Capacity Mechanisms in Northwest Europe

Between a Rock and a Hard Place?

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Summary and Conclusions

Policy makers of various countries in the EU are concerned about the future adequacy of power generation capacities in national markets. These concerns are based on a combination of factors impacting the investment climate for new generation capacity. Factors included are the fragile economic climate, low prices for CO_2 emission rights, and the impact of the expected flexibility from large volumes of near-zero marginal cost capacities in traditional power generation facilities performance. To mitigate the new risks, policy makers are considering new policy measures to improve the prospects of adequate supply availability.

This report examines the outlook of the current "energy-only" market to provide a sufficient power generation capacity, particularly in markets with increasing shares of variable wind and solar power in the power generation mix, and possible further measures to enhance these prospects. Options for new market mechanisms (i.e., capacity mechanisms) to boost necessary investments in new power generation capacity are discussed, as well as the advantages and disadvantages of these mechanisms. Finally, the paper offers an overview of the implications for different countries in Northwest Europe to implement different market mechanisms or to decide not to alter their current market mechanism, in contrast to their neighbours.

This report focuses on the power generation market in Northwest Europe. The report is based on publicly available literature and interviews with industry and energy research experts. Attempting to serve as input into the on-going debate, this study comments on the necessity and consequences of introducing new types of market mechanisms, and their specific advantages and disadvantages in Northwest Europe.

Energy-only markets

In Northwest Europe, power plants currently gain most of their income from power produced and sold. There is no decisive evidence that such "energy-only" markets will not work under appropriate regulatory/policy conditions, as indicated in recent years by investment developments in the Netherlands. However, developments in some other markets in Northwest Europe have led to concerns about the future availability of generation capacity:

- The rapid changes in the mix of generation capacity, coerced by policymakers/regulators (e.g. phasing out of nuclear capacity, inroads made by renewable energy (RES)), may have left markets with insufficient time to adapt;

- The introduction of variable wind and solar generating capacity, often without associated adaptation of the grid, and the resulting impact on the performance of conventional generation capacity, has created unresolved issues and concerns;

- In today's Northwest European markets some generating assets may not even generate sufficient income to continue operations and risk being mothballed;

- There is uncertainty over the future of CO_2 prices, and there are concerns in the industry about policy and regulatory interventions, including price capping in a more volatile price environment caused by variable RES production.

There is certainly room to improve the likelihood for an "energy only" market to succeed where these concerns have surfaced. However, policy measures to improve the market conditions could fall short in turning the investment climate around quickly. In these circumstances, measures to stimulate investment should be contemplated to garner the desired result. Already a discussion has started in various countries about the need for a capacity mechanism with a more or less permanent nature.

The mere consideration of a capacity mechanism could easily become a self-fulfilling prophecy, when potential investors hold back investments pending the outcomes of the policy evaluations.

Capacity mechanisms

There are different types of capacity mechanisms, varying from strategic safety nets to full control of required capacity. These can be grouped into 5 categories.

All are being applied in a limited number of markets, but conditions in each market are very specific and unique, and none have been in existence long enough to draw firm conclusions. Also, none of these capacity mechanisms have been introduced to deal with the impact of large amounts of wind and solar capacity. This makes it very difficult to draw on practical experience when capacity mechanisms are considered.

The results of desk studies are equally inconclusive. There are a variety of studies offering different opinions. Some, favouring energy-only markets or a Strategic Reserve concentrate on the drawbacks of Capacity Markets. Others, favouring Capacity Markets (particularly the Reliability Option) focus primarily on the theoretical efficiency benefits and tend to gloss over the implementation and application risks from regulatory measures.

Capacity mechanisms are inevitably focused on reliable generating sources. For mechanisms that rely on competitive bidding, there are questions about the setting of criteria to qualify for participation in the bidding process. The less stringent the criteria, the more competitive the bidding and the lower the risk of market power abuse. It is not clear from any of the studies how variable renewable sources can be effectively integrated in any of the capacity mechanisms. It is also unclear how technically and economically suitable back-up capacity can be guaranteed in the short to mid-term, while in the long term (without RES incentive schemes) it is unclear how solar and wind power can be remunerated when availability mechanisms could affect their competitive position vis-à-vis non-variable sources.

All mechanisms depend on medium to long-term projections of peak demand and the long-term projection of supply. Projections of future demand offer a useful tool to planners, policy makers and investors. Given market and policy uncertainties, the outlook is generally presented as a range based on different scenarios. However, capacity mechanisms require major commitments being made against a single projection. This projection will never be right, regardless of who produces it.

Central authorities, if responsible for assessing future demand for a capacity market, are likely to err on the side of caution as an insurance against power failures. The result is overcapacity, which comes at a cost.

Cross-border implications of introducing a capacity mechanism in one market

Few studies focus on the cross-border impact of a unilateral introduction in one Northwest European market. In this respect, one of the first choices to be made when a country decides to implement a capacity mechanism is whether or not it invites non-domestic generation capacity to participate in the bidding. Both options have cross-border consequences. When only domestic capacity is eligible to bid:

- This is likely to lead to a reduction of cross-border competition and efficiency, as well as overcapacity in the Northwest European area;
- There is a possible spill-over effect on other markets in Northwest Europe in terms of price (i.e., lower electricity prices in bordering markets) and supply availability, as national consumers could end up paying for the resource adequacy in bordering countries. When non-domestic (external) capacity is eligible to bid: The non-domestic generators could encounter reduced competitiveness with the need to book interconnection capacity to meet their obligation to supply cross-border markets; this could also have a negative impact on the available interconnection capacity and therefore electricity trading as well as conflict with the current processes of allocating interconnection capacity;
- Commitments from generators in a non-domestic market to meet supply requirements abroad could have a negative impact on the availability of capacity in that market.

It is difficult to assess the size of the cross border impacts, because little research has been done so far. This is surprising given that the discussions on capacity mechanisms concern integral parts of the prevailing market model of the internal electricity market. Further research into cross-border implications of the unilateral implementation of capacity mechanisms would be most advisable.

Internal market impact

The introduction of a capacity mechanism in one of the Northwest European member states is a national policy initiative to secure national energy markets, and takes precedence over European market rules, potentially leading to discrimination against non-domestic generating capacity. Different mechanisms across the EU would clearly complicate internal market rules and ambitions. Given the choice, mechanisms with external eligibility offer more potential for preserving integrated internal market efficiency but still harbour the danger of unwanted policy competition among member states.

Capacity mechanisms are likely to lead to (further) erosion of free market principals, with the Strategic Reserve having potentially the mildest impact. However, a Strategic Reserve when implemented unilaterally is also the mechanism which is the least suited to improving supply security in a country interconnected with other markets.

Ensuring generating adequacy of electricity supply is in the first place a matter for the market. National regulators and policy makers monitor and are able to take measures when concerned about insufficiency of new investments. However, the contribution from neighbouring countries to securing electricity supply in an integrated and well-functioning internal market can be significant. A common coordinated approach to deal with the current issues could benefit member states.

Conclusions

It is not possible to empirically prove the supremacy or the inability of either energy-only markets or capacity mechanisms, in terms of safeguarding resource adequacy in the most efficient way. There is limited practical experience with most capacity mechanisms (see Annex A), and some capacity mechanisms have been frequently modified since their introduction. Additionally, it is difficult to surmise whether the market model in place, an energy-only or a capacity mechanism, was the generally decisive factor to invest in the past. Past investment decisions were also influenced by various exogenous variables, such as (also regularly adjusted) environmental policies and economic growth expectations. The discussion is further complicated, because:

- A pure energy-only market does not currently exist (that is, without regulatory measures to ensure resource adequacy); and
- It is unlikely that there is a one-size-fits-everywhere option given the different market characteristics.

It would be judicious for Northwest European governments not to rush into introducing capacity mechanisms, which will undoubtedly have a major impact on their own markets and spill-over effects on those of neighbouring countries:

- The ongoing debates and analyses do not make a sufficiently clear distinction between short- and long-term issues and appropriate remedies. The current concerns and discussions have been caused by a variety of factors in Northwest European markets, including the rapid introduction of wind and solar capacity and the early retirement of nuclear plants. They may well represent short-term problems. Capacity mechanisms may cast a long regulatory shadow over the markets. There may be better solutions to the current issues of a less radical and far-reaching nature.
- From a practical perspective, preparing a market for a capacity mechanism could well take more years than would be available for resolving pressing short-term problems.
- Any capacity mechanism carries a high risk of implementation problems. The current market design, the Third Package framework, is still being implemented and markets experience issues and risks of a regulatory nature which should be addressed. This includes the need for further harmonising of cross-border exchanges and balancing in the Northwest European market. Introducing a major new design such as a capacity mechanism would stack new risks on current shortcomings. Improving current market conditions to improve investor confidence should be a first priority.

- Energy-only markets are considered to work more effectively with Demand Side Response (DSR), which is likely to affect demand profiles. Capacity mechanisms rely on demand projections. Consideration should be given to the expected impact on demand of a functioning DSR mechanism if it were to be introduced on a market.

- Some of the capacity mechanisms essentially represent subsidies to conventional capacities. There is a risk that Northwest Europe will end up creating a complex system of subsidies in its markets, within which policy makers and regulators decide on new investments by tweaking the payment structures for all types of conventional and non-conventional power plants. This would represent a significant departure from the free market philosophy, which was embraced some twenty years ago. It would probably require acceptance of the consequences of further market intervention and could lead to a new model in a future energy market.

- Any discussion on capacity mechanisms and other possible new elements of market design should be approached on the basis of the policy drive for the transition towards a low-carbon energy system, both in a national and in a wider European or Northwest European context.

- National discussions and solutions could well fall short of reaping the benefits of a European energy market and even weaken the efforts of its integration; a co-ordinated European approach could have a valuable pay-off.

The recent economic downturn has led to a reduction in the estimates of future demand. Given the further adaptation of (inter)connection, which has been lagging behind the changes in generation infrastructure, the combined capacity of the Northwest European markets seems to be able to meet aggregated demand for the foreseeable future. Whereas short-term issues may be resolved with short-term measures of a less momentous nature. This should allow for more time to consider measures, if any, to enhance long-term generation adequacy and also to reap the benefits of the internal market and possible generation surpluses in neighbouring countries.

Before national policy makers adopt capacity mechanisms they should consider the implications for the long-term perspective and road maps to a sustainable energy mix, in addition to the implications for neighbouring countries and the functioning of the internal electricity market. All in all, the studies on and experience with capacity mechanisms leave too many issues unanswered to simply move ahead. More research is warranted on exactly which problems they wish to remedy before national policy makers take any definitive steps.

