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Capacity Remuneration Mechanisms

Overview, Implementation in Selected European Jurisdictions and Implications for Switzerland

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Overview, Implementation in Selected European Jurisdictions and Implications for Switzerland

Working Paper

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Executive summary

Capacity remuneration mechanisms are being implemented or their implementation discussed in many European jurisdictions. In light of falling prices on the wholesale markets for electricity, these mechanisms are meant to generate revenues over and above energy-only market revenues in order for plant to recover their fixed cost. In the first part of this paper, we present a framework for discussing the different types of capacity remuneration mechanisms in operation or under discussion. We derive a common terminology based on the three “First Tier” design choices related to the product being traded, the process of determining the amount to be contracted and the responsibility for contracting the required amount. These design choices lead to five main types of capacity mechanism identified in this paper: Centralised capacity market, Capacity Obligation, decentralised capacity market, Capacity Subscription and Reliability Options. We do note, however, that the boundaries between these types are blurred and that Reliability Options in particular can be applied in a way to resemble an energy-only market with a certain amount of mandatory contracting, or indeed a centralised capacity market, in case they are exclusively sold to a central authority. We also present important “Second Tier” design choices, amongst others, relating to auction and penalty design, contract duration and lead time or locational considerations.

In a next step, we take a closer look at the status of implementation of these mechanisms in the main electricity import and export partners of Switzerland, namely France, Germany and Italy. Whilst capacity mechanisms are operational in France and Italy, in Germany it is still being discussed whether a capacity mechanism is necessary. At present, it seems that an enhanced energy-only market design coupled with a Strategic Reserve is the most likely outcome. France has introduced a Capacity Obligation, for which the first auction of certificates is scheduled for January 2016, whilst Italy has introduced Reliability Options and plans to hold the first auction at the end of 2015. Whilst the main motivation for the mechanisms in France is scarcity during winter peaks and therefore an interest in activating demand response, in Italy the mechanism is focussed on scarcity in the summer and mainly envisaged to support gas-fired power stations threatened by closure.

While cross-border participation is already a reality in wholesale electricity markets, it is to date only rarely permitted in capacity mechanisms. Both France and Italy state their intent to allow for explicit cross-border participation, details have, however, not been released yet. In France, they are currently undergoing a public consultation process. One of the few examples of explicit cross-border participation to date is the auction for the British capacity mechanism in 2015. Another example is the German network reserve, where some degree of cross-border participation of Austrian, Italian and Swiss generators is already taking place. However, due to the limited experience many open questions for cross-border participation in general remain. Two main questions to be answered in this paper are with regard to the decision on who is to participate (i.e. generators or interconnectors) and what the product to be traded is (i.e. availability or delivered energy). Whilst there seems to a preference for availability to be traded, in order to avoid distortions on the energy-only market, there are advantages and disadvantages regarding both the generator or interconnector model of participation. The TSOs are likely to play an important role should cross-border participation become a reality and a strong regional coordination will be necessary, as well as new rules for example governing cases of coincident scarcity situations. At present it is not only those questions that have to be solved before Swiss generators may be able to participate in mechanisms in neighbouring countries, but there may also be political barriers, as indicated by the recent rejection of the EU to conclude a preliminary bilateral agreement in the electricity sector with Switzerland.

Besides the potential cross-border participation of Swiss generators, capacity markets in neighbouring countries are also likely to impact on Swiss market participants via their interaction with energy-only market outcomes. The potential decrease in the level and frequency of peak prices may pose problems for the business model of Swiss pumped hydro, whilst Swiss electricity consumers may benefit from lower prices on the wholesale market for electricity. Further distributional implications may arise, e.g. between consumers in a country with a capacity mechanism in place and those in a neighbouring country without a mechanism, but where capacity participates cross-border. In the context of allowing for cross-border participation in its own mechanism, France is currently undertaking research on these issues. Although there are efforts being made at the EU-level to harmonise key design choices with regards to the mechanisms in general and cross-border participation in particular, no such harmonisation is emerging to date. As long as this is not the case, the discussion about how to coordinate and accommodate different designs and the issue of distributional effects will remain a point of discussion.

Part I: Overview and Implementation in Selected European Jurisdictions

1. INTRODUCTION

Resource adequacy in electricity markets refers to the market mechanisms that manage the capacity of installed generating technology, and the adequacy of that generation to meet anticipated demand. Markets, by design, manage resource adequacy using commercial incentives as opposed to central command and control in a utility.

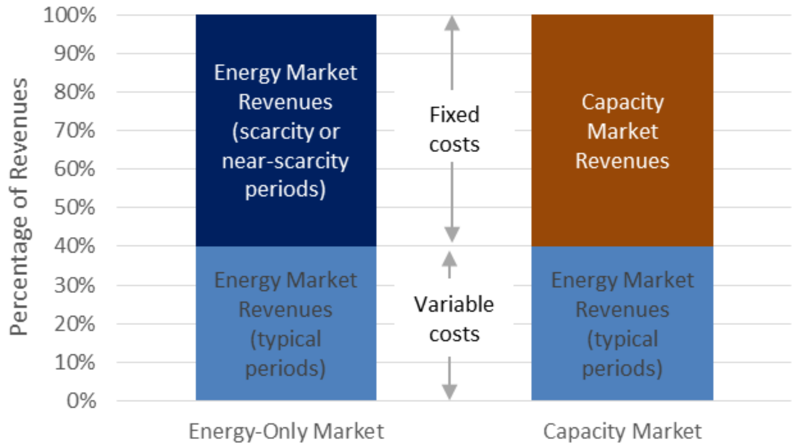
Some markets apply an “energy-only” model; in this framework generators are paid for energy produced in a real-time spot market with the spot price typically based upon the marginal cost of supply (which, strictly speaking, must also include the value to the demand side of the risk of insufficient capacity). Most of the time the spot price is dominated by the variable cost of the marginal generator, which means that the recovery of fixed costs occurs during brief periods of scarcity or near-scarcity. During these scarcity and near-scarcity periods, the mean spot price may be significantly higher than the variable operating cost of any installed plant. Financial instruments are then used to manage the commercial risk due to market volatility and provide a more certain revenue stream to support investment.

In energy-only market models, “missing money” can arise when a spot market price cap is set too low to allow the recovery of fixed costs during scarcity periods. Unwillingness to accept sufficiently high spot prices has contributed to some markets adopting a more explicit capacity remuneration mechanism (CRM), or “capacity market” (where it is implemented in a market fashion), to provide a more certain investment environment. These mechanisms typically provide an additional revenue stream to generators (or demand-side resources) for the provision of available capacity over much longer timeframes more similar to those over which investment decisions are made (periods of years). Conceptually, this allows generators to recover fixed costs via capacity market revenues (both incurred and recovered over periods of years) and allows spot market revenues to cover operating (variable) costs only, with matched decision making timeframes of hours or minutes.

Figure 1 provides an illustrative example. For a particular generator, operating in a particular way in a particular market, they may incur 40% of their costs as variable costs (fuel, operations and maintenance, carbon costs, etc.), and 60% as fixed costs (fixed operations and maintenance, and capital repayments). In an energy-only market they might expect to recover approximately their variable costs during typical periods, and would then contract with Load Serving Entities (LSEs) to earn their fixed costs, with the level of those contracts being dictated by the prices and anticipated occurrence of rare scarcity or near-scarcity periods, when prices reach much higher levels. If a capacity market were introduced, it would typically involve setting a much lower price cap in the energy-only market, such that energy market revenues only recover variable costs. Fixed costs would then be recovered via capacity market revenues.

In reality, the split between revenues from capacity and spot markets can be “tuned” to any level desired, depending upon the market design choices implemented, such as the level of the spot market price ceiling.

Figure 1 Illustrative example comparing the recovery of fixed and variable costs in energy-only and capacity market mechanisms. Proportions are for illustrative purposes only.



