Financing investment in new electricity generation capacity in Northwest Europe

Policy brief

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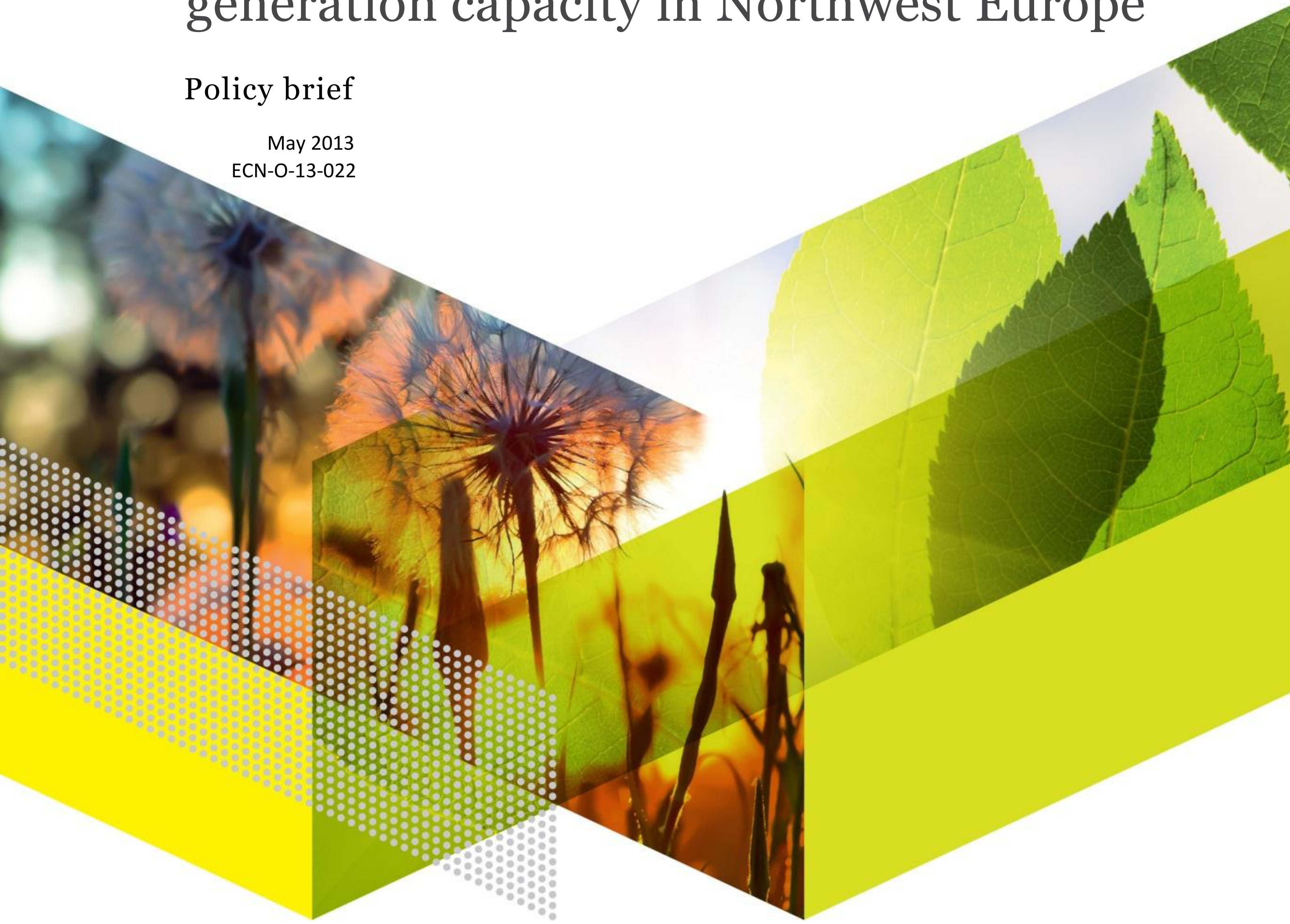

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Summary

Current Northwest European electricity markets are designed as 'energy-only' markets. In an energy-only market the price received for electricity produced is set by the marginal generation unit and potentially leaves the owners of these units with 'missing money': i.e. money that is required to recover investment cost. With a much higher penetration of intermittent electricity sources such as wind and solar PV, these markets may not be capable of providing sufficient incentives for investment in generation capacity, because operating hours and scarcity rents for peak and mid-merit order capacity will be considerably reduced.

There are a number of options available to address this missing money problem. First of all, options should be explored which focus on improving the existing electricity markets. These options include increasing flexibility in both supply and demand,

improving the profitability of investments, for example by means of removing (implicit) price caps and allowing for long-term contracts.

