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Electricity market trends and designs towards 2020 – 2035: a Smart Grid perspective

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Summary	
<p>The report is the deliverable D7.2.1 of the Working Task 7.2 in the 2nd and 3rd funding period in the Smart grids and energy market (SGEM) research programme describing the possible European electricity market development to 2020 and 2035 and how active resources – whose significance are expected to rapidly increase by Smart Grids (SG)- fit in. More intermittent renewables, more real-time measurements, and more active demand side are expected in the future electricity markets. The role of after-spot markets strengthens as flexibility is called for in evolving European electricity markets, but today's intraday and balancing market designs in the EU are far from a fully efficient and harmonized market. In addition to the market integration, there is considerable room to improve market design and accuracy of market signals in Europe.</p> <p>The report looks at different market designs and especially at capacity mechanisms and how active end-users can be integrated into them. The relevant question is if there is any 'best-practice' market design that can ensure generation adequacy in the long run at least cost while minimising regulatory interference with the market, especially taking into account the changes arising by Smart Grids? Capacity mechanisms – at least traditional implementations – can be seen as alternative or additional methods to tackle the imperfections in the electricity market and to ensure long-term generation adequacy. From the SGEM viewpoint, at least more real-time measurements and a more active demand side have potential to move electricity markets in the direction of ideal markets.</p> <p>From market integration of point of view, a European-wide solution is desirable over national mechanisms, even though there seems to be practical challenges in the implementation of such a scheme due to dispersed system operations etc. and differing local practices and conditions. Modern approaches in design, such as reliability contracts and forward capacity mechanisms, are often referred to as potential directions of further consideration in the EU, while strategic reserves are seen as a more easily implementable option. The modern innovation of capacity subscriptions becomes an interesting option with enhanced real-time metering, a characteristic widely discussed among SG concepts. Generally, the lack of experiences of innovative capacity mechanisms can be seen as limiting their use in practice. Another research focus point of this report is the assessment of the overall demand and supply developments towards 2020 and 2035, with closer attention on the Nordic situation, as the market price of electricity is the key trigger to many smart grid and active end-user advancements.</p> <p>The shale gas revolution in the USA has led to large momentum shift which has pushed the price of coal down and led to its increased use in Europe, and a decrease in gas usage. Now, gas plant owners in Continental Europe are demanding subsidies, especially as their profitability is additionally being eaten by the renewables and the low price of CO2 emissions. Fuel prices are, however, expected to rise towards 2030.</p> <p>Renewable electricity production is increasing rapidly, and will do so also in the future. Conventional fossil condensing power will have a hard time in the future in the Nordic, as new renewable (and some nuclear) capacity pushes it farther and farther up on the merit-order list. Even CHP might experience more serious blows to its profitability. Nordic market prices show</p>	

a tendency to come down in the next ten years and are expected to rise again when we approach the 2030's. Although renewables have a big role in the formation of the future prices, the question of the future of Swedish nuclear will perhaps have a bigger role. Extensive feed-in tariffs and other subsidies can at worst destroy the basic operational premisses of the energy-only markets. Luckily, the Nordic market has still been quite well functioning and although there are danger signs, there is a possibility it will continue so.

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Preface

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This report is the deliverable 7.2.1 of Working Task 7.2 in the 3rd funding period of SGEM.

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1. Introduction

1.1 Goal

The report is the deliverable D7.2.1 of the Working Task 7.2 in the 2nd and 3rd funding period in the Smart grids and energy market (SGEM) research programme.

The main objective of this task is to describe the possible European electricity market development to 2020 and 2035 and how active resources – whose significance are expected to rapidly increase by Smart Grids - fit in.

The most influential drivers include the European Union's climate change mitigation policies, energy market integration policy and the drive towards security of supply while retaining the EU's competitiveness.

The climate change mitigation policies in the EU are constantly developing. By 2020, the target is to reduce greenhouse gas emissions by 20%, increase the use of renewable energy sources (RES) to 20% and to improve energy efficiency with 20%. The long term target is to reduce greenhouse gases with 80% to 95% by 2050.

New electricity production from RES, RES-E, is introduced to the European markets with all kinds of subsidies. In the Nordic market feed-in tariffs (FIT) and green certificates together with investment support are the main tools. Large amounts of new variable or intermittent production is putting a stress on conventional condensing power plants: their profitability decreases. How will we manage the high regulation needs of the future?

1.2 Description

We look at different market designs and especially after spot market developments in Europe and how active end-users can be integrated into them.

The Nordic market is one of the most advanced, if not the most advanced, power markets in the world. There is an abundance of market actors, sellers and buyers, in the wholesale and retail markets. The power system is operated as neutrally as possible and with the whole market in mind. The wholesale market is energy based, with no remuneration for capacity, so the big question is, how will new and especially adjustable regulating power capacity be induced to the market and what is the role of smart end-users?

We look closely at different capacity mechanisms. What benefits and what disadvantages do they have, and, for example, how well would they be suited for an advanced electricity market such as the Nordic countries comprise.

The third research focus point is to assess the overall demand and supply developments towards 2020 and 2035, with closer attention on the Nordic situation, and to assess the general trends and especially to estimate the future (wholesale) market price. The market price of electricity is the key trigger to many smart grid and active end-user advancements. As natural gas is key fuel in electricity production in the EU, and in its production significant changes have taken place during the last few years, we take a closer look at natural gas market trends. Our analysis includes e.g. a discussion on the implications of the recent shale gas revolution.

2. Market designs

Market design is a term often used of the arrangements that constitute a “playing field” for market participants of electricity markets. The market design issues have potential implications for profitability of Smart Grid technologies and therefore thoroughly discussed in SGEM. In this Chapter, the main focus area is to study how power market designs in European countries offer opportunities and how they provide with incentives for market participants to adapt to altering technological landscape. Especially, the 20% renewables target of EU is likely to increase intermittent and varying renewable energy sources in European electricity markets (Ruska & Similä 2011), which is a key factor for future performance of market designs.

Relevantly from the market design point of view, the Smart Grid (SG) is a set of emerging technologies that, among other effects, will facilitate "real-time pricing" for electricity and increase price elasticity of demand (Allcott 2012). The technologies include more flexible controls in transmission grids, better monitoring of grid, automatic meter reading and real-time automation of end-use design. Furthermore, the information systems and information distribution attached to SG allow for much finer control of devices attached to the electricity system (Hogan 2010).

As new technologies are increasingly introduced and penetrated in electricity markets in both supply and demand sides, it is of interest to study whether the current **market designs can cope and what are the emerging challenges and opportunities**. Ruska & Similä (2011) provides an analysis of current state and basic characteristics of European electricity markets, focusing on wholesale (day-ahead) market.

In this report, the viewpoint is broadened in future opportunities and design of **after-spot markets**, see Figure 1, and, especially, **capacity mechanisms** that are designed to secure the adequate supply in the long-term and may function in a timescale of several years. The nature of inadequate capacity can be divided in **flexibility** and generation or resource **adequacy** of the electricity system. Flexibility means an ability of an electricity system to deal with the short-term intermittencies. This characteristic has been under growing discussion due to the increasing variable renewable electricity generation in Europe. Adequacy refers to the ability of electricity system to cope with the demand in the long term. Furthermore, regulatory uncertainty concerning policies, economic instruments, etc., can be seen as a factor potentially having an effect on investment decisions. The nature of capacity demand, as well as the uncertainties must be considered with appropriate capacity mechanism designs.

International experiences and theoretical viewpoints are reviewed. Capacity mechanisms can be described an adjustment to the market structure for stabilizing investment in generating capacity (DeVries 2007), sometimes considered to have similar motivation as a part of electricity market as long-term (financial) contracts or bilateral agreements. In some electricity markets, a version of capacity mechanism is included and in others it is not, as will be seen in section 2.2.

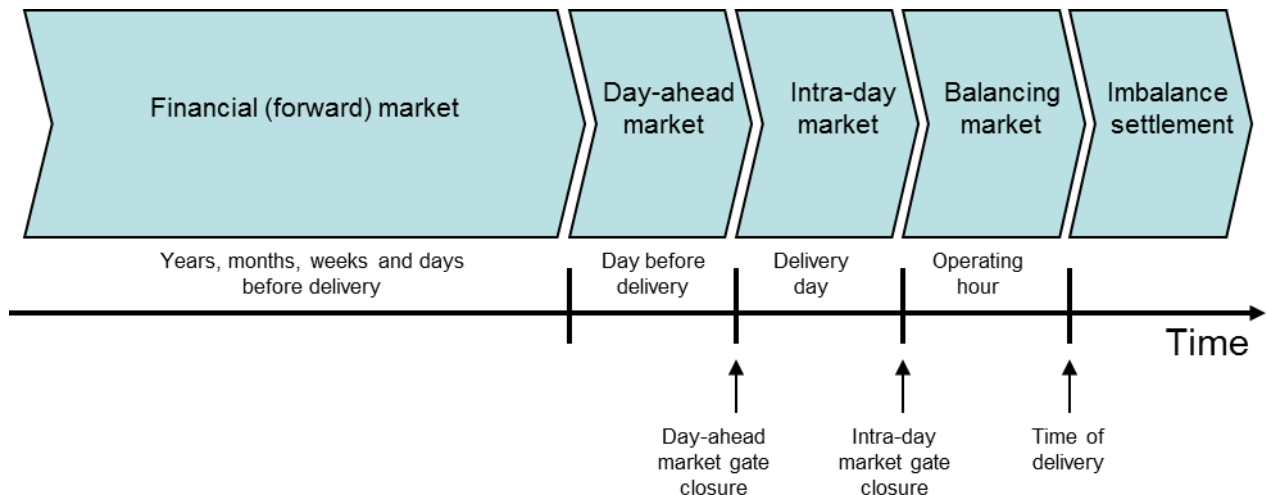


Figure 1. Components of electricity markets and typical structure of power trading in European electricity markets (Ruska & Similä 2011). In this report, the focus is on intra-day and balancing market and in capacity mechanisms that are supplementary mechanisms to the components seen in the Figure.

In a context of this report, typical elements of different market designs of both after-spot markets and capacity mechanisms under review include, in addition to theoretical aspects, practical implementation design parameters such as auction method, timescales, settlement procedures etc.

2.1 After-spot market development in Europe

To adapt to the increasing amount of intermittent sources, a power market needs to be flexible enough to accommodate short-term forecasts and quick turn transactions. Thus, the role of after-spot market strengthens as flexibility is called for in evolving European electricity markets.

System operators in European electricity markets typically acquire ancillary services to maintain the electricity system balance, such as reserve, separately from the energy market. (Ruska & Similä 2011). Reserve and response capacity for this purpose can be contracted in multiple timescales.

In the terminology of this report, after-spot markets comprise of both intra-day markets and balancing markets.

- **Intraday markets** that allow for adjustments after the closure of the day-ahead market until gate-closure, typically about one hour before real time; and
- **Balancing markets** that are used by the system operator to resolve remaining imbalances
- **(Ancillary services markets)**

A term ancillary services markets is occasionally used as a part of or in addition to balancing markets, typically consisting of services managed by system operator to maintain system balance in physical balance such as frequency regulation, spinning reserve, or voltage support.

What are the emerging options for after-spot market design and their pros and cons taking into account the general targets of the European electricity market? Not only integration of markets but also product design, timeframes and other design parameters are of importance

in order to find an optimal design taking the SGEM requirements into account. Key building blocks and characteristics in after-sport markets include at least:

- Gate closure that determines the closure of intraday market and opening of the balancing market
- Mechanism for pricing, compensations and penalties for deviations
- Product design
- Integration of markets

From a finance view, day-ahead, intraday and balancing markets are just different steps of a single trading process and hence require a single platform (Smeers 2008). Thus, if only financial viewpoint is considered and technical characteristics of electricity systems neglected, there would be no reason for separate schemes and arrangements in day-ahead, intraday and balancing markets.

