electricity system can be balanced not only by adapting generation flexibly, but also by adapting consumption. Traditional flexible consumption resources used today include pumped-hydro storage and disruptible loads in the industry (see section 2.2.3).

In principle, flexible consumption can be enabled implicitly, i.e. through dynamic pricing, or explicitly, i.e. by participation in the balancing market either directly or enabled by aggregation.

Power-to-gas

Power-to-gas refers to a group of technologies aimed at converting electricity to hydrogen and/or carbon-based fuels. The process of electrolysis consumes power to generate hydrogen from water. This hydrogen can then be stored, used in direct hydrogen applications (e.g. for industrial production or in transport) or used to synthesise substitute natural gas and transport fuel.

While electrolysis is used around the world to produce hydrogen, the application as a provider of flexibility in the grid is still at an earlier stage.[58] A key requirement for this purpose is to adapt systems from the traditional continuous operation to dynamic start-up and ramping behaviour. According to a study from 2014, a number of manufacturers have solutions at hand for dynamic system design with ramp rates of up to 100% per second in their labs. However, effects of fast ramping regimes on system lifetime are not yet well documented.[59]

Since electrolysers can achieve higher efficiency when operating at part load, one operation strategy is to operate at part load and to offer both positive and negative balancing services to the grid. Bertruccioli et al. (2014) suggest that such a strategy might become increasingly viable.

Depending on the subtechnologies applied, the conversion efficiency for electrolysers is 60-80%.[60] Converting the hydrogen to substitute natural gas or liquid fuel reduces the efficiency to 55% (not accounting for usable heat).[61]

Power-to-heat/cold

Since heat can be stored and used at a different point in time (with losses), electric heating can be operated flexibly if a thermal storage tank is available. Technologies include conventional electric heaters and heat pumps. The same concept holds true for electric cooling. While some industrial players already provide balancing services to the grid (see demand response section), a large potential on the business and household scale could be unlocked by providing access to a market platform or aggregation (see section 2.1.3).

Hybrid heat pumps for households, e.g. devices which include both a gas-fired (condensing) boiler and an electric heat pump, are a promising technology which is increasing in sales. They enable higher flexibility of households by (smart) arbitrage between electricity and gas prices. More households switching to electric heating and cooling is an example of sectoral integration.

[58] Uniper is operating two pilot plants in Hamburg and Falkenhagen, Germany. The latter injects hydrogen into the high-pressure network operated by ONTRAS Gastransport and will be enhanced by a methanation plant producing synthetic natural gas in 2018.

[59] L. Bertuccioli, A. Chan, D. Hart, F. Lehner, B. Madden and E. Standen (2014), "Study on development of water electrolysis in the EU".

[60] T. Smolinka et al. (2011), "Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien".

[61] M. Götz et al. (2015), "Renewable Power-to-Gas: A technological and economic review".

A.3 Electricity storage

Electricity storage can both consume and generate electricity flexibly. Next to pumped-hydro storage (see section 2.1.1), which is the storage technology most widely deployed by far, other technologies are emerging.

According to an IEA report,[62] out of 3.4GW non-hydro storage capacities deployed in 2016, 53% were battery solutions, with lithium ion batteries contributing much more than other battery technologies (lead acid, redox-flow, nickel-cadmium, sodium-sulphur). Flywheels and compressed air energy storage (CAES) contributed 28% and 19% respectively. The majority of projects were launched or coordinated by grid operators either to meet specific ancillary services needs or as demonstration plants, i.e. not based on price signals in wholesale markets.

Batteries

Most battery systems can be switched on (to full load) within milliseconds, which renders them highly flexible.[63] Installed global capacity of grid-connected batteries has increased by 700% since 2006, with a 50% capacity increase in 2016.[64] A variety of battery technologies is applied, with lithium-ion batteries currently seeing the bulk of capacity additions.

Lithium-ion batteries achieve the highest cycle efficiency of 75-97%. Other technologies range between 60 and 90%.

Their scalability makes batteries well suited to a large array of applications and locations in the energy system, including kW[65] and MW[66] scales. They can be used for self-consumption or coordinated with generation technologies and the grid e.g. by aggregation.