Aim of the study and methodology

This study focuses on the power generation market in Northwest Europe. It examines the outlook on whether the market will be able to provide sufficient power generation capacity now that there is an increasing share of variable wind and solar power in the power generation mix. Possible options for new market mechanisms (i.e., capacity mechanisms) to boost necessary investments in new power generation capacity[1] are discussed, as well as the advantages and disadvantages of these mechanisms. The paper includes an overview of the implications of different countries in Northwest Europe implementing different market mechanisms (or deciding not to alter their current market, in contrast to their neighbours).

This study is based on publicly available literature together with interviews with industry and research experts. Several studies (the number is still increasing) have been published on whether or not there is a need to introduce a new market mechanism and what mechanism this should be; however, these studies have varying outcomes. The aim of this study is to give an overview of:

- The views surrounding the current concerns (in some countries) that the current investment climate will not lead to sufficient amounts of investment in new power generation capacity;
- The potential remedies suggested in literature, considering the different capacity mechanisms and their possible weaknesses and strengths; and
- Compatibility with the goal of EU market integration.

In this way the study intends to give input for the debate around the necessity of introducing new types of market mechanisms in Northwest Europe.

[1] Also to prevent decommissioning of existing conventional power plants.

1

Effect of wind and solar power on conventional power plants in Northwest Europe

Solar and wind power is a rapidly increasing share of the Northwest European power generation mix. As a result, the power market is undergoing changes in movement and levels of electricity prices and in the operation of conventional power plants.

In current power generation systems the power supply is continuously adjusted to the power demand of that moment. The order in which power generation plants provide electricity is largely based on the marginal costs of power generation of the power plant. Wind and solar power have nearly zero marginal costs and therefore, when available, will always contribute their produced electricity[2].

Wind and solar capacity need two types of "back-up":

- Short-term back-up to deal with the variability and forecasting error of demand and supply. A large amount of variable renewables requires a slight increase in flexible capacity of the same nature as currently used by Transmission System Operators (TSOs) for balancing purposes.

- Long term back-up, as wind and solar also need a large amount of "long-term" back-up capacity to deal with long periods (hours to days) of low wind and solar supply.

When wind and solar capacity is added to a system, most conventional power generation capacity will have to stay in the system and remain available to provide long-term back-up capacity during periods of low wind and solar power[3,4]. However, output of the conventional power generation plants will be reduced, resulting in a lower total number of running hours. A reduction in the number of running hours affects the predictability of future load and profitability. Based on current fuel and

[2] Wind and solar power have –in most systems– priority over other power generation sources, up to the point that the power grid can accommodate it.

[3] Vos, I., *The Impact of Wind Power on European Natural Gas Markets*, IEA Working Paper, January 2012.

[4] Méray, N., *Wind and Gas: Back-up or Back-out, That is the* Question, CIEP, December 2011. This study showed that about 70-80% of the nameplate capacity of wind power has to be available in the system to provide sufficient level of resource adequacy. The same study also showed that most of the back-up capacity of wind power has to be provided by conventional power generation, as other options are currently unproven, technically limited and/or uneconomical.

CO_2 prices, the order in which *conventional* power generation contributes to demand in Northwest Europe is generally nuclear, followed by coal, and finally gas-fired plants. This makes the operating hours of gas-fired plants most sensitive to the growing input of wind and solar energy.

As a result, today in Northwest Europe even the most modern gas-fired power plants have difficulties operating on a profitable basis. This leads to the consideration of mothballing and earlier than expected decommissioning of some power plants.

Over the long term the reduced number of running hours in conventional power plants increases the risks of investing in new power generation capacity. In this way an increasing share of wind and solar energy in the power generation mix gives extra urgency to the discussions on the effectiveness of the current market mechanism to provide a sufficient amount of generation capacity.

The reduced operational period could be offset by a sufficient increase of the electricity price for periods with low wind and solar supply. However, this would lead to more volatile prices and increase the risk for the introduction of price caps. This will be discussed in the following section.

2

Theoretical considerations in an energy-only market

In Northwest Europe, merchant power plants currently generate most of their income based on the amount of power that has been produced and sold (volume in kWh, MWh, GWh). A market in which electricity producers are paid *only* for the volume of electricity that has been sold, and not for the capacity that they have available, is called an "energy-only" market. In practice pure energy-only markets do not exist, as transmission system operators always need to have a certain amount of power generation capacity available to be able to keep the power grid in balance[5]. Power plant operators receive financial compensation for placing power generation capacity at the TSO's disposal for the short-term balancing of the power grid or for solving local (e.g. voltage) irregularities. However, this "capacity fee" is generally modest and profitability essentially depends on the income from generating power (energy fee).

2.1 The missing money problem

In a competitive market, the price of the electricity is mainly determined by the short-run marginal costs (fuel- and CO_2 price, variable operational costs). The unit having the highest marginal costs at that moment sets the electricity price. The investment costs of the power plants providing peak capacity have to be recovered from a higher than marginal electricity price when the market is tight. This "scarcity" mark-up, albeit during short periods of very tight markets, is generally also required to ensure the profitability of other plants in the system.

The question is whether in an energy-only market this short-run process is capable of providing long-term investment signals. Especially in a power generation system with a large amount of variable wind and solar energy, as the running hours of the back-up power generation plants might be reduced to the level that the investment costs of power generation cannot be recovered within a reasonable period of time. High "scarcity" prices would support the economics of a back-up plant. This would risk the introduction of an electricity price cap increase.

The risk of the reduced number of running hours of conventional power plants, together with the regulatory uncertainty on introducing a price cap, leads to uncertainty as to whether a utility is able to recover the initial investment costs. This concern has been coined in the literature as the "missing money" problem.

[5] To deal with unexpected variations in the power supply/demand and for local voltage control.

The “missing money” problem originates from markets in the US where electricity prices are capped. In the absence of scarcity prices the plant owners are not able to recover the costs and make a return on their investments. In Europe, a similar “missing money” concern arises from lower running hours and concerns of price capping. This typically applies to conventional power plants that provide back-up for wind and solar power. Another type of “missing money” problem deals with the risks of investments in *renewable* power generation sources. During high wind and solar supply electricity prices will drop, making investments in capital-intensive wind and solar power generation capacity less attractive. This type of missing money problem for wind and solar power generation capacity is not addressed this paper.

As the missing money concern and the contribution of new market mechanisms are analysed, one should realize that it is not only the *total* sum of generation capacity that matters for system adequacy. Market mechanisms should also be tested for their ability to provide incentives to invest to a sufficient degree in flexible balancing capacity as well as in the most efficient long-term back-up power generation capacity.

3

Power generation capacity in Northwest Europe

The ENTSO-E scenario outlook and adequacy forecast 2012-2030[6] gives an overview of the expected power generation capacity in Europe. In this study three scenarios have been developed:

- Scenario A (or the "Conservative Scenario") shows the necessary additional investments in generation to be confirmed in the future to maintain security of supply. It takes into account the commissioning of new power plants now considered as sure. Load forecast is the best national estimate available to the TSOs, under normal climatic conditions.

- Scenario B (or the "Best Estimate Scenario") gives an estimation of potential future developments, provided that market signals give adequate incentives for investments. It takes into account the generation capacity evolution described in Scenario A as well as future power plants of which the commissioning can be considered to be reasonably credible according to the information available to the TSO. Load assumptions are the same as in Scenario A.

- Scenario EU 2020 gives an estimation of potential future developments, provided that governmental targets set for renewable generating capacities in 2020 are met. It derives from the EU policies on climate change and is based on national targets set in the National Renewable Energy Action Plan.

Figure 1 shows the "remaining capacity" (RC) minus the "adequacy reference margin" (ARM) in the three scenarios described above. The exact amount of power generation capacity strongly depends on the speed of mothballing and retirement of the existing power plants, and the speed with which new power generation capacity is installed; both are difficult to forecast precisely. Also, the expected load depends on several parameters that are uncertain, such as economic growth, the speed of electrification and the introduction of efficiency measures. Within these uncertainties the main conclusions on the available power generation capacity for the coming decennium are:

- Several conventional power generation capacities will be taken out of production, for economic reasons (partly caused by the increasing share of wind and solar), or driven by environmental goals (e.g. the Large Combustion Plant Directive) or public opposition (e.g. nuclear phase-out in Germany).

[6] ENTSO-E Scenario Outlook & Adequacy Forecast 2012-2030, July 2012.

- Large-scale new investments in conventional power generation capacity will be necessary to compensate for retirement of older plants and to deal with increasing electricity demand.
- There are large differences in the forecasted remaining capacity between the different Northwest European countries in 2020.
- On an individual basis some Northwest European countries will need to realize investments in new power generation capacity[7] by 2020. The situation is most urgent in Germany, possibly also, to lesser degrees, in the UK and France.
- For Northwest Europe the sum of all remaining capacities in the region is positive in the "best estimate scenario" and in the "EU-2020 scenario", suggesting that at least part of the investments in new power generation capacity could be exchanged for investments in interconnection capacity to the extent necessary.

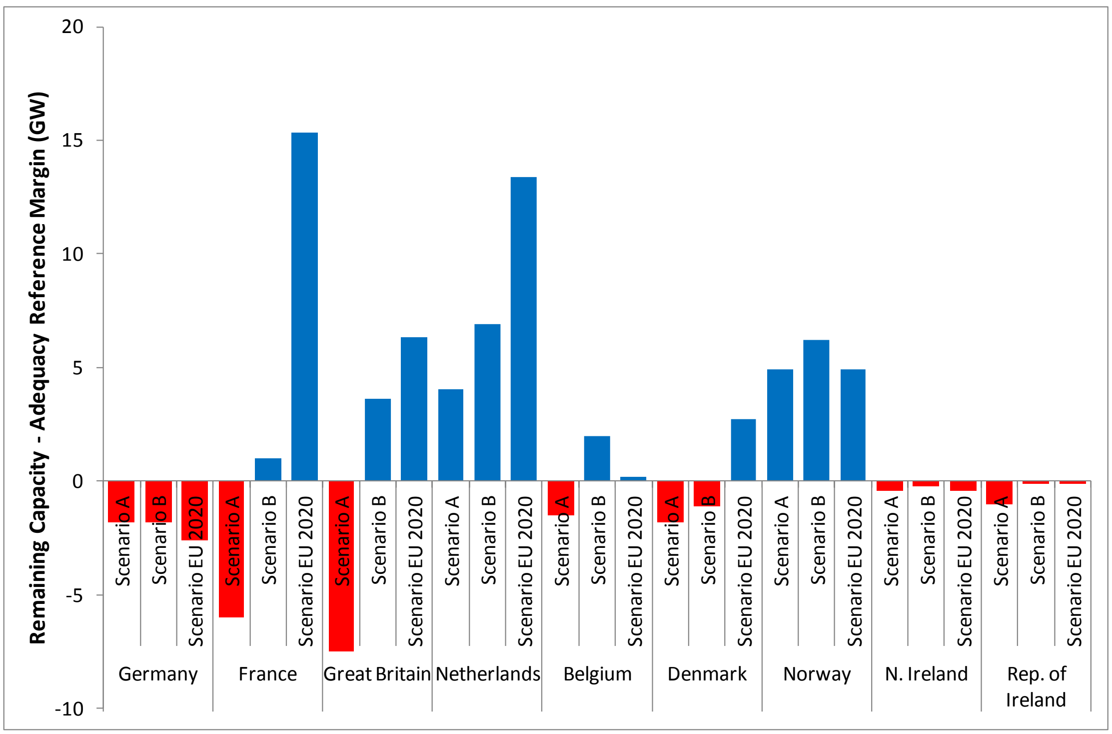

Figure 1: Forecasted remaining capacity (adequacy reference margin) in NW Europe in 2020 in the conservative scenario (scenario A), the best estimate scenario (scenario B) and in the EU-2020 scenario. Data from "ENTSO-E Scenario Outlook & Adequacy Forecast 2012-2030"

[7] Or investments in interconnection capacity, see next bullet.

