A Raw Model for a North European Capacity Market

A Discussion Paper

Elforsk rapport 11:30

Gert Brunekreeft
Niclas Damsgaard
Laurens de Vries
Peter Fritz
Roland Meyer

June 2011

ELFORSK

A Raw Model for a North European Capacity Market

-A Discussion Paper

Elforsk rapport 11:30

Gert Brunekreeft
Niclas Damsgaard
Laurens de Vries
Peter Fritz
Roland Meyer

June 2011

Preface

The Market Design research programme has been operating for more than 10 years. Over the time the focus has shifted from the national to the Nordic and, in certain cases, to the European level. This emphasis will continue over the next three years, with the European perspective dominating.

In this report written by Gert Brunekreeft, Niclas Damsgaard, Laurens de Vries, Peter Fritz, and Roland Meyer various options for European capacity markets are explored.

With the increasing use of renewable energy for electricity production traditional power plants become less profitable. At the same time, the intermittent nature of many forms of renewable electricity production means that these traditional power plants are still needed as backup capacity and to provide demand flexibility. To ensure that generators are prepared to build and maintain sufficient backup capacity, it may become interesting to introduce capacity markets in the EU. This report provides an overview of some of the different capacity mechanisms that are in use in various parts of the world today and proposed two solutions that the authors believe are most suited to European conditions.

More information about the Market design Research program, finished reports and conference documentation can be found at www.marketdesign.se.

Stockholm, April 2011

Peter Fritz,
Secretary of the Market Design-program
Elforsk AB

Sammanfattning

De marknadsmodeller som används på elmarknader idag skapades för c:a 15 år sedan då de flesta elmarknader avreglerades. Dessa marknadsmodeller präglas av det bakomliggande syftet med avregleringarna – att främja konkurrens på elmarknaden. Marknadsmodellerna präglas även av den infrastruktur som dominerade vid tiden för avregleringarna – och som fortfarande dominerar – nämligen en infrastruktur bestående av ett antal stora, centraliserade, samt styrbara produktionsanläggningar.

På senare år har oro för klimatförändringar och leveranssäkerhet lett till en rad åtgärder som syftar till att ersätta fossila bränslen med förnyelsebara energikällor. Olika kraftfulla stödsystem används i Europa för att forcera in stora volymer förnybar elproduktion så som vindkraft och solel, en politik som i sig innebär en störning i marknadens funktion. Denna utveckling förväntas fortsätta då EU-länderna ersätter fler och fler traditionella produktionsanläggningar med anläggningar baserade på förnyelsebar teknik för att på så vis uppfylla de bindande krav som EU ställer på andelen energi som kommer från förnyelsebara energikällor.

Förnybara energikällor ställer samhället inför ett antal nya utmaningar. Även om förnyelsebara energikällor för det mesta kommer att kunna tillhandahålla större delen av den elektricitet som kunderna efterfrågar så kommer det att uppstå situationer då den förnyelsebara produktionen inte räcker till för att möta efterfrågan. För att hantera dessa situationer krävs reserv-kapacitet i form av traditionella kraftverk som kan tas i bruk med kort varsel. Frågan är om elmarknaden som den ser ut idag leder till att det byggs tillräckligt med traditionella kraftverk som kan användas för att tillhandahålla denna reservkapacitet. Dessa kraftverk kommer endast att användas under den tid då de förnyelsebara produktionsanläggningarna inte kan producera tillräckligt med elektricitet – under andra tider kommer dessa traditionella reserv-anläggningar inte att användas. De flesta Europeiska elmarknader är energimarknader – aktörer får betalt för den energi man levererar – inte för att göra reserv-kapacitet tillgängligt.

När möjliga nya investeringar i produktionskapacitet utvärderas tar investerare hänsyn till framtida efterfrågan, framtida utbud, samt framtida möjliga priser för att avgöra om en investering kan förväntas bli lönsam. Intäkter från energi-marknader bestäms av den ordning i vilken kapacitet tas i bruk – denna kommer att påverkas på två olika sätt när en allt större mängd förnyelsebar produktion påverkar produktionsmönster och priser. Dels kommer priser att pressas nedåt av förnyelsebar kapacitet vars marginalkostnad är låg eller t.o.m. noll. Detta gäller även de situationer då efterfrågan är hög. Dessutom kommer den relativt höga variansen i den mängd el som förnyelsebara anläggningar – främst vindkraftverk – förmår producera att leda till en ökade prissvängningar på elmarknaderna. Detta betyder kortsiktigt att ägare till traditionella kraftverk kommer att få svårare att få täckning för sina anläggningars fasta kostnader då dessa kommer att kunna producera el under färre timmar än tidigare. På längre sikt är det oklart om de investeringsförhållanden som råder är tillräckliga för att det skall byggas tillräckligt med traditionella kraftverk för att det skall finnas tillräckligt med reservkapacitet.

Vi kan i denna studie inte ta ställning till om det behövs kapacitets-marknader i EU eller inte. Syftet är snarare att kartlägga de olika sorters kapacitets-marknads-mekanismer som används i olika delar av världen idag samt att föreslå en modell för hur kapacitets-marknader inom EU skulle kunna se ut. Denna modell kan sedan tjäna som startpunkt i diskussioner om olika alternativ om EU-länderna skulle fatta beslut att kapacitets-marknader behövs.

I skrivande stund är det oklart om kapacitets-marknader kommer att behövas. Ökad flexibilitet på förbrukningssidan (via ökad användning av smarta elmätare, intelligenta elnät samt energilagringsenheter) samt en ökande sammankoppling av enskilda länders elmarknader kan leda till att effekterna av en större andel förnyelsebar elproduktion inte blir så kännbara.

Men om myndigheter bestämmer att det kommer att behövas mekanismer för att säkerställa att det byggs tillräckligt med reservkapacitet ser vi två olika huvudalternativ.

Det ena alternativet är att behålla dagens energimarknader samt komplettera dessa med strategiska reserver utöver de ”normala” reserverna. Detta är ett enkelt sätt att garantera att det alltid finns produktion som kan tillfredsställa efterfrågan, men denna mekanism löser inte problem relaterade till kraftiga prisvariationer samt risker för investerare som investerar i nya produktionsanläggningar.

Den svenska strategiska reserven kan användas för att illustrera hur denna mekanism fungerar. Svenska Kraftnät har av riksdagen fått i uppdrag att upphandla en strategisk reserv. Reserven fick tidigare maximalt uppgå 2 000 MW, men kommer successivt trappas ner fram till 2020. De sista åren får reserven maximalt uppgå till 750 MW och då enbart innehålla förbrukningsflexibilitet). Reserven kan användas under extraordinära situationer under vintermånaderna. Säljarna av denna kapacitet erhåller vanligtvis ersättning för att hålla denna kapacitet tillgänglig, och de får även betalt för den el som levereras om och när kapaciteten tas i bruk. Denna strategiska reserv består av både produktionsanläggningar samt kapacitet i form av löften om snabbt minskad konsumtion från vissa storskaliga elförbrukare. Denna mekanism kan dock inte användas till att året runt hantera den naturliga variation i produktionsnivåer från produktionsanläggningar för förnybar kraftproduktion.

Det andra alternativet är att använda obligatorisk handel med kontrakt som brukar kallas tillförlitlighetskontrakt. I denna studie föreslår vi en lösning där aktörer handlar i tillförlitlighets-optioner med krav att det skall finnas bakomliggande fysisk täckning. För handel i dessa kontrakt föreslår vi en centraliserad marknad som organiseras av systemoperatören och som drivs av en etablerad börsoperatör. Eftersom bilateral handel spelar en så stor roll på olika europeiska elmarknader föreslår vi att det även skall finnas möjlighet till bilateral handel i dessa kontrakt.

Iden bakom tillförlitlighetsoptioner är att med hjälp av finansiella instrument skapa incitament för kraftproducenter att bygga ny reservkapacitet samt göra denna kapacitet tillgängligt för elmarknaden vid behov. Optionerna reducerar risken vid investeringar och borde därför underlätta för nya aktörer att ge sig in på marknaden. Dock ökar riskerna för aktörer som inte gör sin kapacitet tillgänglig vid behov vilket gynnar stora aktörer.

I vårt förslag bestämmer myndigheterna vilken reservkapacitet som behövs genom att utgå från ett tänkt maximalt effektuttag. Reservkapaciteten sätts så att den överstiger detta maximala effektuttag med ett visst procentantal. Balansansvariga blir sedan skyldiga att köpa motsvarande mängd tillförlitlighetsoptioner. Vi föreslår att det tänkta maximala effektuttaget sätts till varje elleverantörs faktiska maximala effektuttag. Vi föreslår även att en myndighet bestämmer vilka strike-priser som skall gälla för optionerna. En erfarenhet från den ursprungliga PJM-marknaden var att ny kapacitet inte alltid byggdes där den behövdes mest. Lösningen var att införa olika typer av lägesberoende ersättningsnivåer. Även med en modell med tillförlitlighetsoptioner måste lokaliseringsfrågan hanteras.

Valet mellan strategiska reserver och tillförlitlighetsoptioner påverkas av hur den underliggande lokala elmarknaden ser ut, men även av vilka problem det är man försöker lösa. Strategiska reserver är enkla att hantera men löser inte alla problem. Exempelvis löses inte problem relaterade till prisvariationer, överföring av välstånd från konsumenter till producenter, samt risker för investerare. Tillförlitlighetsoptioner löser dessa problem men är mer komplexa och dras därför med en högre risk för att deras användning som styrmedel misslyckas.

Summary

Current European electricity market designs were conceived when electricity markets were liberalized around 15 years ago. The market designs are heavily influenced by the underlying purpose of those liberalizations – to promote competition in electricity markets. The market designs are also strongly influenced by the infrastructure that existed at the time (and still exists today) where the electricity system is dominated by large, centralised, and controllable generation facilities.

More recently concerns over climate change and security of supply has led to the introduction of measures designed to drive the delivery of renewables and decarbonisation. Strong support schemes are used across Europe to force the introduction of large volumes of renewable generation from wind and solar, a policy that by itself is interfering with the market function. The proportion of intermittent generation on the power system has therefore increased and is expected to continue increasing as EU member states replace conventional fossil fuel plants with renewable generation.

Renewable generation presents new challenges. Even though renewables may be able to provide a large share of the electricity supply most of the time, conventional backup capacity is needed to replace intermittent renewable capacity when that is unavailable and to provide demand flexibility to offset intermittency. A question that arises is whether markets can support generating capacity that is needed to ensure security of supply, but which may only be required for a few hours a year. With few exceptions, European electricity markets are “energy-only”. Generators get paid only for the electricity they generate, and the provision of capacity is not explicitly rewarded.