Next to these options which can help increase the revenue for generation investments some form of capacity mechanism such as capacity payments or capacity markets could be introduced. These capacity mechanisms have attracted considerable attention in recent years, both in the literature and in the policy debate, with a number of countries considering the introduction of such mechanisms. However, unilateral introduction of capacity mechanisms in integrated electricity markets can have a considerable impact on cross border electricity flows and investment decisions. It might negatively affect security of supply in neighbouring countries and will result in price differences between consumers within a country which have to bear the costs of capacity mechanisms and those outside those countries. Moreover, unilateral capacity mechanisms can disrupt the functioning of the internal energy market.

Before the implementation of capacity mechanisms, therefore, the different options available to stimulate investment in new generation capacity should be considered, taking into account the costs and benefits and the optimal timing of these different options. Moreover, should capacity mechanisms be considered, it is important to coordinate the introduction and design of such mechanisms between countries and to take into account the effects of unilateral implementation on other countries.

1 Electricity markets and generation capacity investments[1]

With the onset of liberalisation of electricity markets in both the US and Europe and the end of the last century, a discussion has emerged in both the scientific literature and in the policy debate about how to ensure sufficient investment in new generation capacity in these liberalised markets. Up till then, electricity production and distribution was a public utility and investments in new plants were based upon long-term plans drawn up by governments. With liberalisation, production and investments became the responsibility of companies who had to make a profit on the electricity market. This gave rise to the question whether these markets would provide sufficient incentives for investments or whether additional policy measures would be needed to ensure these investments and thereby security of delivery in electricity markets. This discussion focuses especially on those power plants which will only be needed to meet load demand at peak hours and therefore have to earn sufficient revenues in those hours to cover their investment costs. Uncertainty about these revenues might hamper new investments and thereby threaten future security of supply.

Initially, when liberalisation was introduced in Europe and in the US and electricity markets emerged in the late eighties and nineties of the former century, policy makers held the view that electricity markets would provide sufficient incentives for new

1 This policy brief results from a research project commissioned by the Ministry of Economic Affairs. It has benefited from the comments made by the supervisory committee and from discussions at the BAEE research workshop (September 28, 2012), the CIEP Workshop 'Capacity Mechanisms' (October 29, 2012) and the 2nd BAEE policy workshop organised together with the Ministry of Economic Affairs (November 2, 2012).

investment (the so-called energy-only market). Therefore, no additional measures were put in place to stimulate investments, such as payments for capacity investments or additional capacity markets next to the electricity market. However, experience with these energy-only markets have led policy makers to change their views. In recent years, therefore, more and more European countries and US states have implemented some sort of policy measures aimed at stimulating investments in new generation capacity. The reason for some US markets to adopt some form of capacity mechanism related to the (political) unacceptability of price spikes and concerns over harmful effects related to market power on energy-only markets. In the current European electricity market, the UK, Spain and France have implemented some form of capacity mechanism in response to concerns over capacity adequacy during peak times. In the case of Spain this was related to the large share of intermittent sources in the system, whereas large-scale de-commissioning of conventional generation units were cause for concern in the UK and France.

Parallel to the policy debate, there has also been considerable attention in the scientific literature for the question whether investors can recoup their investments on the electricity market. According to this literature, an optimal energy-only market would allow investors in peak capacity to earn sufficient revenues during peak hours. Important conditions for such an optimal energy only market are prices which are allowed to rise to the point where consumers would prefer to be shut off instead of pay this price (the value of lost load, VOLL) and sufficient flexibility in demand (demand elasticity) to react to high prices.

However, these conditions are not necessarily met in real energy markets. Demand elasticity in electricity markets is very low, due to the fact that most consumers do not face real time prices and therefore will not react to high prices during peak hours. In addition, system operators tend to take measures when capacity is low relative to electricity demand which have the effect that prices are supressed during scarcity conditions[2]. These measures include options such as reducing system voltage, which reduces necessary supply but which does not raise prices and out-of-market contracts for operating reserves. Furthermore, black-outs without scarcity pricing also represent a form of non-price rationing which reduces revenues for peak capacity. Without sufficient high prices, the prospects of making a loss on such markets will deter investments in peak capacity, the so-called ‘missing money problem’. Another potential problem is the large price-volatility in energy-only markets, which increases risks for investors. These risks can be further increased when investors fear political interference in the market which precludes prices from reaching the necessary level to induce investments. This will hamper investments in new generation, especially when investors are risk-adverse[3].

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[2] See Joskow, P.L. (2008). Capacity payments in imperfect electricity markets: need and design, in: *Utilities Policy*, 16(30, pp. 159-170).