4

Investments in power generation capacity in energy-only markets

4.1 Concerns on energy-only markets

Arguably, in an energy-only market investments in power plants could be profitable even with a lower number of production hours, provided that the electricity price is sufficiently high during the reduced period in which they produce electricity. The premise is that in the absence of available wind and solar power supply electricity prices increase considerably, and particularly in cases of insufficient generation capacity in the system. High prices during low wind and solar periods would make conventional power plants profitable and would give a signal to the market to invest in new power generation capacity. There are four reasons why some studies argue that this theory would not work in practice:

- Possible insufficiency of future price spikes to cover total cost of power generation, as price spikes might not be high enough to cover the total costs of the highest marginal cost unit;
- Regulatory risk of the introduction of price-caps in case of high price spikes;
- Low demand participation in times of capacity shortage (absent price elasticity); and
- Less attractive business case for modernising existing power plants and for new investments (higher risks, i.e., higher discount factor in the economic evaluation).

In an energy-only market with a large share of variable renewable sources the volatility of the electricity price will increase considerably[8]. In today's market demand hardly responds to changes in electricity prices, not even when prices are temporarily unexpectedly high, as consumers have no insight in and are not influenced by the actual electricity price. Volatile electricity prices with high peaks during low wind and solar supply can improve the economics of conventional power plants considerably, but also significantly increase the risk of political and regulatory intervention.

[8] A financial arrangement to manage the uncertainty introduced by high peak prices would be to hedge peak price volatility. In this way uncertainty for both the consumer and the seller would be reduced.

4.2 Possible measures to improve the investment climate for new power generation capacity in an energy-only market

Given the above uncertainties in an energy-only market with an increasing share of renewable energy sources, it is easy to become concerned over the realisation of sufficient new investments in power generation capacity. However, as European liberalized electricity markets have not yet seen a full investment cycle, it is impossible to empirically prove that energy-only markets do or do not provide sufficient investment. One example is the current investment level in power generation capacity in the Netherlands, where several utilities made the decision to build new power plants (expected ca. 7 GW of new power plants up to 2015). This shows how difficult it is to model the investment decisions of companies based on pure theories. Also, the industry has not been given sufficient time to adapt to the changing business environment as the the turn-around time in the power generation industry is slow and some if not most of today's issues stem from a rapidly changing market, notably with the introduction of variable RES.

There are several steps that can be taken in an energy-only market without the introduction of new market mechanisms, which can improve the climate for investment decisions on power generation capacity. The following measures are often discussed in the literature:

- Reduction of regulatory risk by means of a sound market framework that minimises uncertainty to the extent possible (especially political and regulatory uncertainty) and can be in place for decades without adjustment;
- The guarantee that price-caps will not be introduced (as part of a stable framework)[9];
- Harmonisation of regulatory regimes across the EU or at least across Northwest Europe (e.g. on programme responsibility and cross-border balancing);
- A more intense co-ordination of the various RES support systems, including the limitation of incentives for intermittent resources which affect the playing field for the industry;
- Lowering of any obstacles for long-term bilateral contracts, as these could reduce market uncertainty for both the power supplier and the buyer;
- Introduction of large-scale demand response to reduce the need of peak generation capacity, which would only be operational with a very low load factor (but would not significantly reduce the need for power generation capacity for long periods of low wind and solar supply); and
- Clear and stable environmental goals would reduce the uncertainty around investment decisions for conventional power plants.

[9] Other measures could be used if authorities are (almost) certain that market power is abused by for example withholding capacity in the electricity prices.

These measures would undoubtedly contribute to a better investment climate. However, there is no objective test to establish whether the above measures would lead to a sufficient amount of power generation capacity.

Also the power investors seem to struggle to find a market mechanism that would be best for their own portfolios. Part of the utilities see a severe regulatory risk and expect introduction of a price cap in case of regular price peaks. Based on this, they do not expect to invest in new power generation capacity without the introduction of a new market mechanism. On the other hand, several utilities argue in favour of fixing regulatory risk in the existing market mechanism, without the introduction of new types of market mechanisms that would possibly introduce even more uncertainties for power generators.

4.3 Energy-only market or capacity mechanism?

Summarising the current situation, there is no firm empirical or academic evidence that an energy-only market will not work under supportive political and regulatory market conditions. However, there are various factors which have given rise to concerns:

- The introduction of variable wind and solar generating capacity has happened very rapidly, impacting the conventional generation capacity;
- There are concerns about policy and regulatory intervention, including price capping in a more volatile price environment;
- Even if measures are taken to improve market conditions, their impact may be too late for an immediate turn-around of the investment climate;
- In today's market some assets may not even generate sufficient income to continue operation and risk being mothballed; and
- The rapid change in the market mix, enforced by policymakers and regulators, has left insufficient time for the market to adapt. This could mean that the current issues are of a temporary nature and that an energy-only market could return in a more stable policy environment.

These concerns have created a business environment in which the industry is becoming more cautious about new investments. This again has led to political concerns that the future security of supply is at risk. As a consequence new measures are under consideration to provide more assurance of the availability of future generation capacity. This can be achieved in different ways. There are different types of so-called "capacity mechanisms". In a capacity mechanism (some) power plant operators are also paid for the amount of capacity that they have available and or plan to build in addition to the income from the sale of electricity. In this way, the extra "capacity income" provides additional assurance in the market for investors in power plants, and for the consumers of future system adequacy.

There are several types of capacity mechanisms that are currently discussed in literature. The next sections give an overview on the different types of capacity mechanisms, their most important characteristics, advantages and disadvantages.

5

Which capacity mechanism?

In the previous sections the extent of the urgency of the generation problem is addressed, discussing perspectives of academic analysis and the current outlook for the Northwest European market. This section focuses on the characteristics of capacity mechanisms currently being practised and/or discussed. Generally, as mentioned earlier, a capacity mechanism provides for all or certain electricity providers a revenue stream additional to the *electricity* price on the basis of having capacity installed or available.

In various countries around the world capacity mechanisms are in place (see Annex A for a non-exhaustive list of countries). Many studies have been published about the strengths, weaknesses, benefits and costs of the different mechanisms. The outcomes of these studies differ substantially, both in terms of the perceived need to change the current system by introducing a capacity mechanism and the preference for a specific capacity mechanism[10]. While most studies use similar performance criteria to compare options, they apply different weights to these criteria. Most studies conclude with a clear preference for a specific design (i.e., a preference for energy-only markets[11], or a certain type of capacity mechanism).

5.1 Features of the main capacity mechanisms

Capacity mechanisms can be divided into five categories[12]. Within these categories there can be many differences in structure and in implementation. In no two countries around the world has a capacity mechanism been implemented in the same way. The table below summarises the general design features. These characteristics are used in most studies to describe the performance of the mechanisms.

Each capacity mechanism has its own impact on the electricity market. The extent to which *electricity* prices drive investments differs per mechanism. In this paper the Strategic Reserve is included under the header of capacity mechanisms. Since a Strategic Reserve mechanism requires the least

[10] Note that certainly not all studies draw the conclusion that a capacity mechanism is needed.

[11] In these studies no change of the market design is preferred. In some of these studies, suggestions are made to improve the energy-only market without introducing a capacity mechanism.

[12] Note that in some studies more or fewer categories are used.

adaptation of the electricity market (i.e. leaving the energy-only design market largely intact), it is sometimes not perceived as a capacity mechanism.

Table 1: Categories of capacity mechanisms

Type of capacity mechanism	General features
Capacity Payment	▪ A central authority determines the payment for installed or available generation capacity which all or some power plants can receive. This price is (partially) determined administratively on the basis of the capacity payment and the projected market-based electricity price, market participants decide if and how much they would like to invest. ▪ An alternative is that the authority sets a capacity price function, in which the Capacity Payment is dependent on how much of the required generation capacity is already installed. The closer to realising the targeted amount of capacity, the lower the payment for every additional new plant. Similar to the other categories of mechanisms this requires a central assessment of the quantity of capacity needed some point in the future. ▪ In some cases only new plants receive the capacity payment. According to some studies there is no specific design feature which encourages plants receiving the capacity charge to be available during tight situations, however, there are examples where this is the case[13].
Strategic Reserve	▪ In this mechanism a central body makes an assessment of the total capacity needed at some point in the future and of the amount which market participants will deliver. The remaining capacity in which the market is expected not to invest (i.e., the reserve) is procured by a central buyer. ▪ The reserve can be bought in various ways, and in most studies a centralised process is mentioned (i.e., tender or auction). ▪ It is a "targeted mechanism" as only the plants in the reserve obtain the capacity charge. The reserve consists of a limited number of usually existing plants. However, new plants could also be allowed to participate in the procurement process. ▪ The incentive for the plants participating in the reserve to be available is set centrally. The reserve does not participate in the market and is only dispatched during extreme circumstances, for example when the price exceeds a certain price threshold in the day-ahead market. The price threshold is called the "dispatch price", which effectively constitutes a price cap in the market where it is dispatched[14]. If the electricity price is lower, the reserve is not allowed to be dispatched.

[13] An example is Ireland. A capacity payment is given to all generators based on their availability to run. Part of the capacity payment is determined *ex-post*.

[14] This implies that the price market participants (excluding the plants in the reserve) will obtain in that market will never be higher than the dispatch price.