Compressed Air Energy Storage (CAES)

CAES has been demonstrated to be a viable concept and several new (subsidised) plants are planned in the United States and Europe.[67] The technology can utilise salt caverns to consume electricity by storing compressed air. This air can afterwards be used for electricity generation through air turbines or in combination with gas turbines. Start-up time is typically 7-10 minutes and ramping rates are 20% per minute (compression) and 100% per minute (decompression).[68] While plants currently in operation have efficiencies below 45%[69], technological developments could push to exceed 70%.[70]

[62] International Energy Agency (2017), "Tracking Clean Energy Progress: 2017".

[63] X. Luo, J. Wang, M. Dooner and J. Clarke (2015), "Overview of current development in electrical energy storage technologies and the application potential in power system operation".

[64] REN21, (2017), "2017 Global Status Report", Paris: REN21 Secretariat.

[65] The Tesla power wall is a well-known household scale product meant to enable self-consumption by prosumers.

[66] A 10MW lithium ion battery plant in Feldheim, Germany, provides ancillary services to TSO 50 Hertz. The project was co-funded by the European Regional Development Fund.

[67] The EU is co-funding a CAES plant in Larde, Northern Ireland as a Project of Common Interest (PCI).

[68] J. Apt and P. Jaramillo (2014), "Variable Renewable Energy and the Electricity Grid".

[69] Two plants in Huntdorf, Germany (290 MW) and McIntosh, Alabama, US (110 MW).

[70] B. Elmegaard and W. Brix (2011), "Efficiency of Compressed Air Energy Storage".

ANNEX 2: GLOSSARY OF ABBREVIATIONS AND TECHNICAL TERMS

ACE	Area control error. Deviation from scheduled net import or export of the control area concerned.
ACER	Agency for the Cooperation of Energy Regulators
Aggregator	A legal entity that aggregates the load or generation of various demand and/or generation units for sale or auction in organised energy and balancing markets
Ancillary service	All service necessary for the operation of transmission system and distribution networks
ATC	Available Transfer Capacity
Balancing Capacity	A volume of reserve capacity that a balancing service provider has agreed to hold and in respect of which the balancing service provider has agreed to submit bids for the corresponding volume of balancing energy to the TSO for the duration of the contract
Balancing market	Balancing market means the entirety of institutional, commercial and operational arrangements that establish market-based management of the function of balancing within the framework of European network codes
Balancing portfolio	Grouping of network user's inputs and off-takes in a portfolio. The imbalances of the portfolio will be billed to the balance responsible party
BRP	Balance responsible party. A market entity or its chosen representative responsibility for its imbalances.
BSP	Balancing service provider, i.e. a market participant with reserve-providing units or reserve-providing groups able to provide balancing services to the TSO
CMOL	Common merit order list: a list of balancing energy bids sorted in order of their bid prices, used for the activation of balancing energy bids with a coordinated balancing area
Congestion management	Set of actions that a network operator performs to avoid or relieve a deviation of the electrical parameters from the limits that define the secure operation, including voltage control
Coordinated balancing area	A region in which TSOs are exchanging balancing capacity, sharing reserves, exchanging balancing energy and operating the imbalance netting process
Countertrade	A market-based transaction initiated by TSOs between two neighbouring control or price areas, or within a TSO control area in the opposite direction of the main power flow, in order to allow for a higher amount of commercial Transactions in the mainly traded direction. By countertrading, the TSO ensures that physical flows of the network are within acceptable limits. Countertrade may be considered either a preventive or curative measure.