[3] See Hesmondalgh, S. J. Pfeifenberger and D. Robinson (2010), Resource Adequacy and Renewable Energy in Competitive Wholesale Electricity Markets, and Neuhoff, K. and L. de

The scientific literature and recent policy choices in the US and Europe apparently indicate that there is indeed a problem with investments in new generation capacity in energy-only markets. Is this corroborated by what is actually occurring in these markets? What do we know about investments, especially in Northwest European countries? Although there has in general been sufficient generation capacity available to meet demand in Europe to date, this does not constitute proof that electricity only markets will result in optimal investment in generation capacity. Given the fact that liberalisation of energy markets is a recent phenomenon, certainly in the light of the lifetime of a power plant of up to 40 years, it is difficult to judge whether energy-only markets will deliver the necessary investments or not based on actual market developments. In other words, there has not yet been a full-scale empirical experiment to test the theory of optimal energy-only markets.

The picture for Northwest Europe for the last years up till 2020 is a mixed one. In the Netherlands, investment in generation capacity has been high, with the expected addition of 11 GWe of installed capacity in the period 2009 - 2014[4], an increase of installed capacity by more than 40% compared to the start of 2009. Expected strong economic growth at the time when investment decisions were taken and comparatively favourable locations for coal plants at sea ports (relatively to other Northwest European countries), have been important reasons for this surge in investments in the Netherlands. The need for new capacity in the post-2020 period in the Netherlands therefore appears to be limited.

In contrast, however, the need for investments in electricity generation capacity is large for countries such as Germany, France and the UK. The largest amount of new capacity, both absolute and relative, is projected in Germany, followed by the UK and France. One of the reasons for the large investments needed in Germany is the planned *Atomausstieg*, furthermore back-up capacity is needed to accommodate the increasing share of renewables in the generation mix. The UK has high needs for investments as of 2015. These investments serve mainly as a replacement of old capacity that has to be decommissioned (such as coal plants, partly due to environmental regulations).

These developments have considerably increased the sense of urgency in the debate on the missing money problem. Is current electricity market design in Northwest Europe sufficient to realize the substantial new investments in generation capacity needed to meet demand in the next decades? Or will there be serious problems with security of supply on electricity markets in the absence of additional policy measures which remedy the missing money problem? A missing money problem which could be exacerbated by the significant increase in intermittent renewable electricity generation projected for the coming years.

Vries, Insufficient incentives for investment in electricity generation, Cambridge Working Papers in economics 0428.

4 Source: PBL/ ECN (2012) *Referentieraming energie en emissies 2012: actualisatie 2012:* Energie en emissies in de jaren 2012, 2020 en 2030.

2 The effect of increased shares of renewables on investments

As was indicated above, the problem of 'missing money' and the possible lack of investment incentives for generation capacity has haunted electricity markets right from the start of liberalised electricity markets back in the eighties and nineties of the last century. The increasing share of intermittent renewables in the generation mix has further increased the fear that there will be insufficient investments in new capacity. Is this fear correct, how will these renewables affect investments and how large are these effects? This has been the subject of recent studies which have assessed the impact of increasingly large amounts of wind and solar PV in the Northwest European electricity system on investment incentives in back-up generation capacity[5].

An increasingly large penetration of wind and solar PV based generation units reduces average load hours for gas-based units and increases the missing money problem

In a model-based simulation study, ECN analysed the impact of adding additional wind and solar PV-based capacity in Northwest Europe in the period between 2010 and 2020 on the operation of gas-based units in the Netherlands. According to figures reported on in National Renewable Energy Action Plans, the increase in wind and solar PV based electricity generation capacity in the Netherlands and Germany between 2010 and 2020 in total could amount to about 64 GWe of installed capacity, which is equivalent to about one third of total installed capacity in these countries in 2010[6]. Based on these figures, ECN analyses how the dispatch of generation units changes over time. As wind and solar PV-based electricity has marginal costs that are close to zero, the increase in such capacity over time increasingly pushes more expensive generations units -such as coal and gas-based units- out of operation during specific hours of the year (see Figure 1 below). The blue bars indicate the increase in the contribution from wind and solar PV in the electricity mix, whereas the grey bars illustrate how the contribution of gas-based units throughout the hours and days of the year becomes more volatile between 2010 and 2020.

Analysis shows that the increase in intermittent electricity generation capacity increases the variability in the contribution of gas-based units to the Dutch electricity system from hour-to-hour and day-by-day (in terms of electricity produced). The increased volatility leads to a lower number of full loud-hours for this type of units. This makes it more difficult for investors in these units to recover their investment over time, as the contribution margin per MWh produced is reduced.[7] This points to

[5] In a study commissioned by the Bundesministerium für Wirtschaft und Technologie, EWI analyses the case for Germany (*EWI Studie Strommarktdesign Endbericht April 2012*). In a similar study, ECN analyses the case for the Netherlands / Northwest Europe (forthcoming).

[6] In fact, renewable shares in Germany have already grown at an even higher pace since the action plans were published.

[7] The contribution margin (in Euro/MWh produced) is defined as the difference between the revenue from electricity production and the variable cost of producing electricity. In order to remunerate the cost of investing in generation capacity, the contribution margin of the

an increase in the amount of 'missing money'. The order of magnitude of this effect in terms of full load-hours lies in the range of -55 to -75% for gas-based units in respectively off-peak and peak hours, while generation units operating in the super-peak hours are hardly operating at all. The resulting investment gap for these units can consequently increase significantly (with 36 till 72%).