Hiroux & Saguan (2010) address the European market design especially from the viewpoint of wind energy. Integration costs related to large-scale development of wind power are identified and the impacts of the electricity market design – especially day-ahead market, intra-day markets and balancing markets - on these costs are discussed. For the goal of this report and taking into account the foreseeable development of electricity markets and wind power in Europe (Ruska & Similä 2011), Hiroux & Saguan (2010) provide with an interesting subject.

2.1.1 Intraday and balancing power market development in Europe

Borggreffe & Neuhoff (2011) explore whether the power market designs in European countries offer opportunities and incentives for market participants to realize the technological opportunities of flexibility. This is called for from both transmission systems and the use of different generation technologies to effectively respond the increased uncertainty.

According to Borggreffe & Neuhoff (2011) “the EU has made some progress towards integrating power markets, but today’s intraday and balancing market designs are far from a fully efficient and harmonised market.”

The European Commission agrees on development needs regarding the intraday and balancing markets, as boosting their liquidity is mentioned in the communication “Making the internal energy market work” (EC 2012a). That is, according to the Communication “In electricity, new technical rules such as on cross-border balancing markets and on liquid intraday markets, should, in combination with smart grids, help improve system flexibility and the large-scale integration of electricity from renewable energy sources and participation of demand response resources alongside generation”. In the communication, a clear deadline of 2014 is set for completion of the internal energy market.

Besides the market integration, there is considerable room to improve market design and accuracy of market signals in Europe. According to the study by Hiroux & Saguan (2010), wind power cannot be set aside of market signals with high penetration levels in Europe and market design improvement is one potential means in this. Market signals can be beneficial for the selection of wind sites, to improve maintenance planning, to improve the combination with other technologies etc. However, exposing the wind power produced to market signals means trade-off between increased risks and transaction costs. In most of the European designs, re-dispatching or counter-trade model is in use in short-term congestion management. Consequently, no locational signals where to produce or consume for the cost of congestion of the whole system are given. These costs of these actions are socialized among the network users. (Hiroux & Saguan 2010)

The US electricity market design allows ISOs to manage both transmission and the markets and they can acquire energy and most of their ancillary services in a single, cooptimized, process, which is theoretically supportable. However, this kind of optimization calls for pool type trading arrangements with centralized dispatch and trades operated by ISOs – which is not very common solution in the European electricity markets (see e.g. Green 2008).

2.1.2 Active resources' potential in after-spot markets

Active resources discussed in SG environment – especially such as Demand side management (DSM), and renewable energies, have the technical potential to provide their services to the market. Currently, only a small share of these reserves is integrated in the markets. If these resources could be more efficiently utilized, intraday and balancing services could be enhanced. These resources present unleashed potential since DSM technologies (such as reduction of electricity demand) face low costs for providing reserve capacities, especially for positive balancing power. Demand side management might further provide load shifting from peak to off-peak and low-wind to high-wind periods. (Borggreffe & Neuhoff 2011)

To allow the demand-side and renewable resources to bid their services in after-spot markets to a greater extent, there are some recent developments in the European markets such as Nord Pool market in the Nordic countries and the markets in Germany (see Borggreffe & Neuhoff 2011). SG technologies enhance opportunities to further integrate the demand-side in after-spot markets through improved real-time metering and information exchange. The Nordic system offers significant demand response opportunities on the household level due to the vast existence of electric heating combined with heat storages, a playing field on a very different order of magnitude than white goods such as dish washers, washing machines or refrigerators can provide.

Considering the essential characteristics of markets and the general goal of SG to more largely enable small-scale customers to participate in the markets, thought of integrating active resources in after-spot markets seems supportable. Diversifying product portfolio and transferring intra-day markets to function closer to real time are also potential ways for improvement. As summarised by Hogan (2010), *Smart Grid needs smart pricing*. As market information is averaged and suppressed in re-dispatching pricing models used widely in balancing in Europe, Locational Marginal Pricing principle seems attractive in order to provide incentives that take the constraints of the grid into account and support market participants in making efficient decisions. However, such a scheme would call for fundamental changes in current EU market structures. In order to justify smart pricing and small-scale end user customer participation, their implementation barriers and costs must be considered, too. This issue is partly studied in other working tasks in this SGEM program, where cost effectiveness of different sources for flexibility are analysed.

Net metering on a level above one hour (or whatever the minimum time unit in the market is), for example monthly or yearly netting of consumption and production, would be a significant barrier for a market driven demand side management. For demand response to be meaningful, the end-user has to be affected by the market price. For example, if production and consumption are not netted each hour, it is not in synchrony with a market structure, where one hour is the basic element. The asynchrony issue doesn't only concern net metering above the basic market time step, it is an issue also if net metering is shorter than the market time step. To be both a producer and a consumer during the same hour is not how a well working market functions, but can be seen as a barrier to distributed generation.

2.2 Capacity mechanisms

2.2.1 Adequate capacity

One of the most distinctive characters of an electricity supply and demand system is its need for a momentary balance of generation and use of electricity. A shortage of supply on any given moment can trigger costly blackouts, but it takes years to build new conventional capacity. To deal with the short term issue, several institutions have to be in place to take care of functions of different time scale as described in the previous section. But if there is not enough generating capacity in the *long-term*, it will not be possible to serve all loads and achieve security and firmness in the short-term. In this way, adequate generation capacity is the most fundamental reliability issue (Cramton & Ockenfels 2011).

We first define a few concepts to increase clarity. **Reliability** is the ability of a power system to deliver power with a voltage and frequency within their normal limits. A system will be reliable if it has adequate installed capacity and is operated within security limits. **Adequacy** is the ability of the electric system to supply the aggregate electrical demand at all times taking into account the outages of the system elements. **Security** is the ability of the electric system to withstand sudden disturbances. (Stoft 2002). The first two are of interest here.

Suppliers earn the variable production cost of the last loaded production unit in an efficient market. The price cannot be higher because the investment costs are sunk and therefore they are not taken into consideration when bidding into a competitive market. In competitive markets capacity has a positive price only when it is scarce. This means that energy-only markets, i.e. an electricity market without any capacity mechanisms, have an inherent tendency to produce **scarcity**: When generating capacity is adequate, electricity prices are too low to pay for adequate capacity making capacity scarcity a necessity in any energy-only market to give incentives for new marginal capacity (e.g. base capacity may well have enough incentives). In an efficient equilibrium the resulting scarcity rents earned in scarcity events cover the fixed capital and operating costs of all resources. In addition, they are fully consistent with perfect competition and marginal cost pricing. In theory, in energy-only markets scarcity rents can be paid by voluntary and market based loss of load, i.e. price flexibility.

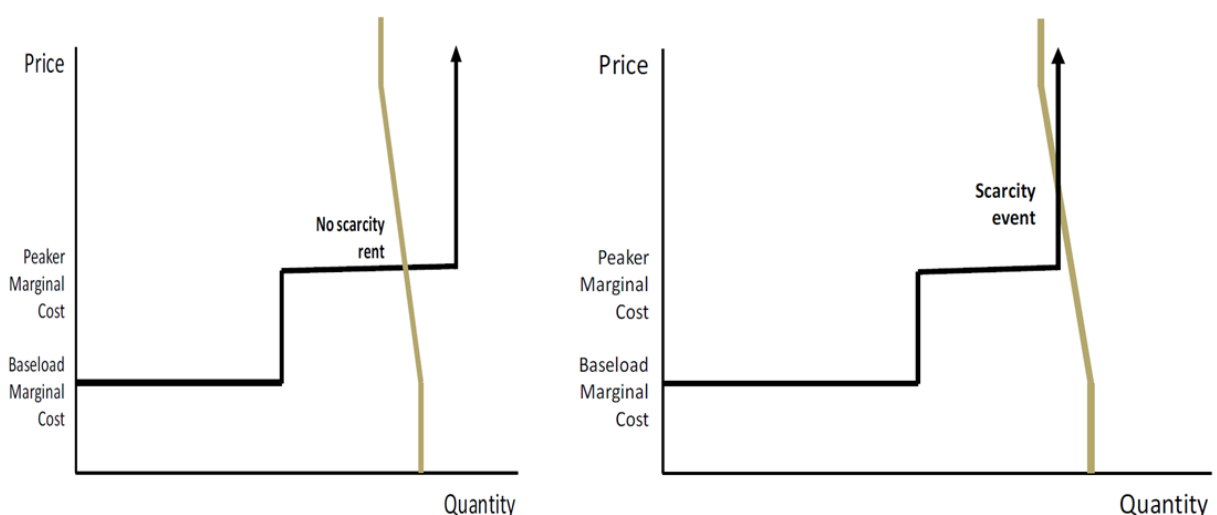


Figure 2. Left: Normal prices are too low for adequate peaker capacity; Right: Scarcity event in which market price is higher than short-run marginal cost of production (Cramton & Ockenfels 2011).

Efficient scarcity prices as illustrated in Figure 2 can be very high - hundred times the production cost of the last produced energy unit is not an exaggerated price level. During

times of scarcity the opportunity for suppliers to exercise **market power** is also very large. It may be impossible to distinguish efficient scarcity prices from prices reflecting market power during scarcity events.

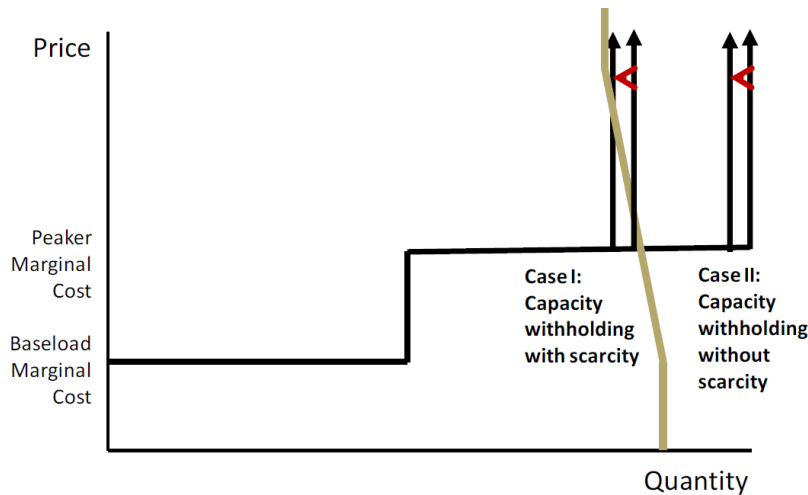


Figure 3. Scarcity and market power. Case I: With capacity scarcity even a small power generator can affect substantially to market price by withholding capacity. Case II: The same manoeuvre without scarcity does not have any effect on price (Cramton & Ockenfels 2011).

When a producer's own capacity is in full use the ability to substitute other producers' withheld capacity vanishes and a supplier with only a small share of the total capacity could exercise market power. Because scarcity is needed to provide incentives for new investment and because scarcity implies market power, any pure-market design will sooner or later run into market power problems.

When the price elasticity of demand is insufficient to guarantee that supply and demand match, the price can rise without a limit. This is a crises situation and leads to the system breakdown without the intervention of the system operator. The outcome, then, depends on the actions taken by the responsible system operator. In these situations they typically apply procedures that depress market prices. The actual operations include, among others, system voltage reductions and/or rolling blackouts for demand decrease, and on the supply side, calling on generating capacity based on bilateral out-of-market based contracts with specific properties of location and availability (Joskow 2007, Cramton & Stoft 2013).

The central problem is that with adequate generating capacity, electricity prices are too low to pay for adequate marginal capacity. This is the problem of "missing money". The consequence of it is a long-run average shortage of capacity and too little reliability. The missing-money problem is not that the market pays too little, but that it pays too little when we have the required level of reliability (Cramton & Ockenfels 2011).

