TEN STATEMENTS ABOUT

The future Power Market Design

NEPP
north european power perspectives

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NEPP is a coherent multi-disciplinary research project focusing on the development of the electricity systems and the electricity market in Sweden, the Nordic countries and Europe with the time perspective 2020, 2030 and 2050. The research is performed by around ten well-merited researchers and analysts. The current phase of NEPP will run up to March 2016.

NEPP's goal is to deepen the insight about how the Nordic countries and the actors on the Swedish and Nordic energy markets can act to be able to - in a cost effective way and with the focus on the growth perspective – meet the expectations from the energy and climate politics in EU and the Member States, and the challenges from a changing world.

The research is charged with the task of showing how a *balanced* and *effective development* of the Nordic countries' and the EU's energy systems can be achieved, and how the political goals can be realised. The research should strive to identify the *success factors* for this balanced development. This can relate to the choices made in the development of the operations of electricity and energy systems, market rules, the choice of and the design of policy instruments, etc. A deeper understanding should also be gained about *the expectations* on the energy actors, politicians and the society at large, to realise various goals and development paths.

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The research and synthesis efforts in NEPP are carried out by five research teams at Chalmers University of Technology, KTH Royal Institute of Technology, Profu, Sweco and IVL Swedish Environmental Research Institute. Profu is the project leader for NEPP and Sweco is assistant project leader.

This publication presents results and conclusions from NEPP's analyses of the electricity market, which are mainly done be Johan Bruce, Andrea Badano and Rachel Walsh at Sweco.

If you have questions regarding the content, please do not hesitate to contact any of the responsible researchers at Sweco.

More information about the NEPP project can be found at www.nepp.se.

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can be found on the project's homepage:
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Ten statements about

The future power market design

1. **There is a need for a redesign of the European power market.** The market design of today – based on an energy-only market – will not necessarily deal adequately with large amounts of renewable electricity generation. The low marginal costs of renewable generation will depress the price on the electricity market, making conventional generation unprofitable. There are concerns that this could - without some form of intervention - lead to underinvestments in conventional capacity.

2. **An energy-only market will have difficulties to deliver needed investments in generation.** Energy-only markets have some disadvantages. Generators are expected to recover their fixed costs during a small number of hours when generation capacity is scarce. This is not always politically feasible. Capacity mechanisms are suggested as an answer to this problem. Also demand-flexibility is brought forward as a possible solution.

3. **The choice between a strategic reserve and a capacity market is dependent on how often it is expected to be used.** Capacity systems can either be targeted or market-wide. Targeted capacity mechanisms, as the Swedish strategic reserve, are well suited for peak load plants that are only needed for a few hours every year to handle occasional load peaks. These mechanisms have a limited impact on the market and they are relatively inexpensive. Market wide capacity systems, e.g. the capacity markets that have been implemented in some European countries, are well suited for capacity that is expected to be used frequently, e.g. to handle fluctuations in wind power. These systems will have a major impact on the electricity market and can be quite costly.

4. **Capacity markets will lead to increased investments.** The introduction of a capacity market will mean yet another revenue stream for the generators in addition to the payment for energy. Uncertainty, and thereby risk, will be less and it should lead to lower capital costs. If a capacity market is introduced in a country, it might result in distorted investment incentives in neighbouring countries, so that investments are transferred to the area with a capacity market. This can lead to a decreased security of supply in the neighbouring countries.

5. **Capacity markets will lead to lower wholesale prices.** The increased capacity, which is a result of a capacity market, will lead to lower wholesale prices. If the capacity mechanisms are unevenly distributed, the price effects will spill over to neighbouring countries. For the end consumers, the lowered energy price is balanced out by the payment for capacity.

6 **The cost of capacity markets will increase once new investments are needed.** The capacity price on a capacity market is expected to cover the fixed costs that are not covered by revenues from the energy market. In a capacity market where the demand can be met by existing generation, the price should be capped by the fixed operation and maintenance costs. If new capacity is needed, also the capital costs to cover the investment must be included, which results in a considerably higher capacity price.

7 **Including interconnectors in a capacity mechanism is far from simple.** The implementation of national capacity markets in Europe might lead to distorted cross-border competition. Therefore, there are discussions about whether it is feasible to rely on import in scarcity situations, and how national capacity mechanisms could incorporate contribution from generators outside the national borders. Different models are proposed where it is either generators in neighbouring areas or the interconnectors that are incorporated. In both approaches the major topic of discussion is about who carries the accountability for non-delivery.

8 **Flow-based capacity allocation will lead to a more efficient use of transmission.** Unscheduled flows impact both transmission system security and the economics of electricity markets. Large volumes of unexpected flows make it more difficult for TSOs to manage the electricity system in an efficient and reliable way. TSOs may therefore choose to limit the amount of cross-border interconnection capacity that is made available to the electricity market. To reduce unscheduled flows, Europe is adopting flow-based capacity allocation methods. This means that a simplified flow calculation is included in the market-coupling algorithm, which is different from today where transmission capacity is allocated to the market before the market-coupling algorithm is applied.

9 **Locational marginal pricing will allocate transmission capacity more efficiently, but lead to less liquidity on the market.** In a market with nodal pricing, a full network model is used to simultaneously establish both dispatch volumes and prices at each injection and exit node, taking into account not only the bids from the market participants but also the resulting flows. The price at each node will vary not only depending on costs of generation electricity, it will also reflect the costs associated with transmission constraints and transmission losses. Nodal pricing is considered to encourage a more efficient use of the network. As an effect of the increased complexity with many nodes, the market will be less liquid. In the US, nodal complexity is simplified by aggregating nodes into trading hubs.

10 **Europe is moving towards a centrally planned power market.** A large majority of all new capacity introduced in recent years is based on subsidies rather than market based payments. Up to now, this has been especially true for renewable generation, but it is becoming true also for conventional and nuclear power. The UK is an example of a market that is becoming increasingly more centrally planned, with long term contracts for renewables and nuclear power, and a capacity market for conventional generation. In France a part of the nuclear power generation is traded with regulated tariffs.

Tio påståenden om den framtida marknadsdesignen

1. **Den europeiska elmarknaden kommer att behöva en ny marknadsdesign.** Dagens marknadsdesign som är baserad på en energy only-marknad klarar inte nödvändigtvis av att hantera stora mängder intermittent produktion. Den förnybara produktionens låga marginalkostnader sänker priset på elmarknaden så att konventionell produktion blir olönsam. Det finns farhågor om att detta kan leda till underinvesteringar i konventionell produktion om inte några åtgärder sätts in.

2. **Energy only-marknaden har svårt att leverera nödvändiga investeringar i ny produktion.** Det finns vissa nackdelar med energy-only-marknader. Till exempel förväntas producenterna täcka sina fasta kostnader under ett fåtal timmar när produktionsresurserna är knappa. För att detta ska ske måste höga elpriser tillåtas under ett fåtal timmar när kapaciteten är knapp. Detta är dock inte alltid politiskt genomförbart. Kapacitetsmekanismer föreslås som en lösning på problemet. Ökad efterfrågeflexibilitet lyfts även fram som en möjlig lösning på problemet.