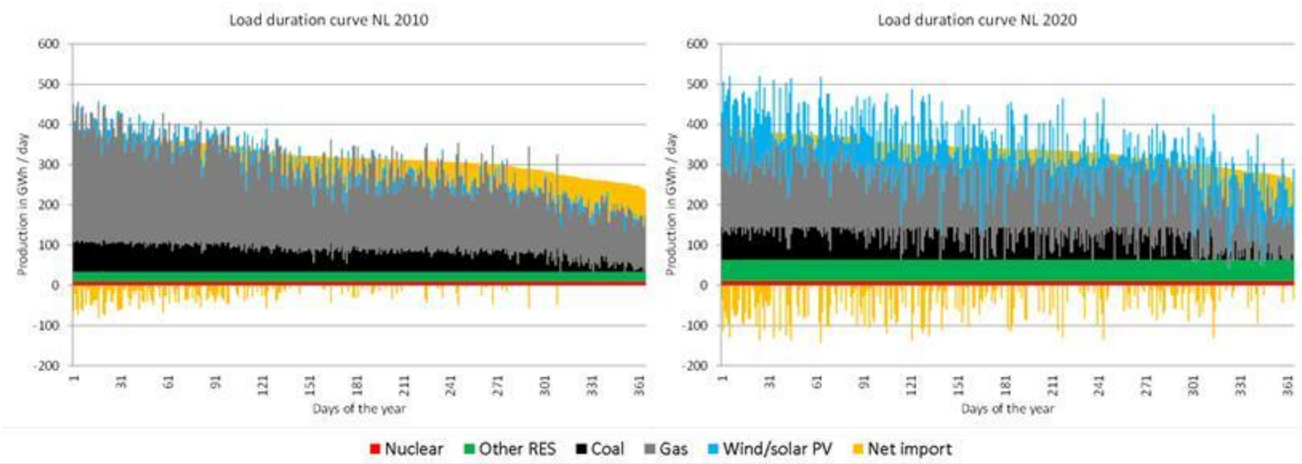

Figure 1 Illustration of the impact of an increasing amount of wind and solar PV based electricity generation capacity between 2010 and 2020 on the operation of different electricity generation units in the Netherlands[8] (Source: ECN, forthcoming)

Figure 2 illustrates the increase in the missing money problem in terms of required and actual revenue per kWe of installed capacity using data from the model simulation.

The required revenue per kWe installed capacity needed to recover both operational and investment costs for each year that the unit is in operation depends on the capacity factor of operation – which is related to the number of full load-hours. The reduction in full load hours of a gas-based generation unit between 2010 (left) and 2020 (right), results in a lower capacity factor (as shown on the X-axis). The figure depicts the variable and total costs of operating, as well as the actual revenue received. The revenue is the average market price times the volume produced. The lower the production (lower capacity factor), the lower the revenue generated given average prices, as shown by the purple revenue line. Given the reduced capacity factor in 2020, the contribution margin is significantly reduced. Consequently, the gap in investment cost recovery (per kWe of installed capacity) increases, as illustrated by the difference between the total operating cost and the actual revenue in 2010 and 2020.

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average MWh produced over the lifetime of the generation unit needs to be positive. When the contribution margin is insufficient to recover cost there is a 'missing money problem'.

8 In this figure, the total electricity production from each generation technology (with net imports being a separate category to correct for cross-border flows) is summed over 24 hours of each day of the year, and ranked from high to low. This results in a load duration curve based on daily flows.