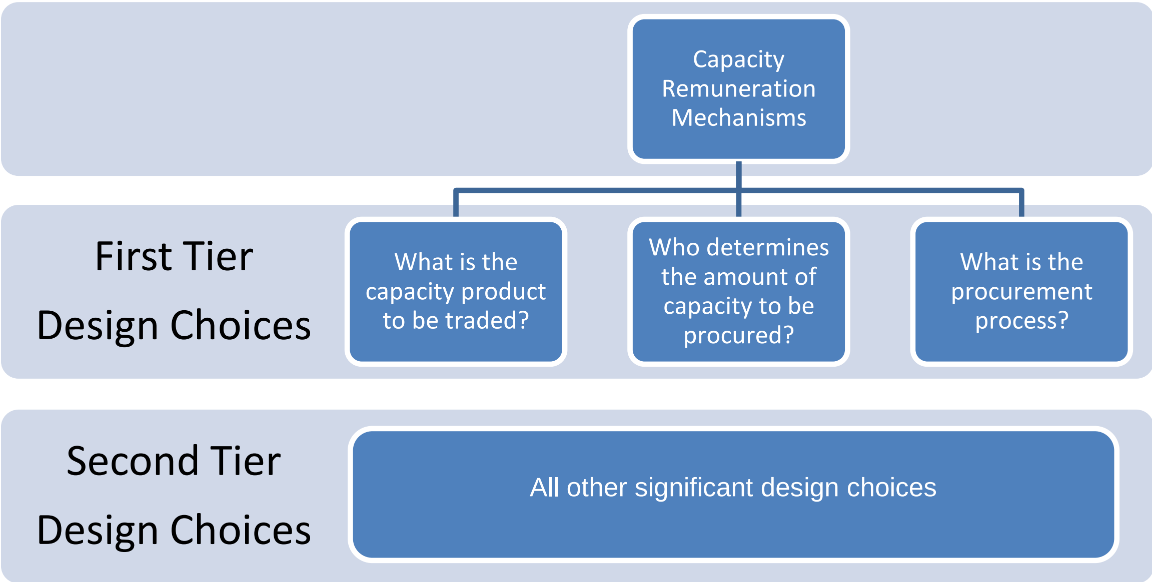
New challenges for resource adequacy mechanisms

Electricity markets around the world are currently facing new pressures that exacerbate challenges around market mechanisms for maintaining resource adequacy. Plateauing or reducing demand in many nations is combined with policies intended to drive investment in renewable and other clean technologies, many of which have variable availability (such as wind and solar photovoltaics). Both of these factors are likely to create a more challenging investment environment, with less certainty around market revenues. For this reason, many markets are considering moving towards more explicit capacity remuneration mechanisms to increase investment certainty (including France, Germany, Great Britain, Italy and others). This makes it an important time to provide clear frameworks for the design of capacity markets.

2. A FRAMEWORK FOR CHARACTERISING CAPACITY REMUNERATION MECHANISMS

Three key design choices have been identified as being fundamental in defining the distinguishing features of the capacity market under consideration. The distinctions between most common types of capacity markets implemented around the world can be defined by characterising these three design choices. These three design choices are therefore referred to as First Tier design choices. Other design choices may also be significant in determining how the mechanism operates, but are less important in dictating the differentiating terminology that is used to describe common models. These are designated as Second Tier design choices. This framework is illustrated in Figure 2, and described in more detail in the following sections.

Figure 2 Illustration of Tier 1 and Tier 2 design choices for the development of capacity remuneration mechanisms.



2.1. First Tier design choices

First Tier Design Choice 1 – What is the capacity product to be traded?

Like all created or "artificial" markets, it is important to define the product that is to be traded. There are two broad choices: physical capacity, or financial instruments (or both).

– ***Option 1: Physical Capacity*** – Most common types of capacity markets trade physical capacity via a "capacity credit" or similar product, which is usually defined as a megawatt (MW) of generating (or demand-side) capacity made available to the market in a particular year (or defined timeframe). There may be complex provisions that define the consequences if that capacity is ultimately not available at times when it is required, to ensure adequate incentives for capacity availability during rare scarcity periods.
– ***Option 2: Financial Instruments*** – A more recent innovation has been to instead trade a financial instrument such as "Reliability Options". A reliability option is a call option similar to a cap contract traded in energy-only electricity markets. In a reliability options model, generators sell reliability options (usually to a central authority, although not necessarily), and must then pay that central authority the difference between the spot price and the strike price, whenever the spot price exceeds the strike price (Bidwell 2005). In markets with a high spot market price ceiling, this creates a severe penalty for failing to be available during scarcity periods (when the spot price may exceed the strike price by a significant margin, and any generator that is not operating will not be earning spot market revenues to meet that contractual requirement). Any capacity market that trades reliability options (rather than capacity credits) could be termed a Reliability Options mechanism.

Notably, a decentralised market (defined below) founded upon reliability options (rather than capacity credits) could be considered to be very similar to an energy-only market with some degree of mandatory contracting, creating a convergence between capacity market designs and energy-only market designs. Whether or not reliability options can be termed financial instruments in practice also depends on who can sell these options. If only generators are allowed to do so, every reliability option would be backed up by actual physical capacity.

First Tier Design Choice 2 – Who determines the amount of capacity that will be required?

In an energy-only market, electricity retailers (or load-serving entities, LSEs) directly determine the degree to which they wish to contract, based upon the anticipated demand from their customers, the cost of procuring contracts to cover that demand, and the risk of spot market exposure (related to the potential for very high scarcity prices). In this model, then, the amount of capacity installed is determined by the market, and will be critically dependent upon the market price ceiling (usually set by a central authority).

In contrast, the implementation of a more explicit market for capacity requires that some authority become responsible for determining how much capacity must be procured. There are three broad options:

- ***Option 1: Central Authority*** – In many capacity markets, a central authority directly determines the volume of capacity that is required (possibly based upon a forecast of peak demand several years in advance).
- ***Option 2: LSEs*** – In other models, LSEs self-determine the amount of capacity to be procured, based upon their own forecast of their anticipated customers' demand, and the risk associated with the penalties defined by a central authority if they fail to forecast accurately.
- ***Option 3: Customers*** – In yet other models, customers themselves determine the amount of capacity that they want to contract for directly with providers.

First Tier Design Choice 3 – What is the procurement process for that capacity?

All capacity markets must implement some approach for the procurement of capacity from the market. There are two broad options:

- ***Option 1: Central Procurement*** **–** A central authority directly procures capacity through a central process (such as an auction or tender).
- ***Option 2: Bilateral Procurement*** – LSEs or customers are responsible for procuring capacity, potentially through a bilateral trading process.

In any case, the cost of procuring capacity is typically levied on customers through retail tariffs.

2.2. Common terminology based upon First Tier design choices

The First Tier design choices lead to a number of common combinations, which are often described by the names outlined in Table 1. Terminology may vary between different markets, but these definitions are provided as a common foundation for discussion used throughout this paper.

Table 1 Common terminology for capacity mechanisms

	Product Description	Who determines how much is procured?	Procurement process
Centralised Capacity Market	Physical Capacity	Central Authority	Central Procurement
Capacity Obligation	Physical Capacity	Central Authority	Bilateral
Decentralised Capacity Market	Physical Capacity	LSEs	Bilateral
Capacity Subscription	Physical Capacity	Customers	Bilateral
Reliability Options	Financial Instrument	Central Authority (usually)	Central Procurement (usually)

These common groupings of First Tier design choices can be described as follows:

- ***Centralised Capacity Market*** – A central authority determines the amount of physical capacity required, and then directly procures that capacity from the market.
- ***Capacity Obligation*** –the central authority determines the amount of capacity required, and then passes the obligation for procuring that capacity on to LSEs (usually in proportion to their respective customer loads). LSEs then bilaterally procure capacity directly from providers.
- ***Decentralised Capacity Market*** **–** LSEs themselves determine how much capacity must be required, and then bilaterally procure that capacity.
- ***Capacity Subscription*** **–** Customers directly self-determine how much capacity they wish to contract for, and bilaterally enter into contracts with providers (Doorman 2005).
- ***Reliability Options*** **–** This generally could refer to any model based upon financial instruments, although markets implementing this at present utilise central procurement, with a central authority determining the volume of capacity to be procured.