When potential investments in new generating capacity are evaluated, investors look at the prospects for supply and demand, and at the forward price curve when they try to determine if an investment will return acceptable economic returns. Revenue from energy-only markets is determined by the merit order. As increased proportions of the generating mix are dominated by renewable generation, price and production patterns will change, affecting the merit order in two ways. First, renewable generation tends to have low or zero marginal costs. This means that wholesale electricity prices will be pressed downwards, even during peak hours. Secondly, price volatility will increase due to the intermittent nature of most notably wind power. This means that shorter-term, existing generation will find it more difficult to recover fixed-costs, as they will be dispatched for fewer hours. Longer-term, it is unclear if there are investment incentives that are strong enough to permanently ensure a sufficient level of generating capacity.

The question as to whether Europe will need capacity markets is beyond the scope of this study. The purpose of this study is to provide an overview of some of the different capacity mechanisms that are in use in various parts of the world today, and to propose a model for a capacity market for Europe. This model can be used as a basis for discussions if authorities in Europe decide that some form of capacity mechanism is necessary. At this point it is still unclear if capacity markets will be needed. The future contribution of new

technologies that facilitate demand response, such as smart meters, smarter grids, and energy storage, as well as increased levels of interconnection between national electricity markets, may mitigate the effects renewables will have on the markets.

Given the aim to create regulatory incentives for maintaining and investing in less-frequently used generating capacity and in demand response facilities, we see two potential ways forward.

One way forward is to retain the current energy-only market design and to reinforce this design with a strategic capacity reserve in addition to the “normal” operating reserves. This is a simple and straightforward way to “keep the lights on”, but it does not address issues like price volatility or investment risk. To illustrate how a strategic reserve might work, we look at the Swedish strategic reserve. The Swedish TSO is mandated by the Swedish Parliament to procure and maintain a strategic reserve. The reserve will next year be a maximum 1750 MW, and will gradually be reduced to 750 MW for the last years up to 2020. The reserve is only used in extraordinary circumstances during winter months. Participants are usually paid an annual capacity payment in addition to the energy payment they receive when the capacity is called upon. The reserve consists of both generating and demand reduction resources, thus stimulating demand flexibility in the market, but it does not provide year-round demand flexibility to offset intermittency.
Another way forward is the use of mandatory reliability contracts, of which there are several alternatives. Among these alternatives, we propose a reliability contract framework where participants trade options contracts with a requirement of physical backing. For trading in these contracts we are proposing a centralised backbone market place, organized by the TSO and operated by an established exchange. However, as European market design is based on bilateral trading it is important to include the possibility of making bilateral arrangements.

The idea behind reliability options is to use financial instruments to incentivize generators to invest in backup capacity and make this capacity available to the system when needed. By reducing investment risk, reliability options should facilitate market entry. However, generators that do not make their capacity available face higher risks, thus favouring companies with large generation portfolios.

In our alternative of a reliability contract framework, the regulator determines the required reserve margins as a percentage over a defined peak demand, and the obligation to purchase the reliability options is assigned to the balance responsible parties. We are proposing that the definition of peak demand is based on the current actual peak demand of the balance responsible parties. Furthermore, we believe that a regulatory body should set the reliability option strike price. An experience from the original PJM–capacity model was that new capacity was not built where it was needed, whereas transmission constraints prevented the electricity from going where it was needed. This was dealt with through a locational component in the obligation. This issue must be addressed also in this model.

The choice between strategic reserves and reliability options should depend on specific market conditions, as well as on the problems that are being addressed. Strategic reserves are simple to implement, but leave a number of potential concerns unsolved. They do not address issues related to price volatility, wealth transfer from consumers to generators, and investment risks. Reliability options address these problems, but are more complex. This complexity increases the risk for regulatory failures.

Contents

1 Introduction

1.1 The task

In theory, current market design works...

One of the major challenges for power systems is to maintain a level of generation capacity that ensures an acceptable level of certainty against power shortages. A power market with a well-functioning spot market and long-term markets for allocation of risks between consumers and producers should in theory generate optimal investments in new power generation capacity and demand flexibility. This is also the basic principal behind the present market design in North West Europe including the Nordic countries.

...but will it work in the future with more intermittent generation?

This being said one must recognise that the design of markets and institutions has evolved based on an understanding of the present needs and the present structure of the market. The EU's RES directive and climate change targets and policies pose a major challenge for the European electricity system. Renewable energy generators like wind farms are intermittent sources. With a large share of electricity supply from such generation units, the need for backup capacity and demand flexibility will grow and new investment incentives may have to be introduced.

What would an alternative model look like?

The purpose of this study is to design and describe what a market model including a capacity market for the European electricity market would look like, if politicians decide that such model is desirable. The objective is <u>not</u> to establish whether or not it will be necessary to create dedicated capacity markets. This of course depends on a number of circumstances and is a much larger task, but with a concrete market model on the table, a constructive discussion can start.

The work was carried out by the following team:

Gert Brunekreeft, Jacobs University Bremen / Bremer Energie Institut, Germany; Roland Meyer Jacobs University Bremen / Bremer Energie Institut, Germany; Laurens de Vries, Delft University, the Netherlands; Niclas Damsgaard, Sweco, Sweden; Peter Fritz, Sweco, Sweden. All the conclusions in the report are the authors.

The Market Design Program appointed a reference group for the study. The reference group consisted of the following members:

Jan Andrea, E.ON, Magnus Thorstensson, Sweden Energy, Pekka Vile, Fortum, Christina Simón, SvK, Jan Sundell, Vattenfall, Jörg Jasper EnBW, Håkan Östberg, Energy Market Inspectorate.

As part of the project, EnBW and the Market Design Program organized a workshop on 8 April 2011 in Berlin.

The project was financed by the Swedish research organization

Elforsk through their program Market Design www.marketdesign.se

1.2 The Target Model for a European Wholesale Market

A target model for a European wholesale market

Besides meeting security of supply and climate change targets, a priority from the EU perspective is to create an integrated and competitive European electricity market. Such a market will only be possible if the different member states can agree on some common design principals and cooperate to implement these. Our work must therefore fit in that general perspective.

A new design should fit into the general picture

These last years the creation of a common European electricity market has been speeding up. The most concrete example is the development of a “target model” for a European Wholesale Electricity market. It is within the context of the wholesale market that a possible future “capacity market” will have to fit.

1.2.1 The decision making process

A more efficient decision making process in EU

As a consequence of the Third Package for the internal market for electricity and gas decided by the EU parliament, the decision-making process concerning the electricity market has been reformed.

First of all, the general design of the market is outlined in EU regulation, mainly in Regulation (EC) No. 714/2009.

Framework guidelines and network codes

Secondly, the market rules will be formulated in more detail in EU-wide “Network Codes”. The process of establishing network codes is described in Article 6 of the new regulation and involves the Commission and two new organizations, the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E). In short the process shall include the following steps:

The Commission establishes a priority list for areas to be included in the development of network codes.

ACER will develop non-binding framework guidelines setting out the principles for the network guidelines. All guidelines should contribute towards non-discriminative, effective competition, and to an effective functioning of the market. In this process ACER should formally consult ENTSO-E and other relevant stakeholders.

After reviewing the guidelines proposed by ACER, the Commission can either accept them or request ACER to review them. After acceptance the Commission will request ENTSO-E to submit a network code in line with these guidelines.

The new codes have to be approved by the Commission after recommendation from ACER, before they are finally adopted.

Among the first network codes expected to come into force is the network code for cross-border trade and involves therefore the design of the wholesale markets.

Several steps have been taken during the last years to prepare for the framework guidelines.

A target model taking shape

The work started in 2008 with the establishment of the Project Coordination Group (PCG) with participants from the Commission, the Regulators, TSOs, and other relevant stakeholders. The group was chaired by the European energy regulators trough their organisation ERGEG. A model and a roadmap for capacity allocation and congestion management were proposed in December 2009. The target model covered forward, day-ahead, intraday and balancing markets as well as capacity allocation and governance issues.

Encouraged by the Commission, ERGEG, assisted by an ad hoc advisory group (AHAG) carried out the work to develop framework guidelines during 2010. After public consultations a final draft is now sent to the Commission.

1.2.2 The Target Model for the European wholesale market

Traditional focus on efficient markets

The target model for the European wholesale market (as well as current European market design) is basically an “energy-only” market. The target model is based on an auction-based day ahead physical market, an intraday market with continuous trading and a real time market run by the TSOs. The real time market is used to enable sufficient balancing for a safe operation of the system.

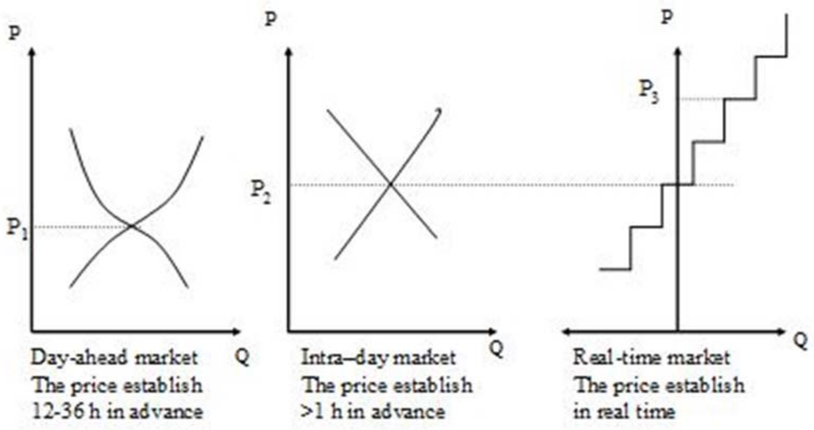


Figure 1. Balancing the system in the short run.
Source: SWECO

The two markets day-ahead and intra- day are designed to help the actors to optimise their physical power sales and purchases.

The purpose of the short-term markets is to create incentives and tools for the market players (producers, suppliers, and consumers) to sell and purchase physical wholesale power efficiently through a common platform, and to participate in the balancing of the system. An example can illustrate how short-term markets are supposed to work.

A power company with a number of generation facilities uses the day-ahead market to sell its generation. They bid power into the market according to their marginal generation costs for the various generation plants. Market clearing price (P1) and volumes for the participants are established. During the time span between the closure of the day-ahead market and the actual delivery hour things change. The expected demand and/or expected wind power generation increases or decreases due to changes in weather forecasts, and failures in generation facilities planned to operate may occur. To make sure that the necessary rescheduling of generation due to these changes in the market is carried out in a cost effective way, market players meet on the “intraday market”. Here it is possible to trade up to approximately an hour before the actual time of delivery. The price on the intraday market can be higher or lower than the price on the day-ahead market. In a shortage situation the price will be higher. The generator in our example chooses to sell more power for which it receives the price P2. During the actual delivery hour the system is run by the system operator (SO). To be able to do that all excess flexible capacity in the system is bid into the real time market. The SO will also hold special reserves (tertiary reserves) allocated only to this market and to possible counter-trading needs due to real-time grid congestions. Market participants responsible for imbalances in the real time market due to shortcomings in their planning will have to pay the marginal price on the real time market. That is why this market is also called the “balancing market”. In our example the generator will be paid P3 for power bid in and called upon in the real time market.