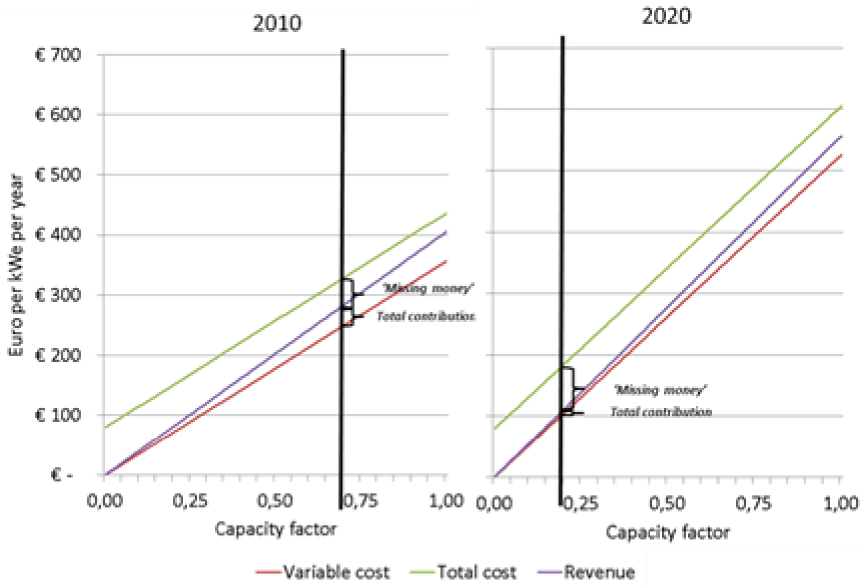

Figure 2 Illustration of the impact of an increase in intermittent electricity generation capacity in Northwest Europe between 2010 and 2020 on the business case of a gas-based power plant in the Netherlands. The impact is measured in terms of required and actual revenue per kWe of installed capacity given the capacity load-factor of operations.

The impact on conventional gas-based generation capacity (in terms of operating hours and financial performance) may differ across technologies. This is because different types of gas-based units may have different positions in the merit order and because there are two different effects of intermittency on the missing money problem, depending on the position of generator in the merit order. First, the missing money problem of peak generators such as gas turbines is exacerbated by reducing their full load hours substantially. Second, mid-load generators (e.g., CCGTs or CHPs) will become marginal units for more hours a year (for example, when there is a substantial generation from wind energy). Not only will this decrease their total full load hours, the number of hours they become a marginal unit (and receive no additional margin) will also increase.

The results of the German study[9] which investigates the missing money problem for the case of Germany corroborate the findings of the ECN analysis. This study, which is based on a comparable research approach as the ECN study, confirms that gas-based generation units may not be able to recover investment costs in a future electricity system with a higher level of intermittent renewable energy sources. The study underlines that the share of intermittent renewable electricity generation itself is not at the root of the problem but can add to the challenges of providing long-term generation capacity adequacy in an energy-only market.

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[9] EWI (2012), Untersuchungen zu einem zukunftsfähigen Stromarktdesign, Endbericht, March 2012.

3 Options to tackle capacity investment problems

The projected growth of renewables in the generation mix will significantly increase the missing money problem. This will endanger security of supply on electricity markets, the more so because considerable back-up capacity will be needed to accommodate the growing share of renewables. It will therefore be necessary to take additional measures to ensure that intermittent renewables can be integrated in electricity markets without further reducing incentives for investments. A distinction can be made between measures which improve the performance of the electricity market itself and measures which are aimed at stimulating investments in new capacity (or keeping existing flexible resources from retiring).

A major element in the improvement of the electricity market is to increase flexibility in both supply and demand. Furthermore, energy-only markets can be improved to make investments more profitable, such as removal of price caps and allowing long-term contracts. Last, current electricity market design can be adjusted through the introduction of some form of capacity mechanism such as capacity payments or capacity markets.

Increase flexibility in electricity markets

In competitive markets ***demand response*** is related to load shaping and refers to strategies which can be used to increase the participation of the demand-side or end-consumers, in setting prices and clearing the market. When customers are exposed in some way to varying electricity prices, they may respond by shifting the time of the day at which they demand power to an off-peak period, or by reducing their demand through energy efficiency measures or distributed generation. To the extent that they respond, the profile in the demand will be smoothed or follows the production of intermittent renewable power. Consequently, less generation will be needed to meet demand. There are several ways to stimulate demand side response. Demand response can be rewarded by specific contracts, which allows the TSO to disrupt electricity supply to a specific customer once a specific price is reached. In exchange, this customer will receive a reward from the TSO, either direct or through lower tariffs. Another option is to use smart metering combined with smart appliances which can temporarily reduce demand such as, for example, cooling applications. Specific contracts with consumers which allow for such smart demand management can be used to provide incentives for the use of demand side response.

Flexible supply resources will be important to adjust to changes in intermittent renewables supply. Especially flexible peaking and mid-merit power plants need incentives additional to that of a fluctuating electricity price to prompt them to offer the full extent of their flexibility to the market. These incentives should also allow for the costs of increasing wear and tear of start-ups, shut-downs and ramping. Such incentives might consist of prices on balancing markets which include a compensation for increased wear and tear.

Increasing the size of power markets through improved interconnections and larger balancing areas will allow for a more efficient use of flexible resources. Moreover, larger power markets with renewable resources widely distributed over a strong grid will also reduce the requirements for flexible resources because in such a larger area there will be more opportunities to match demand and supply from different parts within the network.

With ***more dynamic power-trading***, more efficient use can be made of flexible resources. Because of its intermittency, renewable electricity from wind and sun is less predictable than electricity from conventional power plants on a day-ahead basis. The main electricity market, however, at present is the day-ahead market. This will lead to relative large errors in the prediction of supply and demand, which will lead to imbalance and therefore additional costs. In contrast, the forecast error for intermittent generation a few hours ahead, and thus the imbalance, is substantially lower than the forecast error for one day ahead. Trading on intraday markets and a short gate closure time would reduce the need for balancing and provide a better incentive to use flexible resources in the market.