3. **Valet mellan en strategisk reserv och en kapacitetsmarknad beror på hur ofta den förväntas användas.** Kapacitetsmekanismer kan antingen vara riktade eller omfatta hela marknaden. Riktade kapacitetsmekanismer, t.ex. den svenska effektreserven, passar för topplastanläggningar som bara behövs ett fåtal timmar per år för att klara tillfälliga lasttoppar. Dessa mekanismer har en begränsad påverkan på elmarknaden och är relativt kostnadseffektiva. Marknadsomfattande kapacitetsmekanismer, t.ex. de kapacitetsmarknader som implementeras på kontinenten, passar för kapacitet som behövs ofta, t.ex. för att hantera variationer i vindkraften. Dessa system får en stor påverkan på elmarknaden och kan bli kostsamma.

4. **Införandet av kapacitetsmarknader kommer att leda till ökade investeringar i ny produktion.** Införandet av en kapacitetsmarknad innebär ytterligare en intäktsström för producenterna utöver de intäkter de får från energibetalningarna. Osäkerheten för producenterna att täcka sina kostnader, och därmed risken, minskar och bör även leda till lägre kapitalkostnader. Om kapacitetsmarknader införs i ett land kan det leda till att investeringssignaler i närliggande länder störs så att investeringar flyttas till området med en kapacitetsmarknad. Vilket i sin tur kan leda till en minskad leveranssäkerhet i grannlandet.

5. **Införandet av kapacitetsmarknader kommer att leda till lägre priser på grossistmarknaden.** Den ökade kapacitet som en kapacitetsmarknad leder till kommer att leda till minskande priser på grossistmarknaden. Om kapacitetsmarknader införs okoordinerat kommer priseffekten att spilla över till grannländerna. För slutkunderna kompenseras det lägre energipriset med kostnaden för kapacitetsbetalningen.

6 **Kostnaden för en kapacitetsmarknad kommer att öka när nya investeringar krävs.** Kapacitetspriset på en kapacitetsmarknad förväntas täcka de fasta kostnader som inte täcks av intäkter från energimarknaden. I en kapacitetsmarknad där behovet kan täckas av befintlig kapacitet förväntas kapacitetspriset begränsas av de fasta drift- och underhållskostnaderna. Om ny kapacitet behövs måste även kapitalkostnaderna inkluderas, vilket leder till betydligt högre kapacitetspriser.

7 **Att inkludera utlandsförbindelser i kapacitetsmarknader är långt ifrån enkelt.** Implementeringen av nationella kapacitetsmarknader i Europa riskerar att leda till snedvriden konkurrens över gränserna. Därför diskuteras det om det är möjligt att förlita sig på import i knapphetssituationer och hur nationella kapacitetsmekanismer kan inkludera bidraget från producenter utanför nationsgränserna. Ett flertal modeller har föreslagits där det antingen är producenterna i närliggande områden eller om det är överföringsförbindelsen som deltar i kapacitetsmarknaden. I båda fallen utgör den främsta diskussionen om vem som bär ansvaret vid utebliven leverans.

8 **Flödesbaserad kapacitetsallokering (flow-based) kommer att leda till ett mer effektivt utnyttjande av elnätet.** Oplanerade flöden påverkar systemsäkerheten och ekonomin i elmarknaden. Stora oplanerade flöden gör det svårt för TSOn att hantera sitt system på ett säkert och förutsägbart sätt. TSOn kan därför välja att begränsa kapaciteten på den överföringskapacitet som tilldelas elmarknaden. För att minska de oplanerade flödena införs flödesbaserad kapacitetsallokering i Europa. Det innebär att en förenklad flödesberäkning inkluderas i marknadsalgoritmen till skillnad från dagens metod där överföringskapaciteten tilldelas marknaden innan marknadsalgoritmen körs.

9 **Nodprissättning kommer att medföra ett mer effektivt utnyttjande av elnätet, men ger minskad likviditet på elmarknaden.** I en marknad med nodprissättning används en fullständig elnätsmodell för att simultant beräkna både volymer och priser i varje enskild in- och utmatningspunkt. På en sådan marknad tas hänsyn både till marknadsaktörernas bud och de resulterande flödena. Priserna i varje enskild nod kommer inte bara att reflektera produktionskostnaderna, utan även kostnaderna för överföringsbegränsningar och överföringsförluster. Nodprissättning anses leda till ett effektivare utnyttjande av elnätet. På grund av den ökade komplexiteten med många noder blir den finansiella marknaden mindre likvid. I USA har detta lösts genom att aggregera flera noder till så kallade hubbar.

10 **Europas elmarknad är på väg tillbaka mot centralplanering.** En klar majoritet av all ny kapacitet som tillkommit de senaste åren har baserats på subventioner snarare än marknadspriser. Hittills har detta framförallt gällt för förnybar produktion, men det har också börjat bli aktuellt för konventionella kraftverk och kärnkraftverk. Storbritannien är ett exempel på en marknad som blir allt med centralplanerad med långa kontrakt för både förnybart och kärnkraft och med en kapacitetsmarknad för konventionell produktion. Ett annat exempel är Frankrike där en andel av kärnkraftsproduktionen säljs till reglerade priser.

1 There is a need for a redesign of the European power market

On July 15th 2015, the European Commission launched a public consultation on a new energy market design, arguing that achieving Europe´s sustainability and environmental goals will require a fundamental transformation of Europe's energy system, including redesigning the European electricity market. This at a time when countries across Europe are still busy implementing significant modifications to their market design in order to comply with network codes and guidelines that define the common European Target Model upon which the single European electricity market is to be established.

In recent years, doubts have emerged about whether the Target Model is fit for purpose. The Target Model is heavily inspired by the successful Nordic market design, which is essentially an "energy-only" market model in which trading between properly defined bidding zones takes place in four time-frames: a forwards market, an auction-based day-ahead physical market, an intraday market and a balancing market run by the Transmission System Operators (TSOs). This market model has served the Nordic countries well, but it was conceived at a time with a fundamentally different generation mix, with large-scale, centralised power plants and passive consumers.

Since then, Europe's commitment to source a progressively higher proportion of electricity generation from renewable energy sources has meant that a very different energy system from the current has started to emerge, one which the Target Model does not necessarily deal with adequately. Renewable generation is often intermittent, has low short-run marginal costs and is often located either far away from load centers or is connected to the distribution network.

Intermittency implies that while renewable generators have the potential to generate large amounts of electricity, it is difficult to rely on them, and greater amounts of total installed capacity are needed to meet a given security of supply. However, in a system with large amounts of renewable generation, the low marginal costs of renewable generation will depress the average wholesale price of electricity, making it more difficult for conventional plants to recover their costs. As conventional plants will be running considerably less, they will be relying on high but uncertain price spikes to recover their costs. There are growing concerns that this could lead to underinvestment in conventional capacity without some form of intervention.