2.2.2 Demand side in focus

An energy-only market is defined as an electricity market in which there are no specific structures or incentives to stimulate investment in generation capacity. Consequently, generating companies base their investment decisions on expected future demand and prices as in a "normal" market. NordPool is an example of this kind of an electricity market. Normal market operation would dictate that the price should increase whenever demand

exceeds supply. In a normal market, this will clear the market. In the traditional markets with storage and demand response, it is the cost of new entry that determines overall long-run price levels. The reliability of service seen by a buyer in the marketplace is determined by the amount of new entry and exit. The relative scarcity of a product pushes its price up. In the short term some consumers will either find a substitute or wait for it, or forget about it, i.e. there are shortages. But the market does not break down due to temporary shortage of supply. When the degree of scarcity leads to a price that is equal to the cost of new entry, there will be new entry and that will establish the natural level of reliability of that market and the single long-run market price that will be paid by all consumers (Bidwell & Henney 2004).

In electricity markets decisions have to be made continuously to maintain the momentary balance between generation and use of electricity. But the customers neither receive nor adapt to real time price information. If it were possible to interrupt or limit consumption easily on an individual basis in real time, the situation would change completely. Then it would be possible to use a price mechanism to ration demand and the reliability would then be priced according to individual valuation. This would make the demand side of the electricity market to behave like a normal market. Due to the need of making decisions continuously this can only be carried out by automation equipment.

For the time being this is not nearly fully possible, although smart grids are developing and there exists spot-price based end-user tariffs, home energy management systems and, for example, pilots of aggregator managed heating. That is why we have to be satisfied with a substitute. It can be shown (e.g. Stoft 2002) that the social cost of market failure – defined as a situation in which supply and demand do not match, market price is not defined and demand has to be curtailed to prevent the breakdown of the system – can be minimized by capping the electricity price at the average value of lost load (VoLL). This will not prevent service interruptions but limits them to an economically efficient duration (de Vries 2004). This is a second-best¹ outcome.

The supply side responds to price cap (e.g. VoLL) by building additional capacity up to the point where the last capacity unit costs just as much as it earns from being paid VoLL during blackouts. Investing stops when the cost of the last unit of capacity equals VoLL times the expected number of scarcity hours, BH . The value of serving the load that would have gone unserved without that unit of generation can be calculated as $VoLL \times BH$. So, at this point the cost of capacity equals the value of capacity to consumers, and beyond this point, consumer value per unit of capacity can only decline as the system becomes more reliable. Hence, the VoLL pricing rule causes the market to build the second-best amount of capacity. This solves the adequacy problem - with the help from a regulator. This price-based approach to the adequacy problem ultimately depends on the quality of the regulator's estimate of VoLL (Joskow & Tirole 2007).

Currently customers have no channel for their views on electricity system reliability. Without this information the markets cannot determine how much customers are willing to pay for reliability. If reliability were sold as a product then the market could answer the reliability question. But that market is not an energy-only market. Rather than attempting to define a reliability market, it may be better to increase demand elasticity with real-time equipment to the point where the market becomes perfectly reliable with regard to adequacy. If this can be achieved with prices well below the Value of Lost Load (VoLL), then such a market will be more efficient than an inelastic market with even a perfectly optimal level of adequacy. Still, one should not hope for dramatic efficiency gains because peaking capacity is cheap relative to the total cost of power (Cramton & Stoft 2008).

To conclude, there are two demand-side flaws: the operator's inability to control the real-time flow of electricity to a particular customer (for electric heating more a business model

¹ when one or more optimality conditions cannot be satisfied

problem than a technical one), and lack of real-time metering and billing (spot-based pricing are not yet that popular among small end-users, but for very large users this is reality already), which means that the consumer in general does not have an incentive to react to the fluctuating generation costs. The individual level controlling the use of electricity is largely missing in some markets, but nearer at hand in others. Missing individual level control is why, during scarcity hours, the system operators apply rolling blackouts on an area basis and not on an individual basis. If the demand side were perfectly elastic in real-time, which is one target of smart grids development, then there would not be any reliability problems in the short-term as the demand would always adapt to the prevailing supply situation. But the solution to the adequacy problem, the question about the sufficient generation capacity, is dependent not only on the demand side but also on the investment behaviour of the generators.

2.2.3 Generation investments

Can energy-only markets provide an optimal amount of generation capacity in equilibrium or is there a need for a specific mechanism to insure a sufficient amount of capacity? This is the question and relevant issues with regard it is discussed below.

It is not easy to estimate future generator revenues because they depend on the frequency, height and duration of price spikes. Consumers have to be protected against overpricing in times of capacity scarcity by applying a price cap. While the theory clearly states that the average value of lost load is the right value for the cap it is not easy to find out the right level. Even if it could be estimated, the difficulty to allow the energy price to be set at VoLL is that it may be too high to be accepted generally. If a normal price level for energy is about 40 €/MWh, the VoLL may be estimated at, say, 20,000 €/MWh. And even if this is allowed initially, investors may not believe that the policy is durable, in which case it will not induce the required investment (Cramton & Ockenfels 2011). This is an example of uncertainty in which there is both the system (electricity market) and the regulatory aspect (price cap) involved.

Emission trading schemes and environmental aspects in general is a major source of regulatory risks affecting electricity market. Also the almost continuous changes concerning the input markets, fuels for conventional generating forms, and all kinds of taxes or subsidies like feed-in tariffs, pose uncertainty concerning investments in generation capacity. These changes are due to both European and national level decisions.

In theory, the optimal amount of generation capacity can be determined from the average value of lost load and the long-run marginal cost of generation. To the difficulty to estimate the VoLL we have to add the uncertainty concerning the demand at the time the next power plant would come on-stream. It will be several years from the decision to build. Because these uncertainties cannot be resolved in advance, the more relevant question is how large are the additional costs of investing less or more than the optimal amount.

The cost risk of deviation from an optimal amount of generation capacity is asymmetric and it is dependent on the perspective: Private investors have an incentive to prefer to err on the side of less generation capacity because less capacity makes it more certain to recover the fixed costs. Less generation means lower turnover but higher average prices compensate. The competitiveness of the market as well as entry barriers affect the risk-averseness of the generators.

For the society the opposite holds true: Shuttleworth et al. (2002) came to the conclusion based on their calculation on different reserve margin levels that the provision of electricity is, indeed, a strongly asymmetric in such a way that the social costs of a deviation are higher on the side of insufficient capacity compared to that on the excessive capacity. This is easy to

believe because the peaking capacity is the cheapest of all capacity types and welfare cost of not being able to use electricity is high. For example, an extra 10% of capacity increases capacity costs by much less than 10%. As a consequence, increasing total capacity by 10% will cost consumers only, perhaps, 2% extra. But resulting extra reliability amounts to extra benefits so the loss of net benefit is less than 2% (Cramton & Stoft 2008).

High price volatility, long lead times, imperfect foresight, regulatory uncertainty and risk aversion are reasons for generating companies to delay investment until the need for new generating capacity becomes reasonably certain (de Vries 2007). Cautious investors would tend to provide less capacity than would be preferred by the consumers. Due to the relative flatness of electricity supply curves prices do not rise significantly until the margin between available generating capacity and peak demand becomes small. Taking the delay between the decision to build and commissioning a new plant into account this margin is likely to decrease further and it may even disappear altogether before new capacity is available. This may lead to prolonged periods of high prices and possibly triggers new decisions to build more capacity leading to excess capacity. This is what happens in other capital-intensive industries and all the elements are there to reproduce the investment cycles also in electricity generation.

Because of this tendency towards investment cycles, it is in the interest of electricity users to implement a mechanism in order to ensure a certain amount of generating capacity, especially because the cost of accidentally investing too much is relatively small (de Vries 2007).

By offering less generating capacity to the market, the generators can significantly affect the market price of electricity. This leads to an unfair transfer of wealth from consumers to generators. On the other hand, the less capacity there is available, the higher the probability of supply shortage and blackouts: an increased inconvenience for customers. In addition, if it is unclear, whether the price spike is due to the shortage of capacity or due to an application of market power, high price cannot be considered as an indication of need for additional investments. If a capacity mechanism can be used to make sure that there is always a sufficient amount of reserve margin, it would significantly reduce the abuse of market power.

There are two main disadvantages with regard to capacity mechanisms. Generators may have a new channel to apply market power when a new institution is established. This can be carried out by withholding capacity because capacity is highly inelastic in the short-term. Therefore, the mechanism must be defined carefully so that it gives right incentives to the generators. The second disadvantage is that the generation capacity may differ from the optimal level of capacity. From the society's point of view a small over-capacity does not pose a big problem due to the asymmetry of the costs.

But capacity mechanisms have some additional benefits, too. First, it reduces the risks of investing in capacity making the demand of capacity explicit and reducing the volatility of generator revenue. This should decrease the capital costs of investing. Second, it reduces the risks of capacity shortages and market power connected to it.

2.2.4 Theory and practical view from Nordic electricity markets perspective

Generally, when talking about commodities or products there are no reasons for separate payment for capacity. Capacity mechanisms are typically not discussed in textbook economics at all. Other industries – e.g. car industries – do not get money for building factories but the revenues from selling cars must cover the total costs, including investments for production capacities (Cramton & Ockenfels 2011). What makes electricity markets so special that separate capacity mechanisms are in use or their introduction is widely discussed?

In usual textbook economics, assumed theoretical conditions markets must meet are strong – these are the usual General Equilibrium assumptions. The assumptions of markets include

perfect foresight, price-taking behaviour by producers and consumers, risk neutrality (or adequate risk-sharing contracts), and **convex production possibilities** (Roques 2007).

Considering electricity markets, the assumptions of perfect markets are certainly not fully met. This is, however, the case is practically any other real-life markets. The most fundamental flaws related to electricity markets are listed in the following (Milligan 2011):

1. “Expression of demand is muted by the absence of dynamic pricing -> price signals are ineffective;
2. Elements of supply (transmission, reliability) have attributes of public goods and potential free riders;
3. Reliability can’t be easily purchased or valued;
4. Market power often exists and can be significant;
5. Some resources (wind, solar) have near-zero marginal cost;”

Provided the assumptions are met, the spot prices in energy-only markets should result in an efficient dispatch and allocation of available resources. Together with forward prices and rational expectations, they should also signal the need for additional generating capacity (Roques 2007). Ideally, under so-called “scarcity conditions” – when demand near its peak level and generating capacity fully utilized – prices would rise to clear the market consistent with maintaining network reliability. In this case, wholesale prices would rise to reflect the opportunity cost of a network failure or the value of lost load (VOLL) (Joskow 2007).

The imperfections discussed and their implications in real-world markets impose a threat that marginal cost pricing will not likely allow for revenue sufficiency for some generators. As a result, prices are prevented from rising to the level needed to ensure sufficient revenues to compensate generators for the capacity needed. Joskow (2007) summarizes the fundamental source of the missing money problem as “the failure of spot energy and operating reserve markets to perform in practice the way they are supposed to perform in theory”.

There are also practical examples, also not too promising, of the market functioning according to theory in “scarcity conditions” in the Nordic market. That is, as the Nord Pool price ceiling has been reached, the political outcry has been extremely loud with bold statements of the market malfunctioning. And it is true, a market price should not reach the opportunity cost of a network failure, but instead the high end marginal price should be formed by the demand elasticity or, in other words, the value of voluntary lost load (VOVLL). If the market price is high long enough, then there is an incentive for new marginal generators. If there is enough VOVLL below the overall cost of new marginal generators, there is no need for new generation capacity.

Some of the points of electricity market flaws mentioned above by Milligan (2011) can be debated in relation to the Nordic system.