The day-ahead market has a strategic role in the design as it facilitates cross border trade

In this “energy-only market” generators only get paid when they generate. This is the case for all three markets day-ahead, intra-day and real-time. To make sure there is a minimum level of reserves in the system for the Transmission System Operator (TSO) to maintain a safe operation of the system generators may get paid for allocating resources (standing ready to produce but not actually producing) through special arrangements (tertiary reserve contracts) carried out by the TSO. This type of “capacity payment” exists in nearly all markets even in so called pure energy-only markets.

Day-ahead markets have a very specific role in the allocation of cross-border transmission capacity and thus facilitate trade between countries.

Forward markets are free to develop as seems fit

The idea is that power flows between countries shall be a result of decentralised decisions made by generators and consumers. Capacity between countries (or regions) is used to minimise price differences between markets. From a practical point of view this is done through the use of a common day-ahead-market (like Nord Pool Spot for the Nordic countries) or through close cooperation between market places often referred to as "market coupling" or "price coupling". The obligation of the owners of transmission capacity is to allocate maximum capacity to the day-ahead-market (some capacity may be kept for ancillary services). The payment for transmission capacity will be the remaining price differences between the two markets after trade, multiplied with the actual traded volumes. This way to allocate and pay for transmission capacity guarantees optimal utilisation. Excess transmission capacity after the day-ahead market clears will be allocated to the intraday market and to the real-time market.

As a complement to the short term physical markets there will be a forward market. The forward market can be based on physical delivery or financial settlement. The forward market is basically free to develop as seems fit, while the short term physical markets must have a common design to be able to facilitate non-discriminative, effective competition and the effective functioning of the market. One discussion regarding the forward market is whether or not the owners of cross-border lines should have an obligation to sell long term contracts covering the risk for price differences between countries. These contracts are often referred to as physical or financial transmission rights (PTR or FTR).

2 Problem Definition

2.1 A changing landscape

Traditional focus on efficient markets

Europe's electricity markets are facing substantial changes that may require the rethinking of the current market design. Traditionally, focus has been on developing competitive markets. Current market design has been heavily influenced by the original infrastructure, which consisted of large, centralised and controllable generation. The philosophy has been "predict and provide", i.e. that generation follows demand (even though the European spot and derivatives markets facilitate active demand-side participation as well).

Change in policy objectives...

More recently, focus has to some extent shifted from on efficient markets towards maintaining security of supply and reducing carbon emissions. These changes in policy objectives have led to the stimulation of investments in renewable generation.

...and in generation structure...

Increased feed-in of renewable energy sources (RES) has led to larger amounts of intermittent baseload supply, notably in the form of wind power. Figure 2 illustrates the dramatic, expected increase in RES generation over the coming decades as well as the high variability in RES generation.

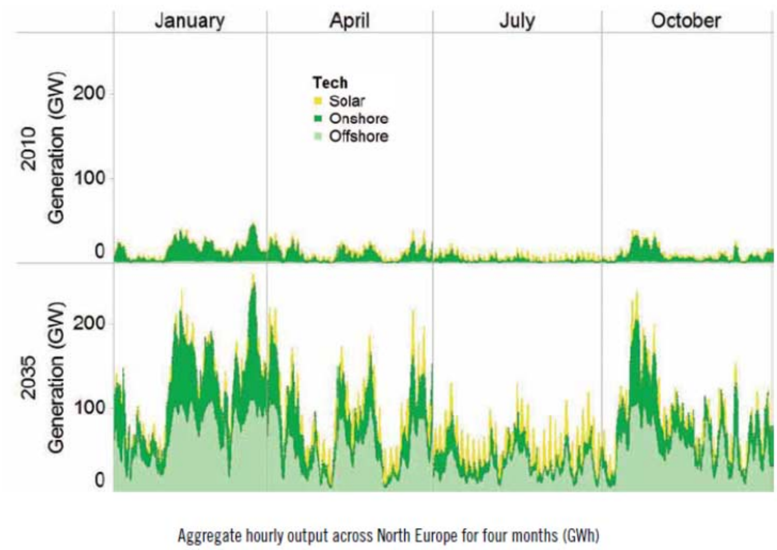


Figure 2. Renewable electricity generation across Northern Europe.
Source: Pöyry Management Consulting

...will result in increased price volatility...

As most demand is inelastic, this causes higher levels of market price volatility. However, in most European countries, generators rely to a large extent on *energy-only markets*, i.e. they have to recover both variable and fixed costs solely from market prices they receive for the amount of electricity sold and do not receive payments for capacity. Due to a lack of efficient ways to store electricity, adequate supply can only be maintained if enough generators are able to adjust their output to fluctuating supply and demand. Generators providing flexible supply may either be hydro or conventional plants. These generators are strongly influenced by the change in generation structure, since an increasing share of intermittent RES changes both the amount and volatility of revenues they can expect to earn from selling to the electricity markets.

...and changes to generation profiles.

Decarbonisation of the energy sector and the increasing amount of intermittent power generation will impact the wholesale generation market in several ways. Wholesale prices, generation profiles and the investment environment will all be affected. For generators, this means that the load factors and running patterns of their power plants will change.

2.2 Changes in generation and revenues

More peaky prices due to...

Revenue from energy-only markets is determined by the merit order. All dispatched generators receive the price that is given by the highest marginal cost of those plants needed to meet system demand. The introduction of significant amount of intermittent electricity generation will change production and price patterns. Figure 3 shows the evolution of price duration curves for some selected countries up to 2030 (based on model simulations). Generally, simulations show that wholesale prices will become much more peaky.

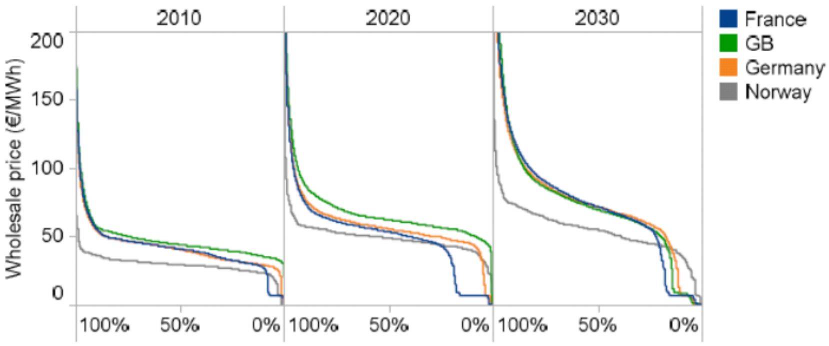


Figure 3. Price duration curve.
Source: Pöyry Management Consulting

...the merit order effect lowering market prices by adding capacities, and...

Due to the low marginal costs of RES generation, its growth causes a merit order effect. There are two distinct effects. First, market prices are reduced by adding new capacities with lower marginal cost, as illustrated in Figure 4. This will result in periods with very low and possibly even zero or negative prices. Negative price spikes may even occur after some conventional plants are closed down, if for the remaining plants the costs of reducing their output would be higher than production costs, e.g. due to start-up costs after shutdowns.

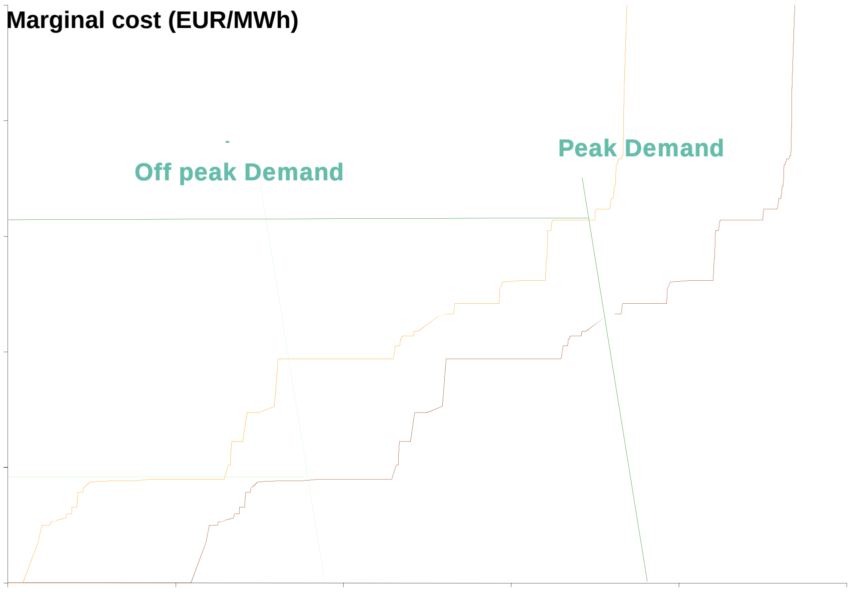


Figure 4. The merit order effect

...a scarcity effect pushing peak prices upwards.

Second, it increases price volatility due to the intermittent character of RES, most notably wind power. The fixed costs are recovered in relative short periods with high prices. Increasing amounts of intermittent generation will cause more periods with scarcity and high prices.

Short-run cost recovery may be worsened...

The increase in RES shifts the merit order to the right. One may distinguish between the short-term and the long-term perspective. A short-run effect from the restructuring process is that existing power plants may fail to recover their fixed costs, since they will be dispatched (and therefore earn their revenues) only for a smaller fraction of the time. Even in peak hours, prices will be too low as long as there are overcapacities in the market that prevent real scarcities to occur. Although this is a pure distributive effect caused by *stranded assets*, it is nevertheless an important problem given the long lead-times of generation assets. In Europe, problems of cost recovery are observed or expected in Germany, the Netherlands, and Spain.

...but more importantly, long-run investment incentives may be too weak.

An important economic problem could be expected in the long run. The critical issue is whether the investment incentives under an energy-only market design are strong enough to permanently ensure a sufficient level of generation capacity, and hence, supply adequacy. Although RES may be able to provide for a large part of electricity supply for most of the time, conventional generators are required for two reasons. First, adequate available generation and demand response is needed to ensure that the remaining demand can be met in peak times. Hence, overall capacities must exceed average demand to cover peak periods, even though some of these power plants are only dispatched for a few hours per year. Second, there is a need for flexible capacities to ensure the required adjustment of generation to demand at each point in time. In addition to the fluctuating demand, the growing share of RES also increases the intermittency of supply. As a result, the importance of both peak-load and flexible capacities increases. By contrast, notably peak-load capacities may be utilised less and may therefore fail to earn sufficient revenues for cost recovery. Accordingly, investment signals sent by electricity market prices may be too weak to sustain long-run supply adequacy if high scarcity prices are not accepted. Theoretically, energy-only markets should be able to induce efficient investments, but in practice there are a number of potential market failures and technological characteristics of electricity supply and demand that may hinder the market mechanism to work efficiently with respect to maintaining reliability.