At present, the debate is still ongoing as to how to best respond to this challenge. Will the Target Model stand up with only smaller adjustments, or will there be a need for a more fundamental redesign of the market? In addition to concerns about securing investment both to maintain existing generation and to encourage the development of new sources of capacity, several other issues deserve attention. Large variations in generation over both time and space will further strain the electricity networks, making the efficient expansion and utilisation of the grids increasingly important.

Finally, the volatility in electricity generation is also likely to lead to more volatile electricity prices. Price spikes are likely to be higher in systems with large amounts of renewable generation as conventional generators will have to recover their costs during fewer hours. Public opinion and the media have little or no understanding of this fact. Furthermore, price spikes that significantly exceed the marginal cost of the last generator needed to meet demand can lead to accusations of anticompetitive and manipulative behavior and calls for price caps. Price caps are already in place in several countries.

How electricity markets will evolve will depend on the decisions made by investors and policymakers. Will investors be willing to accept (risky) investments based on the risk of electricity prices being more volatile and possibly lower on average, or will they be discouraged to invest in generation capacity? Will politicians (and regulators) rely on the markets even if this will result in volatile prices, or will they opt for an interventionist approach with more detailed regulation and central planning? Will the scale of the investment challenge simply force politician to interfere?

2 An energy-only market vill have difficulties to deliver needed investments in generation

Environmental policy interventions are putting in doubt whether energy-only markets that rely on market incentives for investment will attract the appropriate quantity and type of capacity needed to ensure security of electricity supply. Increasingly larger volumes of subsidised renewable generation are driving wholesale electricity prices below the long-run marginal cost of supply in many European countries. The question is therefore being asked as to whether energy-only markets can deliver adequate incentives to invest in unsubsidised flexible generation to back up intermittent renewables. A number of European Governments believe that this is not the case, and have decided to introduce different mechanisms to guarantee generation adequacy.

Following liberalisation and to foster competition in electricity generation, a number of countries adopted what has come to be known as energy-only market design. The main characteristic of energy-only markets is that decisions about the level of investment in new generation and the corresponding reserve margin are strictly commercial, and will mainly depend on projections of future energy prices. Normally, energy-only markets are expected to fluctuate around an equilibrium reserve margin where generators earn a reasonable rate of return and cover the cost of their investment. When reserve margins are low, prices are expected to rise to very high levels, signalling to investors that it is time to build new generation capacity. If, on the other hand, reserve margins are high, energy prices will go down and will not be high enough to support new investments.

There are some disadvantages of energy-only markets. For example generators are expected to recover a large share of their fixed costs during a small number of hours when generating capacity is scarce. For this to happen, energy prices need to reach increasingly higher levels as generating capacity becomes more and more scarce. This is not always politically feasible, as very high market prices are likely to raise fears of market power and calls for administrative measures such as price caps to limit the highest prices. If price caps are set too low, electricity prices will not go high enough at times of scarcity, and revenues from the sale of electricity will not be sufficient to cover neither the fixed costs of existing generators nor the investment costs of new generators. This is known as the "missing money" problem. It is important to note that even if revenue is adequate, investors have to perceive it as adequate as also the threat of price caps and policy interventions may scare off investors.

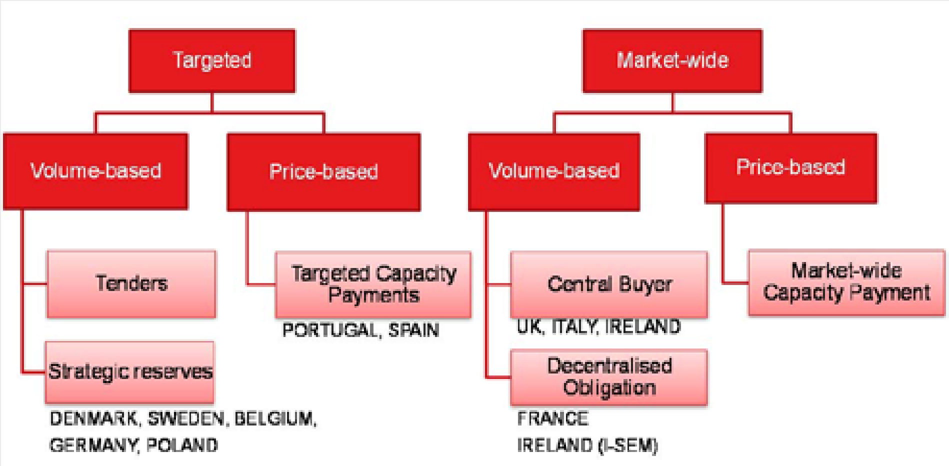
The missing money problem has risen in importance in recent years because of subsidies to renewable generation. Increasingly larger shares of intermittent generation are pushing wholesale prices down and limiting the operating hours of conventional plants. This has brought to question the sustainability of energy-only market design, and a number of countries have decided to introduce capacity remuneration mechanisms to support conventional flexible or peaking generation and overcome the imperfections of energy-only markets.

Complex capacity remuneration mechanisms, however, are not always seen as the optimal solution. The co-existence of often uncoordinated, national rules and approaches to security of supply entails risks and undermines the internal market for electricity. Instead, there are renewed calls to solve a known and fundamental market failure: the lack of demand-side price-responsiveness. Technological development has made it possible for customers to receive and respond to real-time spot prices. In theory, in a well-designed energy-only market with substantial demand-side participation customers can determine for themselves the level of reliability and reserve margins they are willing to pay for. Customers that during a given period place a low value on their electricity supply can reduce their consumption whenever energy prices rise to unacceptable levels, whereas customers that place a high value on their supply may continue to consume electricity even at very high prices.

The challenge remains of how to integrate demand side responses to energy prices without risking further depressing wholesale energy prices in an inefficient manner. The prices that are paid for demand responses or the prices that can be avoided by responding to price signals should not be too low compared to the cost of maintaining adequate reserve margins. Some countries believe that the capacity and flexibility demand responses can deliver, are best remunerated under a capacity mechanism. If this is the case, it could signal the end of the energy-only market.

3 The choice between a strategic reserve and a capacity market is dependent on how often it is expected to be used

Figure 1: Different types of capacity mechanisms



The purpose of capacity remuneration mechanisms is to ensure that there is enough capacity and demand flexibility in the power system. This is achieved by providing a separate payment for available capacity rather than only paying for the energy delivered.

Capacity remuneration mechanisms are usually classified as targeted systems or market-wide systems.

Targeted mechanisms are typically aimed at specific technologies or actors. The Swedish strategic reserve is an example of a targeted system, see the box below. Typically targeted systems are aimed towards unprofitable peak load capacity that otherwise would be shut down or mothballed unless they received special support. It may involve oil-fired power plants that are only needed for a few hours every year. To make sure that the support will not have any negative impact on competition in the wholesale market supported capacity is not allowed to participate in the regular wholesale market, but is activated by the system operator. One of the largest challenges in designing a targeted system is to ensure that support is not given to capacity that would be profitable without the support. In that case, there is a risk that capacity is removed from the wholesale market. The targeted systems cover only a small share of the installed capacity and the total cost of the system will therefore be small.