CSP	Curtailment Service Provider. A participant in the market for balancing reserves who enters into contract with willing retail customers to reduce electricity usage for a limited period of time per annum when required by the CSP in exchange for a financial reward. Through aggregation the CSP is able to meet capacity performance requirements when making bids in certain reserve auctions (e.g. in the PJM market).
Curtailment	Reduction of the electricity flow at the connection of a network user (generator, end user) with the grid
DA	Day Ahead
Demand Response	Voluntary changes in electric usage end-use customers make from their normal consumption patterns in response to changes in the price of electricity or system conditions
DSO	Distribution system operator
FBMC	Flow Based Market Coupling
FCR	Frequency containment reserves, also called primary control reserves. Operating reserves with typically an activation time of 30 seconds, used for constant containment of frequency deviations from the set point, 50 Hz in continental Europe, in order to constantly maintain the power balance in the whole synchronously interconnected transmission system. Activations of these reserves results in a restored power balance at a frequency deviating from nominal value. Usually activated automatically by locally measured frequency deviation.
Flexibility	The ability of an electricity system to adapt to rapid and large fluctuations of supply and demand and to efficiently deploy resources for congestion management
Forecast error	The difference between forecast feed-in from an intermittent renewable generating installation and actual, real-time feed-in. Forecast errors become less on average, the closer forecasts are submitted ahead of real-time.
FRR	Frequency restoration reserves, also called secondary control reserves. Operating reserves with typically an activation time up to 15 minutes used to restore frequency to the set point value and to re-balance the balancing area concerned to the forecast value after a sudden system imbalance. Usually activated by IT signal (sometimes manually) and centrally (by the TSO concerned).
ID	Intraday
Imbalance	The difference between the actual net in-feed and the final schedule (programme) of net in-feed submitted by a balance responsible party for a programme time unit. Note that in this context a given positive net off-take volume is equated to the same volume of negative in-feed.
Imbalance settlement	A financial settlement mechanism aiming at charging or paying balance responsible parties for their imbalances
Imbalance settlement period (ISP)	See: Programme time Unit
Imbalance price	The price at which the imbalance (negative and positive balance separately or, alternatively, net balance) volume is settled. In some member states single pricing is applied where short and long positions are settled at identical prices, whereas in other member states dual

	pricing is applied settling short and long positions at different prices either for all PTUs or, alternatively, only for those PTUs in which the TSO has regulated both in upward and in downward direction.
Integrated scheduling process	An iterative process that uses at least integrated scheduling process bids (multi-part bids) which contain commercial data, complex technical data of each power generating facilities or demand facilities which explicitly includes the start-up characteristics, the latest control area adequacy analysis, and the operational security limits as input to the process. Used for dispatch and balancing energy activation optimisation with due allowance for operational security
Load profile	The estimated variation of load versus time. A load profile will vary according to customer type and/or temperatures, and/or weekdays/public holidays. Load profiles are used to convert the monthly/yearly metered consumption data into estimates of daily/hourly or quarter hourly consumption
Loop flows	Unscheduled cross-border flows resulting from internal exchanges. (ACER/CEER, 2016: 21). Typically, because of critical branches in the national grid, part of the paths of least resistance crosses national borders in an unscheduled fashion.
Market time unit	Trading period of a certain electricity market segment (forward, day-ahead, intraday).
Multi-part bids	A multi-part bid consists on top a bid for energy separate prices for costs such as start-up costs, no-load costs and information from the bidder on technical constraints and capabilities such as minimum load requirements and ramp rates
NEMO	Nominated electricity market operator
Network codes	Codes that encompass the technical rulebook of the European energy sector. They are secondary legislation addressing technical issues, binding in all member states. They can be subdivided into market codes, connection codes and operational codes (based on an ENTSO-E brochure on network codes)
NTC	Net Transfer Capacity
OTC	Over-the-counter: bilateral trade typically at non-disclosed terms
Overcapacity	A situation where the difference between observed reliability margins and the reliability standards defined for a given system is above a certain threshold during a period of time.
Peak shifting/shaving	The flattening of an electricity consumption load curve
Prosumer	A consumer who produces electricity.
PTU	Programme time unit: the standard period for which the net feed-in schedules needs to be specified by balance responsible parties and over which the costs of the measured total imbalance (negative and positive balance separately or, alternatively, net balance) volume are settled. Also called ISP (imbalance settlement period).
Redispatch	A measure where TSOs (jointly on both sides of the congestion or unilateral) change generation (or load) patterns in their grid in order to change physical flows in order to solve a congestion situation. Often used only as a curative measure after day-ahead market gate closure. Generators and consumption units are directly involved in cases of