Capacity Market *(Capacity Obligation)*	▪ A central agency determines the quantity of capacity needed some point in the future. An obligation is put on each retailer to contract the projected capacity with generators[15] based on their customers' cumulative share of total peak load. The amount they have to contract is determined centrally. ▪ The capacity can be bought de-centrally (i.e., contrary to a central buyer). Hence, it is not determined by a central authority where capacity has to be bought. ▪ Contrary to the mechanism above, this is a market-wide mechanism. All (qualifying) existing and new plants offering capacity can receive payment by entering a contract with a retailer. These capacity contract terms can also be set centrally. ▪ The incentive for retailers to buy enough capacity and for the generator to be available when required is based on contractually determined penalties.
Capacity Market *(Capacity Auction)*	▪ A central agency determines the quantity of capacity needed some point in the future. A central buyer buys capacity contracts equal to the total projected demand. ▪ The capacity contracts are sold in an auction. This implies there is one capacity price paid to all plants successful in the auction[16]. ▪ This is a market-wide mechanism, and both existing and new plants can participate in the auction. ▪ Similar to the Capacity Obligation the penalty for non-availability is determined centrally.
Capacity Market *(Reliability Options)*	▪ A central agency determines the quantity of capacity needed some point in the future. Call options (i.e. Reliability Options) equal to this amount are bought several years ahead. The remuneration option-providers receive for this call option is the capacity charge. ▪ The options can be bought centrally (similar to a Capacity Auction) or de-centrally (similar to a Capacity Obligation). Usually a Capacity Auction is referred to. The strike-price can be fixed for the duration of the contract or indexed to a reference price. ▪ Under the contract the Reliability Option provider is obliged to deliver electricity when a "strike price" is reached in an electricity market in return for this strike price[17]. In case of a central mechanism it receives the electricity price in the market but has to pay the difference between this electricity price and the centrally-determined strike price to a central agency. In case of a bilateral system, the option provider provides the electricity to the buyer of the option against the strike price. ▪ The strike price is a revenue cap for the provider of the option in the electricity market. If all demand is hedged adequately by the options, it constitutes a revenue cap for the total market in case of an isolated market[18].

[15] This includes the possibility for retailers to use their own plants.

[16] However, several auctions can be held at the same time to enable differentiation of plants participating in the auction.

[17] In case the option provider is able to physically meet the contract, he receives the strike price while the price in the market is higher. If the provider is not able to physically live up to the contract, he has to pay the electricity price to the option holder (to enable the option holder to buy the electricity himself) and dependent on the implementation of the mechanism, an additional penalty.

[18] If the area with this capacity mechanism is connected to other markets via transmission capacity – which is the case for every Northwest European country − the price could exceed the strike price due to a tight situation in a neighbouring country. See the last chapter for an elaboration.

6

Performance criteria of capacity mechanisms

In Northwest Europe there are no capacity mechanisms in place, as described in Table 5 (see section 7.1), except for the Capacity-Payment mechanism in Ireland. It is very difficult to derive any learning from the capacity mechanisms already in place in other parts of the world, and to determine whether they lend themselves for successful application in Northwest Europe.

The main reasons are:

- Each market is unique, with its own market conditions[19].
- In no two countries around the world has a capacity mechanism been implemented in the same way.
- None of these capacity mechanisms have been in place for a long period without significant adjustments.
- Northwest Europe is currently in transition towards a power generation mix, that is for a large part based on renewable generation sources. Environmental goals and measures are being adjusted regularly, which makes it more difficult to choose the most adequate market mechanism.
- In no country around the world has a capacity mechanism been introduced to specifically cope with the problems of (very) short-term and long-term variability of supply sources[20].

Studies assessing the performance of a certain mechanism are based on different qualitative methodologies, which can be divided in two categories:

- Studies starting under the assumption that a market mechanism will function as intended, i.e. based on theoretical design considerations. These analyses usually result in favour of the introduction of the mechanism.

[19] For example, public ownership of generation companies and the level of market concentration.

[20] In some countries such as Colombia, Brazil, Finland and Sweden capacity mechanisms have been introduced to cope with the variability of hydro power. This primarily constitutes long-term (i.e. year-to-year) variability. Compared to wind and solar power, short-term variability is a less important issue with hydro power.

- Studies in which the appraisal of mechanisms is primarily based on the theoretical risks and the way in which these have materialised in practice. These studies are more inclined to draw a negative conclusion on introducing a new capacity mechanism.

The performance indicators used in the various studies fall under three criteria, against which capacity mechanisms are evaluated:

- Effectiveness: The primary goal of a capacity mechanism is to safeguard generation adequacy. This implies that there should not only be sufficient capacity installed, but that capacity will also be reliably available when needed.
- Efficiency: Another general goal is to achieve generation adequacy with the most economically efficient electricity system possible.
- Implementation costs: This includes an analysis of difficulties of changing the market design with a capacity mechanism (see section 6.3). The main risks involved are regulatory errors.

This section gives an overview of the evaluations in various studies of five capacity mechanisms based on these criteria. First, the effectiveness and efficiency of the capacity procurement processes of the different capacity mechanisms will be addressed. Subsequently, an assessment will be made of the different means to ensure that capacity is available when needed. In a separate section, the implementation and design risks will be dealt with.

6.1 The capacity procurement processes of the capacity mechanisms

Different reasons have driven the introduction of capacity mechanisms in various countries around the world. In most countries, the prime reason is that authorities expect a shortage of capacity, immediately[21] or in the future, and do not believe the market will invest in time under prevailing market conditions[22].

To improve the prospect of an economic return on investment, a capacity mechanism introduces another more stable income stream for providers of electricity, in addition to their revenue from selling electricity. Whether a specific capacity mechanism is effective in this regard is dependent on various design features. These characteristics are either specific to a particular mechanism or are mechanism-independent.

Design parameters which are not necessarily dependent on a specific mechanism, but which can have an impact on the effectiveness and the efficiency of a mechanism are, for example, the lead times and contract durations of the capacity contracts. Also important is the scope for regulatory adjustment of key variables affecting the income of companies, for instance Capacity Payments, strike prices, penalties and dispatch prices. All mechanisms could introduce new sources of regulatory risk (see Annex B for an elaboration on the parameters which potentially need to be

[21] For example a demand reduction programme was needed in Brazil to prevent a black out in 2001-2002.

[22] Another reason may be compensation for stranded cost due to market design change. This was for example the case in Spain when liberalisation was introduced.

determined centrally for the various capacity mechanisms). Safeguarding a reliable supply also requires that a locational element is included in the capacity mechanism to prevent capacity from being installed in areas where the transmission system is congested.

Design features which are (primarily) specific to a mechanism are:

1. Quantity- or price-based mechanism: In the three Capacity Market mechanisms the total required quantity of capacity needed (i.e. the future capacity demand) is determined centrally. These are so-called quantity-based mechanisms, and the quantity of capacity receiving the capacity payment is determined by a central body while the capacity payment for qualified capacity is set by market forces. In some studies this is considered as positive due to the claim that it will ensure the total capacity is built (or stays in operation), as is perceived to be needed,. In most of these studies the Capacity Payment mechanism receives a negative evaluation. It is the only mechanism in which the capacity price is determined centrally; how much will be invested on the basis of this capacity payment will be decided by companies. Hence, with this mechanism the risk is that it will not be effective in increasing the volume of installed capacity to a sufficient level.[23] A Strategic Reserve can be acquired under a quantity-based mechanism.

2. Targeted or market-wide mechanism: With all types of capacity mechanisms, there can be differences in the conditions under which plants are allowed to participate in the capacity procurement process. In some studies it is believed to be best to ensure that *all* future demand is met on the basis of a capacity payment; some of them also consider it best to procure all capacity centrally to achieve maximum certainty of sufficient future capacity [24]. On the former point, the Capacity Payment mechanism as well as the Strategic Reserve are deemed inferior to the other capacity mechanism options because both do not offer secure generation adequacy. With the Strategic Reserve, only the reserve is secured. In addition, most of these studies point out that the Strategic Reserve could reduce the incentive to invest because it could limit peak prices while market based investments are dependent on the level of peak prices for their profitability (see section 6.2).

   From the perspective of efficiency and the objective of a level playing field, some studies consider it best if all plants, existing and new, as well as non-generating options, e.g. DSR, storage, and interconnection capacity, (see section 7) participate in the capacity procurement process and receive a capacity payment. Mechanisms targeted at only a part of the (qualifying) plants are considered less efficient than market-wide capacity incentives. These could distort the competitive position of the plants receiving a capacity payment versus other plants in a market.[25]

[23] But for example in Spain a capacity margin is determined centrally and linked to the capacity price, making it a more quantitative system.

[24] Furthermore, it also depends to what extent it is believed that companies have an inherent interest in under investing (see theoretical part).

[25] For example, in a mechanism where solely new plants receive a Capacity Payment, competition between new and existing power plants would be distorted, possibly resulting in lower revenues for existing plants to the level they are inclined to mothball. In this way new financial incentives would have to be introduced to stimulate the building of new power generation capacity.

This results in a positive evaluation of all Capacity Market mechanisms and a negative appreciation for the Strategic Reserve. As a result, (1) only a few plants receive a capacity payment (i.e. the ones in the reserve), but also because (2) in some countries (for example Sweden) only existing plants can participate in the procurement process of the reserve. In addition, (3) it could create more efficiency risks because the plants in the reserve are only dispatched when the dispatch price is reached. The risk is that these plants may be more efficient than the plants in the market, and yet not operate often enough.

The latter two efficiency risks depend on the choice of design features, as a Capacity Payment mechanism can also get a negative judgement because in some countries only new plants are eligible to receive the payment (for example Portugal). However, in other countries both existing and new plants can qualify (for example Ireland).

3. Central or de-central procurement: In general, the Capacity Obligation mechanism is put forward as a de-central mechanism. Strategic Reserve, and Capacity Auctions are generally central mechanisms. Reliability Options can be both, although in much literature central procurement is preferred. The question of central versus de-central focuses mainly on the issues of transparency of price formation and market power. Market power abuse is often considered one of the risks of energy-only markets[26]. However, it can also distort the capacity procurement process in a capacity mechanism. Examples of exerting market power are: overstating the capacity offer price, withholding capacity or depressing auction prices (i.e. to discourage new entry), all undermining efficiency in the electricity system.

An often mentioned design feature, which could help to counteract market power abuse, is a central *procurement* system (as opposed to a de-central/bilateral *procurement* system). However, almost all measures cited to reduce the risk of market power abuse, which can be employed particularly in a central procurement system, have negative implications that could clash with other criteria. These measures include:

- If there are a limited number of suppliers, pooling demand and supply by holding a centralised auction is often regarded as superior to bilateral trade. This could limit the ability to develop more than one specific capacity product, and potentially reduce ability to differentiate between plants on the basis of their technical abilities in the procurement process.