Depending on the way in which reliability options are designed, they can represents a variant of a centralised capacity market, where generators sell one-way call options rather than capacity credits to the authority (European Commission 2013). Whilst the payments for the underlying capacity may be similar, the penalty for non-availability is then presented by the difference between the spot market price and the strike price during times of scarcity or near-scarcity. Therefore, the boundaries between the two types are not always clear cut. As we will show below, reliability options can also be added to a centralised capacity market, providing a cost containment mechanism for electricity consumers and creating a second penalty for non-availability.

2.3. Other types of capacity remuneration mechanisms

There are a number of other types of capacity remuneration mechanisms implemented in various markets around the world. These are generally understood as follows:

- ***Capacity Payments*** – In a capacity payments mechanism, a central authority makes contractual agreements with new entrants to the market, negotiating to make additional capacity payments to that specific market participant at a particular level for an agreed period of time. Agreements can be individually negotiated, or may be based upon simple rules (such as a published payment rate for a certain technology type entering the market at a particular time). The central authority may target a certain volume of capacity deemed to be necessary for achieving resource adequacy and adjust the price offered upon that basis, or may simply offer a set price for additional capacity.
- ***Strategic Reserve*** – In a strategic reserve mechanism, a sub-set of generation is "reserved" from the market, and is paid additional capacity payments by a central authority (these may be negotiated individually, or at a set rate). This generation is typically low capacity factor plant that is withdrawn from usual market operation, and is only dispatched in rare circumstances when all other plants in the market have already been dispatched.
- ***Focussed Capacity Markets*** – A focussed capacity market could be any kind of capacity market that makes distinctions between different types of capacity in the level of capacity payments that are made. This may be related to the flexibility of plant (with more flexible plant being eligible to participate in a different capacity auction, with typically higher prices) or other factors, such as emissions-intensity (see also Section 3.2).

2.4. Second Tier design choices

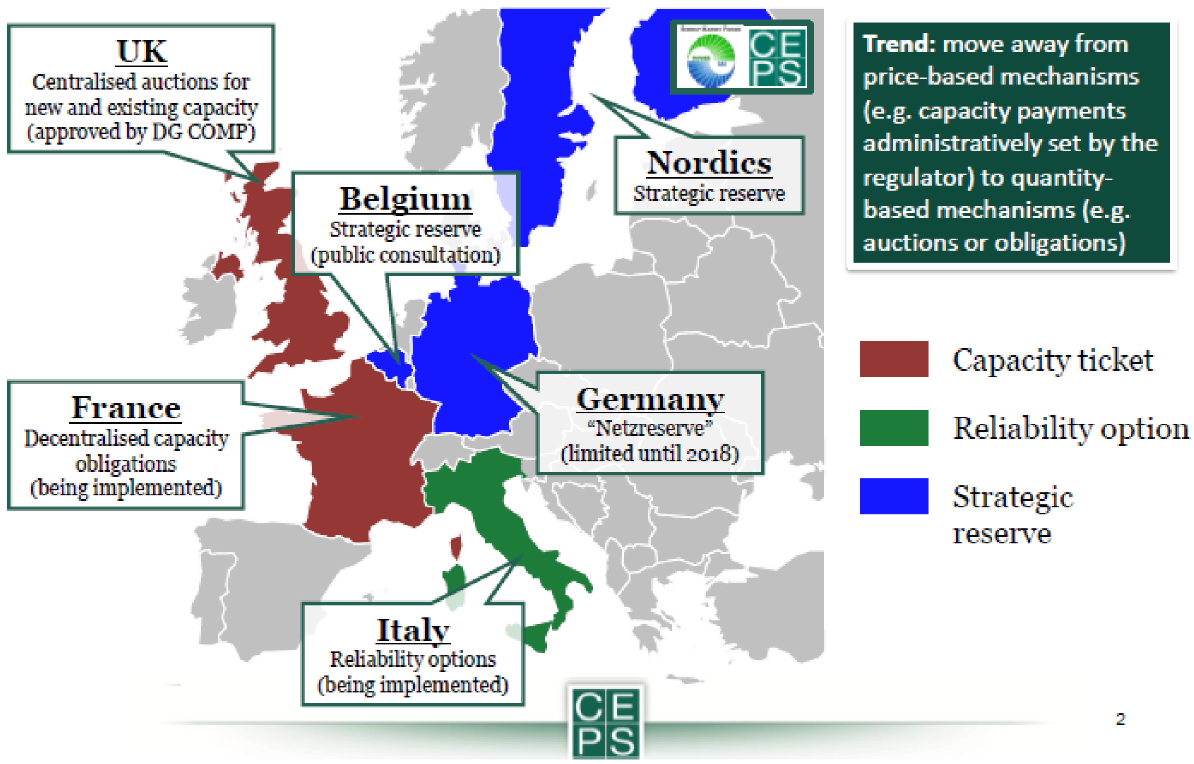
There are many Second Tier design choices that are also important in dictating the operation of capacity remuneration mechanisms. These include:

- ***Auction design*** – There are many design choices to make in the development of an auction process, if one is to be included in the CRM design. Many involve features such as auction demand curves, which dictate the price to be paid for capacity, depending upon the volume demanded by the market.
- ***Contract duration and lead time*** – The duration and lead time for contracts is a critical feature of CRMs, since it relates closely to the investment timeframes for new capacity, and influences the financing of new entrants.
- ***Price caps*** – Price caps must usually be applied, both in the energy-only market, and in the capacity market mechanism. These are important in determining the revenues earned by market participants.
- ***Penalties for non-availability*** – As discussed in Section 2.1, penalties for non-availability determine the incentives for generators (and demand side participants) to be available during periods of scarcity, and are therefore important in determining market outcomes.
- ***Determination of capacity credits for different technology types*** – Different types of technologies may be eligible to create different amounts of capacity credits. For example, variable generators (such as wind and photovoltaics) are usually eligible to sell only a proportion of their rated capacity as capacity credits, given their variable availability.
- ***Locational requirements*** – Transmission constraints may impose physical limitations on the ability of generators in some locations to supply load at other locations. It is important that these physical constraints are taken into account in the procurement of capacity.
- ***Cross-border participation*** – In countries that are closely integrated with neighbours there are often complex provisions for the participation of capacity in neighbouring markets. Cross-border effects must be carefully considered and taken into account (see also Section 4).

3. CRMS IMPLEMENTED OR UNDER CONSIDERATION IN SELECTED EUROPEAN JURISDICTIONS

A large number of European countries has introduced or is considering the introduction of a capacity mechanism (Figure 3). The designs and approaches vary significantly between individual countries. In the following, we will look more closely at the French and Italian capacity markets and at proposals for a mechanism in Germany, since those three countries are most relevant for the discussion of the implications for Switzerland (Part II below).