1. Large customers are active parties on the power exchange and they do experience a dynamic price signal. Even small end-users are nowadays introduced to spot-based pricing. The Nordic system has historically had adequate generation capacity so that there has been only short spells with higher prices, but prices which the demand clearly can afford on the short scale.
2. and 3. Transmission and reliability are managed by the system operators, true enough, but for example up and down regulation is provided by market actors in the balancing market and all actors are payers of balancing of the system according to

their own imbalances, although small customers only indirectly through their balancing responsible counterparts.

4. On the system level, market power in the Nordic market is quite insignificant compared to other markets with a Herfindahl–Hirschmann-index of less than 1000 (= not concentrated markets) in 2008 (Ruska & Koreneff 2009). This is so because of the existence of a multitude of large and small producers, although the situation in single areas is not as good.
5. The point that some resources have near-zero marginal cost at least in the short term is per se not a problem, as the large amount of Nordic hydro clearly shows, but the problem lies in external subsidies for selected resources. German type of feed-in-tariffs are the worst, as they are extravagant (massive bonus and thus large profits), excessive (continue for new installations even when the market shows severe problems) and take away all the market responsibility, such as balancing requirement, from the wind or solar producers. Thus, at worst, feed-in-tariffs can cause a dampening of market signals, with subsequent calls for e.g. capacity mechanisms of some type to motivate investments in regulable power. This scenario can be seen as a vicious circle in the light of market-based operation in electricity sector.

2.2.5 Alternative capacity mechanism designs

We have seen in preceding sections that as a consequence of the missing money problem, underinvestment to support the efficient quantity of capacity becomes a potential threat in energy-only electricity markets. This motivates the discussion concerning capacity mechanisms. Roques (2007) formulates the dilemma of capacity mechanisms neatly: *The practical question is not whether electricity markets will deliver perfect outcomes, but whether the specific characteristics of electricity introduces systematic biases in market behaviour that require more complex market designs and regulatory requirements.*

Green (2008) states that: “In principle, an energy-only market may be able to provide sufficient revenues to compensate generators for the capacity needed to give the consumers the standard of security that they would (collectively) like.” Imperfections in electricity markets, however, may prevent the prices to reach the necessary levels (further discussion in section **Error! Reference source not found.**). Would it ever be possible to remove the mperfections arising in electricity markets – such as lack of demand response – or should we accept the need for and offsetting intervention? (Green 2008.)

Capacity mechanisms are one option for the above-discussed regulatory requirement or intervention. Typically, capacity mechanism organiser, e.g. system operator affects the outcome of the mechanisms directly or indirectly - either by determining the payment or an amount of capacity to be auctioned. Capacity mechanisms can take many forms and designs. Many different capacity mechanism designs have been implemented and/or are under discussion throughout the world.

Capacity mechanism can be described as an adjustment to the market structure for stabilizing investment in generating capacity (DeVries 2007). Additionally, in recent years, a question about adequate flexibility in electricity systems has constantly been brought up. A rapid increase in intermittent renewable generation has contributed to the rise of these concerns, since it cannot be dispatched similarly as conventional generation and potentially affects their utilisation and profitability. Capacity mechanisms are also debated as a potential measure to tackle these problems.

Theoretically, a capacity market can also be described as a mechanism to transfer the shadow price of the reserve margin constraint to capacity owners (Allcott 2012). The reserve margin can be, say, around 15% of the estimated peak demand.

Principally, the starting point of capacity mechanisms is simple: generators are additionally incentivized for maintaining available or investing in new generation capacity in addition to their income from energy market. However, details of capacity mechanisms are various and of extreme significance. For example, who defines the amount of needed capacity and how? Is all capacity compensated or is a mechanism targeted to peak-load and/or regulable generators only? What is the timeframe between auctions and delivery periods, which can reach as far as up to several years ahead of the auction time? Is the incentive to generators financial or is a level of total capacity required determined by a regulator? How is the level of financial compensation defined? All the design parameters have to be thoroughly reviewed when considering potential capacity mechanisms in SG environment.

Capacity mechanisms are divided in DeVries (2007) into following categories, under which the design options vary according to e.g. product design and auction design. Figure 4 classifies the mechanisms.

- Capacity payments
- Strategic reserve
- Operating reserves pricing
- Capacity requirements
- Reliability contracts

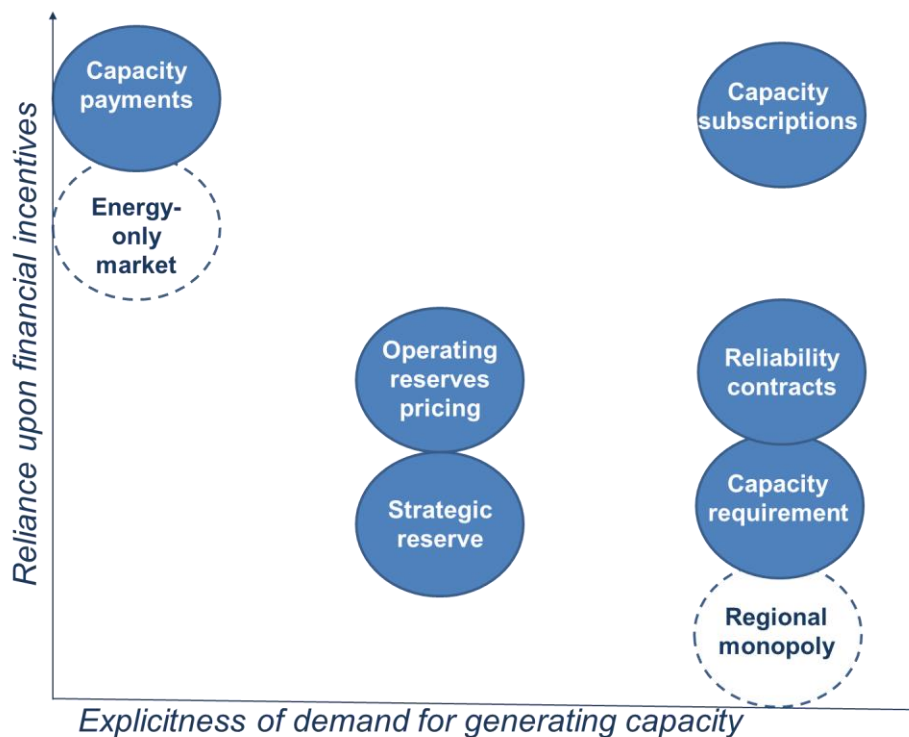


Figure 4. Capacity mechanisms classified according to De Vries (2004) (Brunekreeft et al. 2011). As can be seen from the Figure, the mechanisms differ according to their reliance upon financial incentives and explicitness of demand for generating capacity. In capacity payments, the amount of capacity is totally determined according to market actors' responds to financial incentives, and, on the other hand, with capacity requirements, the demand for generating capacity is explicitly known and does not result from financial incentives.

A detailed assessment of the pros, cons, experiences, and design parameters of different designs is provided for each capacity mechanism type separately by Pfeifenberger et al. (2009). In the following, we briefly describe the capacity mechanisms.

Capacity payments can be described as traditional type of mechanisms. Systems used in Spain in the All-Island market (i.e. Ireland and Northern Ireland) belong under a type of capacity payments.

- The capacity payment used in Spain since 2007 is a typical availability-based capacity mechanism. In these systems, generators offering capacity into the energy market would receive an administratively determined payment as compensation for having capacity available, regardless of whether it was dispatched to run. For example, In March 2008, the Spanish system operator proposed availability payments of 2.45 €/MWh for hydro, 5.48 €/MWh (for NGCC, and 0.81 €/MWh for coal. At an availability of 95 percent, the proposal would have amounted to annual payments of 21 €/kW-year, 46 €/kW-year, and 6 €/kW-year respectively. (Pfeifenberger et al. 2009.)
- In addition, the Spanish system has had an additional investment mechanisms based on downward-sloping capacity payment curve, or "investment incentive curve". That is, an additional payment is provided for new capacity and significant upgrades. The investment incentive curve describes how the capacity payment is related to the need for capacity, which is lower when the reserve margin is high. (Pfeifenberger et al. 2009.)
- In 2012, capacity payments in Spain represented 10.2% of the total Spanish market price. However, proposals on revisions to the capacity mechanism of Spain have also been discussed. (Cochran et al. 2013.)
- In the All-Island Market (Ireland and Northern Ireland), the total payment is equal to fixed cost of a peaking plant, less any revenues from ancillary services and from selling energy at more than its variable costs, multiplied by a capacity requirement based on the forecast peak demand (Green 2008).

Finland and Sweden are among countries that have implemented a scheme of **strategic reserves**. In the arrangement of Finland, the peak load capacity is procured through auctioning and the contracted reserve capacity is kept outside the markets. Energy Market Authority assesses at least every four years the level of contracted capacity. The system has been in use since 2008. Strategic reserves can be seen as a potentially temporary solution and relatively easily implementable mechanisms. Sweden will phase out their strategic reserve scheme after the winter 2019/2020 as the market is desired to take a larger responsibility of the security of supply (Energimyndigheten 2013d).

Capacity requirements mean that the level of capacity required by LSEs (Load Serving Entities²), are administratively set around an engineering standard, and they have an obligation to meet either by their own production assets or by contracting bilaterally or through organised auctions. Capacity requirements are in use in many electricity markets in

² In practise, retailers or large consumers

the United States, with typically an order of 15 % reserve margin above estimated peak load based on engineering standards.

Capacity markets are a marketplace which set a price for capacity units according to their supply and demand. Basic design features of capacity markets can be divided as in Cramton & Ockenfels (2011).

- Determining the need of adequate capacity
- Product design
- Auction design

Table 1 demonstrates the challenges and complexity of designing capacity markets. In each design parameter, there are several challenges and choices to be made.

Table 1. Capacity market parameters. Source: Baritaud (2013), adapted from Hogan.

Capacity definition	<i>Peak generators, dispatchable plants, intermittent sources, demand response</i>
Horizon and duration	<i>Annual to multiple years, period of capacity availability (definition of peak period)</i>
Capacity Requirements	<i>Uncertain demand forecasts, coherence with reliability standards</i>
Network constraints	<i>Definition of locational capacity requirements</i>
Cost of New Entry	<i>New power plant, mothballed plants, power uprate, demand side</i>
Energy Revenues	<i>Ex ante or ex post determination</i>
Capacity Demand Curves	<i>Fixed capacity requirements vs variable demand slope to smooth revenues</i>
Capacity Cost Recovery	<i>Suppliers or socialized payments</i>
Penalties	<i>Control of availability, outage rates, penalties</i>

The concept of auction-based capacity markets held several years ahead of need is called **forward capacity markets**. Multi-year auctions are a response to concerns of price volatility and market power of earlier designs (Joskow 2007). Furthermore, a distinction between selective and installed capacity markets can be made (e.g. Söder 2010). That is, selective capacity provides only some selected units to receive capacity payments, whereas in installed capacity (ICAP) markets, all units receive the capacity payment.

Capacity subscriptions is an innovative and fundamentally different type of capacity mechanism. In the capacity subscription system, consumers are directly involved by requiring them to purchase electronic fuses which, when activated, limit their electricity consumption to a predetermined capacity. "Each consumer chooses the level of capacity that he wishes to have permanently available to him and pays for it per unit of capacity. As a result, a capacity market develops between generating companies and consumers. In this

market, consumers choose between purchasing a high volume of firm capacity³ and risking that their consumption is limited during shortages.” (DeVries 2007).