In a market-wide system, basically all firm capacity receives compensation. This means that capacity participating in the capacity market will also participate in the regular electricity market. As a market-wide system covers a large part of the market, it is also a much more costly system.

In summary, the targeted systems are used for reserves that are not expected to be used frequently, while the market-wide systems are used to support capacity that is expected to be used often in the regular power market. It can be expressed as:

- Capacity expected to be used only a few times per year, for example to handle the occasional load peaks, fits better in a strategic reserve.
- Capacity expected to be used frequently, for example to manage fluctuations in wind power, fits better in a capacity market.

A strategic reserve has a relatively limited impact on the market and is relatively inexpensive, which means that it can be introduced and decommissioned without a major impact on the electricity market as a whole. An introduction of a capacity market is a far greater intervention and will have a significant impact on the electricity market.

The Swedish strategic reserve as an example

Background

In Sweden, many oil-fired condensing power plants were shut down due to poor profitability following the liberalisation of the electricity market. When the Barsebäck 2 nuclear power plant was closed, Swedish TSO Svenska Kraftnät (SvK) assessed that Sweden could no longer meet the power requirements of a so-called 10-year winter. The Government therefore decided to introduce a strategic reserve consisting of both production and demand reductions up to 2 000 MW.

When the strategic reserve was introduced in 2003 it was decided that it would be phased out by 2008, but a phase-out has not been possible to date. In 2010, the Government delayed the phase-out until 2020, but also decided that the proportion of demand reductions should gradually increase. The phase-out was once more delayed following the decisions to decommission the nuclear power plants Ringhals 1 and 2 and Oskarshamn 1 and 2 by 2020. The strategic reserve is now expected to remain operational until 2025.

Procurement of power reserve

The strategic reserve is normally procured annually in the spring before the winter season (however it has occasionally been procured for several years at once)

The Swedish strategic reserve as an example (cont.)

and is only active during the winter. Generation resources and demand resources are handled differently.

Activation of the strategic reserve

Activation of the strategic reserve can be done in several ways, and generation resources and demand reduction are handled differently.

SvK activates the procured generation resources. In a first step they are offered to Nord Pool Spot when there is a risk of curtailment, i.e. that supply bids will not meet the demand. It is offered at 0,1 EUR / MWh over the highest commercial bid. SvK can also bid the generation resources into the balancing market. In order to minimise the impact of the strategic reserve on the electricity markets, the strategic reserve will only be used after all commercial bids have been exhausted, even if the strategic reserve is cheaper.

Demand resources are required to bid demand reductions into the balancing market at a price they determine themselves. An exception is made if they are already activated on the spot market.

4 Capacity markets will lead to an increase in investments

The introduction of a capacity market (CRM) would be expected to increase the amount of generation capacity installed compared to an energy-only market; with a payment in addition to energy market revenues, there is a more stable environment to make investments in generation and flexible load – returns should appear more secure and the cost of capital should be lower.

As can be seen in Figure 2, most capacity is introduced when capacity markets exist in all countries in Europe – the Integrated Capacity Market – and in the “patchwork” scenarios the levels of capacity in Europe are somewhere in between the Target Model and Integrated Capacity Market.

As noted elsewhere, one of the main risks of distortion with the introduction of CRMs is the risk of encouraging an over-investment in generation capacity.

Figure 2: Total new capacity installed in Sweco scenarios by 2030. *Source: Sweco Energy Markets, 2013*

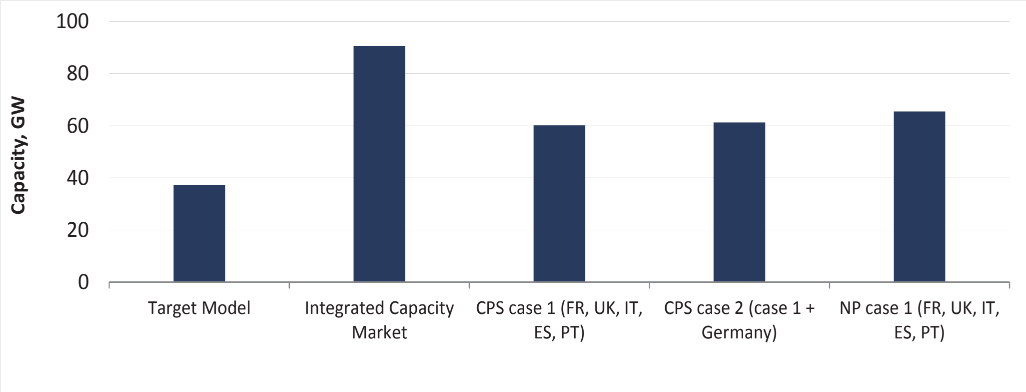
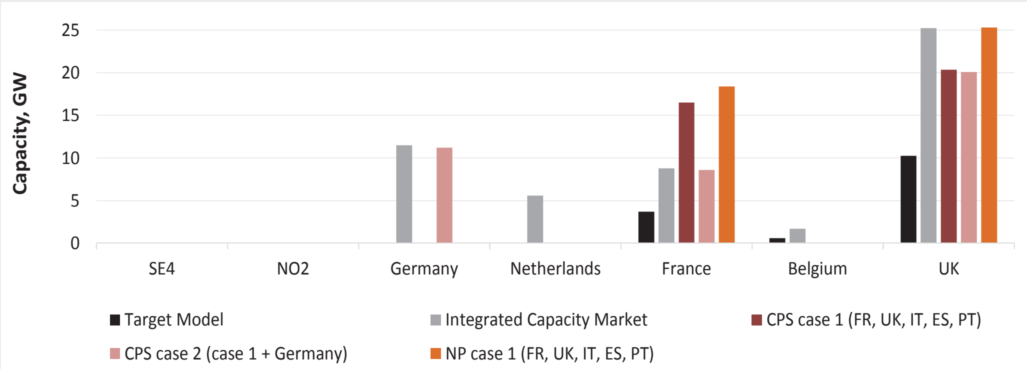


Figure 3: Total new generation investments in individual countries by 2030.
Source: Sweco Energy Markets, 2013

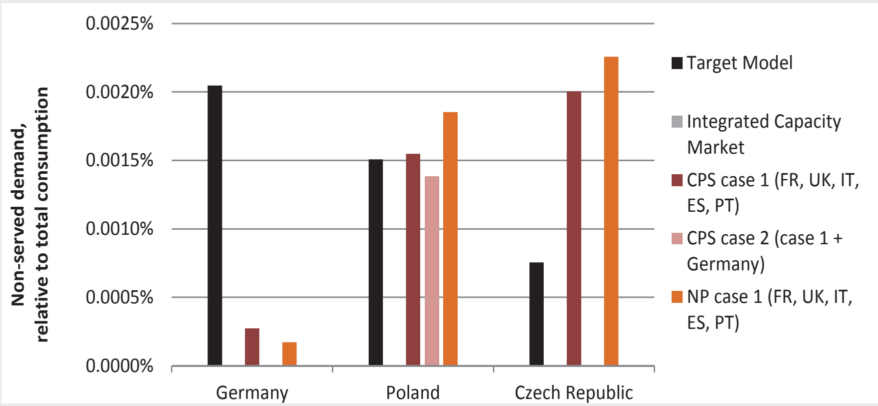


Central to the discussions prompting and involving CRMs is the issue of generation adequacy; by introducing a capacity market, a country is hoping to increase this. This can however have a positive or negative impact on the security of supply of neighbouring countries.