Figure 3Capacity mechanisms operational or under implementation in Europe



Source: Recent EU development on capacity markets, CEPS presentation by Fabio Genoese,, http://www.ceps.eu/sites/default/files/EU_Recent_developments_1.pdf

3.1. The French capacity market

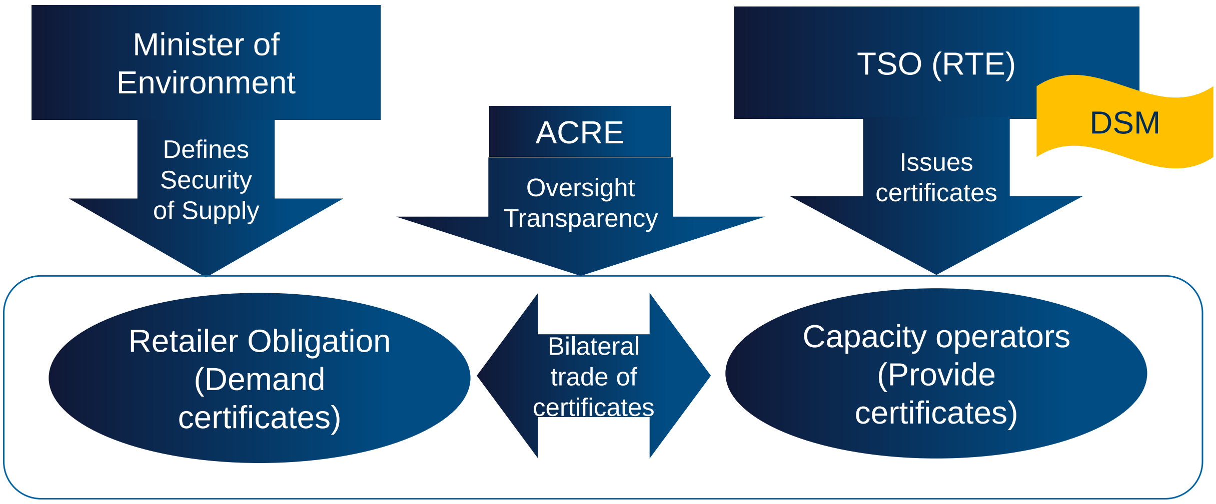
France has implemented its capacity mechanism in 2015, the first delivery year ranging from January 2017 to end of December 2017 with the months of July and August 2017 excluded.[1] The first certificates of capacity were issued in April 2015 and EPEX plans to establish a regular auction to trade those certificates from January 2016 onwards. The stated aim of the French capacity market is the security of supply especially in winter. There is a specific load scarcity situation in France in winter since many households use electrical heating. Therefore

[1] Note that there is a shorter gap between the start of the mechanism and the first delivery year compared to the originally envisaged 4 years lead time. This has been especially addressed in the decree.

demand response measures are given a prominent role in the market design, since they may help modify consumption behaviour during peak periods (RTE 2014).

Under the French capacity mechanism, LSEs have an obligation to hedge their demand and need to buy capacity certificates equal to their customers` consumption during a standard winter cold spell, which reflects the risk of a shortfall. Eligible operators of generation and demand response capacity receive capacity certificates issued by the Réseau de transport d'électricité (RTE/TSO). The amount of capacity certificates created corresponds to their contribution to reducing the shortfall risk and thus this price will tend toward zero in situations of overcapacity. Certificates can be traded decentrally four years in advance of delivery, but also shorter timescales are possible in order to better accommodate demand response. Certificates can be traded until the transfer deadline, which is set after the delivery year. Only when the transfer deadline is reached the compliance is assessed and in case of non-compliance an imbalance settlement is required to be paid. The imbalance settlement depends on the actual situation: If security of supply was not at risk, is close to the market price (market price * incentive coefficient), if security of supply was at risk, it is set at the annualised cost of a reference peak capacity, which is published four years before the delivery year by the Energy Regulatory Commission (CRE).

Figure 4 Functioning of the French capacity market



Source: Own illustration based on RTE (2014)

Two institutions are responsible for market oversight (see Figure 4). On the one hand, the RTE is responsible for making adequacy forecasts with different time horizons and for setting up a registry for demand management and capacities. Second, the Regulatory Commission of Energy (CRE) publishes statistics on exchanges so that estimates can be made of the volumes traded or offered and prices. It is also responsible for setting the imbalance settlement prices. Given those characteristics, the French mechanism corresponds to a Capacity Obligation where the volume to be procured is set centrally and the procurement process takes place bilaterally (Table 2). Given its rather low involvement, the French government considers its capacity market to be in no conflict with EU state aid rules and therefore does not deem it necessary to have the mechanism approved by the European Commission.

Table 2 The French capacity market – Overview of First Tier design choices

Status	How is the product defined?	Who determines the amount of product required?	What is the procurement process?	Who is responsible for procurement?	How are costs allocated?	Cross-border participation	Fundamental type
First auction January 2016	Physical capacity (0.1 MW)	Central authority sets volume	Decentralised procurement; EPEX plans regular auctions	LSEs	The price of certificates should reflect short-fall risk; temperature-sensitive consumers (electric heating) to bear costs	Envisaged but in first stage not explicit (i.e. implicit consideration of import capacities when determining volume required)	Capacity Obligation

The French capacity mechanism allows different technologies to create certificates. Certificates are then corrected to take technical constraints (limited time of use will generate less certificates) and flexibility issues (e.g. number of certificates from inflexible capacities may be reduced) into account. New and existing plants are treated equally and in a technology neutral manner including demand side response. Demand side response can participate in two ways: Either implicitly by reducing the obligation for the supplier or explicitly through the certification process.

Table 3 The French capacity market – Overview of Second Tier design choices

Capacity treated identically			How is capacity payment determined?	Contract duration and lead time	Penalties for non-availability	Price caps
New / existing	Technology	Imports				
Existing and new plants are treated equally	Limited time of use and flexibility will generate less certificates	Only implicit in first stage	Market, bilateral	1 year contract with two peak periods 4 years lead time, but shorter for demand response	After a 2 year balancing period the “imbalance settlement” is set situation specific (supply at risk or not)	Indirectly, through regulated retail prices

3.2. Considerations in Germany

Germany is experiencing a debate on whether the energy-only market currently in place will be sufficient to guarantee “security of supply, economic viability and environmental compatibility” (BMWi 2014, p. 6) going forward or whether a capacity mechanism will be required. In their Green Paper, the Federal Ministry for Economic Affairs and Energy notes that even under the current energy-only market design there exists some implicit capacity remuneration through the system of balancing groups and imbalance settlements, which need to be paid if the actual production and consumption is at odds with a group’s schedule. In the context of network stability, Germany already has in place a mechanism to secure the capacity required. This network reserve was conceived against the backdrop of increasing generation (in particular wind energy) in the North and East of Germany and demand centres in the South.

Network reserve

In June 2013, the German government put in place a regulation regarding the mechanism by which capacity deemed relevant to ensure the stability of the network (the goal to date is network stability not resource adequacy) to be procured. (Bundesregierung 2013). Under the regulation, which is in force until the end of 2017, the Federal Network Agency publishes the capacity to be held in the reserve on the basis of forecasts and analyses made by the network operators. During the first winter (2013-14) of its operation, the network reserve of 2,500 MW did not have to be used at all, amongst others, because of the very mild weather (BNetzA 2014).

In May 2014, the Federal Network Agency published its report detailing the requirements until 2018 (BNetzA 2014). For the winter of 2014-15 a need of 3,091 MW was determined, rising to 7,000 MW in 2018. A share of these requirements are already secured through a process by which the Agency can transfer “system-relevant” power stations that are planned to be closed, into the reserve. Whilst for the winter of 2014-15 nearly all of the necessary capacity is already secured, for 2017-18, only about 55 % are already contracted in this way. Before they can call on the reserve, the network operators have to first employ all other measures available to them to stabilise the network.

Operators can bid for the remaining capacities and then negotiate with the relevant TSO. Both operators situated in Germany and within the European electricity market or Switzerland can take part. For power stations situated in Germany it is a requirement that those power stations that become part of the network reserve no longer participate in the energy market. Installations are reimbursed for all those costs related to keeping or making the installation ready to be reserve capacity, i.e. no costs related to the mothballing of the installation.