Improve price signals in energy-only markets

An important element of an optimal energy-only market is the ***absence of implicit price caps.*** Prices have to be allowed to increase to levels that reflect full costs. In the presence of price reducing measures, peak capacity will not be able to recoup its investment costs. This is one of the reasons for US markets to adopt some form of capacity mechanism. In addition to improved price forming on energy-only markets, regulation should also be transparent and credible enough for investors to believe that high price spikes will also be allowed in practice, without interference from regulators, otherwise they will not invest anyhow.

A usual solution to bridge the difference between average and marginal costs is to conclude ***long-term contracts***. Such contracts bind customers to pay the full costs. Consumers benefit if these longer terms commitment can reduce investors costs and allow for solutions that otherwise would have been impossible. Investors have the advantage that investment costs will also be covered in the electricity price they receive. Long-term contracts however do not fit well with the current model of competition between retail companies[10]. They would be the logical counterparts for long-term supply contracts, however they will not be sure of their customer base, given retail competition, and therefore long-term contracts will not be attractive. The European Commission has also been critical of the use of long-term contracts in the power market because it may lead to foreclosure of new producers when a significant part of demand is tied to incumbent producers[11]. However, long-term contracts can provide a solution for a lack of investment in new generating capacity, therefore it should be considered whether these contracts could be allowed without reducing competition.

Introducing capacity mechanisms

Improving flexibility and price signals in energy-only markets are the preferable options to improve the profitability of investments in new generation capacity.

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[10] See Neuhoff, K. and L. de Vries (2004). *Insufficient incentives for investments in electricity generation*, Cambridge Working Papers in Economics 0428.

[11] Hauteclocque, A. de and J. Glachant, (2009). Long-term energy supply contracts in European competition policy: Fuzzy not crazy, in: *Energy Policy*, 37, pp. 5399-5407.

Another, more radical option is to change the market design for the electricity system can be changed by implementing a capacity mechanism which provides funding for capacity investments in addition to the revenue realized by selling electricity. Given the more fundamental character of introducing a capacity mechanism compared with options to improve the existing market, capacity mechanisms should be approached with the necessary caution.

There are various different forms and design options for capacity mechanism, the main ones discussed here are capacity markets, capacity payments and auctioning of new capacity in combination with obligations.

In a ***capacity market*** load-serving entities (e.g. retail companies) are required to contract for a fixed percentage of reserve capacity. The capacity requirement is designed to achieve a target level of reliability. This mechanism is used (in different variants) in several regions in the US to solve the problem of high prices in peak demand. Locational pricing is used to stimulate capacity at the right place in situations of congested transmission lines, however this could increase market power problems in specific local markets because of smaller market sizes. Capacity markets can be either bi-lateral markets in which load-serving entities have to demonstrate that they have acquired sufficient reserves, or a central auction in which the transmission operator auctions for additional capacity or demand response and these capacities are rewarded for availability. The main difference between these two models is in the last case there is one central organized market while with bilateral trading it is up to the market parties themselves to trade and to organize the market. Capacity markets can differ considerably, given their complex character.

Capacity payments or strategic reserves by TSOs are a solution for the capacity problem in which the TSO itself plays an active role. This is especially the case with the strategic reserve in which the system operator maintains a reserve of power generation units that it dispatches when the reliability of the supply is threatened or the price surpasses a threshold. In the capacity payments solution, an independent agent - such as a regional wholesale market operator or TSO - pays generators for keeping capacity available. A disadvantage of capacity payments is that price and quantity are administratively determined, which may imply a deviation from efficient price signals and market outcomes. Moreover, a system of capacity payments may be vulnerable to *ad hoc* administrative changes, which may give rise to regulatory risk and affect investment behaviour. Finally, when payments are differentiated across different technologies there is a risk of market distortion.

Another option is to put ***obligations*** on supply companies (LSE) to contract the electricity needed to meet expected demand for a period of, for example, 5 years ahead. Demand arising from these obligations can be met by central auctions, in which existing capacity and investors can bid in. This provides investors with additional income and reduces price volatility for small consumers. Large power consumers could be allowed to invest in generation capacity themselves. Another option is to award capacity owners capacity certificates which supply companies have to buy in order to meet their obligation. Penalties could be imposed on those supply companies which do not meet their obligation.

Of the different options available to tackle the missing money problem aggravated by increasing shares of renewable, capacity mechanism have attracted most attention in recent policy debates in Europe. Some countries have actually introduced capacity mechanisms, such as France (capacity obligation), Ireland and Spain (capacity payments) and Sweden & Finland (strategic reserve), while other countries (Germany, UK) consider the introduction of such mechanisms. Surprisingly, the discussion has focussed on the national, unilateral mechanisms for one country only, while electricity markets have become more integrated over recent years and in many regional markets extend over more than one country.