Within the Target Model, the modelling results show that there will be insufficient capacity to avoid some hours of physical shortage. This result would be expected, but given the deterministic nature of the model and the optimal level of investments input, the number of hours of shortage could be more in reality. Whilst curtailment in itself can be the optimal solution in a given system, the fear of too many hours of physical shortage is what lies at the heart of this discussion.

In the modelling of the capacity market scenarios, there are no hours of physical shortage in the countries that have capacity markets; this was a part of the modelling process, and as discussed earlier the reality could be different. As seen before, countries that neighbour a capacity market without having one themselves, are able to benefit in terms of investment levels and system cost. There is, however, also a risk that they experience a lower security of supply. This can be seen in Figure 4 for both Poland and the Czech Republic, their non-served demand increases when other countries introduce capacity markets.

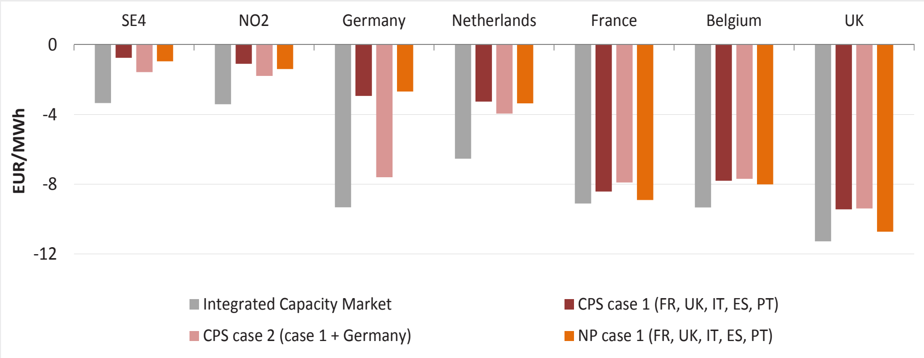
Figure 4: Non-served demand as a percentage of consumption in 2030.
Source: Sweco Energy Markets, 2013



5 Capacity markets will lead to lower wholesale prices

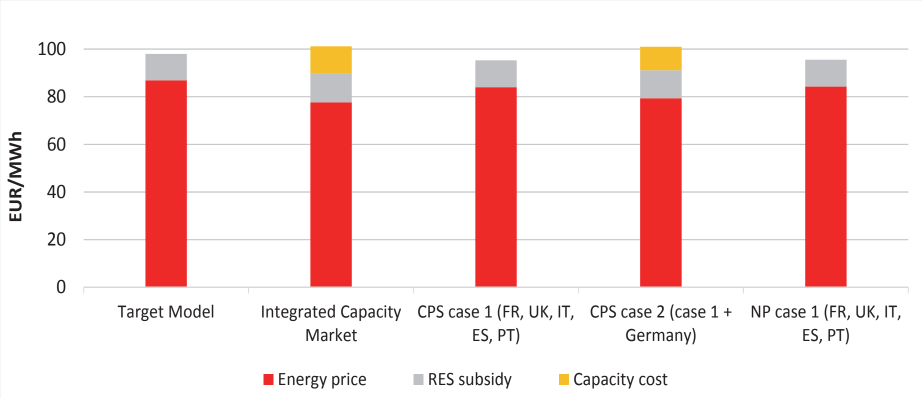
As capacity markets encourage more investment in generation, the wholesale power price decreases when they are introduced. The decrease is seen not only in the countries with capacity markets, but all over Europe in all modelled capacity market scenarios. In some cases the spill over effect is substantial, as can be seen in Figure 5.

Figure 5: Change in wholesale price relative to the Target Model in 2030.
Source: Sweco Energy Markets, 2013



To estimate the impact on consumers, the total customer cost is considered to consist of the combined payments for electricity, renewables subsidies and any capacity payment (excluding grid costs); these cost components are shown in Figure 6 with Germany as an example. Here the bulk of the cost is made up of the wholesale energy price, which decreases in the capacity market scenarios; there is a component to pay for RES subsidies; and in the two scenarios where Germany has a capacity market, there is a component that covers the cost of capacity that clears in the German capacity market.

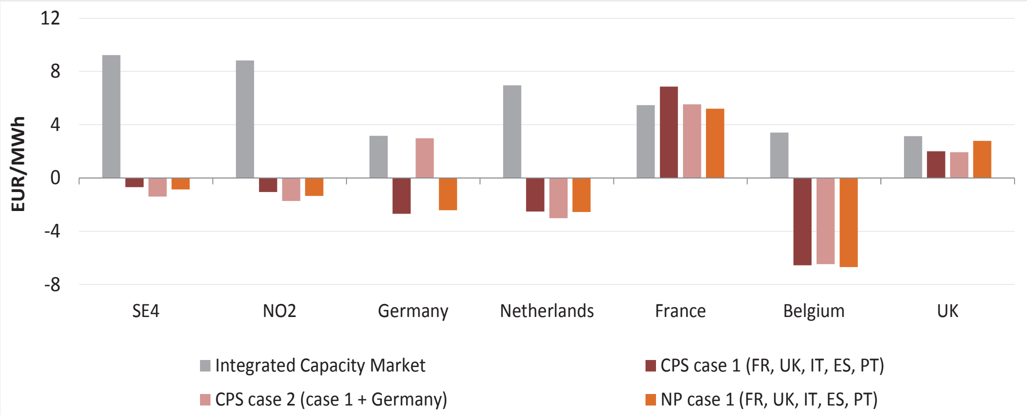
Figure 6: Components of cost to customers in Germany in 2030 in different capacity market scenarios.
Source: Sweco Energy Markets, 2013



Although wholesale prices are reduced, the cost of paying for the additional capacity more than offsets this price reduction, and in those countries with capacity markets, the customers generally pay more, as seen in Figure 7. For those countries that neighbour the capacity market countries, there can be several spillover effects namely, a decrease in wholesale prices, a decrease in customer cost (without having to pay for additional capacity that causes the wholesale price decrease) and a crowding out of investments in that region.

An integrated capacity market is generally the most expensive alternative for the customers, particularly in the Nordic countries. Here, the drop in wholesale price is relatively small, but the cost of capacity is much greater than the drop in wholesale price; hence there is a larger customer cost increase here than in other parts of Europe.

Figure 7: Change in customer cost relative to the Target Model in 2030.
Source: Sweco Energy Markets, 2013



6 The cost of capacity markets will increase once new investments are needed

Capacity remuneration mechanisms are introduced to ensure generation adequacy. Many mechanisms are open to both generation and demand response. In this section, we discuss capacity remuneration mechanisms from a generation point of view only.