In order for generators from other EU countries or Switzerland to participate, it is a prerequisite that they are suitable, obtain permission from the relevant national authorities and can commit to be available when needed. Furthermore, their offer has to be as competitive as from German installations. In fact, in the reserve for the winter 2013-14, 1,000 MW were contracted in Austrian power stations and 200 MW from Italian ones (BNetzA and Bundeskartellamt 2014). Swiss power stations have also participated in the bidding process and obtained the relevant approval from the regulatory authority.

In special cases, if not enough existing power stations can be contracted or if the contraction of existing power stations is more costly, the network reserve can be used to build new installations. However, those generators are then also not allowed to take part in the energy-only market.

As the Green Paper states, the network reserve would no longer be necessary if the grid was extended to the relevant degree. On the other hand, power stations that are now part of the network reserve could become part of a capacity reserve mechanism. If this reserve mechanism was regionally divided, it could still address the bottlenecks between Northern and Southern Germany, should those remain.

Strategic Reserve

The so-called Strategic Reserve is mainly discussed as a mechanism to be implemented for the transition to either an optimised energy-only market design or the introduction of a capacity mechanism. As opposed to the network reserve, where the contracted generators are used to overcome bottlenecks, the power stations in the capacity reserve are dispatched if demand and supply do not balance. The power stations in the reserve are only deployed after all market transactions have been concluded, so as to not interfere with the functioning of the market. In order to guarantee this, the capacities would be bid into the market at the current ceiling price of 3,000 €/MWh.

In this framework, the amount of capacity required is defined by a central authority and procured and dispatched by the TSOs. Similarly to the network reserve, the power stations can then no longer participate in the electricity market. This measure is taken to ensure that the existence of the strategic reserve does not distort decisions on the energy-only market (BMU et al. 2013). Whilst the network reserve is, to a large extent, a regulatory mechanism, where a number of “system-relevant” power stations are required to take part, the strategic reserve is planned to be procured based on tenders. Similarly to the network reserve, the cost of the mechanism is passed-on to electricity consumers via network charges.

The network reserve and strategic reserve are therefore similar in a lot of ways. They can co-exist alongside each other or the requirements of the network reserve can be transferred to the strategic reserve, by, for example, focussing on capacity situated in Southern Germany where grid bottlenecks can be expected until the grid expansion is fully realised.

Proponents of the strategic reserve mechanism state its advantages such as ease of implementation, the possibility to integrate it with a host of different electricity market designs and its low cost. Some critics note that the interactions between the reserve and the energy-only market may be underestimated, potentially leading to a situation where prices that would be needed for investments on the energy-only market are no longer achieved. Furthermore, the argument that limited regulatory intervention is required and costs are low only holds if the strategic reserve remains small and does not influence market results on the energy-only market.

Centralised capacity market

Two types of centralised capacity markets are under consideration in Germany: i) a comprehensive capacity market (“Versorgungssicherheitsverträge”), where, in general, all capacity would be eligible to bid in the market (EWI 2012) and ii) a focussed capacity market, where the market would be split into two different segments, one for new entrants meeting certain flexibility and emissions standards and one for non-viable existing capacity (e.g. determined by the capacity utilisation in a certain year) (Öko-Institut et al. 2012). In both cases, the central authority sets the volume of physical capacity to be put out to tender in each of the segments, which is then procured centrally through auctions (descending clock auctions). Costs are passed on to consumers in the form of a surcharge on the electricity price. These surcharges can be proportional to individual consumption or differentiated by the structure of consumption, by which consumption in peak times would pay more (EWI 2012). These First Tier design choices imply that both proposals fit under the common heading of “centralised capacity markets”. Reliability options (restricted to the contracted capacity) are added as a cost containment measure for (rare occasions) of very high scarcity prices (Table 4).

Table 4 Germany: Comprehensive and focussed capacity market – Overview of First Tier design choices

How is the product defined?	Who determines the amount of product required?	What is the procurement process?	Who is responsible for procurement?	How are costs allocated?	Cross-border participation	Fundamental type
Physical capacity	Central authority sets volume	Central procurement	Central authority	Capacity surcharge	Under certain conditions	Centralised capacity market with reliability options

The two proposals differ most notably as to which types of generators can receive capacity payments. Whilst the comprehensive capacity markets rewards all types of (dispatchable) technologies and generators with a uniform capacity payment[2], the focussed capacity markets divides the market into two market segments: one for new facilities (achieving predefined flexibility and emissions requirements) and one for existing facilities that are threatened by closure.

However, although a common auction for all capacities is foreseen in the comprehensive capacity market, it differentiates between existing and new plant through contract duration and bidding requirements. Whilst new plants bid for 15 years of capacity payments, existing plants bid for 1 year. Furthermore, existing plants are required to participate and have to bid with 0 in the capacity auction.

Both proposals advocate the introduction of reliability options alongside the capacity auction and additional to a penalty for non-availability of capacity. These options are expected to limit the price paid by the retailer on the energy-only market in scarcity situations, which the retailers are then expected to pass on to consumers. Furthermore, these options incentivise reliability, since the difference between the spot market price and the strike price has to be paid in any case, whether or not the generators produces during the given hour. It can however be expected that in a market with sufficient capacity the relevant strike prices (tentatively set at 300 €/MWh in one proposal; EWI (2012) will very rarely be reached.

[2] Note, that the proposal states that renewable generators may be able to participate subject to certain conditions. However, it favours leaving renewables out of the market.

Table 5 Germany: Comprehensive and focussed capacity market – Overview of Second Tier design choices

	Capacity treated identically			How is capacity payment determined ?	Contract duration and lead time	Penalties for non-availability	Price caps
	New / existing	Technology	Imports				
Comprehensive capacity market	One auction for all capacity, but different contract durations and bidding requirements	Technology neutral including demand response	Advantages of European integration discussed, but no explicit mechanism presented	1 Auction (descending clock auction)	Lead time: 5-7 years, plus interim auctions Duration: Existing: 1 year New: 15 years	yes, but not specified further Plus reliability options	Existing generators have to bid at 0; potential floor price Plus reliability options
Focussed capacity market	Two market segments: 1) Existing plants threatened by closure – based on capacity utilisation (plus controllable loads) 2) New plants subject to flexibility and emissions-intensity prequalification		Only those in single price zone, i.e Luxembourg, Austria and if not taking part in national mechanism	2 Auctions for separate market segments (descending clock auction)	Lead time Existing: 1 year New: 5 years Duration: Existing: 1 (25%) or 4 (75%) years New: 15 years Controllable loads: Predefined intervals and frequency	Requirement: at least 90% availability at peak demand Plus reliability options	Restrict share of capacity that can be bid for by a single generator Plus monitoring Plus reliability options

Decentralised capacity market

As a third option, the Green Paper discusses a decentralised capacity market mechanism (BDEW 2013; BET and enervis 2013), where LSEs[3] are required to hold capacity credits to cover their demand at situations of scarcity, i.e. peak demand. These situations of scarcity are defined by the central authority that sets a price trigger (for the day-ahead market). If electricity prices exceed this trigger, retailers have to prove that they have contracted enough capacity to cover their demand. If this is not the case, they have to pay a penalty. Furthermore, the generators have to also pay a penalty if their capacity is not available in those situations of scarcity. Therefore,

[3] In the proposals balancing group manager are the liable parties, however, in most cases, those are equivalent to the LSEs.

the level of trigger price and the penalties for both retailers and generators play a crucial role for the outcome of this mechanism (Table 6).