Spot prices should reflect the opportunity cost...

The major shortcoming of energy-only markets is a possible lack of sufficiently strong scarcity prices, known in the literature as the “missing money problem” (see Cramton and Stoft, 2006). In a competitive market the spot prices would reflect the opportunity costs. For most of the time this would be the variable operating costs of the marginal plant. Occasionally prices would rise above the variable operating and start-up costs of the peaking units, reflecting scarcity. The opportunity cost would then be determined through demand response by the incremental value of demand.

...but scarcity prices may be suppressed...

Peak-load capacities must recover their full costs during relatively few hours when generation capacity becomes scarce. It could be during extra high peak demand or during situations with failures in other power plants or transmission lines. However, in many circumstances scarcity prices may not be high enough to induce sufficient investments, in particular in peaking capacities. A reason may be politically motivated price caps that aim to protect consumers from generators exercising market power in times of scarcity. However, it is difficult in practice to distinguish between real scarcity events (in times of high demand or outages) and the artificial scarcity caused by strategic withholding of capacities resulting from the abuse of market power.

...creating the missing money problem.

Accordingly, possible price caps and other mechanisms to reduce peak prices will most likely also suppress real scarcity signals that are needed to induce efficient generation investments (see Joskow, 2006). Furthermore, there are cases when market prices do not exist, for instance when demand exceeds available capacity so that the TSO has to rely on out-of-market mechanisms to keep the system in balance. However, if markets fail to clear in cases of extreme scarcity, there is also no market signal providing investment incentives. Accordingly, the investment level will be too low compared to the social optimum due to a lack of adequate returns (missing money).

Investment cycles may increase...

Even if price spikes would be high enough, the investment signals may come too late to incentivise the required investments in time. Even though peaking units can be built in 1-2 years, scarcity may increase further, until newly built generators are in operation. A result of this time-lag is the existence of strong investment cycles. Given imperfect foresight about other firms' investment plans, scarcity prices may induce more investments at a time than are required in the long-run as a result of investors overacting (see De Vries, 2007). Instead of reaching a long-run equilibrium, one may observe a sequence of over- and underinvestment causing additional price volatility that increases investment risks. However, this argument depends on the assumption that investors would not be able to anticipate such investment cycles. One would expect that this strong assumption does not hold in practice, even though foresight is certainly imperfect.

...price volatility and investment risk

Given the long lead times of generators and the reliance on (future) market prices to finance investments, price volatility is a major determinant of investment risk. Typically, price volatility is highest in times of scarcity, i.e. peak demand. This is illustrated by the price duration curve given in Figure 5 showing for which fraction of the time different price levels occur. Since scarcity prices only occur for less than 5% of the time, only small changes in the duration and magnitude of price spikes have large impacts on the expected revenues. Accordingly, the risk of prediction errors due to unexpected developments in supply or demand may be a severe obstacle to investments in generation capacities.

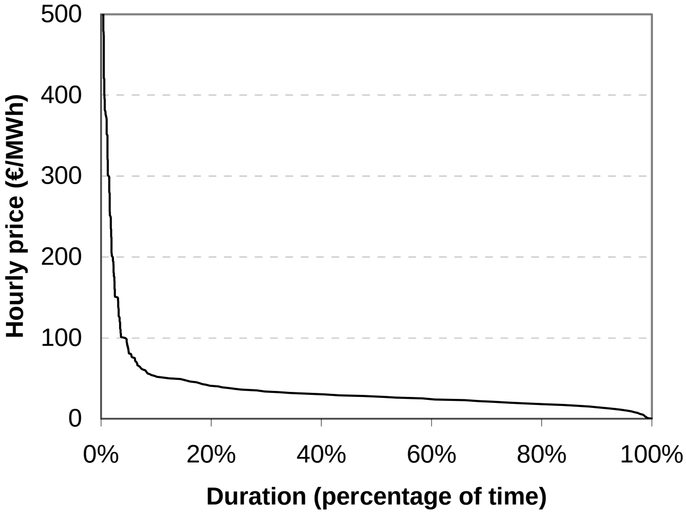


Figure 5. Price duration curve
Source: De Vries (2007), p. 21, based on APX data.

Forms of price volatility differ between regions.

In Europe, the forms of price volatility differ between market regions. In *central-western Europe*, where the share of intermittent wind power is very high and hydro power plays a minor role, the amplitude of price volatility is relatively short, i.e. prices mainly vary from day to day and within a day. *The Nordic countries* in contrast are characterised by a larger share of hydro reservoirs that can be used to compensate the major part of short-term supply and demand fluctuations. On the other hand, availability of hydro reserves varies between years depending on weather conditions. Hence, the amplitude of price volatility is typically larger, although still small compared to average lead times of generation assets.

Long-term contracts to hedge volatility are difficult to sustain under retail competition…

In principle, producers and consumers have a common interest in reducing price volatility. A possibility to hedge both parties against *price risks* is either to sign long-term contracts or to vertically integrate. While vertical integration between generation and retail is quite common in Europe (and is compatible with the European unbundling requirements), there may be a problem with long-term contracts. The reason is that generators and retailers have different preferences with regard to *volume risks*. While generators prefer a constant utilisation of their plants, and hence fixed-volume contracts, retailers need flexible volumes to be able to adjust to changing market conditions. In competitive retail markets like in Europe, consumers can easily switch between suppliers. Hence, it is difficult for retailers to predict the volume of electricity they need for years in advance. They may therefore hesitate to enter into supply contracts with durations long enough to effectively hedge generators against price and volume risks. This argument may be less relevant for *baseload generation*, since retailers can adjust their imbalances by additional market transactions. But for *peaking units* – which are needed exactly for short-term adjustments – there is less room for long-term contracts, since retailer would most likely not want to fix volumes ahead of time.

...and markets may fail to provide adequate reliability in face of its public goods attributes.

The reason why energy-only markets may fail to provide sufficient investment incentives is not only due to supply-side characteristics. What adds to the problem is the existence of two demand-side flaws. One is the inability of most customers to react on prices due to a current lack of real-time metering. This makes a significant part of demand price-inelastic. The second one is the inability to control power flows to customers on an individual basis (see Stoft, 2002). These demand-side flaws render reliability a public good, since competitive suppliers (as intermediates of their customers) will not reveal their willingness to pay for reliability, as long as hourly consumer pricing is not used and power interruptions are not restricted to their own customers (see Joskow and Tirole, 2006). As a result, it has been difficult to establish a market for reliability that adequately rewards generators for holding capacities on stand-by.

Determining the optimal level of reliability (and thus the required amount of peak-load capacities) is not a trivial task, in particular as

Asymmetric risk effects for consumers and producers

long as the lack of hourly metering prevents customers from sending efficient signals about their willingness to pay. Given this uncertainty, it is important to be aware of the different distribution of risks for producers and consumers regarding under- or overinvestment. The cost of underinvestment in terms of insufficient reliability affects customers in a much stronger way than generators. The foregone profits of investing a little less is almost negligible compared to the consumers' costs of high prices and an increased risk of power interruptions. Overinvestment, on the other hand, will drive the market price down and may prevent generators from recovering their capital costs. Hence, in case of doubt, consumers would rather err on the side of overinvestment; by contrast, generators may more easily take the risk of underinvestment (see e.g. De Vries, 2005). However, a significant portion of the loss to consumers would come from increased prices in shortage situations, rather than actual interruptions. Given a low price elasticity of demand this would mostly result in a transfer from consumers to producers, while the loss in total welfare would be much smaller.

Increased regulatory uncertainty

The transition to a low-carbon electricity sector will likely take several decades. During this time, the dynamics of the electricity sector will gradually change due to a shift towards capital-intensive, low-carbon energy sources. It is inevitable that in the course of this transition there will be many regulatory changes, for instance in the areas of renewable energy, the CO_2 market, the regulation of carbon capture and storage and nuclear power, but perhaps in other fields such as congestion management, the design of the balancing mechanism and transmission tariff regulation as well. As generation plant that is constructed now will function much or all of its lifespan during this transition period, the increase in regulatory risk may discourage investment.

Rethinking the market design

Summarizing the problems in current market designs, energy-only markets might not be able to provide adequate investment incentives, notably due to administratively set price-caps, lack of demand response, inadequate contracting or imperfect foresight of investment cycles. In the current market design, generators have to finance their capital costs for peak-load power plants solely through price spikes in times of scarce capacities. Insufficient cost recovery, and hence too low investment incentives, may result from insufficiently strong price spikes ("missing money"), in which case under-investment occurs. The risk may be exacerbated by the regulatory risk that results from the transition to a low-carbon economy. A specific case arises in the presence of a large volume of intermittent generation sources, which reduce the use factor of fossil plant while still requiring significant capacity as a back-up.

Physical or financial problem?

As stated in the introduction, the objective of this report is not to establish whether or not it will be necessary or desirable to create special capacity markets. In spite of all these potential problems with the energy-only market some of these problems may never occur and others may be fixed along the way. For example, the present "smart grid" development may lead to a substantial increase in demand flexibility. Creating new mechanisms such as capacity markets may also create new problems.

Still, the challenges ahead of us may be of such magnitude that a rethinking of the current market design will be necessary. Capacity mechanisms could provide one way forward in dealing with the challenges and problems the current market design is facing. Choosing the most suitable capacity market design(s) for Europe requires a critical analysis of given alternatives with respect to the technical and economic goals they should achieve. While this report is not about the question of generation adequacy and the question whether intervention is necessary, it is important to realize that different perceptions of the problem may lead to different choices. In particular, it matters whether one's concern is that 'the lights go off', that an acute power shortage may arise, or whether one is concerned about the sustained high prices that may occur during a period of shortage (whether or not the shortage is physical). In the California crisis in 2001, the high prices were the main negative effect on consumers, despite the widely published occurrence of rolling black-outs.

3 Design criteria for a North European capacity market

The problem formulation in chapter two is rather generic, but the discussions in different countries in Europe are focused on specific problems. In Spain it is the massive closedowns of CCGT, in UK the investments in wind-power and nuclear and in Sweden and Finland the risk of capacity shortage during extreme winter demand peaks. Different problems may have to be addressed by different measures.

At the same time there are some general design parameters that the capacity mechanism must relate to. Having these criteria's in mind may help to understand the various mechanisms outlined in next chapter.