In a capacity market, capacity is normally procured through an auctioning process where eligible generators can offer their capacity. The auctions may cover different time periods to give signals to both existing and new capacity, e.g. 1-year ahead and 5-year ahead auctions.

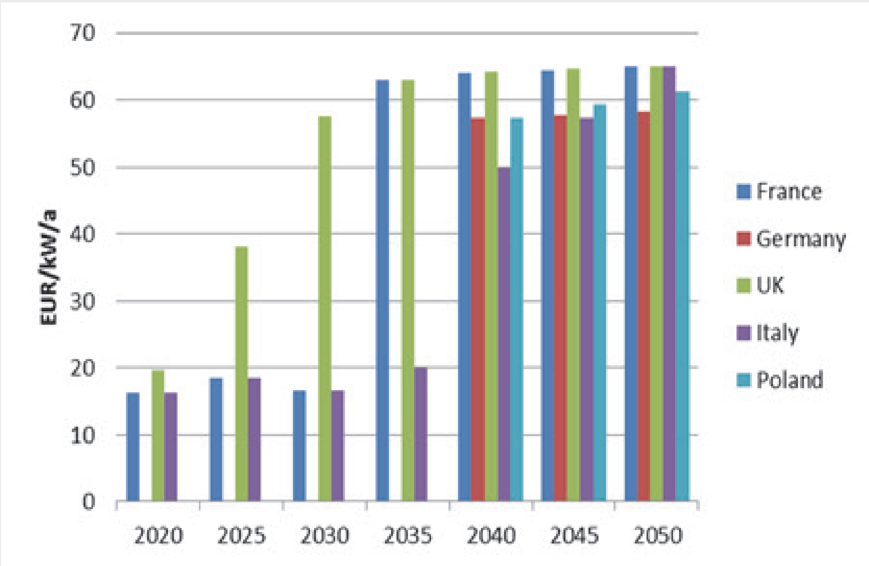
If a capacity market is introduced in a market where demand can be met by existing generation, capacity prices should in theory be capped by the fixed operation and maintenance (O&M) cost. This will cover the costs of keeping a power plant ready to generate, not needing to cover any costs from the energy market. Historical capital cost should not be taken into account and should be considered as sunk costs. Plants that are expecting to cover part of their fixed O&M costs through the energy market should in theory offer their capacity at a price that is lower than the fixed O&M costs.

If the capacity demand needs to be met by new capacity, the capital costs to cover the investment also needs to be considered in the offer to the capacity market, resulting in a considerably higher price in the capacity market.

Figure 8 below shows simulation results from Sweco's reference scenario. The capacity price in the model is defined as the marginal capacity price needed to cover the cost of all required generation. In this scenario there is little need for new generation in most countries before 2040, except for the UK where new investments are already needed in 2025.

In markets where existing capacity can meet demand, the capacity price is between 15-20 EUR/kW/year, which is close to the fixed O&M cost for thermal plants. When investment in new generation is needed, the price rises to about 60 EUR/kW/year as the capital cost of the investment also needs to be covered. This level is in parity to the capital cost of an open cycle gas turbine, which can be seen as an expected upper ceiling in a capacity market.

Figure 8: Simulated capacity prices for selected countries. *Source: Sweco 2050 reference scenario (2015)*



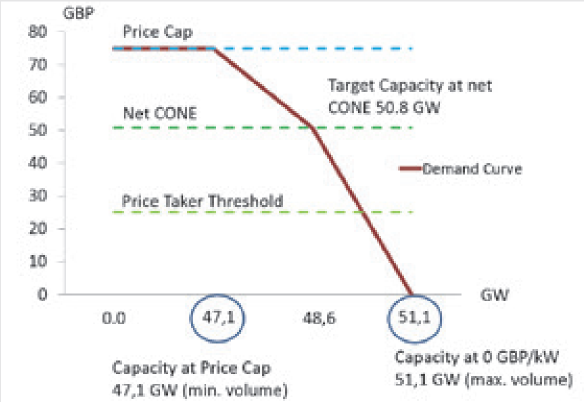
First UK capacity auction set up and results

The UK market design includes centrally-managed annual capacity auctions to procure a Target Capacity set by the Government. Below are the main characteristics of the UK capacity market:

- Auctions are held 4 years and 1 year ahead of delivery
- Open to new and existing generators, DSR and storage.
- Successful bidders receive a steady payment (GBP/kW per year) during the duration of the Capacity Agreement in return for a commitment to deliver electricity at times of system stress.
- Financial penalty in case of non-delivery

In the UK a sliding demand curve is used. The price at the target volume is set at the net Cost Of New Entry (net CONE, e.g. the estimated cost of a new gas turbine). The min and max volumes are then set to +/- 3% of the target volume. The price at the maximum volume is set at 0 while the price at the minimum volume is set at a price cap. New capacity can bid for a period of up to 15 years. The price cap is set for new capacity at 75 GBP/kW/a. Existing capacity can only bid for one year at a time and is considered to be so called price takers and are not allowed to bid at a price higher than 25 GBP/kW/a.

The first auction was held in in December 2014 with delivery: 1 October 2018 -30 September 2019. The capacity bidding into the auction was 54.9 GW and the procured volume was 49.3 GW at 19.4 GBP/kW/a. The price was lower than the market had expected.



7 Including connectors in a capacity mechanism is far from simple

National capacity mechanisms are being planned in an uncoordinated manner across Europe, risking to distort cross-border trade and competition. Topics of discussion have therefore included whether it is possible to rely on imports at times of scarcity, and how national capacity mechanisms can incorporate mechanisms to account for the contribution that generators outside national borders can make to ensure national security of electricity supply. Ignoring the contribution of imports will result in significant inefficiencies, most notably an over-procurement of domestic generation capacity. Too much capacity will result in higher capacity payments, lower wholesale electricity prices, and too few hours with scarcity pricing, undermining the capacity market.

Including interconnectors in a capacity mechanism is, however, far from simple. Assessing the contribution that interconnectors can make is complex, and there are several ways in which such a contribution could happen. A number of models have been proposed. Some models have generators in neighbouring countries participating in the capacity mechanism, while others have the interconnector directly participating in the capacity market. Also implicit participation through "corrective" payments has been proposed. In this alternative, neither generators nor interconnectors participate in the market, but an amount is calculated ex-ante or ex post and paid to interconnectors and interconnected generation to compensate them for market distortions caused by the capacity mechanism. Finally, a model in which cross-border generators participate in the capacity mechanism but in an auction separate from the domestic capacity has been proposed. The derated interconnector capacity limits the amount of capacity purchased at this separate auction, and the marginal bid sets the price that generators receive. A mechanism is included in order to avoid under-investment in interconnectors; if the price of capacity on the domestic capacity market is higher than the price on the cross-border market, the model allocates the difference in capacity payment to the interconnector as a type of "scarcity payment".