	redispatch if a TSO orders them to adjust their generation capacity when a trade transaction leads ultimately to a change in generation. Consequently, generators or operators of large consumption units might face higher costs (e.g. reflected in bids submitted in the balancing market) for these changes as they might result in an economically sub-optimal dispatch situation from their point of view. In addition, redispatch implies that TSOs have a clear basis for ordering generators to adjust their generation capacity. This basis can be contractual or even derive from legal provisions. Moreover, TSOs require proper information on planned generation and actual generation of plants potentially involved in such redispatch actions.
Reserve margins	Any generating capacity that is available to cover the load in a given point in time.
RR	Replacement reserves, also called tertiary control reserves. Operating reserves with an activation time from 15 minutes up to hours, used to replace FRR over time and to restore the required level of operating reserves to be prepared for further system imbalance. Activation is a decision taken by TSO staff based on current and expected deployment of FRR. Activation is done manually or sometimes by IT signal
RTO	Regional Transmission Organisation. Coordinates the transmission of wholesale electricity in the region concerned. For example: PJM in the US.
Self-consumption	Consumption of power generated at the premises of a consumer, either consuming this power instantaneously after self-generation or after having stored self-generated power in a storage device at the aforementioned premises
Self-generation	Power generation at the premises of a consumer
Scarcity	Situations whereby the actual "reserve margins" are close to zero. Although scarcity only arises in real time, scarcity situations are likely to be anticipated by market participants in the form of high-price periods in the different market timeframes
Standard product	A harmonised electricity trading or balancing market product, facilitating cross-border exchanges
System balancing	All actions and processes, on all timelines, through which TSOs seek to ensure, in a continuous way, to maintain the system frequency within a predefined stability and to comply with the amount of reserves needed per frequency containment process, frequency restoration process and reserve replacement process
TSO	Transmission system operator
UAF	Unscheduled (cross-border) allocated flow, resulting from non-coordinated capacity allocation
Unscheduled flows	Loop flows and UAFs
Voltage control	A distribution system control managed by distribution system operators in order to maintain voltage in their networks within limits and to minimise the reactive power flows and consequently, technical losses and to maximise available active power flow

ANNEX 3: LIST OF TASK FORCE PARTICIPANTS AND INVITED GUESTS AND SPEAKERS

Chairman: Jacques de Jong
Senior Fellow
Clingendael Energy

Rapporteurs:

Christian Egenhofer
Director & Associate Research Fellow
Energy Climate House
CEPS

Arndt Hassel
Associate Researcher
Energy Climate House
CEPS

Jaap Jansen
Non-resident Fellow
Energy Climate House
CEPS

Zheng Xu
Intern
Energy Climate House
CEPS

MEMBERS OF THE TASK FORCE

Ina Adler
Head of Corporate Communication/
Energy Policy
ONTRAS Gastransport GmbH

Camille Alléguède
Policy Advisor
European Affairs
ENEDIS

Paolo Basso
Regulatory Affairs Manager
EHI

Arno Behrens
Senior Research Fellow & Head of Sustainable Resources
Energy & Climate Change
CEPS

Francisco Beirao
Head
European Affairs
EDP Energias de Portugal

Nicolas Berghmans
Research Fellow
IDDRI

Jeroen Bode
Director
USEF Foundation

Arnaud Chaperon
Vice President
European Public Affairs
Total

Victor Charbonnier
Political Advisor
Wind Europe

Jorgo Chatzimarkakis
Secretary General
Hydrogen Europe

Gaëtan Claeys
Manager of European Affairs
EUGINE

Sonia Clarena Baron
Manager of European Affairs
EUTurbines (European Association of Gas and Steam Turbine Manufacturers)

Giorgio Corbetta
Advisor
Regulatory Affairs
EEX

Gerda de Jong
Electricity market developer
Customers & Markets
TenneT TSO BV

Bert den Ouden
Managing Director Energy & Sustainability
Berenschot, Flexiblepower Alliance Network

Bertrand Deprez
Vice President EU Government Affairs
Schneider Electric

Alvaro Dorado Baselga
Vice President
Energy Europa
Alcoa

Eleanor Drabik
Researcher
Energy & Climate Change
CEPS

Marcus Franken
Head of EU-Representative Office
Communications and Political Affairs
E.ON SE

Rémy Garaude Verdier
Enedis

Francesco Gazzoletti
Senior Advisor
Corporate
ERG S.p.A.