A target capacity model should ensure reliability...

A possible future capacity market should be able to maintain an *adequate level of reliability* by inducing sufficient investment in generation capacity (and demand flexibility) to provide the necessary back-up for intermittent energy supply. This implies keeping investment risk and uncertainty moderate, notably by providing *regulatory stability* that minimizes the fear of discretionary political intervention.

...reduce price volatility and market power...

Price stability to reduce investment risk for generators and price risks for retailers is often outlined as one of the great benefits of capacity markets. This is of course only true if the purpose of the mechanism is to stabilize the price. Furthermore, it should help to *mitigate market power* by reducing possibilities and incentives for price manipulation. In times of scarcity, generators should be incentivised to make their *capacity available* instead of withholding it for strategic reasons. Regarding distributive effects, the income transfer from consumers to producers should be limited.

...and contribute to efficient technology choice and dispatch....

An important economic goal for a new market design is to favour efficiency both in long-term *technology choice* of investments and in short-term *generation dispatch*. The first aspect claims that investment decisions should not be distorted, notably regarding more or less capital intensive generation technologies. The latter criterion refers to an undistorted merit order that ensures a cost efficient generation mix for serving any level of demand (incl. demand response).

...considering European market characteristics.

A precondition for a future capacity model is its compatibility with the European market characteristics and developments. It should consider that Europe's electricity markets are *decentralized.* TSOs and market operators are distinct entities, and energy trades are not bound to mandatory pools. The European case of *retail competition* and its implications for long-term contracting mentioned above should be taken into account. Last but not least, Europe is moving in the direction of smart grids and smart metering. A new market design should therefore favour and not hamper the expected increase of *demand response* by smaller customers. Based on this set of criteria, the following sections present and discuss the most promising capacity market designs for Europe.

4 Overview of capacity mechanisms[1]

4.1 Introduction

Price vs. quantity regulation

The object of a capacity mechanism is for the government (or a delegated party, such as the TSO) to influence the volume of generation capacity. More objectives may apply, but this is the most basic function. The volume of generation capacity can be influenced directly by the government or through financial incentives.[2] For several reasons, it appears that direct regulation of the volume of generation capacity (or letting consumers control it explicitly) is more effective than financial incentives.

The consequences of errors

A first reason is that the demand curve for generation capacity has a steep slope and the supply curve has a gentler slope, a small error in the capacity price leads to a large shift in the equilibrium volume of generation capacity. Errors in controlling the quantity of generation capacity have a relatively small impact. A related reason is that price-based mechanisms provide a less stable investment signal, as a result of which investment cycles may develop.

Incentives more difficult than volume regulation

It is true that a regulated volume of generation capacity is not likely to be socially optimal, but it should not be overlooked that applying financial incentives also requires an idea of the optimal volume of generation capacity. This target volume of generation capacity needs to be known in order to set the level of the financial incentive. Consequently, there is more risk of erring in applying financial incentives: first in estimating the optimal volume of generation capacity, then in estimating the effect of the incentive upon investment in generation capacity. Estimating this effect requires precise knowledge of load-duration data and the average value of lost load. As generating companies have difficulty estimating these data (in order to estimate price spike revenues), it is unlikely that a central planner would do any better.

[1] This section of the report is based on De Vries (2004).

[2] This is a manifestation of the classic prices versus quantities debate; cf. Weizman (1974).

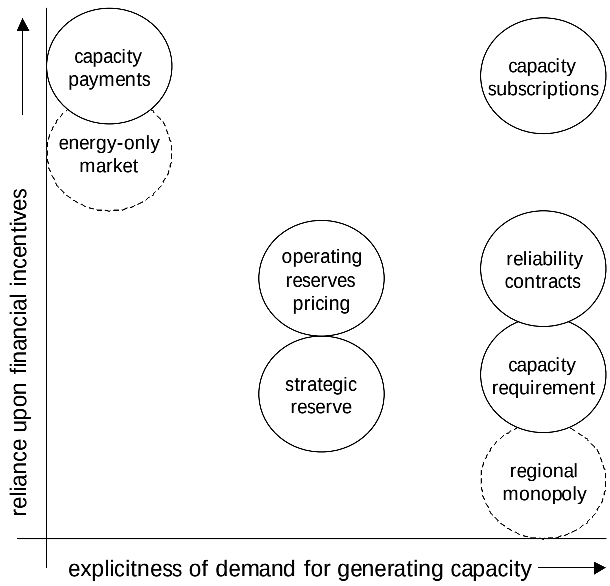


Figure 6: Overview of capacity mechanisms.
Source: De Vries (2004).

4.2 Capacity payments

Intuitive solution

One of the first capacity mechanisms to be developed was a capacity payment. These payments are made to all available generation capacity, in the hope that they will shift the investment equilibrium to a level where the risk of shortages is brought down to the socially optimal level. The level of the payment is determined by the government or its representative (such as a TSO). Capacity payments have been implemented in a number of countries such as Columbia, Spain and Argentina (Vázquez et al., 2002).

But effectiveness is unclear

Capacity payments have a number of fundamental drawbacks. First of all, it is difficult to determine their effect, and therefore how high they should be. It takes at least as long as the construction time of new power plant for their effect to become visible, while in case of an investment cycle their effect may not be visible until the next period of tight capacity. Secondly, if capacity becomes tight, the payments do not mitigate price spikes, nor the incentive to manipulate prices during shortages. Fundamentally, the problem is that capacity payments are a very incomplete contract: consumers pay producers without receiving a defined product in return.

Variable payments

A different kind of capacity payments were in the former England and Wales Pool (Wolak and Patrick, 1997). These payments varied depending on the reserve margin, hence their name 'dynamic capacity payments'. The payments were larger when the need for more capacity became more urgent. The payment was made both to active generators and to ones that were out of merit. The pool, with the capacity payment scheme, was manipulated by the generation companies, which was an important reason for the abandonment of the pool and the accompanying capacity payments in favor of NETA, and later BETTA. A more fundamental objective to variable capacity payments is that with their short-term fluctuations, they may not remove much investment risk and therefore not be very effective.

4.3 Strategic reserve

Centrally operated back-up capacity

The second most intuitive market intervention in response to concerns about shortages is the creating of a strategic reserve, sometimes also called a mothball reserve (in case it consists of old plant that otherwise would have been dismantled) or a ring-fenced reserve (in New Zealand). It consists of a set of generating units that are kept available for emergencies and are operated by an independent agent, typically the system operator. In theory, the revenues from dispatching the reserve should equal the costs, but if not, an adder to the electricity price may be necessary.

Low-impact back-up solution

The reserve is intended to operate only when the market does not provide sufficient capacity and should therefore be dispatched at a price above the market price. In theory, the reserve should only be dispatched at a price equal to the average value of lost load in order not to disturb peak prices during shortages. If this is the case, the natural price formation in the market is not affected and generation companies should receive the same investment incentive as if there were no reserve. Consequently, the risk of an investment cycle is also not affected. As price formation is not affected, this instrument does not affect the position of new market entrants.

Reserve may suppress investment

A key issue is how to decide when to dispatch the reserve. The market price at which the reserve is dispatched will become a de facto price cap, as generation companies cannot charge more for their power than the reserve price. So if the reserve is dispatched at a price below the average value of lost load, it will reduce the level of price spikes. This will reduce the average income of generation companies and therefore their investment incentive. Consequently, the reserve needs to be larger than the gap between existing generation capacity and the desired volume of generation capacity: the lower the dispatch price, the more investment will be suppressed and the larger the reserve needs to be. Figure 7 illustrates this point. It shows a sample price-duration function, in which daily average prices have been ranked from high to low. If the reserve is dispatched below the highest market price, the generation companies miss peak revenues. This can be mitigated by creating a larger reserve, as a result of which price rise sooner (up to the reserve price level). Thus price spikes are lower but broader.

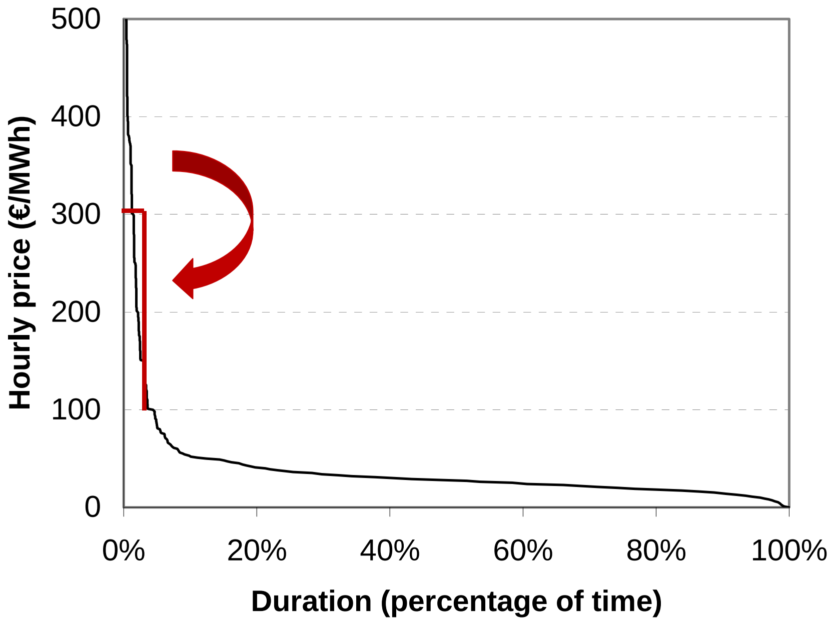


Figure 7: Effect of strategic reserve on price formation

Less simple than it looks

It is not easy to determine how much investment will be discouraged by implementing a strategic reserve with a dispatch price lower than the average value of lost load. It would be necessary to know the price duration function and how this would change as a result of the dispatch of the reserve, and how generation companies would change their investments in response to these price changes. Consequently, it is not easy to determine how large a reserve would need to be, given a certain dispatch price.

Dispatch criterion is crucial

A key factor for the success of a strategic reserve is the way in which it is decided when to run the plants. These rules should be transparent, so generation companies can estimate the effect of the reserve on prices and adjust their investment behavior accordingly. They must be convinced that the reserve will never be operated at lower prices, lest they will discount their future revenues and invest less.

Only for emergencies?

In theory, it could also be decided to dispatch the reserve only during dire emergencies, when there is an acute shortage of power. In theory, electricity prices should reach the value of lost load during such moments. (In practice, they may rise even higher, if consumers are not exposed to short-term prices and retailers have an obligation to serve their consumers.) Thus one could envision a reserve that is only dispatched when prices reach the average value of lost load. This should not distort the price duration curve, and hence not suppress any investment. However, the average value of lost load is difficult to measure. Moreover, at this level consumers, on the average, are indifferent whether they receive power, so the social benefit of the reserve is minimal (zero in theory) and the effect is limited to 'keeping the lights on'.