Table 6 Germany: Decentralised capacity market – First Tier design choices

How is the product defined?	Who determines the amount of product required?	What is the procurement process?	Who is responsible for procurement?	How are costs allocated?	Cross-border participation	Fundamental type
Physical capacity	Central authority sets penalty level and trigger price; LSEs determine capacity needed in scarcity situations	Decentralised procurement	LSEs	To electricity consumers by LSEs	Under certain conditions	Decentralised capacity market

This capacity mechanism treats existing and new plant equally and is technology-neutral. Demand response is incentivised in that a LSE can reduce demand of its customers (in peak times) and thus has to hold a smaller number of capacity certificates. Those capacity certificates can be traded bilaterally or on an exchange. As a starting point, the BDEW (2013) suggest capacity credits for a duration of 3 months, but notes that the adequate duration and lead-time (i.e. forward sales of certificates) will subsequently be determined by the market. The proposal does not specify the level of an adequate penalty for both generators that cannot deliver the contracted electricity and LSEs that do not hold the required amount of certificates, but notes that probably a multiple of the average certificate price in a given period may be adequate. Capacity from other countries should be able to participate if the necessary Physical Transmission Rights (PTR) are secured. Furthermore, their participation should only be allowed, if they do not participate in a potential national capacity market (Table 7).

This proposal is similar to some extent to the French capacity market design. However, as compared to this proposal, under the French mechanism there are additional parameters that are set by the authority and determine the amount of generation capacity to be purchased by the retailers.

Table 7 Germany: Decentralised capacity market – Second Tier design choices

Capacity treated identically			How is capacity payment determined?	Contract duration and lead time	Penalties for non-availability	Price caps
New / existing	Technology	Imports				
Existing and new plant treated equally	Technology neutral including demand response	Yes, if physical delivery (PTR) is ensured and if no participation in national CRM	Market, bilateral	Duration: starting point: 3 months, then determined by the market	Multiple of the certificate price	n.a.

Legislative process

In essence, as the Green Paper notes, the decision on which market design will be chosen depends on a range of fundamental assumptions and definitions, including assumptions on the behaviour of market participants (including small consumers) or the definition of the adequate level of reliability. Following a public consultation on the Green Paper (open until March 2015) and discussions with the German Länder, neighbouring countries and the EU, the Federal Ministry for Economic Affairs and Energy has presented a regulatory proposal in the form of a White Paper (BMWi 2015), which has confirmed the recent signals from the German government pointing to a preference for enhancing the energy-only market in combination with a Strategic Reserve, rather than implementing a full-fledged capacity mechanism.[4]

3.3. The Italian capacity market

The first auctions under the Italian capacity market are expected to take place at the end of 2015 (Petrian 2015). The aim of the capacity market is to ensure system adequacy at minimum cost for the electricity system as a whole in the medium and long term. Since, there is currently plenty of capacity in the Italian market, the main issue is to ensure that not too much is retired. This applies, in particular, to gas-fired generators.

Table 8 The Italian capacity market – Overview of First Tier design choices

Status	How is the product defined?	Who determines the amount of product required?	What is the procurement process?	Who is responsible for procurement?	How are costs allocated?	Cross-border participation	Fundamental type
First auction planned end of 2015	Financial instrument	Central authority sets volume	Centralised procurement	TSO	Capacity surcharge	Envisaged	Reliability Option

As shown in Figure 4 there will be yearly auctions which are organised by Terna (the Italian TSO). Terna will define adequacy targets for different regions (capacity in MW, year and area), which are identified according to transmission limits. Each target consists of an elastic yearly demand curve (maximum of 4 years into the future) which is a function of the volume, Loss of Load Probability (LOLP) and the variable costs of marginal technologies. Sellers submit their portfolio offers for a period of three years. A descending clock auction is used to reveal the price to be paid for the obligation, which is a uniform price set at the intersection of demand and supply which will reflect the standard variable costs of an efficient peak plant. Both new (planned and under construction) and existing resources can participate in the auction as long as they are dispatachable, not subject to other

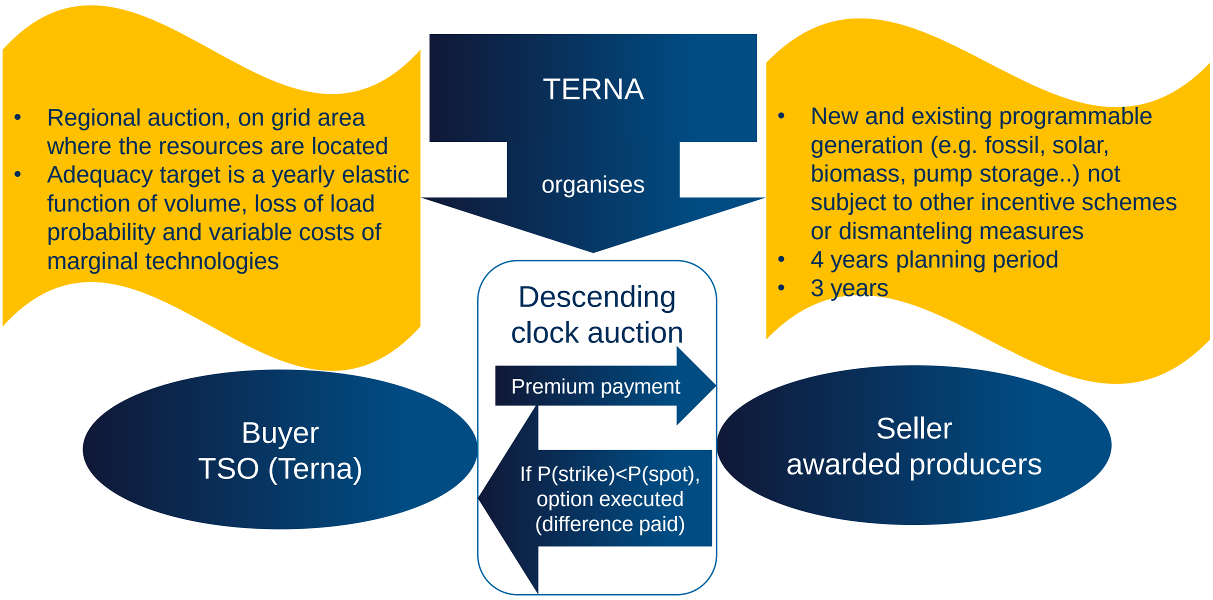
[4] http://www.handelsblatt.com/politik/deutschland/sigmar-gabriel-nein-zu-kapazitaetspraemien-fuer-fossile-kraftwerke/11251096.html

incentive schemes or any dismantling measures. The winning generators will receive a premium payment. However, they are obliged to submit offers in the day-ahead market, ancillary services and balancing markets and will need to pay the difference between the spot and the strike price back to the TSO, in case they end up producing electricity. This mechanism aims to reduce the risk for private investors by setting longer term price signals (AEEGSI 2014).

Table 9 The Italian capacity market – Overview of Second Tier design choices

Capacity treated identically			How is capacity payment determined?	Contract duration and lead time	Penalties for non-availability	Price caps
New / existing	Technology	Imports				
Existing and new plant treated equally	Only dispatchable, not subject to other subsidies or dismantling measures	Envisaged	Descending clock auction	Lead-time: 4 years Contract duration: 3 years	Difference between spot price and strike price in case of non-availability	Price floor

Figure 5 Functioning of the Italian capacity market



Source: Own illustration based on AEEGSI 2014

Part II: Implications for Switzerland

Although Switzerland is not planning to introduce a domestic capacity mechanism at present, the introduction of capacity mechanisms in neighbouring countries, or consideration thereof, has a number of implications for Swiss electricity producers, network operators, regulators and electricity consumers. Therefore, affected stakeholders have actively contributed to the discussions about capacity market design in neighbouring countries. Consider, for example, the joint submission of the BFE, Elcom, Swisselectric, Swissgrid and VSE to the German green paper on future market design (BFE et al. 2015).

On the one hand, the interaction between capacity mechanisms and the energy-only market will impact on prices observed on the Swiss electricity market and have repercussions on profits of electricity generators, costs faced by electricity consumers, investment decisions and create new circumstances that regulators and market and network operators have to react to. On the other hand, Swiss electricity producers may be able to participate directly in foreign capacity mechanisms. This cross-border participation again has the potential to influence profit margins, investment decisions at home and abroad and will necessitate a number of agreements and clarifications between regulators and market and network operators in Switzerland and abroad. In this section we therefore want to give an overview of the state of play with regards to cross-border participation. In the discussion, we highlight potential impacts of interactions of introduced capacity mechanism with energy-only markets.