The most important point of discussion on this theoretical level, is around who carries the accountability for non-delivery. For generator models, cross-border generation needs the interconnector capacity to be available and flowing in the correct direction, to be able to deliver to the capacity market. And for interconnector models, interconnectors need a sufficient generation in the cross-border market to be able to deliver to the capacity mechanism. Which is a particular issue when the interconnector is a merchant line as they do not have any control over this. If, however, neither the cross-border generator nor the interconnector carries the accountability for non-delivery, then there is no incentive for any of these parties to deliver at times of scarcity in the capacity mechanism.

It should also be noted that at present not all markets in Europe reflect the value of capacity at times of scarcity equally well. Moreover, interconnectors do not always operate efficiently. For instance, there are several interconnectors for which capacity is allocated explicitly where flows will go in the "wrong" direction, i.e. from the higher-price side of the interconnector to the lower-price side. And while in theory implicit auctioning will result in power flows that will better reflect price differentials, it is unclear what will happen under flow-based capacity allocation. Under border-by-border capacity allocation all resulting exchanges are "intuitive", i.e. exchanges are scheduled from low to high prices. Under flow-based capacity allocation however, capacity is allocated to maximize welfare across the entire market-coupled region, so flows at particular interconnectors may be "unintuitive", i.e. may go in the wrong direction to relieve congestion and facilitate more beneficial trades elsewhere. The market-coupling algorithm Euphemia currently suppresses the non-intuitive exchanges, but it is unclear how long this "patch" will be in place, or how it could affect including interconnectors in capacity markets.

8 Flow-based capacity allocation will lead to a more efficient use of transmission

Unscheduled flows impact both transmission system security and the economics of electricity markets. Large volumes of unexpected flows make it more difficult for TSOs to manage the electricity system in an efficient and reliable way. TSOs have to resort to different types of remedial actions to adjust flows on the network in a manner that is acceptable in terms of security of supply, at a considerable cost for society. TSOs may therefore choose to limit the amount of cross-border interconnection capacity that is made available for day-ahead and intraday trading, again at a cost to society. To reduce unscheduled flows resulting from trade between bidding zones, Europe is adopting flow-based capacity allocation methods, widely considered as the most efficient way to allocate cross-zonal transmission capacity.

Because of the laws of physics, a commercial exchange between two nodes will follow the path of least resistance. This means that scheduled flows resulting from market participants' bids and offers will result in actual physical flows that are different from the contracted flows. Unscheduled flows that are the result of trading *between* bidding zones are known as unscheduled transit flows, whereas *unscheduled flows* that are the result of trading *within* bidding zones are known as *loop flows*.

Unscheduled transit flows are the result of inefficiencies in the mechanism used to determine and allocate cross-zonal capacity. In Europe, TSOs have traditionally decided in advance and on a border-by-border basis how much cross-zonal transmission capacity to make available to the markets. In the case of the Nordic countries, the Nordic TSOs determine all capacities between bidding zones and communicate these capacities to Nord Pool Spot, which will enter these values as constraints into its day-ahead market splitting algorithm. These capacities, along with market participants' bids and offers, is the only input to the algorithm.

Needless to say, this approach is highly inefficient in the meshed networks of continental Europe. The CWE region has therefore moved on to flow-based methods to determine and allocate cross-zonal transmission capacity. Central to flow-based methods is the inclusion, in the market coupling algorithm, of a simplified yet sophisticated network model that roughly represents the underlying network. Before each day-ahead auction, TSOs provide the market coupling algorithm with information about how changes in generation and consumption at individual nodes in the network will affect flows across interconnectors. The market-coupling algorithm will then predict the physical flows resulting from all cross-zonal bids and offers throughout the region, and will prioritise those flows that will resolve congestions within the region in the most economically efficient way. This means that the market coupling clears those trades that maximise social welfare *globally across the entire market-coupled region* by allowing more trades in the most valuable directions than would have been the case with traditional border-by-border welfare optimisations. Flows are also determined by the market, as all bids in all bidding zones within the region compete against each other for all transmission capacity in the region.

The CWE region's flow-based approach is likely to be implemented across the rest of Europe. In the Nordic countries, TSO:s launched the *Nordic Flow-Based Project* in September 2012 to assess the implications of implementing flow-based methods in the day-ahead market, and to develop a methodology and a prototype tool for the implementation. Following market simulations with parallel runs and an economic welfare assessment of market results, a decision will be reached on whether the Nordic countries should also move on to flow-based capacity allocation. The decision is expected to be taken in 2016.

9 Locational marginal pricing will allocate transmission capacity more efficiently, but lead to less liquidity in the market

The zonal approach to energy pricing and congestion management that Europe has adopted aggregates nodes into bidding zones and treats congestion within bidding zones independently from congestions between bidding zones. As was discussed in the previous section, transmission capacity between bidding zones is assumed to be a scarce resource and is allocated by a capacity allocation mechanism to the most valuable trades. Within bidding zones, however, market participants may trade as if transmission capacity was unlimited. While good for trading purposes and market liquidity, this approach increases the complexity of congestion management and reduces market efficiency if bidding zones are not properly defined to reflect the underlying network.

Critics of the zonal approach argue that because of increasingly larger volumes of wind generation, and the difficulties associated with improving transmission infrastructure to relieve congestions within bidding zones, it could make sense for Europe to consider a move to locational marginal pricing, also known as nodal markets.

Nodal markets use a full network model to simultaneously establish dispatch volumes and prices at each injection and exit node on the network, taking into account not only market participant's bids and offers but also the effect of the resulting power flows. Under nodal pricing the wholesale price of electricity will not only vary depending on the short- and long-run costs of generating electricity, there will also be locational price adjustments to reflect the costs associated with transmission constraints and transmission losses. Locational adjustments for congestion will see prices in export-constrained nodes with a generation surplus fall, while prices in import-constrained nodes with a generation deficit will rise. Locational adjustments for transmission losses will take into account that a given demand will need more generation from a far-away plant to be met than from a nearby plant, as transmission losses increase as power is transferred over longer distances.

Being more cost-reflective, nodal pricing is widely considered to encourage a more efficient dispatch of generators than zonal pricing, in the short term, and a more efficient use of the existing network.