- The more generation and non-generation options that can participate in the process the fewer the opportunities to exert market power. To achieve this, limited technical constraints can be placed on plants participating in the procurement process, potentially allowing more plants to compete. However, this could jeopardize the reliability criteria. In a similar vein the longer the lead times and contract durations, the more opportunities for new investments and new entrants to take part in the capacity purchasing process. Yet longer time frames imply a longer-term market forecast of demand, possibly resulting in more significant

[26] Please note that in all Northwest European countries competition authorities keep a sharp eye on price formation.

projection errors of the required amount of capacity. In the long-term this could lead to paying for stranded capacity if demand turns out to be lower than expected. Additionally, longer contract durations could potentially exclude more efficient options over a longer term.

To accommodate the fear of market power abuse by existing plants, it is also suggested by some studies that they should be treated differently from planned new plants in the capacity procurement process. One way could be to have shorter contract durations (e.g. one year or until the next round of procurement). Another option is cited to prevent existing plants from setting the price during (descending clock) auctions to prohibit participation until the auction price hits a certain threshold. All these possibilities contain an arbitrary element, which needs to be determined centrally, embodying a potential source of regulatory risk.

6.1.1 Summary

Table 2 offers a summary of how in some studies certain features of the capacity procurement process of the capacity mechanisms are evaluated.

Table 2: Capacity procurement process

Design feature of capacity mechanism	**Quantity or price-based mechanism**	**Targeted or market-wide mechanism**	**Central or de-central procurement (i.e. robust against market power)**
Capacity Payment	Price based	Targeted	Central: but this does not always have direct relevance for dealing with market power abuse in the procurement process.
Strategic Reserve	Quantity based	Targeted	Central: pooling benefit in case of limited suppliers & more (administrative) options to reduce market power abuse during procurement.
Capacity Obligation	Quantity based	Market-wide	De-central: more robust if there is no restriction on participation of generators or suppliers. Otherwise: less transparent price-formation & liquidity issues.
Capacity Auction	Quantity based	Market-wide	Central: pooling benefit in case of limited suppliers & more (administrative) options to reduce market power abuse during procurement. However, various caveats involved with this measures.
Reliability Options	**See Capacity Auction or Capacity Obligation*	**See Capacity Auction or Capacity Obligation*	**See Capacity Auction or Capacity Obligation*

A quantity-based mechanism is generally considered more effective and efficient than a price-based mechanism.

A market-wide mechanism is generally considered more effective and efficient than a targeted mechanism.

6.2 Incentives to be reliably available during a tight supply-demand balance

6.2.1 Reliable capacity

To achieve secure generation adequacy, capacity mechanisms should be geared to sources that can be technically relied on at times of peak demand. As sun and wind sources are less reliable (i.e. more variable and less predictable) than other sources, reliability becomes more important with more sun and wind entering the Northwest European system. This raises various issues and may require specific design features, which are not taken into account in most studies:

- More variable renewable sources reinforce the importance for a sufficient capacity procured under a capacity mechanism, which can technically serve as a back-up for these variable sources. For example this raises the question whether it is necessary and desirable to define technical criteria centrally, which providers wishing to participate in the capacity procurement process should meet[27,28]. The next question is whether all capacity should adhere to these technical requirements and if not, how to differentiate. This would be particularly complex in a market-wide central procurement system, such as a Capacity Auction. However, using different auctions (and different prices) for flexibility, additional base load capacity products could be considered. Using a Strategic Reserve for back-up purposes leads to a situation where the plants in the reserve compete against the plants in the market, and if proven more efficient cause further reductions in the operating hours of the latter plants. This leads to the risk of the slippery-slope effect (see section 6.3). For this reason, it would probably not be feasible to accommodate long periods without wind using a Strategic Reserve.

- This still leaves the question of, to what extent can variable renewable sources participate in the capacity procurement process of the market mechanisms. Currently, wind and solar energy are largely remunerated out-of-market by subsidies. This would make it legitimate to exclude them from the capacity procurement process, as long as these subsidy schemes remain in place. Even if wind and solar power become competitive in terms of capital and operational costs compared to conventional plants, it is still questionable whether they can be competitive with conventional sources in the capacity procurement system. As these variable sources are inherently less reliable, they are more exposed to penalties for non-availability.

[27] In this sense one could think of defining ramping rates and availability periods of a capacity contract as well as setting de-rated capacity for unavailability instead of nameplate capacity.

[28] However, it could also be regarded as an opportunity to differentiate on the basis of other energy policy objectives (i.e. not only system security) such as environmental targets. Other tools such as the CO_2 price are probably better suited to provide an incentive for reducing CO_2 emissions. Furthermore, factoring in other criteria could induce discussions on fuel diversity and fuel mix debate as these requirements could be interpreted as “picking winners”.

6.2.2 Available capacity

In nearly all studies a capacity mechanism is only seen as effective in a market if it provides sufficient installed capacity, as well as an effective incentive to ensure output of that capacity is maximised for that market whenever needed. There may be circumstances in which this is not the case:

1. If electricity prices in surrounding countries are higher when relatively tight situations coincide, the owners of installed capacity may sell their electricity in other markets, avoiding the market for which the capacity mechanism was introduced. This issue will be addressed in the next chapter.

2. Tight supply conditions may tempt capacity owners to abuse market power in the electricity market by withholding capacity.

In almost all studies it is argued that an availability regime needs to be included in a capacity mechanism to deal with these two factors. In some studies other criteria have been linked to the availability regime as robustness against**:**

A. Price volatility – resulting in the risk of a higher cost of capital for investors as well as a (possible) higher (short term versus average) price for consumers

B. Regulatory intervention in the electricity market – the risk of regulators capping *electricity* prices.

The Strategic Reserve is the only mechanism in which no penalty or an availability incentive is needed to guarantee the availability of the plants receiving the capacity payment. The plants in the reserve will be automatically employed[29] by the central body when the centrally set dispatch price is reached in an electricity market[30]. In other words, those plants neither have the incentive, let alone the opportunity to withhold capacity or send it to higher priced markets.

With a Strategic Reserve, the dispatch price constitutes an implicit price cap on the electricity market in which it is dispatched. Consequently, electricity providers withholding capacity can only influence prices up to the level of the implicit price cap. The regulatory price-capping risk is mitigated, and price volatility is reduced as electricity prices cannot rise above the implicit price cap.

The opponents of the Strategic Reserve emphasise that the dispatch price is generally too high a price cap to have significant advantages in mitigating market power abuse potential, price volatility and regulatory price-capping risk. Market participants are not compensated by a capacity payment for any reduction of scarcity rents induced by this implicit cap of the dispatch price. Therefore, it should be set sufficiently high that it does not discourage investment,[31] or lead to the mothballing of plants (see also section 6.3 on the slippery-slope risk).

[29] The Strategic Reserve does not participate in the electricity market while the electricity price is below the dispatch price. When the dispatch price is reached it is employed by the TSO.

[30] This could be for example the day-ahead or balancing market.

[31] Therefore, the dispatch price should be at VoLL or between VoLL and the long-run marginal costs of the last peaking unit which can commercially be dispatched. A proxy contains when all other feasible market-based options have been dispatched.

6.2.3 Two availability regimes

In general, there are two ways to safeguard availability:

1. The administrative penalty, which can apply to all capacity mechanisms except the Strategic Reserve. An administrative penalty can be set without any direct link to the electricity market and, as such, does not constitute any intervention in the electricity market. An administrative penalty reduces the risk of capacity being withheld, as this would lead to paying a penalty, – and therefore the risk of regulatory price capping. The higher the penalty the more effective it is. However, it in itself does not reduce price volatility, except when caused by the exertion of market power.

2. The Reliability Option contract obliges the seller to provide electricity when the strike price is reached. With a financial Reliability Option model the seller does not have to demonstrate that he has the physical capacity to deliver. If the seller is not able to deliver (all) electricity at times the electricity price exceeds the strike price, the contract may stipulate that the seller has to pay the "penalty" for the quantity of electricity not delivered by paying the whole electricity price[32] for that quantity. In some studies the Reliability Option with its strike-price is regarded as having the best potential to stimulate availability when needed, but also the best potential to reduce market power abuse opportunities, price volatility and regulatory price-capping risk[33]. Another theoretical benefit put forward is that this strike-price regime is easier to enforce than an administrative penalty, because it is very clear when the penalty can be "called" when a certain price-threshold is reached. Opponents stress that this mechanism constitutes the biggest intervention in the electricity market as it involves a revenue cap. It reduces the ability of electricity prices to reflect scarcity and hence provide adequate investment signals. Most studies consider a pure financial option without any physical check inadvisable.

Table 3 below (and in more detail in Annex B) summarises and compares the risks of setting a dispatch price for the Strategic Reserve, determining the strike price and defining an administrative penalty. Note that the two penalty regimes could (theoretically) also be present in a Capacity Payment mechanism.

[32] This means he has to *pay* the option holder: either a market participant for example a retailer (in a bilateral model) or a central entity (in a central model).
[33] Logically, abusing market power is still possible, just below or up to the level of the strike price.

Table 3: Availability incentive

Benefits & risks **Availability trigger/penalty regime**	**Reduced market power potential, volatility & regulatory risk in the electricity market**	**Intervention in the electricity market**	**Other risks mentioned**[34]
Dispatch price strategic reserve	Dispatch price > strike price, hence perceived as having less market power reduction potential.	Performs better than the reliability option, provided the dispatch price is set sufficiently high.	Dispatch price (perceived) too low or too high: efficiency risk, slippery slope, compatible with variable RES?
Administrative determined penalty	Dependent on the height of the penalty, has potential to reduce market power potential and price-capping risk, but not necessarily price volatility.	Generally the least as there is no explicit price cap.	Primarily implemented in pool markets, arbitrary penalty level, determining and specifying more parameters centrally, higher monitoring cost, more difficult to enforce[35].
Strike price reliability option	Strike price < dispatch price, hence perceived as having the most reduction potential.	Performs worst as there is an implicit price cap. The lower the strike-price, the higher the payment in the capacity mechanism needs to be to recoup total costs.	Complex design, original design: mandatory pool systems (increases regulatory risk) limited practical experience (Columbia), risks involved with strike price system (if strike price is set centrally).

6.3 Implementation considerations and risks

Implementation risks are not always fully taken into account in the reviewed studies, particularly those in which capacity markets are favoured. In this paragraph various considerations with regard to implementation and its risks are discussed. In the Table 4 below the impact of these aspects under the different capacity mechanisms is summarised.

6.3.1 The risk of setting (complex) parameters centrally

In many studies it is believed that, the fewer parameters have to be defined centrally, the higher the chance of preserving an effective and efficient market. Generally market forces are perceived to be superior in achieving efficiency and effectiveness to a central planning entity setting parameters. Equally, a high complexity of design and administration of a mechanism logically leads to concerns. Complexity also enhances the risk of regulatory change. A stable and predictable market design is considered an important pre-condition for investors. Annex B contains an overview of these parameters and the key risks per mechanism.