Reliability contracts or reliability options are another innovative type of capacity mechanism with still limited practical experiences. They are designed as an improvement upon capacity requirements (DeVries 2007). As this review takes a look at the future, this motivates us to take a deeper look into these mechanisms. Reliability contracts are a scheme where an independent agent (e.g. TSO) purchases call options from generators. The call options give the TSO the right to the difference between the spot (energy) price and the strike price, and the payments are passed to consumers. Table 2 demonstrates the differences of capacity requirements (obligations) and reliability contracts. For more detailed and analytical example of reliability options, please see Appendix.

Table 2. Characteristics of reliability contracts and capacity obligations mechanisms. SO=system operator, LSE=load serving entity. (Source: Khalfallah 2006)

	Capacity obligations	Reliability contracts
Organization	-SO determines: Q=expected peak load + reserve margin -LSEs required to purchase Q	-SO sets the strike price and the volume of reliability contracts (Q)
Market setting	-Transactions between LSE and generators via the capacity market -Capacity price (CP) is determined	-Generators bid quantity and price (Premium) -Market is cleared as a simple auction (Call option) -SO exerts the option whenever the energy price exceeds the strike price
Generator revenues	-CP from the capacity market and energy price from the energy market	-The premium from the auction and the energy price (capped by the strike price)
Adequacy	-Commitment by the agents to purchase and to sell -Identifiable commercial product (capacity) -Guarantee a regulated generator adequacy level -Extra revenue for generators -Consumers remain fully exposed to high prices in the energy market	-Generators committed to produce whenever they are called (otherwise, penalties) -Guarantee a regulated generation adequacy level -Extra revenue for generators -Consumers are fully protected from high prices in the energy market

Reliability contracts have originally designed for electricity markets in the US. The US

³ Firm capacity is a measure of the contribution of generation units to the electricity system reliability

markets are fundamentally different than typical European markets. This fact has raised a question of suitability of reliability contracts in European markets.

Green (2008) divides the electricity markets designs in two “families”: the US style and European style. Three central choices are determined in the design:

- is the energy market run by the system operator that also procures ancillary services;
- treatment of transmission effects (national/zonal/nodal pricing mechanism); and
- presence or absence of a capacity market

European markets typically do not have mandatory power pools where TSOs are also operating the markets but the exchanges are voluntary. Thus, Brunekreeft et al. (2011) highlight the fact that there is no single system price at which level the TSO should call the options, and this calls for adjustments on the reliability contract mechanism if applied in Europe. Their approach is more thoroughly discussed in Section 2.2.7. Also, Cramton and Stoff (2008) conclude that mandatory reliability option schemes do not necessarily call for centralized day-ahead market.

2.2.6 Capacity mechanisms and the future market environment in Europe

In this section, the question of appropriate market design is addressed especially from the viewpoint of Europe and its changing technological landscape due to increasing of SG technologies. Discussion in different studies is reviewed.

There seems not to be an unequivocal opinion among experts about the necessity of capacity mechanisms or what would an ‘optimal’ design be. In a report commissioned by German Association of Energy and Water Industries, ECOFYS (2012), discusses the necessity of capacity mechanisms and reviews studies on the subject. The report illustrates that the conclusions of the studies on the necessity are dependent on the assumptions made on e.g. technical lifetimes of the power stations, level and structure of demand, and pricing. It suggests the energy-only market and the EU internal market integration offers possibility to cope with current challenges, and temporary challenges of a transition period may be coped by means of a strategic reserve. Meyer et al. (2014) see some kind of a capacity mechanism almost unavoidable for flexible generation capacity to recover their fixed costs in present European context with substantial investment in renewable capacity. The problem is also seen to not fade away during the long-term.

If introduction of capacity mechanisms in European-style electricity markets is considered or assumed relevant, the pros of characteristics of reliability contracts and forward capacity mechanisms seem to be emphasized in many research papers reviewed.

Green (2008) recognises the fact that evidence of whether a separate capacity market is needed is still lacking. However, his view is that in the environment of increasing intermittent generation, a capacity market should be a part of the solution. A central justification for the observation is that the costs of under-investment rise more rapidly than those of over-capacity, and it is thus better to risk a surplus than a shortage. Joskow (2007) discusses methods to improve the performance of energy only spot wholesale energy market, focusing on the US context. His belief is that not all the problems, especially those associated with the implementation of engineering reliability rules and the associated behaviour of system operators during scarcity conditions, can be fully resolved quickly if ever. Thus, his conclusion is that the reforms of spot markets need to be accompanied with properly designed forward capacity mechanisms.

Cramton & Ockenfels (2011) deal with the economics, market design, and the suitability of the capacity market for Europe and Germany in particular. According to their study, the increasing demand-side flexibility cannot fully solve the missing money problem. This is due to the fact that despite the increasing utilization of smart approaches (i.e. Smart Grid technologies and applications), there still remains inflexibility in demand, indicating market power in scarcity events still becomes a potential threat. They describe a system based on forward reliability options. Also, it is emphasized that there are issues in electricity markets a capacity market *cannot* improve in resource adequacy, relating to drastic interventions of energy policies etc. Thus, their recommendation in the current phase of transition in Germany is to give highest priority to build a stable and reliable political, and a sound market framework. A capacity market will be of important complementary value once the market operates on a stable political, regulatory and economic basis. (Cramton & Ockenfels 2011)

Cervigni & Niedrig (2011) also discuss the capacity market from Europe-Germany viewpoint. Their conclusion is that "As of today Germany in particular does not appear in need of being a front-runner in the introduction of a capacity support scheme for several reasons." These reasons include

- The reserve margin seems appropriate, decreasing the need to introduce capacity mechanisms which have potential harmful issues
- High interconnection between the German electricity markets and the neighbouring ones highlights the need and opportunity to trade in flexibility on the Continental-Europe scale
- Wholesale electricity trading is comparably well developed in Germany and there are indications that more sophisticated and longer-term hedging strategies are available. Also, demand-side flexibility can be expected to further increase.
- Before resorting to more impacting regulatory measures, some elements of the German market design should be reviewed in order to remove any frictions in the price-formation mechanisms.

Brunekreeft et al. (2011) do not address the question of whether a capacity market should be implemented but what are the alternatives if one is implemented. If a way of moving towards capacity mechanisms is chosen in Europe, Brunekreeft et al. (2011) consider strategic reserve and a mechanism of what they call "A Mandatory Reliability Contract Market" best candidates for evolving European electricity market. The suggested Mandatory Reliability Contract Market mechanism is a mix of centrally operated reliability contracts and a bilateral reliability contracts market. Reliability contracts are a relatively new and 'heavy' capacity mechanism, which means that there may be a higher risk of regulatory failure. Strategic reserve, on the other hand, is considered relatively easily implementable 'light' alternative for Europe, addressing the problems only partially (Brunekreeft et al. 2011).

Hogan (2010) reminds of difficulties of defining and measuring capacity for new low carbon technologies such as wind power, solar power, and load management are particularly relevant in considering market design in low-carbon future. This may also have an implication on the functionality of capacity mechanisms.

According to Hogan (2010), concerns with resource adequacy are more acute in the US than in the EU, having an impact of the need for capacity mechanisms. US models often include regulatory procedures, e.g. offer caps to mitigate the exercise of market power, depressing the energy market prices. The EU markets are less inclined in directly intervening in the bidding process, which opens more opportunities for market power, resulting in more mixed picture about the adequacy of incentives for new generation investment and the need for capacity mechanisms.

In European context the substantial investment in renewable capacity has aroused the concern of how to prevent the premature decommissioning of flexible generation capacity that is unable in the present situation to recover their fixed costs although the system needs conventional backup capacity. And this problem will not fade away during the long term. Some kind of a capacity mechanism seems almost unavoidable in the light of this issue (Meyer et al. 2014).

2.2.7 Experiences and plans of capacity mechanisms

Internationally, there are varying experiences of the use of capacity mechanisms. Past experience with capacity payments and installed capacity markets revealed that their implementation might prove complex and have unintended incentive effects, such as vulnerability to market power and price volatility. In some cases, unsuccessful mechanisms have contributed to their reforms, fine-tunings, or abandonments, as in the case of Britain in early 21st century.

It is evident that capacity mechanisms have been widely discussed in a context of European power markets during the last few years. In Europe, there are also recent experiences: at least the Iberian Market covering Spain and Portugal, and the All-Island market (Ireland and Northern Ireland), have included capacity payments (Green 2008). However, during the very last few years, the discussion of capacity mechanisms has activated in Europe and many European countries are considering pros and cons and appropriate designs of such schemes. Importantly, these countries include large European electricity consuming countries such as Germany, France, Italy, and Great Britain. EC (2012b) introduces details of existing capacity mechanisms and plans on forthcoming systems in the Member States:

- In the single electricity market between **Ireland** and **Northern Ireland** a capacity payment is determined by the regulator ex ante, which is paid to all available generators. This has created difficulties in cross border trade with Great Britain with a capacity charge being imposed on exports and capacity uplift provided to imports to compensate for the effect of the payment on market prices. (EC 2012b.)
- **Spain** also operates an explicit capacity payment, which was recently reviewed. This review in large part resulted in the design and operation of the mechanism in such a way to correct for the impact of other regulatory interventions, notably support schemes for particular other generation. (EC 2012b.)
- **France** is currently developing a capacity market based on supplier obligations to address concerns about meeting the peak demand in winter. (EC 2012b.)
- As part of a wider programme of electricity market reform, which seems to result in government taking a more direct role in the market, the **UK** also intends to implement a capacity mechanism (EC 2012b). According to plans, the first capacity market auction would run in 2014 and concern a winter for 2018/2019. For the penetration of SG technologies, it is notable that demand-side is included in the plans. That is, *in the Capacity Market, both **generation and non-generation providers of capacity such as DSR and storage** will receive a predictable revenue stream for providing reliable capacity, and face financial penalties if they fail to do so* (DECC 2012).
- **Italy** is planning to implement a system of reliability option contracts between generators and the transmission system operator. (EC 2012b.)
- “**Germany** is providing for a system which would allow the regulator to approve contracts between transmission system operators and generators to ensure that generation capacity which is needed for grid stability reasons is not closed down.” (EC 2012b.)

Most prominent experiences of capacity mechanisms to date include several markets in the United States. According to DeVries (2007), the most effective capacity mechanism that has been tried in practice is the PJM's system of capacity requirements. However, original capacity payment mechanisms implemented in the US suffered from prominent deficiencies, such as market power and price volatility, and **forward capacity obligations** and associated auction mechanisms are seen necessary to restore the appropriate incentive (Joskow 2007).

Consequently, forward capacity auctions have been conducted instead of traditional installed capacity mechanisms over the last few years. PJM capacity requirement system experienced a reform where the former installed capacity (ICAP) system was transformed into forward-looking approach in 2008. Also, the ISO New England (ISO-NE) electricity market now conducts forward capacity auctions that permit a wide range of demand-side resources to compete with supply-side resources in meeting the resource adequacy requirements of the region."(Gottstein & Schwartz 2010). For detailed design of the forward capacity mechanisms, see e.g. Gottstein & Schwartz (2010).

Pfeifenberger et al. (2009) recognises **complexity** as a concern associated with implementing forward capacity markets. Complexity imposes considerable implementation costs and risk of unintended design flaws on both system operators and market participants.

There are practical experiences of **reliability options** in at least electricity markets of New England in USA and in Colombia. With first auctions in 2008, this demonstrates their suitability in both thermal and hydro dominated electricity systems (Cramton & Stoft 2008).

In Mandatory Reliability Contract Market for the Europe, suggested by Brunekreeft et al. (2011), the US-originated scheme is adjusted to the European-style market design as follows:

- In the European market model, it must be possible to make bilateral arrangements
- The proposal includes "centralized backbone": the TSO would be responsible for organising the market place. However, operation of the market could be done by e.g. established exchanges.
- Instead of TSO, the requirements are put on the balance responsible parties.
- Regulator determines the required reserve margin
- A commonly accepted reference price for calling the options should be agreed. As the European market model is developed towards market coupling, this should be no problem in the future European markets.