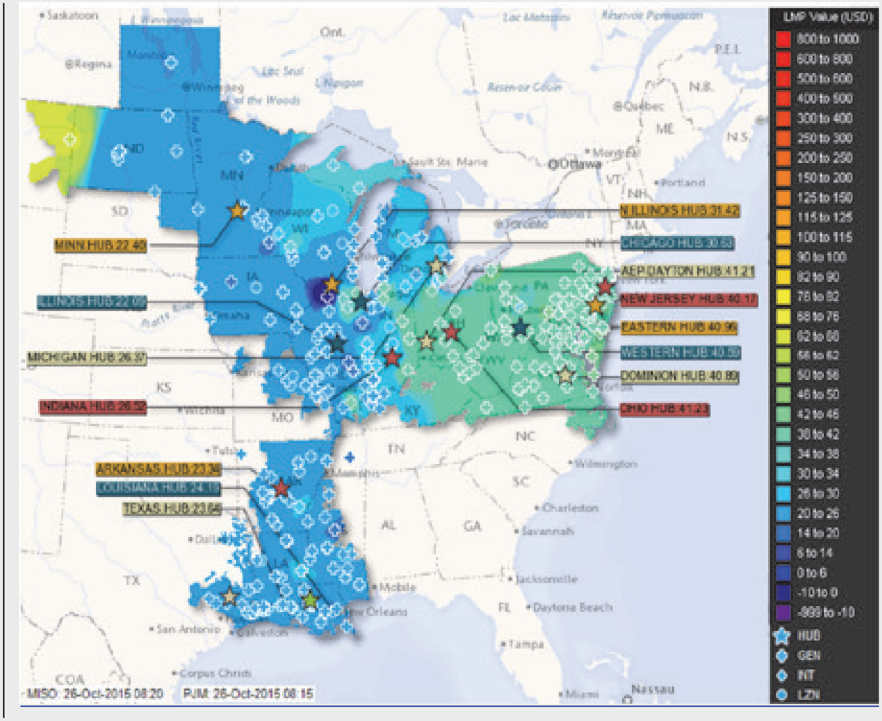
Nodal pricing is sometimes dismissed for being difficult and expensive to implement. Advocates of nodal pricing argue that the information needed to compute nodal prices is the same information that system operators already use to plan the operation of the system, so no new data collection is required. Full nodal pricing, however, may not be possible without a mandatory pool and centralised dispatch.
A further argument against nodal pricing is that because of the potentially very large number of nodes that make up a nodal market, nodal markets are inherently less liquid than zonal markets, particularly when bidding zones are large. In the United States,

nodal complexity is simplified by aggregating nodes into trading hubs. Hub prices are calculated by averaging the individual nodal prices at the nodes that make up the hub. Moreover, wholesale demand is settled at a zonal price. The reasons for having zonal prices for demand are similar to the reasons for having large national or supranational bidding zones: a desire to have the same price across a certain region or state and to remove or decrease the exposure of independent retailers to congestion price volatility.

The shortcomings of the zonal approach can of course be mitigated. Under the recently adopted Guideline on Capacity Allocation and Congestion Management, the efficiency of bidding zone configuration will be assessed every three years. If this assessment reveals inefficiencies, ACER may request the TSOs concerned to launch a review of the existing bidding zone configuration.

Finally, electricity markets also need to facilitate longer-term contracting and investment in new generation. Experience from markets with nodal pricing suggests that forecasts of nodal price differentials do not play a major role in investment decisions, as potential investors may regard transmission constraints as temporary and likely to be relieved by transmission investments in the future. In such cases, only the impact of losses on nodal prices will be taken into account, bringing – if possible – new generation closer to demand. Investment decisions appear to be mostly driven by other factors such as permits, renewable subsidies, capital costs, expected operating costs and fuel availability.

Figure 9: The LMP contour map below provides a real-time map of the footprint of the MISO/PJM markets in the United States. The map shows selected commercial hubs, with their respective LMP values. Each hub is represented as a circle with the zonal color dependent on the price.



10 Europe is moving towards a centrally planned power market

While EU is setting up a Target Model based on an energy-only market and several countries are implementing capacity mechanisms, there are many signs that Europe is actually moving towards a centrally planned power market.

In the past 10 years a majority of investments in new generation have not been triggered by the electricity price but rather by subsidies. An increasing share of the revenue stream to power generators comes from subsidies or other non market-based payments. This is especially true for renewable generation, but is also becoming true for investments in conventional and nuclear power plants. The cost of the German support system currently exceeds the electricity price in the electricity bills for household customers. The UK and France are examples of markets with an increasing element of central planning.

The British government has concluded that current electricity market arrangements do not provide the long-term market certainty for the large volumes of capital-intensive low carbon generation sources, including nuclear power, needed to decarbonise Britain, ensure security of supply, and make sure that costs to consumers are kept reasonably low. Unlike the Nordic countries, the Britain's share of renewables is low, and demand is expected to increase as the heating sector switches from natural gas to electricity.

The British Government has therefore decided on a set of reforms. The key elements are long-term contracts in the form of technology differentiated feed-in tariffs, long-term price signals implemented though a carbon floor price, a capacity mechanism to ensure an adequate security of supply, and stricter environmental legislation to make sure that new carbon-based power plants without CCS (Carbon Capture and Storage) are not built.

The long term contracts are in the form of contracts for difference (CFDs) that guarantee a pre-defined price for electricity generated by paying the difference between an agreed strike price and the reference price, a measure of the average market price for electricity in the UK market. For renewable generation the strike price of the CFD is the result of an auction. In the first auction in 2015 the strike price was between 50 and 120 GBP/MWh (2012 years money) depending on technology and delivery period. For nuclear power there are too few credible vendors for an auctioning process. Instead, the strike price has been a result of a negotiation. In the UK the government has agreed to pay 92.5 GBP/MWh (2012 years money) for 35 years to secure the investment. These numbers should be compared to the current wholesale price of about 50 GBP/MWh. The French government has passed a law to reform the electricity market. This law regulates the price of a significant volume of France's nuclear output by granting EDF's rivals supplying end-consumers the right to buy electricity generated by EDF's nuclear power plants at a regulated tariff set by the

Government. In addition, the law hints that future costs to replace the nuclear fleet, i.e. to build new plant, will be covered by a regulated item included in end-consumers electricity tariffs. It can therefore be argued that only investment in peak generation will be left to market forces. The law also opened the door for the establishment of a capacity market.

The aim of the capacity market is to secure adequacy given the extreme temperature dependency and volatility of France's peak load. The French capacity mechanism is set to enter into function on 1 January 2017, if found compliant with state aid rules by the European Commission.

Ten statements about The future Power Market Design

There is a need for a redesign of the European power market. The market design of today – based on an energy-only market – will not necessarily deal adequately with large amounts of renewable electricity generation. The low marginal costs of renewable generation will depress the price on the electricity market, making conventional generation unprofitable. There are concerns that this could - without some form of intervention - lead to underinvestments in conventional capacity.

NEPP (North European Power Perspectives) is a multi-disciplinary research project dealing with the development of the electricity systems and the electricity markets in Sweden, the Nordic countries and Europe with the time perspective of 2020, 2030 and 2050. The research is performed by well-merited researchers and analysts.

We have summarised NEPP's analyses of the development of the electricity market in a separate theme-book. This publication gives an overview of the most significant conclusions in the theme-book, e.g:

- The energy-only market will have difficulties delivering needed investments in new generation.
- The choice between a strategic reserve and a capacity market is dependent on how often it is expected to be used.
- The introduction of capacity markets will lead to increased investments in new generation, and at the same time to lower prices on the wholesale market.
- The costs of a capacity market will increase once new investments are needed.
- Including interconnectors in a capacity mechanism is far from simple.
- Flow-based capacity allocation will lead to a more efficient use of transmission.
- Nodal pricing will allocate transmission capacity more efficiently, but lead to less liquidity on the market.
- Europe is moving towards a centrally planned power market.

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north european power perspectives