Tendering procedure

The European Union allows member states to enter a 'tendering procedure' for new generation capacity in the case that existing generation resources appear insufficient (Art. 8, Directive 2009/72/EC). Depending upon the details of the measures taken, the tendering procedure is likely to lead to the creation of a strategic reserve or capacity payments. If the tendering procedure simply is a way to stimulate the construction of new capacity by private parties, it may be regarded as a capacity payment to the investing parties. However, this would have a distorting impact upon competition and investment incentives, so it would run against the principles of competition law. If the tendered power plants are under the (indirect) control of the government and they are not allowed to participate in normal market operations, it would be tantamount to a strategic reserve.

4.4 Capacity requirements

Improvements to capacity payments

In the 1990s, PJM, the largest wholesale electricity market operator in the USA, made two important improvements to the concept of capacity payments. First, generation companies who received capacity payments were required to have this capacity available when the system was short and to supply it to the market at a price below the price cap of 1000 USD/MWh. Second, the payments were made by consumers (or their representatives, 'load-serving entities') in exchange for 'capacity credits', vouchers which proved that a certain volume of generation capacity was available. As these capacity credits are tradable, a capacity market was introduced. The intention of these measures was to regulate the total volume of generation capacity and to ensure that consumers received a defined benefit in return for the payments. Similar systems are in use in New York and New England.

Regulated market for capacity credits

In a system with capacity requirements, a central planning agency determines the desired generation capacity margin.[3] Based upon the expected total coincident peak demand of the loads served by each load-serving entity (retail company or large consumer), the system operator calculates how much generation capacity each load-serving entity must purchase (PJM Interconnection LLC, 2003).[4] Capacity may take the form of available generation capacity or interruptible

[3] The description of this method is largely based upon Doorman (2000), PJM Interconnection, L.L.C. (2001) and Hobbs et al. (2001c).

[4] In principle, the capacity requirements could also be placed on other parties, such as generating companies or consumers. Using the load-serving entities appears most practical, however. A disadvantage of placing the requirement upon generating companies is that the trade of the capacity credits may be affected by strategic behavior, while placing the requirement upon consumers would create large transaction costs.

contracts. Generating companies may sell capacity credits up to the volume of generation capacity that they have reliably available, which is determined by the regulator. Capacity credits can be traded, so there is a secondary capacity market. Load-serving entities include the cost of purchasing capacity credits in the price they charge to final consumers for electricity. In theory, if the capacity margin is chosen optimally, the average price paid by consumers should be the same as in a perfect energy-only market. The requirement to contract generation capacity in excess of the projected peak causes the capacity market to become constrained before the energy market does. As a result, the incentive to invest in new generation capacity develops before the electricity market becomes constrained. When the PJM market is short of electricity, the system operator 'recalls' generation capacity. All generators that have sold capacity credits are required to offer their capacity into the PJM pool, even if they have export contracts. Thus the capacity requirement is a type of call option, with the strike price equaling the pool price cap ($1,000/MWh).

Issues

PJM's capacity market initially suffered from some important shortcomings that have been repaired, such as that the system could be gamed by selling credits for plant that was not physically available, which would not be found out if the plant's power was bid at the price cap. Another problem was that the capacity credit prices were highly volatile, which was remediated by making the demand for credits price-elastic (which was done by making the penalty for non-compliance a function of the degree of non-compliance). A third issue was that new capacity was not built where it was needed, whereas transmission constraints prevented the electricity from going where it was needed. This was dealt with through a locational component in the obligation. PJM's capacity market is highly complex – we have only given you a summary overview here – which has resulted in a substantial bureaucracy.

4.5 Reliability contracts

Financial version of capacity requirements

Reliability contracts, also called reliability options, are designed as an improvement upon capacity requirements.[5] A capacity requirement resembles an option contract: generators receive money in exchange for giving consumers the option to purchase power at a certain price (the system price cap). The only difference is that if generators fail to deliver on the option, their penalty is not market-based but determined by the regulator. The idea of reliability options is to use financial instruments, rather than regulate physical availability of power plant, in order to incentive generators to invest sufficiently and to have their capacity available. By reducing investment risk, this instrument should facilitate new market entry. However, it also imposes greater risks on generators who are not available, and in this way favours companies with large generation portfolios.

[5] The description is based upon Vázquez et al. (2002), who proposed this system.

TSO purchases call options from generators

The original design of reliability contracts calls for an independent agent, which we will assume to be the TSO, to purchase call options from generators on behalf of consumers. The call options give the TSO the right to the difference between the electricity spot price and the option strike price. The TSO passes these payments on to consumers. The options are called when the spot price exceeds the option strike price. Consequently, the strike price effectively becomes the price cap for consumers. The difference with a regular price cap is that this price cap is 'purchased' from generating companies through the payment of the option premiums. These premiums provide generators with compensation for their lost price spike revenues, with as a benefit that now their incomes are more stable and predictable.

Risk reduction for consumers

The volume of the contracts and the strike price are determined by the TSO (or the regulator). The volume of reliability contracts should be equal to the forecasted peak load plus a reserve margin, similar to in a system with capacity requirements. The strike price should be above the highest marginal cost of operation of all the generators, to make sure it will not discourage any generator from producing. The price of the reliability contracts (the option premium) is determined in auctions. Generators lose their peak revenues above the strike price. They will make up for this loss through the option premiums which they receive. As the option premiums are fixed payments, this makes their incomes more predictable.

Efficient incentives to generators

An important benefit is that reliability options provide a strong incentive to generating companies to maximize their output when capacity is short and prices rise. When the system operator calls the options, generating companies who have sold options pay the system operator the difference between the market price and the strike price for which they have sold options. An operational generator will receive the market price from selling electricity on the market, so his net income will be equal to the strike price (namely the market price minus his payment, which equals the market price minus the strike price). Consequently, the generating company's option payments are fully hedged by market prices.

Strong incentive to maximize generation during shortage

On the other hand, a generator who has sold option contracts but happens to be unavailable when the options are called, still is required to make the option payments, but does not have any revenues to compensate these payments. Therefore generating companies have a strong incentive to make their capacity available when the options are called, which is when electricity is scarce.[6] This is one of the main advantages of this system. A second advantage is that the generating companies have an incentive to sell a volume of

[6] The proposal by Vázquez et al. (2002) adds a fixed penalty to the payments by the generators to further discourage them from not being available. An attractive consequence is that reliable generators are able to bid lower in the auction than unreliable generators.

call options equal to their expected output: selling less would reduce the fixed part of their income, while selling more would expose them to a high price risk during shortages. In order to prevent price volatility in the option market, the option contracts should be sold a number of years in advance, and also have a duration of a number of years.

Implementation in Europe

An issue with implementation in most European markets is that the reliability contract scheme was designed for a pool-based (integrated) wholesale market, in which the TSO is also the market operator and there is a well-defined system price. In the absence of a mandatory power pool, there is no single system price at which level the TSO should call the options. Some parties may be receiving electricity through long-term contracts with price close to cost, whereas others may be purchasing spot electricity at much higher prices. In this case, it appears necessary to devise a variant of the reliability contract scheme that can be implemented in Europe's decentralized wholesale electricity markets.

4.6 Capacity subscriptions

New possibilities with real-time meters

Fundamental to the issue of generation adequacy is the fact that small consumers are isolated from the electricity market. They are not confronted with short-term price signals – which convey crucial information about a product that cannot be stored commercially – and are also not able to express their preferences regarding the level of reliability that they wish to receive (and pay for). The advent of digital, real-time electricity meters may offer solutions to both issues.

Principle

In the original proposal (Doorman, 2000), a sort of electronic fuse was to be installed at every customer. These fuses would be activated during shortages and thereby limit consumption. Consumers would be able to choose the size of their fuses, but they would have to purchase them from generating companies, who would be obliged to provide a volume of generating capacity equal to the combined volume of the fuses that they sold. The main obstacle to this solution was the need to install a fuse at every customer, but now that digital meters are being installed, it is a logical step to investigate whether they can be used for a similar scheme.

Ultimate implementation of option requirements

A market with capacity subscriptions is the most market-oriented of the capacity mechanisms, as both the quantity of reserve capacity and the price are determined by the market. The only role of the regulator is to enforce that generating companies do not sell more capacity than they can provide. Consumers purchase capacity subscriptions, which entitle them to a certain peak volume of consumption when the system is short, but not more than their subscribed volume of capacity. This will need to be enforced with a threat of a penalty. Alternatively, consumers who consume too much during a shortage could be individually interrupted, if their meters have this functionality. During off-peak times, consumption is not limited.

Market signals the demand for generating capacity

By forcing consumers to pay for the generation capacity that is made available on their behalf, generators receive a signal regarding the demand for generation capacity and therefore are induced to provide the amount of capacity that consumers consider optimal. This way, consumer preferences for reliability are correctly reflected in the volume of available capacity. This is the only capacity mechanism discussed so far in which consumers can directly influence the volume of installed generation capacity, like they do in an ideal energy-only market.

Consumer capacity market

When the demand for electricity begins to approach the available generation capacity, the system operator sends out a signal to the consumers that their electricity use will be limited to the capacity of his subscription. Consumers can choose the size of their subscription; the price depends on the cost of the generation capacity. Thus, incentives are introduced for consumers to manage their own loads and rationing occurs in an economically efficient manner. The payments made for the subscriptions represent the costs of keeping an equivalent of generation capacity available, while the price of electricity represents the variable cost of electricity production. Because physical shortages are almost completely prevented, the price of electricity should rarely rise above marginal cost.

Enforcing the availability of plant

A complication is the stochastic nature of the availability of generation capacity, which means that generating companies need to sell less capacity than they have installed. However, even if a generating company maintains an ample margin between his installed capacity and the volume of capacity subscriptions that he sells, there is a possibility that it will not be able to meet its obligations. The first recourse is the balancing market but there is a remaining probability that the entire system is short of available capacity compared to the volume of capacity subscriptions that have been sold. This means that service interruptions may still occur. To keep these to a minimum, generating companies who do not meet their obligations should pay a penalty equal to the average value of lost load. The penalty can be paid to the consumers whose service was interrupted as a form of compensation. This is also a market-oriented solution: as the capacity subscription is a product that consumers buy, the penalty is an indemnification of their losses.

Feasibility

The main question about this proposal is how small consumers will react. This will depend on the implementation details. How should a shortage be signalled to consumers? Presumably they do not look regularly at their electricity meters, nor are they interested in having a conspicuous display in their living rooms. When they know that the system is short, how will they respond? Do they first need all sorts of ‘smart’ applications at home that will automatically curtail certain load, such as washing machines, in case of a shortage? To answer these questions and develop practical solutions, we recommend first to develop a pilot with a number of households.