2.2.8 Stakeholder views in the EU

The European Commission launched a communication of integrated European electricity market (EC 2012a). The communication also includes views on capacity mechanisms discussed in member states. The Commission expresses its concern by the following statements (bold font added by the authors)

- *Some Member States have introduced or plan to introduce separate payments for the market availability of generation capacity, as they are concerned that the 'energy only' market will not deliver sufficient investment in generation to ensure security of supply in the longer term. Such capacity mechanisms are long-term tools that aim to provide a stream of revenue to (selected) generators and commit consumers to paying for the capacity provided.*

- *However, the Commission is of the view that if capacity mechanisms are not well designed and/or are introduced prematurely or without proper co-ordination at EU level, they risk being counterproductive. If capacity mechanisms do not treat demand reduction fairly, they can **lock in generation-based solutions rather than energy efficiency or demand response solutions**. If they do not distinguish base load from peak load, **they may not attract sufficiently flexible generation capacity**. Capacity mechanisms **distort the EU-wide price signal** and are also likely to **favour fossil fuel generation sources** over more variable renewable sources (**beyond levels necessary for maintaining power systems in balance**) and may therefore run counter to EU decarbonisation and resource efficiency objectives.*

Consequently, EC (2012a) includes capacity related initiatives seeking to ensure appropriate state interventions:

- *Analyse investment incentives and generation adequacy in electricity under the existing European framework*
- *And develop criteria for assessing and ensuring consistency of national capacity-related initiatives with the internal market*

The communication declared a Public Consultation on generation adequacy, capacity mechanisms and the internal market in electricity (EC 2012b). The consultation included a description of potential risks of poorly designed capacity mechanisms (bold font added by the authors) (EC 2012c):

- *Poorly designed capacity mechanisms can **undermine demand side participation and measures to support energy efficiency, and instead act as a crutch for inefficient fossil fuel generators**. Even Member States who do not see the need for intervention will be affected by the capacity mechanisms implemented by their neighbours, as they can distort market behaviour and investment decisions across the internal market. It is important that any capacity mechanisms or other interventions to ensure generation adequacy and security of supply meet the principles of necessity and proportionality – principles that are firmly anchored in European law.*

The Consultation stimulated responds 2 Citizens, 14 Public Authorities, 60 Registered Organizations, and 52 Non-Registered Organizations, including ENTSO-E, European Network of Transmission Operators for Electricity (ENTSO-E 2013), and The Union of the Electricity Industry–EURELECTRIC (EURELECTRIC 2013), whose responds were reviewed as large European entities representing TSOs and electricity industry.

The consultation (EC 2012b) provides with interesting material on stakeholders' statements on capacity mechanisms considering the current European debate and this report. Questions interesting from the topic included:

- **“Do you consider that capacity mechanisms should be introduced only if and when steps to improve market functioning are clearly insufficient?”**

EURELECTRIC sees that first of all, the energy only markets must be enhanced to work properly to deliver generation adequacy. However, the development is recognised be slow and capacity mechanisms to be potentially considered by policymakers **if** generation adequacy is seen endangered. EU wide market integration progress should be consistent with the mechanisms and they should be designed regional or at least in coordination with neighbouring markets. However, integrating of the wholesale markets and strengthening the transmission capacities are seen as the top priority for EU and national policymakers. (EURELECTRIC 2013)

ENTSO-E supports development of internal energy market to deliver reliability, similarly as distortions on the markets must be minimized. If regulatory authorities or national TSOs see security of supply as a threat, ENTSO-E supports examining all the possibilities to address it. Flexibility, voltage control and transient stability are complex issues and call for appropriate technical analysis before effective market mechanisms for them can be developed. (ENTSO-E 2013)

EC (2012b) included a question on a relation between need of flexibility and the appropriate capacity mechanism relevant for this work

- **“Which models of capacity market and /or payments do you consider to be most compatible with ensuring flexibility in a low carbon electricity system?”**

EURELECTRIC sees that capacity markets are not potential measure to incentivise flexibility but their incentives should come from energy and balancing markets and/or ancillary services. This way it is believed that competitive capacity markets, where all capacities contributing to security of supply receive remuneration proportionate to their contribution, can be achieved, which is seen as important. (EURELECTRIC 2013)

ENTSO-E finds that flexibility has not been the main focus in implemented capacity mechanism designs but they have been focused on adequacy. Increasing electricity from renewable sources will call for new solutions to replace the system services contracts today widely in use as payments for flexibility. Furthermore, what is notable for the design of capacity markets, ENTSO-E believes in its response that is more appropriate to develop general guidelines than detailed criteria for EU-wide capacity mechanisms. Thus, one-fits-for-all-solution is unlikely to be appropriate due to difficulties to ascertain the appropriate level of capacity adequacy for each individual Member State. Capacity markets should not distort the innovation and flexibility that might come from innovations based on price signals of the balancing markets. (ENTSO-E 2013)

The risks of capacity mechanisms were also indicated in comments given of the Communication on electricity markets by different stakeholders:⁴ It is seen as a potential threat that capacity payments might only address generation and neglect the demand-side management, energy savings and storage solutions.

- *"The capacity payments proposed in some Member States will be counterproductive. They only address generation, neglecting the huge potential from demand-side management, energy savings and storage solutions and do not provide fair conditions for participation to all market players. Such mechanisms favour fossil fuel or other mature generation capacity investments in energy savings and flexible renewable energy.", Daniel Fraile, senior energy policy officer at Climate Action Network (CAN)*

2.2.9 The role of active resources and capacity mechanisms for Smart Grids

Active resources of both demand-side (e.g. DR), and supply side (intermittent renewables: solar, wind etc.) are of particular interest in Smart Grid and SGEM environment. This is due to their potentially increasing partaking in electricity markets, which arises from new technology and increased need of flexibility due to increasing uncontrollable electricity production. Thus, it is of interest to see how active resources interact with capacity mechanisms, both theoretically and in practical implementations.

DR can be seen beneficial from market point of view since any energy market does benefit from load that can protect itself against blackouts and market power in scarcity events. This moves the market towards an ideal market. Thus, since lack of demand side is one of

⁴ <http://www.euractiv.com/energy/brussels-urges-eu-countries-ener-news-516075>

primary reasons for the discussion of capacity mechanisms in a context of electricity market, by integrating the demand side in electricity market to a greater extent reduces the need of capacity mechanisms. Thus, in fact, it might be better to install real-time meters and use real-time pricing to increase elasticity to the point where the market becomes perfectly reliable with regard to adequacy, than to implement a capacity market. (Cramton & Ockenfels 2011.) This point is particularly interesting from the SGEM viewpoint.

Cramton & Ockenfels (2011) states that the lack of demand side in electricity market could change with the development of smart grid and smart metering solutions - and possibly faster than capacity markets yield results. However, according to Cramton & Ockenfels (2011), even increased demand responsiveness cannot contribute to (fully) solve the missing money, risk and coordination problems. So, even as the pure-market design moves towards an ideal environment, a capacity market might still be beneficial.

There are theoretical arguments that demand-side should be treated symmetrically to supply side in capacity mechanisms (Joskow 2007). Demand-side resources can be included in capacity mechanisms in certain designs, at least in examples in US-type electricity markets. "Both the PJM RPM and the ISO-NE FCM (forward capacity market) allow demand-side resources to offer "supply" into the capacity market. These services can take the form of contracts with customers on interruptible rates or direct load control." (Pfeiffenberg et al 2009). Moreover, there are promising signs in US markets of the ability of capacity mechanisms to support the penetration of demand-side resources. "early experience in the United States (US) suggests that these markets have the potential to play a supporting role in delivering capacity from low-carbon, demand-side resources, including energy efficiency." (Gottstein & Schwartz 2010).

Potential difficulties in inclusion of demand-side include measuring, ensuring the availability of resources during peak hours etc., verification of demand-side actions etc.: "Integration of DR resources into capacity market designs faces a number of challenges, including how to monitor and verify availability of the committed resources and how to adjust load forecasts for any such commitments without understating or double-counting their impacts." (Pfeiffenberg et al 2009).

Active resources discussed in a context of the future SGEM environment also include supply side technologies, for example varying RES production (wind, solar). Also supply side active resources set their requirements for the design of capacity mechanisms and suitability of Smart Grid technologies. This is due to the stochastic nature of their availability. "For example. contribution of wind units to resource adequacy is obviously smaller than the contribution of coal units, and moreover may depend on the capacity mix in the market, location and transmission constraints" (Cramton and Ockenfels 2011). Therefore, the calculation methods to assess the peak contribution of these technologies in different capacity mechanisms become an important question.

Renewables may contribute to the adequacy problem. Renewables are typically subsidized via a feed-in tariff which is fixed and guaranteed for years plus an obligation of system operators to feed in this electricity into the grid whenever it is produced. This partly explains why renewables' supply is not price-sensitive and another reason being the low incremental costs. As a consequence, renewables create the same problem as the problem which is at the heart of the adequacy problem: the price-inelastic demand. In fact, renewables can be thought of as completely price-inelastic *negative* demand.

Moreover, because neither wind nor the sun can provide firm energy, renewables can only to a small part substitute conventional resources. At the same time, however, renewables increase price volatility, tend to reduce market price levels and worsen the capacity utilization of conventional capacity. This makes investments in conventional resources, ceteris paribus, less attractive, in particular when renewables are planned to produce a considerable share of consumed electricity. Also, politics, regulation and society are constantly arguing over the

right time, the right place, the right technologies and the right price for new capacity. As a result, investors face a large amount of uncertainty with regard to future energy prices, the needed future mix of generation, and future regulatory interventions. The capacity-market benefit of market coordination may then become useful.

In Europe, it appears that the PJM style capacity requirement system cannot be implemented in its current form in most European markets. “There would be a risk of ‘leakage’ in case of unilateral implementation: if one country implements a capacity requirement, its reserve capacity could be sold outside the country in case of a regional shortage, so that the net contribution to the reliability within the country would be diluted. Capacity requirements would work, however, if implemented in a large, contiguous region with relatively limited outside trade, such as the UCTE area.” (DeVries 2007). According to Brunekreeft et al. (2011), the main reason for direct unavailability of the North American mechanisms is that Europe’s electricity markets are decentralized: TSOs and market operators work separately and energy trades are not bound to mandatory pools. Similarly, DeVries (2007) concludes “Restricting exports requires a mandatory pool, in which all physical trade goes through the pool and the market operator also is the system operator. Only then does the system operator have a means for verifying that commitments to sell to the pool are met.”

Capacity subscriptions are an interesting option discussed in SGEM environment due to their utilization of real-time metering. This directly integrates the consumers to capacity levels. **“With the advent of real-time meters, a variant of capacity subscriptions may be the most effective and economically efficient solution, but it is unclear how consumers would respond to such a scheme.” (DeVries 2007).** According to a simulation by Doorman (2008), the capacity subscription policy increases the social welfare, and both producers and consumers benefit. “This is possible because capacity subscription explicitly utilizes differences in consumers’ preferences for uninterrupted supply”. However, since implementation has its costs, the advantage must be weighed against the cost of implementation.

2.3 Conclusion and discussion

From the SGEM viewpoint, at least more intermittent renewables, more real-time measurements, and a more active demand side are expected in the future electricity markets. Subsidies for selected technologies affect the operating hours and profitability of other plants, which raises the discussion about mechanisms to keep strategically important reserve plants in the market. Thus, the relevant question is if there is any ‘best-practice’ market design that can ensure generation adequacy in the long run at least cost while minimising regulatory interference with the market (Roques 2007), especially taking into account the changes arising by Smart Grids? How is the changing landscape of electricity market interacted with the question of resource adequacy, flexibility, and the need for capacity mechanisms?