Michael Gerecht
Senior Expert Energy Economics and Market Analysis
E.ON SE

Kyriakos Gialoglou
EU Affairs Director
Eurogas

Andreas Graf
Associate
EU Energy Policy
Agora Energiewende

Christos Kolokathis
Associate
Research, Analysis, and Technical Assistance
RAP

Jani Leirimaa
Business Developer
Technology and New Ventures
Fortum

Paulo Lopes
Planning expert
EDP

Valentina Mauri
Governmental Affairs Manager
Covestro

Nicola Melchiotti
Head of European Public Affairs and Regulation
ENEL

Matteo Moraschi
ENEL

Adele Naudy-Chambaud
Policy Director
Trans-Atlantic Business Council (TABC)

Roosa Nieminen
Fortum

Christoph Reißfelder
Energy Analyst
Group Purchasing
HeidelbergCement

Immavera Sardone
EU Affairs Manager
Norsk Hydro ASA

Andrea Villa
Head of European Regulation
European Affairs
Enel S.p.A.

Ignacio Vizcaino
Wholesale Energy Markets
Regulation
Iberdrola

Philip Vogel
Senior Expert Markets and Renewables
Markets and Renewables
Innogy

Thomas Walter
Managing Director
Easy Smart Grid GmbH

Michael Wriglesworth
Emeritus
Energy & Climate Change
CEPS

Perizat Ybrayeva
Deputy Secretary General
Storage division
Gas Infrastructure Europe

LIST OF SPEAKERS

Manuel Baritaud
IEA

Christian Baer
Secretary General
Europex Secretariat
Europex

Sara Bell
CEO
Management
Tempus Energy

Rui Roseiro Boavida
Permanent representation of Portugal to the EU

Luis Cunha
EDSO Member
EDSO for Smart Grids

Mike Hogan
Senior Advisor
Power
Regulatory Assistance Project

Aleksandra Kozlowska
Policy Officer
DG GROW
European Commission

Karsten Neuhoff
Head of Department
Climate Policy
DIW Berlin

Matti Supponen
Policy Co-ordinator
DG Energy
European Commission

Alain Taccoen
Head of Stakeholders Relations
European Affairs Division
EDF

Claude Turmes
MEP, (The Greens Group)
European Parliament

Stef Vergote
Advisor
DG CLIMA
European Commission

Hans Vandenbroucke
Belgian Market Structure - Market Development
ELIA

Matt Wieckowski
Case Handler
DG COMP – Energy and Environment
European Commission

Georg Zachmann
Senior Fellow
Empirical microeconomics, Energy, Electricity Markets
Bruegel

ABOUT CEPS

Founded in Brussels in 1983, CEPS is widely recognised as the most experienced and authoritative think tank operating in the European Union today. CEPS acts as a leading forum for debate on EU affairs, distinguished by its strong in-house research capacity and complemented by an extensive network of partner institutes throughout the world.

Goals

- Carry out state-of-the-art policy research leading to innovative solutions to the challenges facing Europe today
- Maintain the highest standards of academic excellence and unqualified independence
- Act as a forum for discussion among all stakeholders in the European policy process
- Provide a regular flow of authoritative publications offering policy analysis and recommendations

Assets

- Multidisciplinary, multinational & multicultural research team of knowledgeable analysts
- Participation in several research networks, comprising other highly reputable research institutes from throughout Europe, to complement and consolidate CEPS' research expertise and to extend its outreach
- An extensive membership base of some 132 Corporate Members and 118 Institutional Members, which provide expertise and practical experience and act as a sounding board for the feasibility of CEPS policy proposals

Programme Structure

In-house Research Programmes

Economic and Finance
Regulation
Rights
Europe in the World
Energy and Climate Change
Institutions

Independent Research Institutes managed by CEPS

European Capital Markets Institute (ECMI)
European Credit Research Institute (ECRI)
Energy Climate House (ECH)

Research Networks organised by CEPS

European Network of Economic Policy Research Institutes (ENEPRI)
European Policy Institutes Network (EPIN)