[34] See Annex B for an elaboration of the risks and more risks.

[35] This means that it is deemed more difficult to prove that someone did not live up to its availability commitment.

An important parameter which has to be determined centrally under virtually all capacity mechanisms is the total amount of peak demand which has to be accommodated at some point in the future and acquired through the capacity procurement process. Determining the right amount of capacity needed is generally considered an ambitious challenge. It depends on many uncertain factors, such as economic growth and the speed of implementing efficiency measures and demand response. The uncertainty in forecasting peak demand increases considerably with increasing time horizons. To ensure that new plants can participate in the capacity procurement process, the design of the mechanism must include long term provisions, which enhances the chance of projection errors.

This poses a significant risk to the success of a capacity mechanism[36]. If the projection of demand is incorrect, there is a serious risk that the electricity price formation will be distorted:

- if set too low, this will lead to under investment. The electricity price could become very volatile with high price peaks and there is the risk of black-outs;
- If set too high, this will lead to over compensation. Overinvestment could depress peak prices, which would reduce the profitability of power plants.

6.3.2 The risk of limited experience

All mechanisms have been introduced in some form in only a few countries. None of the mechanisms have been in place for a sufficiently long period of time to prove they are successful, and none have been introduced to deal with market conditions that are experienced in Northwest Europe. The absence of adequate experience creates more risk of failure or unexpected side effects for both policy-makers and investors.

6.3.3 Ease to exit

The ease to exit a mechanism and return to the current (energy-only) model, either because the mechanism is considered ineffective or has become obsolete, is generally regarded as a positive feature of a mechanism. It depends on the amount and the duration of the capacity contracts involved. The lower the amount and the shorter the duration the better. Market-wide mechanisms (i.e. all capacity market options) are considered more difficult to exit than targeted mechanisms. The Strategic Reserve is deemed the best mechanism in this respect because only plants in the reserve receive a capacity charge.

6.3.4 Compatibility with de-central/bilateral electricity trading

Currently de-central, bilateral electricity trading is the way electricity is traded in all countries in Northwest Europe except Ireland. In Ireland, and also other countries outside of Northwest Europe where capacity mechanisms are in place, all electricity is sold and purchased through a (mandatory) pool. If a mechanism is only or primarily tried into a pool model, it is considered an additional risk for

[36] Please note that the risks of over- or under investment are also present with a Capacity Payment mechanism, because the capacity payment is set administratively instead of market based. Particularly if the payment is not linked to a capacity target or to the electricity price (ex-post) there is a high risk the payment is either too high or too low.

the Northwest European countries not using a pool model. The concerns are that it involves significant price risks for generators when it is implemented in a non-pool market and/or accompanied by a transition to a pool model.

Furthermore, in some studies compatibility with the electricity market is also made dependent on the extent to which the current model needs to be changed. In a power market with a Strategic Reserve, the electricity price remains the main driver of investment. This is regarded as positive by those who take the view that energy-only is still the best market mechanism. They consider the Strategic Reserve as the mechanism which involves the least change, and the least uncertainty and regulatory risk. The capacity charge under this regime has a limited impact on the market, as only a few out-of-market plants (i.e. those in the reserve) receive it. Other studies stress the risk that if the price at which the reserve is dispatched is considered too low by market players to achieve an economic return on investment could discourage investments. It is (in theory) also possible that existing plants not selected for the reserve could close down[37]. If no investment were to take place and/or existing plants were mothballed, for this reason more and more plants would need to be included in a Strategic Reserve for it to remain effective. This risk is often referred to as the "slippery-slope effect". In the worst (theoretical) case, no "market price" or "reserve" would be left as all plants are included in the reserve. However, we did not come across any evidence that a dispatch price has been set so low that this effect actually materialised[38].

In Table 4 these criteria have been applied to the capacity mechanisms.

Table 4: Implementation

	Setting (complex) parameters centrally	**Ease to exit**	**Experience (see also Annex A)**	**Compatibility with de-central/bilateral electricity trading**
Capacity Payment	Potentially less than the capacity market options, but complex.	If it involves a targeted-mechanism it will be easier than the capacity markets options as not all plants have capacity contracts.	Tried in Ireland, Spain and England & Wales Pool (does not exist anymore). Results not promising for at least the latter two. Frequently changed.	In principle ok, however primarily implemented in pool markets.

[37] Due to the implicit price cap, scarcity rents could be reduced. This could undermine the operational profitability of old existing plants.

[38] In Sweden this theoretical risk has been tried to accommodate by including in regulation that the reserve is temporarily and has a maximum size. Furthermore, it is dispatched at a small premium to the last commercial bid in the market in case the demand and supply curve do not intersect.

Strategic reserve	Less than the capacity market options, and less complex than a payment.	Easiest: only focused on limited part of total capacity.	Tried in Finland and in Sweden, but results are not yet clear.	Implemented in a de-central market, but the more the slippery-slope effect occurs, the less electricity there is to trade.
Capacity obligation	Many and complex, but potentially less than capacity auction.	Market-wide, hence difficult.	Yes, but only implemented in pool markets. Frequently changed.	Risky, only implemented in pool markets.
Capacity auction	Many and complex.	Market-wide, hence difficult	Yes, but only in pool markets. Frequently changed	Risky, only implemented in pool markets.
Reliability Option	Many and complex.	Market-wide, hence difficult.	Only tried in Colombia and New England, which are not de-central markets. Problems have already been identified in Colombia.	Risky, only tried in one pool-market. Involves selecting a reference market for the strike price, which is difficult in a bilateral market system.

6.4 Summary of findings from studies of capacity mechanisms

6.4.1 No unanimity and high risks

All capacity mechanisms bring significant challenges. There is no unanimity or objective proof of the superiority of a specific capacity mechanism and it is also not possible to develop a clear qualitative ranking. In any case, some mechanisms may be better suited to deal with specific markets than others. While in various studies similar conclusions have been drawn, most of them have their own preference for a specific design, based on the significance they attach to a specific performance indicator and its contribution to resolving the concern(s) in particular markets.

In many studies either the Strategic Reserve or the Capacity Auction of Reliability Options are mentioned as superior. Generally, in the studies where the Strategic Reserve is the preferred mechanism, much value is attached to the view that this involves the least change and complexity to develop, creating the least (unforeseen) risks and thereby has the least impact on the electricity market. Opponents emphasise the slippery-slope effect. Many academics tend to favour the Capacity Auction with a Reliability Option as the most *theoretically* efficient design, with an additional benefit of reducing market power, price volatility and the risk of regulatory price-capping in the electricity market. Opponents argue that this mechanism brings great regulatory risk and is less or incompatible with the current de-central/bilateral way of trading.

6.4.2 Final remarks on consumer benefits

As put forward in the last part of the first chapter, the advantages, risks and costs of introducing a new mechanism as opposed to operating an energy-only market are difficult to quantify. This also applies when comparing different mechanisms. However, in some studies either the benefits or the costs for consumers of a particular capacity mechanism are highlighted, without quantification. Mentioned benefits of a capacity mechanism for consumers are:

- Higher level of reliability of supply;
- Less volatile and potentially lower average *electricity* prices.

Studies focusing on costs point to:

- Consumers will end up paying for the cost of procuring the capacity and
- The potential implementation and design risks (see Annex B and section 7.3) involved with introducing a capacity mechanism, and their cost to consumers.

The latter point is not always fully recognised in studies. Frequently the underlying assumption is that regulators have projected the required level of investment correctly and that the capacity mechanism functions well (i.e. all parameters are set correctly), resulting in sufficient capacity with a working penalty system in place.

7

The cross-border/internal market dimensions

A functioning internal electricity market is a cornerstone of the EU energy policy. This process is still evolving with the implementation of the Third Package and development of the network codes. The goal is to enable competition between electricity generators and suppliers across borders with the aim to maximize efficiency for the total EU market. It also aims to achieve the optimal benefits from comparative advantages regarding the location of new electricity plants.

In several studies on the need for a capacity mechanism, the internal market aspect is also addressed. In fact, it can be regarded as another performance criterion. It involves the following questions:

- To what extent is a capacity mechanism compatible with the internal market goal in case neighbouring countries implement different mechanisms, or do not introduce a new mechanism at all?
- Is there a significant cross-border effect?
- What level of harmonisation would be required in case these effects are (potentially) significant? Would a cross-border (European) approach towards capacity mechanisms be feasible?

In the first section, the status of this discussion in key Northwest European countries is briefly described. Several countries are considering implementing mechanisms, albeit different ones, and for others this is not (yet) the case. In the second section the dimensions of the impact of the internal market aspect will be discussed. Several studies highlight some of the internal market dimensions, but few studies mention them all. In this section, an attempt is made to bring all the dimensions together and provide an overview. Finally, the issue of cross-border harmonisation will be briefly addressed.

7.1 State of affairs in various Northwest European countries

Table 5 below briefly describes the state of affairs regarding capacity mechanisms in Northwest European countries.

Note that in most countries, the TSO currently contracts for capacity for short-term balancing purposes. This is a type of capacity mechanism, albeit for small volumes. These mechanisms are not included in the table below.

Table 5: Status of discussions on the need and possibilities of new market mechanisms in various Northwest European countries
(Note that of all NW European countries described in this table, only Ireland has currently a capacity mechanism in place)

Member State	**Urgency according to authorities & market participants**	**Mechanism**	**Follow up**
UK (Draft Energy Bill, May 2012)	**No immediate threat according to authorities but:** • Closure 20% of existing capacity between now and 2020; • More intermittent (wind) & inflexible (nuclear) generation. **The consultation held before the draft bill points out that market parties have mixed opinions about the need & which mechanism.**	**Capacity Market proposed:** • Competitive central auction; • Capacity agreements: deliver or face penalties; • Includes both existing and new providers, and demand side; • In the delivery year, providers will be paid for their capacity; • Need & timing of 1st Capacity Auction decided by Ministers.	Completed design expected 03/2013 **First auction:** administered by National Grid: in 2014 if needed for capacity in 2015/16 **Main issues:** • Availability incentive: strike price (i.e. Reliability Option including a physical check) or administrative penalty; Government's preference is the strike-price option; • How interconnection capacity will participate.
Germany (Study EWI for Ministry of Economic Affairs, March 2012)	**Challenge is increasing:** • "Missing money" , driven by increasing share of RES; • Electricity price insufficient for OCGTs to recoup cost & some cases for CCGTs.	**Capacity Market** (Reliability Option model) recommended by EWI: • Central auctioning with Capacity Auction regional differentiated prices; • Implementation: prior to 2020.	Consultation on study's findings .
Germany (Study Ecofys for Federal Environment Agency, July 2012)	**Capacity Markets are not needed at the moment according to Ecofys:** • Energy-only model is the appropriate framework to guarantee SoS.	**Energy-only market with maybe a Strategic Reserve:** • Congestion management including grid expansion and demand-side response is needed. **Strategic out-of-market Reserve in addition to the temporary and small Strategic Reserve capacity for southern Germany to accommodate bottlenecks in the power grid[39,40]:** • Less risky than Capacity Market; • Provides more incentives to practise congestion management; • Capacity Market: risk of inefficiency, mechanism is almost irreversible.	Consultation on study's findings.