Large consumers

At large consumers, this solution can immediately be implemented. Presumably, all contracts already have a fixed component that depends on consumption. In this market segment, implementing capacity subscriptions requires nothing more than stipulating in the power purchase contracts that the consumers are held to their contracted peak capacity whenever the system operator declares the system to be short.

4.7 Analysis

Limited choice

Despite the large number of capacity mechanisms, each of which has many variants, the options are limited. Capacity subscriptions, at least when based on the use of real-time electricity meters, first need to be further developed and tested before they can be implemented. Capacity payments without an obligation by generation companies to deliver a certain product in return are too non-committal and therefore too unpredictable in their effect.

Strategic reserve or reliability options

This leaves us with a choice between a strategic reserve and some form of capacity requirement or reliability option. As we saw, the latter two options are related to each other and a hybrid may be the best candidate for Europe's decentralized wholesale markets. A PJM-style capacity market requires a mandatory power pool and intensive regulation, whereas the original reliability options proposal is also based on a pool and requires a larger role for the TSO than might be desired. A solution in which consumers are required to purchase option contract may work in Europe's decentralized markets.

A simple but limited solution?

A strategic reserve is a simple and tried solution, but its effectiveness is limited. Moreover, as it can be expected to suppress some investment, it will need to be larger than the volume of generation capacity that is currently deemed necessary as back-up. While a strategic reserve is administratively easy to implement, economically it is not easy to implement it in such a way that it provides an optimal investment incentive to market players. It leaves the risk intact that price spikes are manipulated; even only a suspicion of price manipulation may have negative consequences for investment.

Or a complex and innovative solution?

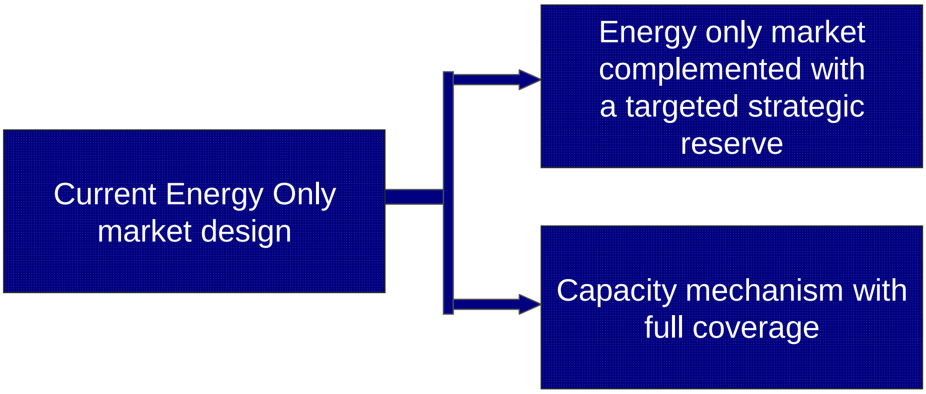
The alternative is to develop a new version of reliability contracts. This would be more effective in stabilizing investment and provide better operational guarantees, but the innovative nature carriers a risk of policy failure. An advantage of reliability options is that they can be used to stimulate specific technologies, such as flexible generation which can serve as a back-up for wind. (It could also be conceived that wind generators themselves purchase this capacity so they can sell reliability options on their portfolio.)

5 Models for a European capacity market

5.1 Introduction

Two ways to go

There are two ways forward if the aim is to create regulatory incentives for maintaining and investing in less-frequently used generation and in demand response, both of which are resources that are needed in the future European electricity market.



Energy-only complemented with a strategic reserve as a temporary solution

One path is to stick to the present design where the incentives to develop these goods come from the price volatility and price spikes in the short-term electricity markets, i.e., essentially keeping the energy only market design. To make sure this design does not jeopardize security of supply criteria's, a strategic capacity reserve can be added in addition to the "normal" operating reserves that are always needed. This is a rather simple and straight forward way to make sure "the lights stay on", but it does not address some of other issues such as stabilizing the prices or reducing investment risk. To illustrate how a strategic reserve can work we use the Swedish example (see Section 5.2). Sweden's strategic reserve is a temporary solution intended to support the market during the transition period. A special focus is on the development of demand flexibility.

A mandatory reliability contract market

The other path involves a more fundamental change in the market model and affects all actors. This would include a capacity mechanism with "full coverage". Balance responsible parties would be required to purchase capacity. All type of capacity would, in principle, be eligible to sell capacity. We believe it would be necessary to require a physical backing of the sold capacity. We have called our design draft "A Mandatory Reliability Contract

Market" The design is a mix of a centrally operated reliability contracts market and a bilateral reliability contracts market that we feel would be the most suitable for the evolving European electricity market. How this is supposed to work is outlined in section 5.3

5.2 Example of a strategic reserve

Temporary reserve

The Swedish TSO is mandated by an act of parliament to procure and keep a strategic reserve, which may consist of both demand and supply side resources.[7] The reserve is procured in an annual tendering procedure and the capacity should be available for the winter season. The system was introduced as a temporary mechanism in 2003, following concerns that the market alone would not provide sufficient incentives to maintain reserve capacity. Currently the scheme is intended to be phased out by 2020, when the market participants are expected to be able to keep sufficient reserves themselves.

Maximum volumes and minimum volumes demand up to 2020

Winter	Max volume	Demand	Generation
2011/2012	1 750 MW	438	1312
2013/2014	1 500	750	750
2015/2016	1 000	750	250
2017/2018	750	750	0

Also to stimulate demand flexibility

An additional purpose for the reserve, besides security of supply, is to stimulate demand flexibility in the market. At present (winter 2010/2011) the total reserve is 1 892 MW of which 1 309 MW is generation and 583 MW is demand reduction. The plan is to gradually reduce the share of generation facilities and, by the end of the period, only have demand resources in the reserve. The participants are normally paid an annual capacity payment (EUR/MW) and an energy payment (EUR/MWh) when they are called upon. Both payments are individual (paid as bid) and stipulated in the contract between the TSO and each participant. The cost of the strategic reserve is financed by a levy on the balance responsible parties[8].

Evolution

The detailed rules, e.g. regarding how and to what extent the resources are made available to the market, have been changed over time. The intent has always been that the reserves should not affect market prices, in order not to crowd out pure commercial investments. Originally, the reserve was intended only for system reliability purposes, but later on the resources were also made available to help ensuring market clearing on the day-ahead market. The reserves are bid into the market by the TSO, but only when

[7] Finland is running a similar scheme according to harmonized rules.
[8] Approximately 0,5 EUR/MWh weekdays 06-22, from 16 November to 15 March, for all metered consumption.

there is a shortage situation (demand exceeds supply at any given price). The price on the day-ahead market when resources from the strategic reserve are used will be the price of the last commercial bid plus 0,1 EUR/MWh. Reserves not used on the day-ahead market must be made available for the TSO on the real time market, but will only be called upon after all commercial bids have been used.

Experience during past two winters

During the past two winters significant capacity has been unavailable in the Nordic market, primarily due to outages of Swedish nuclear. The cold winters have also pushed up consumption leading to a difficult supply-demand balance. The reserves were used occasionally to secure day-ahead market clearing. At these times, prices peaked at very high levels and small volumes had a very large impact on the clearing price. The Swedish TSO and Nord Pool Spot concluded that it was a disadvantage that the demand reduction reserves were withheld from the market.

From this experience some potential problems were identified:

- the current mechanisms may contribute to withholding capacities from the market that would otherwise be bid in to the market on a commercial basis,
- the current mechanism does not contribute to reduce the possibilities for producers to abuse market power, and as small volumes may have a significant impact on prices there is a risk for market abuse
- the current mechanism may discourage consumers from placing demand reduction bids at high prices as this could contribute to increasing prices.

More room for demand-side bids

For the coming year some changes will therefore be implemented. The most important is that demand side reserves will be allowed to freely bid into the day-ahead market. This change does not apply to supply side reserves. The motivation is that the supply side reserves would not exist without the strategic reserves, while the demand side reserves would fundamentally be there in any case. Allowing them to bid into the day-ahead market is intended to stimulate the development of an active demand side. The rules for the supply side reserves are not changed.

Financing the reserve

The present Swedish reserve is financed through a fee paid by the Balance responsible parties based on gross consumption. This fee is passed through to the consumers.

5.3 A mandatory reliability contracts market

A mandatory market

In order for a capacity mechanism to have any real effect it needs to be mandatory. It is already possible for market participants to enter into various contracts that essentially can serve the same purpose, e.g. long-term bilateral contracts, option contracts etc. There are however substantial elements of a free-rider problem. For example, if there is sufficient capacity on the market price spikes will occur less frequently and be smaller in magnitude. This would benefit both parties that have entered into this type of contracts and those who have not.

With a physical backing

Capacity mechanisms can be designed in different ways. We propose a reliability contracts framework, i.e., an option contract. This contract could in principle be designed as a pure financial contract, without requirements of physical backing. However, we believe that it is necessary with a requirement of physical backing due to two main reasons:

- If most parties enter into contracts with physical backing there will be sufficient capacity and price spikes will rarely occur. It is then very cheap to offer pure financial contracts and pay for the option when it is called (if ever). This is a free-rider problem.

- Secondly, there is a risk of “fly-by-night” traders selling options, but not being around when they are called. This means that either physical backing or financial collateral is needed.

Possibility for bilateral trading

The reliability contracts market will by necessity be circumscribed by substantial regulation. However, the European market design is based on bilateral trading and voluntary exchanges. In order to adapt to the European market model it is important to include a possibility of making bilateral arrangements, and not be forced to a centralised solution. However, also for bilateral solutions it will be necessary to establish certain requirements to ensure that the necessary physical backing exists.

With a centralised back-bone

Centralised market places are however gaining ground in European markets. For market participants using exchanges as the primary market place for selling or buying electricity, it will imply a further complication if bilateral agreements for capacity is the only option. We therefore propose a centralised back-bone market place. The TSO will be responsible for organising the market place, although the operation of it could be done by a different party such as the established exchanges.

Locational components

One experience from the original PJM–capacity model was that new capacity was not built where it was needed, whereas transmission constraints prevented the electricity from going where it was needed. This was dealt with through a locational component in the obligation. This issue must be addressed also in this model.

Reserve margin determined by the regulator

In the original reliability contracts model, the TSO purchases options equal to the expected (peak) demand plus a reserve margin. While we propose a model where it is not the TSO that purchases the options, but the requirements are put on the balance responsible parties, it is still necessary that the regulator determines the required reserve margin, e.g. 15% over peak demand.