An important question therefore is how the introduction of capacity mechanisms in only part of a larger power market will affect the performance of such a market in terms of prices, electricity flows and security of supply. Moreover, such national capacity mechanisms might hamper the development of the internal energy market.

4 The effects of unilateral introduction of capacity mechanisms

The unilateral introduction of a national capacity mechanism may pose benefits and costs in the larger power market area, depending on the type of capacity mechanism introduced and its specific design: the devil is in the details. Below we briefly illustrate the possible advantages and disadvantages and present the key insights from a quantitative study of the cross-border effects of implementing a national capacity mechanism.

Benefits due to *free riding* on foreign reserve capacity

Countries that are considered part of the same integrated market as the country that introduces some form of capacity mechanism may be considered *free-riders* in the case that the national scheme leads to a larger amount of reserve generation capacity than strictly necessary to safeguard national security of supply. In this case, consumers in neighbouring countries may benefit from available reserve capacity across the border in times of scarcity – conditional on sufficient availability of interconnection capacity necessary to be able to use this reserve capacity – while they are not paying for the provision of the reserve capacity itself.[12] This may be considered the biggest possible advantage for countries which adjoin a country which introduces a capacity mechanism on its own. Whether such a free-riding effect exists and how large it is depends on the type of capacity mechanism introduced. For example, a mechanism based on capacity payments has a much larger risk of exceeding the required amount of reserve capacity than mechanism based on a capacity market. Furthermore, the extent to which demand peaks and supply shortages are simultaneous in the two countries will also determine whether benefits will arise or not. The possibility to

[12] Consumers in neighbouring countries do pay for the electricity produced off course, the price of which may be reasonably high given that it concerns an 'extraordinary' situation. However, as the contribution margin implicitly paid is likely to be insufficient to recover full cost of investment in the amount of reserve capacity, the consumers in neighbouring countries overall benefit from strategic reserve capacity realised elsewhere.

profit from the reserve capacity resulting from the capacity mechanism will be higher the more load profiles differ in time.

Costs due to market distortions

The single most important possible cost that may result from a unilaterally introduced capacity mechanism is a distortion of price signals in the market, which as a consequence may lead to inefficient investment decisions and inefficient market outcomes. With a level playing field, investment in generation capacity takes place in those countries and locations that offer the best conditions. This could for example refer to the nearby presence of waterways (for the supply of solid fuels) or strong transmission network properties. Accordingly, also flexible back-up capacity should be located in those locations that can provide this capacity at least costs. The introduction of national capacity mechanisms may create an uneven playing field and therefore harm the interest of consumers.

A specific cost that could arise for neighbouring markets is the crowding out of investment in national generation capacity. The introduction of a capacity mechanism may encourage national investment in new generation capacity at the expense of generation investment across the border. The 'losing' country may not experience a materialisation of investments that would be expected given its comparative advantages in a level playing field situation (i.e. without one country introducing a capacity mechanism). The 'costs' in this case involves lower investment and a reduced level of economic activity, which may be associated with lower national production and lower employment. Furthermore, security of supply might be reduced if less capacity investments are realised within a country. Whether this is the case will depend on interconnection capacity and the correlation between demand for reserve capacity in both countries. With less interconnection capacity, there is a higher risk that a country will not be able to use sufficient reserve capacity in a neighbouring country in case of capacity problems. Furthermore, when the need for reserve capacity will occur simultaneously in both countries, for example because of weather conditions, the risk that there is not enough capacity available for the country without the capacity mechanism will also increase.

What could be the impact of a German capacity market on the Dutch electricity market?

There is surprisingly little literature on the actual impact of introducing national capacity mechanisms on neighbouring markets, especially quantitative analysis[13].

ECN (forthcoming) has analysed the possible market impact if Germany would introduce some form of national capacity market. Discussions on capacity mechanisms in Germany are still continuing, it is not at all certain that some form of capacity mechanism will be introduced and, if so, which type of mechanism. Given the focus in the ECN analysis on the general effects that may prevail from such an initiative, it was assumed that a forward capacity auction (i.e. a capacity market) is introduced in Germany that aims to realise sufficient reserve capacity within German borders. The

13 Cramton and Ockenfield 2011 gives a qualitative explanation how German capacity market could affect their neighbours.

study has analysed the impact on generation capacity investment, electricity generation, market prices, and cross-border flows, assuming a perfect competitive European electricity market and taking into account cross-border transmission constraints. The optimal market outcomes (regarding, for example, generation capacity investments, generation, prices and flows) in the North-west European electricity market in 2020 have been compared for the case of a pure energy-only market in North-West Europe and case with implementation of a unilateral forward capacity market in Germany. The major results from this analysis are:

- A German capacity market increases investment in flexible gas-based capacity in Germany at the expense of investment in such units in the Netherlands. This is explained by the fact that the introduced capacity auction does not allow for foreign bids and by the fact that in the absence of the capacity mechanism, the Netherlands is likely to be the most suitable location for building flexible generation capacity in the Northwest Europe with strong connections to most of the countries in North West Europe which are all in need of a certain back-up capacity due to increase in their intermittent generation.
- Because of the decrease in gas-based capacity in the Netherlands, less electricity is produced in the Netherlands and less electricity is exported over the year.
- Due to the large increase in flexible gas-based capacity in Germany, Germany becomes a net exporter. Exports will be high especially during peak hours when residual demand in the Netherlands (demand corrected for renewable supply within the Netherlands) is high.