[39] In the winter of 2011/2012 cold reserve capacity had to be used from plants in Germany and Austria, in addition to the system balancing energy of the TSOs, as the latter amounts were insufficient to cope with imbalances in the grid in Southern Germany. It is projected that these cold reserve plants will also be needed in the coming winter. This is to accommodate the closure of nuclear plants in southern Germany and the fact that bottlenecks in the power grid prevent that this can sufficiently be compensated by plants located elsewhere in Germany. Grid expansions are planned. In the meantime, the reserve power plants should cope with very tight situations. These reserves plants can be seen as a small and temporary Strategic Reserve for Southern Germany. In the medium term the need for a capacity mechanism should also be researched in depth according to the Federal Regulator.

France (Ministry, March 2012)	**Main reasons according to authorities:** • Need to replace coal-and-oil fired units because of environmental standards; • Increased LT peak electricity demand due to a.o increase of electrical heating; • Increasing share of RES.	**Capacity market (a Capacity Obligation is incorporated in the NOME-law, without further specification)** Proposal (not included in the NOME-law: • Obligation for retailers to procure capacity certificates; • Certificates will be tradable; • Administrative penalties for retailers with a lack of certificates and for producers which do not comply with the certificate (i.e. are unavailable); • Emergency mechanism: call for tenders.	Very unclear, it is indicated that the new government could change the NOME law.
Ireland	**Main Reasons according to authorities:** • Market power worries; • Bilateral market perceived as entry barrier.	**A Capacity Payment System in place since 2005:** • Mandatory pool: all generators required to offer electricity at SRMC; • Additional revenues via the capacity mechanism; • Market-wide model: charge paid to all generators based on their availability to run.	
Netherlands	**According to authorities:** No perceived need • There appears to be ample capacity	[41]	
Belgium	**Main reasons:** • Low investment appetite partly due to a.o. much haziness surrounding nuclear phase-out plans; • Too little flexible capacity for up- and downwards regulating power; • Too little installed capacity to supply-demand in cold periods.	**Plan from State Secretary Wathelet:** • Strategic Reserve consisting of older, not-in-the-money plants; • Guaranteed return for new built CCGT based on auction results; • Creating clarity by fixed dates for nuclear phase-out (but unclear again because of perceived leakage problems with some nuclear plant).	**Planning of Wathelet:** • Nuclear phase-out and life-time extension in law of September 2012; • Capacity mechanism in place Nov 2012.

[40] See: http://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/BNetzA/Presse/Berichte/2012/NetzBericht_ZustandWinter11_12pdf.pdf?__blob=publicationFile. The Strategic Reserve proposed in this Ecofys-study would be much larger than this temporary Reserve and there to deal with long-term generation adequacy issues for the whole of Germany.

[41] In the Netherlands a safety net has been created in legislation. This entails the possibility for the TSO to contract reserve capacity if the capacity margin becomes too low. The TSO has not made use of this possibility up to now; De Vries (2012).

7.2 Cross-border dimensions

Table 5 in the previous section illustrates that various Northwest European countries consider different national capacity mechanisms for implementation. In this section the internal market dimensions, which have been identified in various studies, are collected and discussed.

7.2.1 Effects of including or excluding externally situated plants in the capacity procurement process

Any national authority considering the implementation of a national capacity mechanism should decide how to take account of externally situated plants[42]. They could opt for including or excluding "foreign" plants in the analysis.

External plants can be included in two ways:

1. Foreign plants will be allowed to participate in the procurement process. The benefit of external participation is the possibility of making the procurement process more efficient, as foreign plants could be more efficient than domestic plants. In line with the internal market principles it would allow competition between generators across borders in the capacity procurement process.

   Most studies also emphasize the difficulties with external participation in the current market situation, particularly in case these external power suppliers should be as reliable as internal sources. To achieve the same level of forward reliability as power plants located within the borders (nearly 100%), it is argued that external capacity contract holders would have to reserve capacity cross-border transmission lines for the duration of the capacity contract[43]. For the duration this part of the cross-border transmission capacity would not be available for trading electricity by other parties. This could reduce competition and affect efficiency of the internal electricity market. It could also result in a inefficient level of interconnection capacity, if foreign participation leads to the expansion of interconnection capacity. Note that these arguments are only valid in case there is a risk of cross-border congestion, which should be first assessed. If there is no such risk[44] (or a very small risk), foreign plants can reserve the required capacity without constraining electricity trade or expanding interconnection capacity.

   Another problem is that if foreign plants would have to reserve the interconnection capacity for the duration of the capacity contract, it could make them – ceteris paribus – less competitive compared to domestic plants in the capacity procurement process as the external plants would need to take into account the cost of reserving capacity.

   Furthermore, in a number of studies the notion of reserving interconnection capacity for the duration of the capacity contract is seen as conflicting with initiatives related to market

[42] Obviously, only external power plants that are physically connected can be considered.

[43] This argument is contested by others who suggest that the benefit of secure imports of external supplies can be achieved without long term cross-border capacity contracts.

[44] This effectively means there is much interconnection overcapacity.

integration[45]. As an example, this will conflict with today's regulation that companies have to nominate day-ahead how much of their interconnection capacity they will use. The remaining interconnection capacity will automatically be sold to others. This requires that external suppliers with a cross-border capacity contract should know a day-ahead with a very high certainty, (this example is nearly 100%) whether their capacity will be called on by their contract party in the market with the capacity mechanism. With current forecasting techniques and market dynamics, this is difficult if not impossible, particularly if the market has a high share of wind and solar power.

From the point of view of neighbouring countries without the mechanism**,** another risk is created by letting domestic plants participate in a foreign capacity mechanism, in addition to the possible inefficiencies in electricity trading. Resource adequacy could be jeopardized in these countries at times when tight situations occur simultaneously. If for example the participating plant is an existing plant in these markets, the capacity can no longer be counted upon under all circumstances. If tight situations coincide, a participating plant is committed to provide electricity to the country with the capacity mechanism. In the end this could require new investments and even trigger debate on the need for a capacity mechanism in the neighbouring country.

2. Foreign plants will not be allowed to participate in the procurement process (i.e. will not receive a capacity payment), but authorities include interconnection capacity as a source of system reliability.

   This could reduce the volume of capacity that must be bought in a capacity procurement process. Taking interconnection capacity into account means that power generation capacity of neighbouring countries may contribute to system adequacy, but without further specification of, or contract with any potentially contributing foreign power plant(s) or non-generation capacity[46].

   However, estimating the contribution of imports to a reliable accommodation of peak consumption is very difficult, as it will require a projection of electricity prices, which are impacted by the investments resulting from the introduction of capacity mechanisms amongst others. In any case, an estimate does not constitute a secure commitment to imported electricity. Hence, a trade-off has to be made between the upfront reliability level that authorities would like to achieve and the overall cross-border efficiency.

[45] The goal of these and other market-integration initiatives is to ensure that electricity flows across borders to the highest-priced market, which requires continuously available capacity, for example for day-ahead transactions.

[46] Non-generation capacity includes demand-side response and electricity storage.

If authorities take the view that the forward reliability should be close to 100%[47], they may not include potential foreign supplies in the assessment of the need for investments. In that case, the system efficiency using interconnection capacity could be greatly reduced and as a result overinvestment can occur from the perspective of an integrated internal market. After all, the capacity mechanism aims for full self-sufficiency at any time. Supplies that would otherwise have been expected to be contracted externally will now have to be built within the country itself. If more countries do not take account of any contribution from external plants, this could result in overinvestment in the region. For Northwest Europe, the risk of overinvestment from the introduction of capacity mechanisms excluding external capacity could be serious, particularly since the supply capacity in all Northwest European countries in aggregate is projected to be sufficient in the “Best Estimate Scenario”[48] of ENTSO-E to accommodate cumulative demand up to 2020) (see also Chapter 5).

In a study executed for the Germany Ministry of Economic Affairs, the assignment was to take interconnection capacity into account with close to a zero contribution in the analysis of the necessity of a capacity mechanism up to 2020/2030. This condition could weigh very heavily on the outcome, as the same research institute forecasts that Germany will become an electricity importer (11-12% of the German consumption in respectively 2020/2030).

7.2.2 What if some countries in Northwest Europe implement (various different) mechanisms while others do not?

If there are different capacity mechanisms in place in some countries and others choose to not introduce a capacity mechanism, several effects could occur irrespective of whether external plants can participate or not. These effects can occur both in situations where external plants can participate and in situations where they cannot.

Inefficient investment decisions and the results – The following points apply to all mechanisms except the Strategic Reserve:

- Differences in design or the mere absence of a mechanism could change companies’ preferences for an investment location compared to a situation without capacity mechanisms. This could potentially affect the level playing field of the internal market[49].
- Plants could be constructed where the capacity mechanism is perceived to be more attractive, irrespective of the level (or the expected level) of electricity price differences between countries[50]. Once plants are operational, this could lead to different electricity flows compared to a situation without capacity mechanisms, a previously congested interconnection could become less congested and vice versa. As addressed in the previous

[47] Close to 100% probability that close to 100% of peak demand is hedged.
[48] ENTSO-E Scenario Outlook & Adequacy Forecast 2012-2030.
[49] Not only the design for a capacity mechanism will result in investment decisions, also the overall investment climate, available infrastructure and national power production regulations.
[50] This could lead to a situation where plants are located where the electricity price is (or is expected to be) lower than the surrounding countries.

paragraph, changes in available interconnection capacity could affect the extent to which companies can compete cross-border on electricity; hence the extent to which prices can converge, creating new (in) efficiency dimensions. Thus this may also be perceived as clashing with the EU-wide objective to create price convergence.

- The introduction of a capacity mechanism in a country could also lead to reduced reliability in markets without a capacity mechanism. If this capacity charge leads to investments in new plants with lower short-run marginal costs than the existing plants in the neighbouring country investment, which without such an additional income stream would not have occurred. These "foreign" power plants could be offering[51] electricity at a marginal cost, reducing the running hours and thus the profitability of the plants in the markets without a capacity mechanism except for periods of peak demand[52]. This could lead to possible early mothballing/retiring of these plants. In this case, new investment could be needed to uphold the same level of reliability in the countries without a capacity mechanism.