4. CROSS-BORDER PARTICIPATION

Already today, there are several ways in which generation capacity can participate in markets in neighbouring countries. In particular, in day-ahead market auctions via automatic market coupling (e.g. between France and Germany) or through the auction of transmission rights (e.g. between Germany and Switzerland). Another example is the German network reserve (‘Winterhilfe; see also Section 3.2), where Austrian, Italian and Swiss power stations have participated in the bidding process and have also been contracted (BNetzA and Bundeskartellamt 2014).

Generally, there are two ways in which capacities in other countries can be taken into account in the design of a national capacity market:

– ***Implicit participation:*** Generation capacity situated in neighbouring countries can (and should) be taken into account, when the regulator (in the case of a centralised mechanism) or the liable parties (in the case of a decentralised mechanism) determine the amount of capacity that needs to be contracted to ensure system adequacy.
– ***Explicit participation:*** Generators situated in countries that are connected electrically to a country introducing a capacity mechanism may also be able to directly participate in this mechanism. In fact, the European Commission asks Member States to take into account “the participation of operators from other Member States where such participation is physically possible in particular in the regional context” (European Commission 6/28/2014, p.40), as a prerequisite for approving the mechanism.

In general, both implicit and explicit accounting for cross-border flows is necessary in order for national capacity mechanisms to lead to efficient outcomes. If, for example, the contribution of electricity imports to system adequacy in a country is underestimated, surplus capacities might be built in that country that would not have been necessary and thus make the system more expensive for consumers. Generation adequacy studies highlight the importance of taking generation capacity in neighbouring countries in into account (PLEF 2015), which may significantly reduce the need for additional domestic capacity. A study commissioned by the German Federal Ministry for Economic Affairs, for example, finds that "[i]n the region covering Germany and the neighbouring countries connected electrically and/or geographically, load and generation are balanced at any time with an extremely high probability of almost 100% up to the year 2025" (consentec and r2b 2015, p. 1). This indicates that up to this year, capacity mechanisms may not be necessary, when the demand and supply balance of the whole region is taken into account.

Similarly, explicit participation of foreign generators should ensure that the capacity mechanism supports capacities in a manner that does not distort the efficient functioning of the energy-only market, including the mechanism by which electricity flows to countries with higher prices (ENTSO-E 2015). In case of a well-designed market, explicit participation would probably be preferred on efficiency grounds (build capacity where it is cheapest), but this may then touch on distributional issues (cf. Meister 2015).

Before the introduction of capacity mechanisms, cross-border flows of electricity are either governed by (automatic) market coupling directing electricity flows to the country where prices are highest (until transmission capacities are reached) or follow an auction of transmission capacity. The different TSOs cooperate in monitoring those flows and if necessary take steps to ensure system adequacy at the European level (ENTSO-E 2015). The introduction of capacity mechanisms that would explicitly allow for cross-border participation would add another layer to the governance of these cross-border flows.

With regards to cross-border participation two important design choices have to be made that determine the nature and extent of cross-border participation: (1) who can participate and (2) what is the product being traded? We will explore these and further issues in the next sections.

4.1. Participation

In general, two basic participation models exist when it comes to cross-border participation in capacity mechanisms (1) the generator model and (2) the interconnector model, with a third mixed model (3) that may represent a variant of the first one (Elforsk 2014). This choice determines how liabilities, responsibilities, profits and risks are shared amongst market participants.

1. In a ***generator model***, generators would participate directly in the capacity mechanism in the neighbouring country. In this model, important questions arise with regards to the following questions: Who is responsible for the prequalification, verification and certification of the capacity situated cross-border (the national or the foreign TSO)? How is availability checked (this also depends on the definition of the product that is traded cross border; see below)?

2. In an ***interconnector model***, interconnectors participate, as is – for example – the case in the 2015 capacity auctions in the British capacity market. The important question to be confirmed here is: Do the interconnectors offer interconnector capacity or are they also responsible for procuring the generation

capacity? The receiving country would probably favour generation capacity.[5] If the interconnector is also responsible for the generation capacity to be available, this would pose significant issues with regards to the distribution of responsibility, liabilities and profits. Questions arise with regards to whether or not a foreign TSO should participate in a market mechanism – and do so in competition with domestic generators. This may not be compatible with the neutral oversight role a TSO usually plays and the financing structure of a TSO (natural monopoly).

3. In a ***mixed model***, the generators take part in the foreign capacity market directly, but only after the TSO has determined the amount of domestic capacity that is allowed to take part in the foreign mechanism. Furthermore, the TSO would have oversight of the process of delivery – and maybe other aspects, such as prequalification and certification. In fact, this mixed model may be interpreted as a generator model with extra requirements regarding the role of the TSO. A pure generator model without direct involvement of the TSO in some aspects is most likely not feasible at all.

The association of the electricity industry in Europe favours the direct participation of generators (EURELECTRIC 2015). ENTSO-E (2015) on the other hand, state that the most limiting (and therefore valuable) factor (either generation capacity or the interconnector) should participate and that participation should further take into account the direct advantages of opening the market and disadvantages through increased cost, i.e. that transmission distances should be taken into account.

Besides the direct choice of whether generators or interconnectors should participate, participation may also be limited due to the nature of the contracts being traded on a particular capacity market. Whilst the European Commission demands capacity mechanisms to be technology neutral (European Commission 6/28/2014), decisions with regards to, for example lead times, contract duration and definition of availability may preclude certain technologies. Small pumped hydro resources, for example, may only be able to generate for about 30 hours at a time and are therefore highly dependent on how contracts in the specific mechanism are specified. Therefore, the design of capacity contracts in neighbouring countries may play an important role regarding the involvement of Swiss generators. The French design, for example, with its fairly short availability periods (see Section 3.1) is relatively favourable also for small hydro producers.

4.2. Products

Another important issue determining the nature of cross-border participation in capacity mechanisms relates to the product being traded. The most important question in this context is whether the contract defines that actual delivery of electricity has to occur in periods of scarcity or whether the generator, load or interconnector is merely available in times of scarcity As physical delivery may lead to situations where the capacity market outcomes interfere with the energy-only market and push active plants out of the merit order, the ***availability model*** is usually favoured, as it is more compatible with the energy-only market and does not distort market outcomes

[5] In the case of electricity flowing from Norway to the UK, for example, available capacity is not the limiting factor, rather it is interconnector capacity (cf. ENTSO-E 2015 who indicate that it should be the limiting factor taking part in the capacity market).

(DNV GL 2014; EURELECTRIC 2015). It does, however, pose the question about how availability is measured. This becomes particularly challenging in the case of cross-border capacities.

One way to measure availability would be to ensure that contracted capacity bids into the intra-day or balancing market at times of scarcity. In France, for example, there exists a requirement for generators to bid into the market. In case of the availability model, the actual dispatch would then be determined by the energy-only market outcome. In the case of cross-border participation, the question arises, whether the foreign capacity has to bid into the foreign spot market or foreign market for ancillary services – or whether it suffices to bid into the domestic market, as market coupling or the auctioning of transmission capacity between the two markets would ensure that the flow is directed to where it is most efficient (cf. DNV GL 2014). If bidding into the domestic market suffices, the question arises who would check and communicate this to the relevant authority: The foreign or the domestic TSO?

Whilst a ***delivery model*** may be favoured by the receiving regulator as it would provide more security, its actual implementation may be impossible in practice as it is not possible to reserve interconnector capacity for delivery a long time in advance and this type of model is likely to interfere with the energy-only market and distort market outcomes and efficient cross-border flows.