Generally, Smart Grid technologies have potential to move electricity markets in the direction of ideal markets. This is taking place by increasing demand response and utilisation of real-time data etc. Integration of demand-side seems particularly relevant from a SGEM point of view due to its key characteristics of utilising the demand-side resources more efficiently, including small-scale customers and new data on electricity consumption by SG technologies.

The role of after-spot markets strengthens as flexibility is called for in evolving European electricity markets, but today’s intraday and balancing market designs in the EU are far from a fully efficient and harmonized market. In addition to the market integration, there is considerable room to improve market design and accuracy of market signals in Europe.

Capacity mechanisms – at least traditional implementations – can be seen as alternative or additional methods to tackle the imperfections in the electricity market and to ensure long-

term generation adequacy. For example, Roques (2007) discusses the issue of increasing demand side and capacity mechanisms as a dilemma of between healing causes and symptoms. From a theoretical point of view, the topic of adequate investments in liberalized electricity markets has been widely discussed even for decades. The effects that increasing renewable electricity has on the electricity system and on the profitability of conventional plants is one of the main current topics for discussion in the EU.

In the recent EU debate by generator and TSO representative organisations, the development of balancing markets is seen as a key factor for flexibility, whereas capacity mechanisms are regarded as potential measures to ensure long-term adequacy.

A variety of design options are available for capacity mechanisms and capacity markets. However, theoretically, a capacity market can be fundamentally described as a mechanism to transfer the shadow price of the reserve margin constraint to capacity owners (Allcott 2012). The reserve margin can be, say, around 15% of the estimated peak demand.

The EU Commission seems to identify the potential deficits in the Member States' plans on capacity mechanisms in order to achieve a fully integrated and functioning electricity market by distorting the EU-wide price signal: "Nationally-based capacity mechanisms can increase costs for all Member States by preventing the best use of generation and flexibility across borders" (EC 2012a). More generally, national support mechanisms are also seen as a potential source of distortion to the EU-wide electricity market.

Capacity mechanisms have been criticized for their potential favouring of (fossil) capacity and concentration on the generation side at the expense of the demand-side, as well as for their distortion of the market signals, with national mechanisms creating a barrier for market integration, and for imposing a regulatory risk for market participants. International experiences and research show, however, examples of capacity mechanisms, where the demand-side can also be included. This is of particular relevance when smart technology approaches with increasing real-time information and demand response are considered.

From a market integration point of view, a European-wide solution is desirable over national mechanisms, even though there seems to be practical challenges in implementing such a scheme due to dispersed system operations etc., and differing local practices and conditions. Modern approaches in market design, such as reliability contracts and forward capacity mechanisms, are often referred to as potential directions of further consideration, while strategic reserves can be seen as a more easily implementable option. The modern innovation of capacity subscriptions becomes an interesting option with enhanced real-time metering, a characteristic widely discussed among SG concepts. Generally, the lack of innovative capacity mechanisms can be seen as limited experiences of their use and effects in practice.

Generally, if a market-based and integrated European approach is chosen as the target for future electricity markets, implementations of market interventions and national support mechanisms require utter carefulness. Utilising real-time data and integrating demand side and associated market mechanisms as effectively and widely as possible in the markets can be seen as supporting the target. When considering mechanisms, local market and power system circumstances should always be taken into account.

3. European and Nordic electricity market drivers 2020/2035

3.1 EU goals to 2050

Our special motivation here is to explore the EU's scenarios for input data and appropriate reference for our assessments on electricity price (Chapter 4). That is, our aim is to assess the overall demand and supply developments towards 2020 and 2035, with closer attention

on the Nordic situation, and to assess the general trends and especially to estimate the future (wholesale) market price.

In 2011, the EU adopted the Energy Roadmap 2050 (EC 2011a), where it states the target of reducing greenhouse gas emissions to 80-95% below 1990 levels by 2050. In the roadmap, the EC studies the challenges posed by EU's decarbonisation objective while at the same time ensuring security of energy supply and competitiveness. The launch of Energy Roadmap 2050 also includes, which has of national decarbonisation analysis and preparation work.

The European Commissions published an Impact Assessment (IA) (EC 2011b,c) attached to the Roadmap, including analysis of possible future developments and numerical analysis and assumptions potential for our study. The Impact Assessment includes five decarbonisation scenarios and Reference and Current Policy Initiatives (CPI) scenarios to give some indication on the possible future developments in the EU.

The Commissions' Reference scenario analyses possible future developments in a scenario of unchanged policies. Noteworthy, the Reference scenario is a projection, not a forecast, of developments in the absence of new policies beyond those adopted by March 2010. It therefore reflects both achievements and deficiencies of the policies already in place. Additionally Current Policy Initiatives scenario (CPI) was modelled in order to take into account the most recent developments (higher energy prices and effects of the nuclear accident in Japan) and the latest policies on energy efficiency, energy taxation and infrastructure adopted or planned after March 2010. (EC 2011a.)

The five decarbonisation scenarios are presented in Table 3. The decarbonisation scenarios propose different combinations of the decarbonisation routes. (EC 2011b)

Table 3. Scenario setting in EC (2011b): Reference scenario, Current Policy Initiatives scenario and five decarbonisation scenarios (EC 2011b). Some footnotes and references to the original document have been removed by the author.

	Business as usual (Reference)	The Reference scenario includes current trends and long-term projections on economic development (GDP growth 1.7% pa). It takes into account rising fossil fuel prices and includes policies implemented by March 2010. The 2020 targets for GHG reductions and RES shares will be achieved but no further policies and targets after 2020 (besides the ETS directive) are modelled.
Ibis	Current Policy Initiatives – CPI scenario (updated Reference scenario)	The Reference scenario includes only adopted policies by March 2010. Since then, several new initiatives were adopted or are being proposed by the EC. The EC outlined its future work programme on energy mainly until 2020 in the Communication "Energy 2020 - A strategy for competitive, sustainable and secure energy". This policy option analyses the extent to which measures adopted and proposed will achieve the energy policy objectives. It includes additional measures in the area of energy efficiency, infrastructure, internal market, nuclear, energy taxation and transport. Technology assumptions for nuclear were revised reflecting the impact of Fukushima and the latest information on the state of play of CCS projects and policies were included.
	Decarbonisation scenarios	All decarbonisation scenarios build on Current Policy Initiatives (reflecting measures up to 2020) and are driven by carbon pricing to reach some 85% energy related CO ₂ reductions by 2050 (40% by 2030) which is consistent with the 80% reduction of GHG emissions. Transport measures (energy efficiency standards, low carbon fuels, infrastructure, pricing and transport planning) as reflected in the Transport White Paper are included in all scenarios. All scenarios will reflect significant development of electrical storage and interconnections (with the highest requirements in the High RES scenario). Different fuels can compete on a market basis besides constraints for nuclear investment in scenario 6.

2	High Energy Efficiency	This scenario is driven by a political commitment of very high primary energy savings by 2050 and includes a very stringent implementation of the Energy Efficiency plan. It includes further and more stringent minimum requirements for appliances and new buildings; energy generation, transmission and distribution; high renovation rates for existing buildings; the establishment of energy savings obligations on energy utilities; the full roll-out of smart grids, smart metering and significant and highly decentralised RES generation to build on synergies with energy efficiency.
3	Diversified supply technologies	This scenario shows a decarbonisation pathway where all energy sources can compete on a market basis with no specific support measures for energy efficiency and renewables and assumes acceptance of nuclear and CCS as well as solution of the nuclear waste issue. It displays significant penetration of CCS and nuclear as they necessitate large scale investments and does not include additional targeted measures besides carbon prices.
4	High RES	The High RES scenario aims at achieving a higher overall RES share and very high RES penetration in power generation, mainly relying on domestic supply
5	Delayed CCS	This scenario follows a similar approach to the Diversified supply technologies scenario but assumes difficulties for CCS regarding storage sites and transport while having the same conditions for nuclear as scenario 3. It displays considerable penetration of nuclear.
6	Low nuclear	This scenario follows a similar approach to the Diversified supply technologies scenario but assumes that public perception of nuclear safety remains low and that implementation of technical solutions to waste management remains unsolved leading to a lack of public acceptance. Same conditions for CCS as scenario 3. It displays considerable penetration of CCS.

A closer look at the scenario setting (Table 3) reveals the key parameters in Europe's low carbon energy futures according to current understanding. That is, energy efficiency, RES, CCS and nuclear are seen the key building blocks and the related key parameters is varied between the decarbonisation scenarios. Interestingly from SGEM point of view, the "High Energy Efficiency" scenario highlights smart technologies as a solution.

3.2 Demand development

3.2.1 Demand in the EU

The European Union's final electricity consumption (EU-27) totalled 2767 TWh in 2011 (Figure 5), whereas the number for EU-28 (Croatia included) in 2012 was 2795 TWh. Countries with the largest electricity consumption in Europe are Germany (526 TWh), France (430 TWh), and the United Kingdom (318 TWh) in 2012. The consumption figures for 2012 are adopted from the Eurostat database.

The statistics on European electricity consumption in longer term show only a little increasing or even decreasing trend. In autumn 2008, the European Union and the global economy entered the deepest recession since the 1930's. Due to the downturn, energy intensive industry's electricity consumption decreased, contributing to the fact that the consumption was still in 2011-2012 practically on the level of 2005-2006.

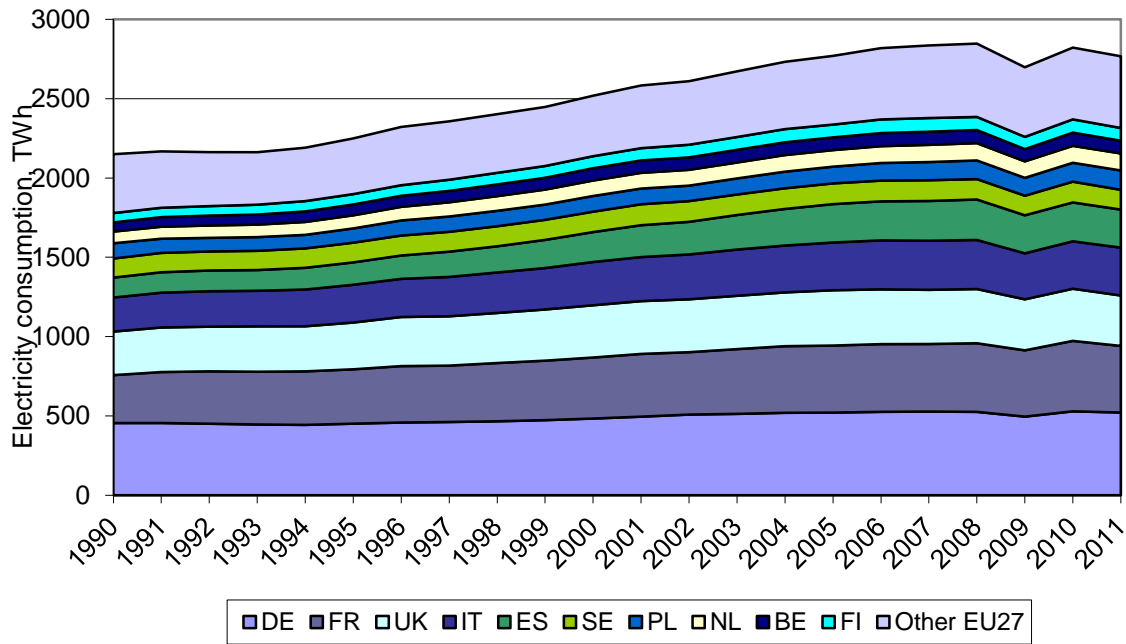


Figure 5. The EU final electricity consumption development in the period 1990 – 2011 (data source Eurostat).