The effect on wholesale prices outside Germany is limited, with a small price decrease in peak hours due to the increased capacity installed in Germany. Wholesale prices in Germany decrease significantly, especially during super peak periods when scarcity caused very high prices in the case without a capacity mechanism. However, German end-consumers will face additional costs because of the additional capacity payments which have to be made on the capacity market. The net price effect for German consumers is uncertain and depends on the allocation of the costs of capacity payments among peak and off-peak consumers. The overall welfare effect for German consumers will not only consist of the costs of additional reserve capacity but also of increased benefits resulting from the higher reserve capacity level. This will reduce the frequency and impact of outages and therefore the costs of involuntary load shedding.

5 Conclusions and policy implications

The phenomenon of the missing money problem, i.e. a lack of investment in electricity generation capacity is not new

It is widely reported on in economic literature and it received attention in the first years of European electricity liberalization. The issue was removed from the agenda as it turned out that there was a situation of overcapacity in the market. Now, the issue is back at centre stage due to an increasing level of volatile electricity production units in combination with a de-commissioning of conventional production capacity.

Intermittent renewables negatively affect the economics of conventional back-up units

Quantitative, model-based analyses for the Northwest European electricity market support the claim that even towards 2020 the expected increase in wind and solar-based generation capacity may threaten the economics of gas-based generation technologies (CHP, CCGT, gas turbines). This may discourage investment and could potentially lead to a future lack of conventional, flexible, back-up capacity. This warrants additional policy measures in order to ensure that sufficient investments are undertaken in generation capacity and security of supply is not put at risk.

Unilateral actions by single EU member states in the area of capacity mechanisms may harm the functioning of the single market

The electricity generation mix across European member states differs. This implies that different levels of flexibility may be required from a national perspective. From an economic welfare perspective, the required level of flexibility needs to be delivered by the most cost-efficient options available within an integrated European market. Comparative advantages between countries in providing system flexibility should be used, thereby taking into account (potential) bottlenecks in the transmission system. Efforts to solve flexibility issues and possible lacking of investment incentives by unilateral introduction of capacity mechanisms risk violation of the level playing field principle. They can have mixed effects on welfare in neighbouring countries, such as on the one hand reduced security of supply because of a shift of investments to the country which implements the capacity mechanism and on the other hand the possibility to free ride on the increase in (flexible) capacity in this country.

'Don't use a canon to kill a fly'

There are a number of options to address missing money problem, ranging from improved electricity markets to capacity mechanisms. Some of these options will be easier to implement in the short term, are probably more appropriate, given the still relatively small share of intermittent electricity source, and will have less harmful side effects on market performance than introducing full blown capacity mechanisms. The various options available to address the missing money problem should be evaluated in terms of their costs and benefits and their impact on system flexibility. In this 'merit order' of options to improve investment incentives when renewable energy shares increase, capacity market mechanisms might well be positioned at the high end of the merit order. A more precise picture of the merits of different options would require further research on the costs and benefits of these options.

Possible options to increase investments include, for example, increased market integration, which will decrease the need for total back-up or peak capacity in the short-term. This will not necessarily solve the missing money problem, however it will shift the generation adequacy problem to a future time when total capacity in Europe becomes scarce. Other options are improving demand response, especially through interruptible contracts with large customers and improving the performance of energy-only markets by allowing prices to rise sufficiently high during scarcity hours.

Harmonize capacity mechanisms

When other options are exhausted or prove to be less cost-effective, capacity mechanisms could be implemented. When capacity markets are adopted across the EU, their implementation should be coordinated and harmonized in order to minimize distortions for the internal energy market. Unilateral introduction of different capacity markets will endanger the performance of the internal energy market because there will no longer be a level playing field in electricity generation across Europe. Naturally, given the different starting conditions of the electricity markets across Europe, the call for capacity markets will be unevenly spread. It is important that the implementation of a capacity market in the 'early adopting countries' is coordinated with neighbouring countries, because the impact of capacity market mechanisms exceeds national borders and because decisions on the design of the capacity market may affect future decision-making on the design of a capacity market in other countries. Moreover, security of supply will be increased in an integrated market, while unilateral introduction of capacity mechanisms will be detrimental to the further development of an integrated electricity market and therefore might have an adverse effect on security supply as well.