4.3. Rules in coincident scarcity situations

It is highly questionable whether a TSO would allow contracted domestic capacity to honour its obligation under a capacity mechanism in times of coincident scarcity situations. EURELECTRIC (2015) proposes to change the responsibilities of the TSOs in order to also account for these types of situations. Most likely, rules have to be developed that specify exactly who pays the penalty in such situations. In fact, a harmonised penalty design may be desirable in those situations. A strong regional coordination between regulators is therefore of high importance. The fact that regional TSOs are actively discussing and advising on this topic (ENTSO-E 2015) confirms this.

On the one hand, concerns over whether interconnected capacity will actually be available in times of scarcity may lead to the de-rating of foreign capacity (cf. de-rating of certain technologies in the French CRM design). On the other hand, as mentioned above, generation adequacy studies indicate that there is currently no indication of these situations occurring (consentec and r2b 2015; PLEF 2015). In particular, the introduction of capacity mechanisms would be expected to further increase available capacity and make coincident scarcity situations less likely. Depending on the way the particular mechanism is designed, it can be expected that regulators would rather opt to include a security margin in their calculations of the capacity required, which would further increase the amount of capacity being available. This also applies to potentially overly conservative de-rating of foreign capacity that could in reality make a larger contribution to the security of supply in the country in question (DG Competition 2015).

4.4. Roles for the TSO in cross-border participation

On the one hand, TSOs play an important role in the operation of capacity mechanisms. They are usually responsible for prequalification, certification and verification (cf. the French CRM design, Figure 4). On the other hand, they also play an important role in cross-border activities already taking place in the European electricity market. Therefore, in the case of cross-border participation to capacity mechanisms, their role would be further extended.

In particular, in case a generator model is chosen (cf. Section 4.1), it is likely to be the TSO that will determine the amount of capacity available to take part in the capacity mechanism of another country. A natural limit could be available transmission capacity between the two countries. However, this is not necessarily evident, in particular if scarcity situations in the two countries occur in different points in time / different seasons (Frontier Economics 2015). In cases where capacity is contracted many years in advance, the TSO would have to make a projection about the capacity that is likely to be available in the future. Moreover, the TSOs may be responsible to avoid double participation in several capacity mechanisms of one generator (again this may depend on whether or not scarcity situations are likely to occur at the same time in different countries).

Furthermore, there would probably have to exist and agreement between the domestic and foreign TSO on measuring availability in scarcity situations. As mentioned above, the TSOs are also responsible for the coordination of physical flow in scarcity situations to ensure system adequacy. A clear system of rules would have to be defined for coincident scarcity situations to ensure regional system adequacy.

4.5. Relationship with the EU

The EU has recently rejected a preliminary bilateral agreement in the electricity sector with Switzerland.[6] Discussions about this preliminary agreement were conducted against the background of the introduction of automatic market coupling between Switzerland and France. Although a bilateral agreement between an EU Member State and Switzerland does not necessarily need permission from the EU, in this case the decision on market coupling had been linked to the existence of a bilateral agreement between Switzerland and the EU.

The course of action of the EU in this case indicates that bilateral agreements regarding the participation in capacity mechanisms between Switzerland and an EU Member State may also be influenced by the existence or not of a bilateral agreement between Switzerland and the EU. Also consider, for example, the German trial tenders for large-scale PV, which are envisaged to be opened to foreign investors, which would then require them to be situated in a country that has a “cooperation agreement” with Germany (Bundesregierung 2/6/2015).

In case, there would indeed be an EU-wide capacity mechanism in the future, it is highly likely that a bilateral agreement in the electricity sector between Switzerland and the EU would be a precondition for the participation of Swiss generators in such a mechanism. Other questions, such as reciprocity (a Swiss capacity mechanism?) would also come into play.

Regarding the relationship between plans of the European Commission with those of EU Member States, it becomes evident that the EU along with other supra-national bodies (e.g. ENTSO-E, EURELECTRIC) would favour the existence of a harmonised EU-wide model (ENTSO-E 2015; EURELECTRIC 2015). This is opposed to the very diverse designs for CRMs currently chosen by Member States. These diverse designs can be traced back to the different goals that countries follow with their capacity mechanisms (winter peak and DSM in France, summer peak and gas-fired capacity in Italy). For efficiency reasons, it would at least be desirable that key design elements are harmonised in adjacent markets in order to enable coupling of markets. However, there seems to

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[6] http://www.srf.ch/news/schweiz/eu-gewaehrt-schweiz-keinen-strom-kompromiss

exist some tension between efficiency considerations and the very diverse goals of individual mechanisms enacted to date. Against this backdrop, the European Commission has recently opened an inquiry into whether or not the implemented and proposed mechanisms have the potential to distort the internal energy market (European Commission 2015). This also applies to the harmonisation of rules around (explicit) cross-border participation, which are also discussed at the EU-level (DG Competition 2015).

5. DISCUSSION AND OUTLOOK

As this paper has shown, many countries in Europe have implemented or are discussing the introduction of capacity mechanisms, including the main import and export partners of Switzerland, France, Germany and Italy. The market designs chosen differ quite considerably depending on individual goals or market circumstances. Some details, such as the mechanism by which explicit cross-border participation could be possible, still have to be defined in the markets investigated in this paper. These developments in neighbouring countries and potentially at EU-level have implications for a host of different Swiss stakeholders, including generators, consumers and regulators.

Besides the potential cross-border participation in the mechanisms in neighbouring countries, the repercussions of the introduction of capacity mechanisms on the energy-only market will also determine their impacts for Swiss market participants. The Swiss electricity price generally follows wholesale prices on the German and Italian, as well as the French market. It can be expected that peak prices that occur in times of scarcity may be reduced or occur less frequently when capacity mechanisms are introduced, as additional capacity is kept online or built anew. The extent of this effect is a point of discussion and will crucially depend on the amount of capacity contracted, either through a decentralised mechanism (France), a centralised scheme (Italy) or by way of a Strategic Reserve (most likely case for Germany).

In case peak prices are indeed reduced or occur less frequently, this poses a threat to the business model of Swiss pumped hydro. For Swiss consumers, on the other hand, the introduction of capacity markets in neighbouring countries may mean lower electricity prices (depending on the extent to which those reach the individual consumer or different consumer groups). Therefore, the costs and benefits associated with the introduction of capacity mechanisms in neighbouring countries may be distributed unequally between different Swiss market participants. Further distributional effects exist between consumers situated in a country, where a capacity mechanism is in place and consumers situated in a neighbouring country, where capacity participates cross-border. Whilst consumers in the country with the mechanism in place pay – to some extent – for capacity built across the border, the consumers in the neighbouring country may benefit from lower prices on the energy-only market without contributing to the capacity cost. This example illustrates that the permission of cross-border participation may not be desirable for a country on distributional grounds (Meister 2015). This fact is also reflected in the current assessments by the French network operator (RTE 2015).

To date, there is no appetite to introduce a capacity mechanism in Switzerland due to its comfortable position with regards to available capacity (in summer in particular) and interconnection to neighbouring countries. However, it seems reasonable to pose the questions whether the energy-only market design will indeed be feasible in markets with very high shares of renewables, given their high fixed costs and low variable costs. Therefore, payments for capacity may become much more important than payments for a particular amount of energy produced in the future. Moreover, given that hydro power capacities in Switzerland are suffering under low electricity prices, subsidies such as capacity payments may be part of the political agenda in the near future. To what extent reciprocity considerations may force Switzerland to introduce a capacity mechanism of their own in case they want to participate in those potentially more potent capacity mechanisms in neighbouring countries in the future, is another point to consider.

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7. LIST OF ACRONYMS

CRM	Capacity Remuneration Mechanism
LSE	Load Serving Entity
MP	Market Participant
SO	System Operator
VoLL	Value of Lost Load

8. LIST OF TABLES

9. LIST OF FIGURES