Defining peak demand

We see two different possibilities for defining the peak demand. Either the peak demand is determined based on current actual peak demand, or it is determined based on forecasted future peak demand. While forecasted future peak demand may better reflect the future needs, it also creates additional complexities and requires that a prognosis is made. In a competitive market place this may be very difficult for balance responsible parties to make such a forecast, as they may lose or gain customers. We therefore propose to base the peak demand on the current actual peak demand of the balance responsible party In case of a rapid increase in demand it could be necessary to add a generic growth factor.

5.3.1 Time horizon

Forward looking model

In order to provide reasonable long-term investment signals the model needs to be forward looking, i.e., capacity that will be needed in some years' time is procured now. A general problem is however that the time horizon of almost any conceivable model that is consistent with the overall European market framework will be much shorter than the time horizon of a generation investment.

5.3.2 Determining the strike price

Determining the strike price

The second central element that needs to be determined is the strike price. The price should be high enough that it does not interfere with merit order dispatch of generation and demand flexibility, so higher than the variable costs of the most expensive plant in the system, but low enough to be politically acceptable. As a minimum it is justified to define a maximum strike price. The requirement of a physical backing however makes the strike price less important, but it will still serve at least one very important purpose – it creates incentives to be available for generation when the option is called. Furthermore, the option strike price is important to what degree the mechanism contributes to price stability. A very high strike price implies that the option component in the mechanism becomes irrelevant. An alternative is to only determine a fixed fee for unavailability when called upon, in order to provide incentives for availability.

Cross-border effects

The strike price should be set by a regulatory body. In order to prevent undesired cross-border effects, it should probably be set in collaboration between the European regulators.

5.3.3 Calling the options

Options are called based on a common accepted reference price

In the centralised backbone alternative the option should be called upon based on a commonly agreed reference price. Currently a large portion of the trade is done bilaterally, and not all parts of Europe have well established and commonly accepted reference prices. As the European market model is evolving towards market coupling, which itself relies on the existence of accepted reference prices, this should not be a problem in future European electricity markets.

In the bilateral alternative calling the option need not trigger a payment

In the bilateral alternative it is not necessary that the financial part of the option is triggered when prices exceed the market reference price. The bilateral contracts may involve other types of hedging, e.g. a long-term fixed-price contract, which makes an option payment redundant. The load however needs to be covered by own /contracted generation, or purchased on the market.

Vertical integration

Suppose a retail company is integrated with a generation company. Does this mean that the retail company may opt out from the obligation to purchase reliability contracts for the equivalent volume of his bilateral contract? The answer should be yes, but measures need to be taken to prevent this company from free-riding. The generation company must commit to making its capacity available whenever the day-ahead price reaches the strike price that was decided by the regulator, which is similar to the bilateral arrangements in general. A penalty will need to be designed that provides a strong enough incentive to meet this obligation.

5.4 Evaluating

There are a number of criteria to evaluate a model against, and it is not necessarily true that everyone agrees on exactly the same criteria or their relative importance. In this section we discuss the proposed models relative to such criteria. To be able to evaluate if either of these models should be implemented one must of course also consider the option to improve the energy only market, but as mentioned earlier this has not been the purpose in this study.

Criteria	**Energy only market with strategic reserve**	**Mandatory reliability contracts market**
Adequate volume of generation capacity	The model only provides remuneration to targeted units. Relies on the energy payments for the majority of the units.	Puts a specific reserve margin requirement and provides payments to all (participating) generating units.
Adequate long-term investment signals	Will add extra capacity to be used in extreme situations, but will not give stronger investment signals in general compare to an energy only market	Depends on the time horizon. A forward looking model provides some long-term investment signals.
Stimulate	The model typically	With appropriate

availability of plants	does not explicitly stimulate availability of plants. The higher peak energy prices however reward availability.	strike price and/or penalty fee availability when the options are called is stimulated.
Efficient dispatch	Strategic reserve risks interfering with efficient dispatch. Either the units are dispatched at a too low price, or units are withheld although their marginal cost is below the market price.	Will not interfere with efficient dispatch. Penalty payments could however cause that defected plants are run instead of repair measures and thus risk further and costly damages.
Efficient investment decisions	A strategic reserve will not discourage efficient investments as long as it doesn´t mitigate price spikes.	Can provide incentives for efficient investments. (but can also result in excess investments if the set reserve margin is too high)
Limit income transfers to producers	Does not limit income transfers to producers during shortage	Limits income transfers in the case of high price spikes, but producers are instead paid for the options.
Stabilize electricity prices	Is not aimed at stabilizing electricity prices. Through supporting demand side participation electricity prices could be stabilised.	Contributes to stabilise electricity prices through the payment from producers to consumers when the option is called. The option price could however be quite volatile.
Reduce market power	Does not contribute to reduced market power. However, through encouraging demand response during high energy prices, market power of generators can be diluted.	Contributes to reduce market power, as units are incentivised to produce when the market is constrained. The market for option contracts may be vulnerable to gaming.
Simplicity	Simple and straightforward	Complex model requiring regulation

	model	
Compatibility with the European market model	Correctly designed it can easily be implemented as a complement to the existing/developing European market model.	Requires substantial more regulation, but bilateral contracting and voluntary exchanges can be sustained.
Permanent system or reversible	Essentially designed to be a temporary fix.	Designed to be permanent. The model can be phased out but may then lead to a stranded asset problem.

6 Conclusions

In this study we have reviewed possible capacity mechanisms for the European market. We did not address the question *whether* a capacity mechanism should be implemented, but rather what the alternatives are *if* one is implemented. We conclude that a strategic reserve and a modified form of reliability options are the best candidates.

The choice between a strategic reserve and reliability options should depend on the reason for implementing a capacity mechanism and on the specific conditions in the market. There are different reasons for implementing a capacity mechanism: general concerns about underinvestment, concerns about a lack of flexible back-up capacity for intermittent generation sources or the possibility of underinvestment due to the increase in regulatory uncertainty, which is an inevitable corollary of the transition towards a low-carbon electricity sector. The perception of the problem also matters: is the main risk considered to be capacity shortages and, consequently, rotating black-outs, or are the main problem related to volatile and spiky price and a risk for high income transfers from consumers to generators that may occur during periods of tight supply? Market conditions such as the degree of interconnection and the shape of the supply function (especially the shares of hydropower and intermittent sources) significantly affect the dynamics of investment in generation capacity, and hence the choice of whether and how to intervene.

A strategic reserve and reliability options differ significantly from each other in a number of respects. A strategic reserve is easy to implement (Sweden and Finland already have one), but will (and is intended to) have a limited effect on prices. Hence it will not change investment risk, the possible development of an investment cycle or income transfers from consumers to producers during shortage. It will also not lead to more flexible back-up capacity for intermittent sources, unless the strategic reserve is to provide this itself. However, then the strategic reserve would need to be dispatched whenever there is too little wind.

Reliability options provide a more stable investment incentive and provide a hedge against high prices to consumers, but are much more complex to implement. Moreover, the original design will need to be adapted to the situation in the European market. Due to the complexity, there is a risk of regulatory failure: if the design of the system is not internally consistent, it may not work as intended. So the choice is (apart from the question whether to intervene at all) between a 'light' version that addresses only part of the problem (depending on one's assessment of the issue) or a 'heavy' solution that offers more features and security, but is more difficult to implement.

7 References

Caramanis, M.C. (1982). ‘Investment decisions and long-term planning under electricity spot pricing’. *IEEE Transactions on Power Apparatus and Systems* 101 (12): 4640-4648.

Caramanis, M.C., Bohn, R.E. and Schweppe, F.C. (1982). ‘Optimal Spot Pricing: Practice and Theory’. *IEEE Transactions on Power Apparatus and Systems* PAS-101 (9): 3234-3245.

Cramton, P. and Stoft, S. (2006). ‘The Convergence of Market Designs for Adequate Generating Capacity’. Manuscript, April 25.

De Vries (2004). ‘Securing the public interest in electricity generation markets, the myths of the invisible hand and the copper plate’. Doctoral Dissertation, Delft University of Technology.

De Vries, L.J. (2007). ‘Generation Adequacy: Helping the Market Do its Job’. *Utilities Policy*, 15: 20-35.

De Vries, L.J., Knops, H.P.A. and Hakvoort, R.A. (2004). ‘Bilateral Reliability Contracts: An Innovative Approach to Maintaining Generation Adequacy in Liberalized Electricity Markets’. In: *Proceedings, IRAEE Conference “Energy and Security in the Changing World”*. Tehran.

Doorman, G. 2000. ‘Peaking Capacity in Restructured Power Systems.’ Thesis (Ph.D.), Norwegian University of Science and Technology, Faculty of Electrical Engineering and Telecommunications, Department of Electrical Power Engineering.

Hobbs, B.F., Iñón, J. and Kahal, M. (2001). ‘A Review of Issues Concerning Electric Power Capacity Markets’. Project report submitted to the Maryland Power Plant Research Program, Maryland Department of Natural Resources. Baltimore: The Johns Hopkins University.

Joskow, P.L. (2006). ‘Competitive Electricity Markets and Investment in New Generating Capacity’. Center for Energy and Environmental Policy Research (CEEPR), April.

Joskow, P.L. and Tirole, J. (2006). ‘Retail Electricity Competition’. *The RAND Journal of Economics*, 37 (4): 799-815.

Knops, H.P.A. 2003. ‘Weighing Ways of Keeping the Energy Balance’. In: *Proceedings, 26th Annual IAEE Conference*. Prague, June 4-7.

Neuhoff, K. and De Vries, L.J. 2004. ‘Insufficient Incentives for

Investment in Electricity Generation'. *Utilities Policy* 12: 253-267.
PJM Interconnection, L.L.C. 2003. 'Reliability Assurance Agreement Among Load Serving Entities in the MAAC Control Zone, Second Revised Rate Schedule'. FERC No. 27. Obtained from www.pjm.com.

Stoft, S. (2002). 'Power Systems Economics – Designing Markets for Electricity'. IEEE Press.

Vázquez, C., Rivier, M. and Pérez-Arriaga, I.J. 2002. 'A market approach to long-term security of supply'. *IEEE Transactions on Power Systems* 17 (2): 349-357.

Weizman, M.L. (1974). 'Prices vs. Quantities'. *The Review of Economic Studies* 41 (4): 477-491

Wolak, F.A. and Patrick, R.H. 1997. 'The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market'. Mimeo. Obtained from: ftp://zia.stanford.edu/pub/papers/eandw.pdf.

ELFORSK

SVENSKA ELFÖRETAGENS FORSKNINGS- OCH UTVECKLINGS - ELFORSK - AB

Elforsk AB, 101 53 Stockholm. Besöksadress: Olof Palmes Gata 31
Telefon: 08-677 25 30, Telefax: 08-677 25 35
www.elforsk.se