As argued in the previous sections, the impact that a Strategic Reserve could have on the electricity price and therefore on discouraging investments and/or mothballing plants in the country where it is implemented, is dependent on its design and particularly on the level of the dispatch price. The lower this price cap the higher the reduction of scarcity rents compared to a situation without a Strategic Reserve. If there is interconnection capacity between a country with a Strategic Reserve and a country with an energy-only market, in theory[53] similar effects can occur in the country with the energy-only market.

7.2.3 Distribution of the benefits of capacity mechanisms

A key question is how to ensure that capacity which is paid for by national consumers benefits these same national consumers instead of other (higher-priced) markets[54]? The distributional effects can be assessed in (either one of) two ways (which are interrelated):

From a (physical) reliability perspective. The extent to which the capacity mechanism provides higher reliability in the countries with a mechanism compared to neighbouring countries without a mechanism.

From a financial perspective. The extent to which the capacity mechanism allows the users paying for the system to recover these costs, as an example paying a lower electricity price than consumers in neighbouring countries.

[51] Provided these "foreign" new plants are not out-of-market (i.e. this example is not applicable to a Strategic Reserve) and there is available interconnection capacity between the two countries so the "foreign" electricity can be offered.

[52] Provided the penalty regime functions in the market with the capacity mechanism. This implies that in tight situations these plants would offer in the domestic market.

[53] As mentioned before, we have not come across any empirical evidence pointing into this direction, let alone the cross-border effects this might have.

[54] It goes beyond the scope of this paper to assess whether preventing electricity from flowing to another market in tight situations complies with European regulation.

Evaluations of the above two perspectives are dependent on the capacity regimes of neighbouring countries, their incentives, the interconnection capacity and on both individual and aggregate supply-demand balances (i.e. is there a cumulative shortage). While not all situations are considered in this paper, the following distributional effects could develop between a country with and a neighbouring country without a capacity mechanism:

A tight situation occurs in a country without a mechanism and this is not the case in a country with a mechanism. Price differentials between the two markets lead to cross border supply of electricity from the latter country to the one without the mechanism. If the supply-demand situation in the latter country is the result of additional investments in capacity, then the country without a mechanism will benefit from the mechanism in the other country (to the extent there is interconnection capacity), irrespective of which capacity mechanism is in place. For example, with a Strategic Reserve this price effect can activate the reserve. Hence, a domestic supply shortage in one market can trigger the use of the Strategic Reserve in another market.

The benefits of lower electricity prices in a market with a capacity mechanism will be shared with the neighbouring countries, as it is likely prices converge across borders with sufficient interconnection capacity[55]. With a Reliability Option, if this converged price exceeds the strike price then the domestic consumers who have paid for the capacity would only have to pay the strike price, while the consumer in the other market pay the higher electricity price. There is no such compensation with the Strategic Reserve and the Capacity Market mechanisms with an administrative penalty[56].

In case tight situations coincide in both countries and the market with a mechanism has sufficient supplies to cope with its own peak demand, while there is insufficient aggregate supply the market with a capacity mechanism can enjoy a higher level of reliability than the country without a mechanism. This inequality can continue, depending on the mechanism and the manner in which it is enforced, even if there is interconnection capacity between those countries . The availability regime in the countries with one of the Capacity Market mechanisms or a Capacity Payment mechanism, that could be either an administrative penalty or a strike-price-based system could prevent the supply supported by the capacity mechanism from flowing to neighbouring countries, provided that it works as intended:

An administrative penalty. Preventing supply flows to the neighbouring country can be achieved if this penalty is higher than the price differential between the two markets. If the price differential is lower than the penalty, the reliability level in the country with the mechanism could also be negatively affected.

A strike-price regime. The reliability option provider could decide to provide its electricity to the neighbouring country to benefit from a higher electricity price and pay the lower domestic electricity

[55] It is assumed the electricity market functions in such a way that all trade is in the end based on the spot market price including bilateral contracts.

[56] Provided the administrative penalty is solely incurred in case a black out occurs. If the penalty is triggered earlier (i.e. no black out emerges), domestic consumers could receive this penalty implying that they are somewhat compensated.

price to the option holder. However, it is rather unlikely that the electricity price in the neighbouring country will be higher when tight situations coincide. Retailers in the market with a reliability option can always bid at a higher price for electricity than the neighbouring country's retailers, because these domestic option holders are not exposed to a very high electricity price as they will only have to pay the strike price.

With both availability regimes a higher level of reliability can be achieved than in the neighbouring country. This is not the case for countries with a Strategic Reserve. The reserve can be triggered by a tight situation in another country. While the reserve could be earmarked for the domestic market, the other installed capacity in that market can still flow to the neighbouring country driven by a higher electricity price. Contrary to the other mechanisms, there is no measure in place with this mechanism which discourages export[57].

7.3 Final remarks on a cross-border/European approach

The debate over the need for a capacity mechanism finds itself at different stages in the different Northwest European countries. For example, in the Netherlands it is felt that there is currently no need to implement one, as substantial new investments have been made which will serve domestic (and potentially external) demand for the coming decennium. In other countries, such as France, Belgium and the United Kingdom authorities are already working on the design of a capacity mechanisms (albeit different ones). In Belgium the decision has been made to support the proposal to consider implementation of a Strategic Reserve mechanism and a system to encourage new investments in CCGTs by guaranteeing a financial return. The exact plan will be discussed and decided later this year. In Germany the discussion on the need for a capacity mechanism for the entire nation is beginning to take shape. Ireland is the only country with a capacity mechanism (and the only Northwest European country with a pool market), as it has introduced a Capacity Payment system.

A legal basis to implement different national capacity mechanisms could be Art. 8 of directive 2009/72/EC. It grants national authorities the right to conduct capacity tenders solely in case security of supply is endangered. However, the article does not specify the market conditions under which this is considered to be the case nor whether only domestic generation sources can take part.

Negative implications for the internal market have been pointed out if some countries in Northwest Europe implement various different national mechanisms and others do not. This is particularly the case when a country, in designing a mechanism places more emphasis on achieving the highest possible national reliability level rather than the highest level of efficiency on both a national and a cross-border level. Overcapacity in the countries with a mechanism and undercapacity in the countries without, and/or an inefficient level of electricity trade between countries could be the result.

In most studies it is argued that some level of coordination between countries is needed. While the negative implications of purely national approaches to capacity mechanisms have been brought up in the various studies, the significance of the effects compared to the current situation has not been

[57] Please note that in current EU regulation countries can close down the border in case a black-out is expected.

researched in depth. The arguments for or against bilateral, regional or European coordination/harmonization would be much stronger if an assessment is made of the benefits of a harmonized approach for individual countries and the internal market as a whole.

Annex A: Different capacity mechanisms in different countries

Below a non-exhaustive list of countries in which different kind of capacity mechanism are implemented can be found:

Mechanism	Country
Capacity Payment mechanism	Ireland, Spain, Portugal, formerly in England and Wales pool
Strategic Reserve	Finland, Sweden, New Zealand, Norway, Poland
Capacity Obligation/Capacity Auction	PJM, Greece, New York, Peru, Brazil, Chile, Russia
Capacity Auction of Reliability Option	Colombia, New England[58]

[58] The system in New England can be characterised as a physical call option- system. Different from Colombia the strike price is enforced by deducting the peak energy rents (that is, excess revenues of a generic peaking unit computed for the annual duration of the contract) from the Capacity Payment instead of paying back the difference between the peak energy and the strike price. In New England no negative Capacity Payment could emerge, contrary to Colombia.

Annex B: Parameters which potentially need to be determined centrally

	Parameters	Risks involved with a few key parameters
Capacity Payment	• Payment; • Possibly reserve margin & relation between reserve margin & payment; • Possibly features of penalty system.	Administratively determined penalty: • Arbitrariness of setting a penalty level: over-or under investment
Strategic Reserve	• Payment plants in reserve; • Total peak demand; • Generation capacity the market will deliver (i.e. size reserve), factor in perception: if reserve is not used often, pressure it should be downsized; • Technical capacity of each producing unit participating in auction/tender; • The appropriate length and structure of contracts; • Dispatch price; • Should it be decided upfront in which market the reserve is dispatched? In which market (for example day-ahead market)? Should it not be the market which appears to be short of capacity?	Dispatch price (perceived) too low: • All generators lose some scarcity rents → discourage investments/induce closure of plants (potentially displacing more efficient (new) plants)→prices spike more frequently to dispatch price → possibly triggering debate on bigger reserve & lower dispatch price; • As back-up of variable generation: possibly called to often? triggering debate? Dispatch price (perceived) too high: • Reserve not called while more efficient than some market options

Capacity Market – obligation with penalty	• Total demand;
	• Forwardness of Capacity Obligation;
	• Which demand needs to be hedged/% (all or not for industrial consumers);
	• Possibly various verification features depended on the perceived need to check availability. If there is an administratively determined penalty system:
	  ○ technical capacity of each producing unit
	  ○ appropriate length and structure of contracts set
	  ○ the conditions under which plants have to be available,
	  ○ penalty when the plant is not available
		Administratively determined penalty:
		• Arbitrariness of setting a penalty level: no or inefficient incentive to be available;
		• Determining and specifying more parameters centrally (?): higher monitoring cost (?);
		• More difficult to enforce: to prove that someone did not live up to its reliability commitment than strike-price system.

	Parameters	Risks involved with a few key parameters

Capacity Market – auction with Reliability Option	• Total demand;
	• What generation capacity the market will deliver to decide whether or not to hold a Capacity Auction;
	• Frequency of auction;
	• Forwardness of capacity contracts: lead time between procurement and its required availability;
	• Strike price, reference market of strike price;
	• Possibly various other verification features depended on the believe in the financial incentive:
	    o technical capacity of each producing unit
	    o appropriate length and structure of contracts
	    o the conditions under which plants have to be available.
		Strike price system (if strike price is set centrally)[59]:
		• Arbitrariness of setting a strike price level is key: fixed or indexed (to what)?:
		    o too high: less benefit of curbing market power & price volatility (+ regulatory price capping risk) & low option price value),
		    o too low: risk lower than other price drivers f.e. fuel costs), direct impact on the level of Capacity Payment/offers in the Capacity Market: higher remuneration needed;
		• Difficulty of finding the right reference market. Not compatible with bilateral contracting: Possibly lowering liquidity in forward markets. Encompasses the risk of paying the "penalty" while being available, however not offering into the reference market;
		• Exposed to uncapped price risk (there is no limit to the difference between the electricity price and the strike price) the risk of gaming the electricity price becomes more important & interaction with variable res, hence more price spikes;
		• Pure financial system sufficient? (or physical check deemed required as a back-up insurance →more parameters determined and specified centrally, hence more administrative and monitoring costs).

[59] In most studies a central system is factored in. In case a Capacity Obligation is set these risks need to be decided on a bilateral basis, making it more fit for the current way of de-central/bilateral way trading.

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