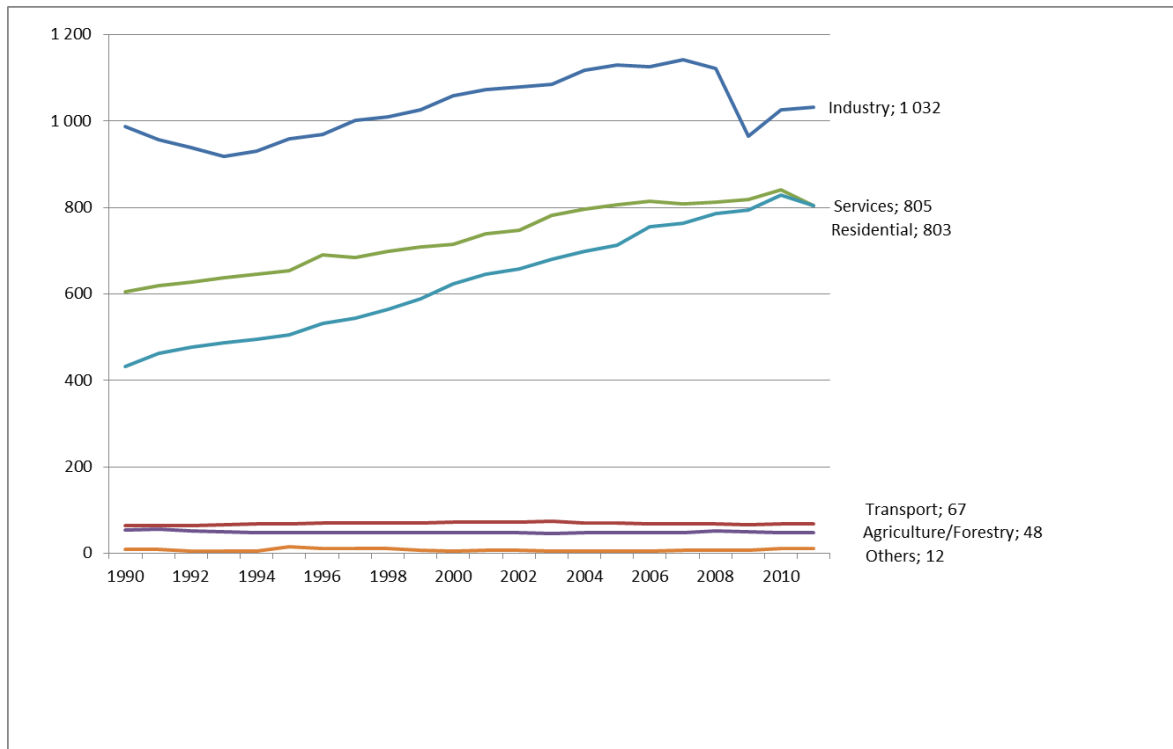


Figure 6. Final electricity consumption by sector in EU-27 in 1990-2011. The industry sector has shown little or no growth during the period. (Data source: EU Stats)

Figure 6 reveals the importance, which is seen as a deep notch due to the recession in 2009, of the industry sector for the European final electricity consumption development. In other sectors, the consumption trend has been smoother in comparison. The household sector has shown the strongest growth since 1990, nearly doubling to 2010, but the service sector also shows an upward trend until 2011.

Electricity final energy demand in different scenarios of the EU Impact Assessment (EC 2011c) of the Energy Roadmap 2050, are shown in

. Industry demand increase significantly in the Reference scenario and in scenario 1bis (i.e. the Current Policy Initiatives scenario), but remains quite stable in all other scenarios. The transport change is multifold in most scenarios and it is equivalent to approximately 200 Million cars. Interestingly enough, households consume more in 2050 in all scenarios.

3.2.2 The Nordic Demand

The Danish, Swedish and Norwegian electricity demands⁵ have been on a quite stable level for some time, see for example Figure 7, allowing of course for fluctuations from year to year. The Nordic demand was lower in 2011 than in 2002. The demand is, however, affected by the global economic recession started in 2008. The Nordic demand is also quite receptive to both the temperature and the hydrological year. The stable demands might be expected to stay more or less stable, although energy efficiency measures are stepped up, as energy efficiency measures are expected to lead to an increased electrification of energy use and thus counterbalance the savings reached in electricity use. However, there are structural changes that might have a large impact. Finland has had a steadily increasing demand that now has been affected by the recession quite harshly, including permanent structural changes in the pulp and paper sector. The increasing use of heat pumps is a structural change, but as can be seen in Koreneff et al. (2009) and in Laitinen et al. (2011), heat pumps in an electric heated houses achieve electricity savings while heat pumps in an, for example, oil heated houses lead to an increased use of electricity. The net effect might not be that large. As for electric vehicles, even a million electric vehicles in the Nordic countries has only a small, roughly 3 TWh effect on the electricity demand (Koreneff et al. 2009, Ruska et al. 2010).

⁵ Demand can be defined in a multitude different ways depending on purpose of its use. In this report we see demand as the net production plus imports minus exports. Not all sources do that, so demand may include power stations' own use, or exclude irregular usages such as, for example, price dependent extra consumption, for example large scale electric boilers. Demand can be climate corrected or not, or even restricted to final energy use. Many sources do not state clearly what kind of definitions they use, which makes it difficult to compare different estimates with each other.

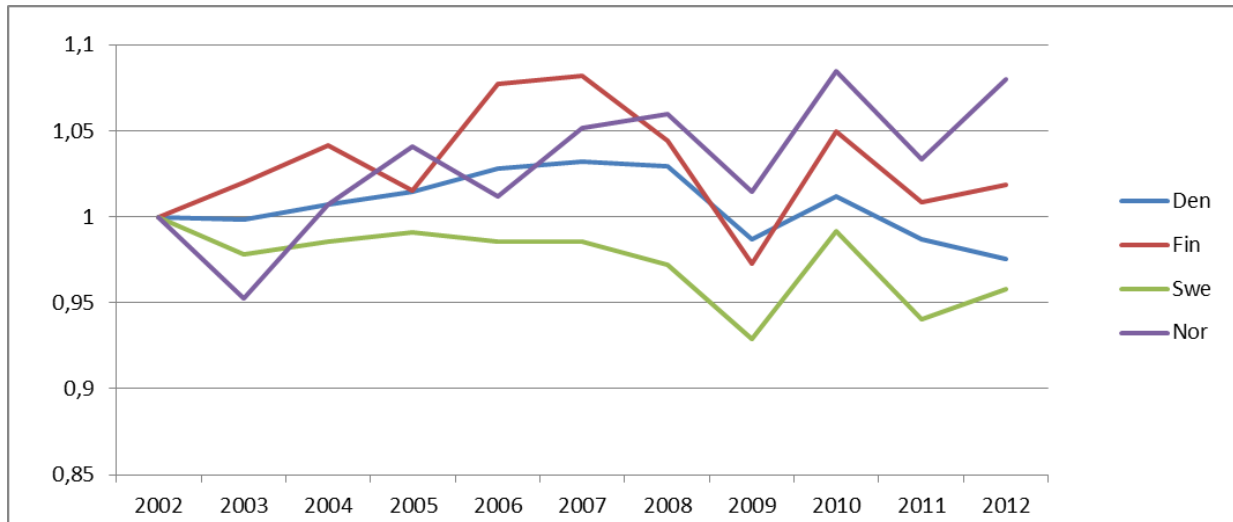


Figure 7. The net electricity demand 2002-2012 in the four Nordic countries (Data source: EU statistics 2013, National statistics 2013)

The Finnish Ministry of Employment and the Economy estimates in newest energy and climate strategy background report (TEM. 2013b) that electricity demand will grow from 88 TWh in 2010 to 94 TWh in 2020 and to 102 TWh in 2030. Over 60% of the growth will come from the industry sector (incl. construction), while the consumption for living will remain constant. Here a decrease in appliance demand is counteracted on by an increase in electric heating.

One modern trend is auxiliary or standard of living influenced heating&cooling. The main heat source may be something else, but ventilation may be electrically preheated, bathroom floors can be electrically warmed and heat pumps can be used in the summer for cooling.

The Nordic power market is assumed to offer lower market prices than Europe in general, due to extensive hydro, nuclear, wind and also CHP production, which can be a magnet for energy intensive industry such as aluminum factories. However, CO₂ emission costs as well as fuel costs in the EU might push energy intensive industry to more inexpensive areas such as developing countries or even the USA, where the gas prices at the moment are manifold lower than in the EU thanks to their shale gas revolution.

3.3 Supply: new renewable power generation capacity – expectations and reality for 2020 and beyond

3.3.1 Power generation capacity trends in Europe

The EU target of getting 20% of the energy from renewables by 2020 has strongly affected the power sector. New renewables, like wind and solar, are pushed to the market with all kind of subsidies, with feed-in tariffs (FIT) being the most prominent support manifestation.

European RES-E power generation capacity is increasing rapidly with Germany as main the increase driver, although it should be noted that the Nordic countries have been and are near or at the top of their genre with Danish wind power, Finnish bio power, and Norwegian and Swedish hydro power.

Another important factor is the relation to nuclear power. Germany has decided to phase out their nuclear capacity by 2022, having already shut down 8 units in the wake of Fukushima. German plans to replace nuclear with renewables. Of course, at a time when greenhouse gas mitigation is seen as the top priority by many, the renewables could have been better of replacing coal or other fossil fuel production. Instead, coal power production has increased in

Germany. France might be on the same road, with president Hollande's election promise to reduce nuclear capacity. UK has taken a different road, where non-fossil production, including nuclear, is seen as the target.⁶

Shale gas in USA has also affected Europe. Although there is now more LNG on the market outside USA, Japanese decision to close nuclear power plants in the aftermath of Fukushima has led to increased import of LNG eating the freed resources. But the shale gas revolution has led to US of A shifting its power production from coal to gas, freeing coal to the market. This has led to lower coal prices and, together with low CO₂ prices, to an increased use of coal in the European power sector. Gas power producers are having a hard time, both with coal and with RES-E gnawing away on their operation time, and have raised demands for support for gas.

The tighter emission (SO₂, NO_x, particulars) restrictions for power plants by the EU's industrial emissions directive (IED 2010/75/EU) is leading to older thermal power plants exiting the system. With the introduction of large scale intermittent RES-E, wind and solar, the demand for regulable power production is increasing. There is a threat that the producers in Europe do not see a business case for controllable and regulable capacity, for example refurbishing older plants to meet the new restrictions, without some sort of capacity mechanisms. The constant political meddling with most European power markets has led to a situation where almost all new capacity has to be supported, raising the question of if this is a market anymore or a planned economy. The Nordic market has fared better and has still a possibility of continuing as a genuine market.

In the IA to the Energy roadmap 2050, the European Commission's study estimates capacity developments in different scenarios. The installed capacity increases in all scenarios compared to the Reference scenario due to the additional balancing and power reserve capacities needed for the variable RES which increase significantly in all scenarios compared to the situation in 2005 (Figure 8). The most notable variable RES growth is seen in solar, and, especially, wind power. All scenarios still have fossil fuel fired power plants as installed capacity, which are used mainly as back-up. The share of CCS capacity in thermal power plants for the decarbonisation scenarios ranges from 12% to 48%. (EC 2011c). Figure 9 on electricity production reveals the effect of lower capacity factors of variable RES. That is, even though there is considerably more capacity, 53%, in scenario 4, ("High RES"), not that much difference is seen in electricity production, 4%.

⁶ UK is in negotiations with producers of what guaranteed price can be offered to new nuclear capacity. The British government is offering a strike price of 90 £/MWh while the producers are asking for 93 £/MWh, according to Financial Times' article "Hinkley Point nuclear reactor deal expected 'within weeks'" on Oct 2, 2013.

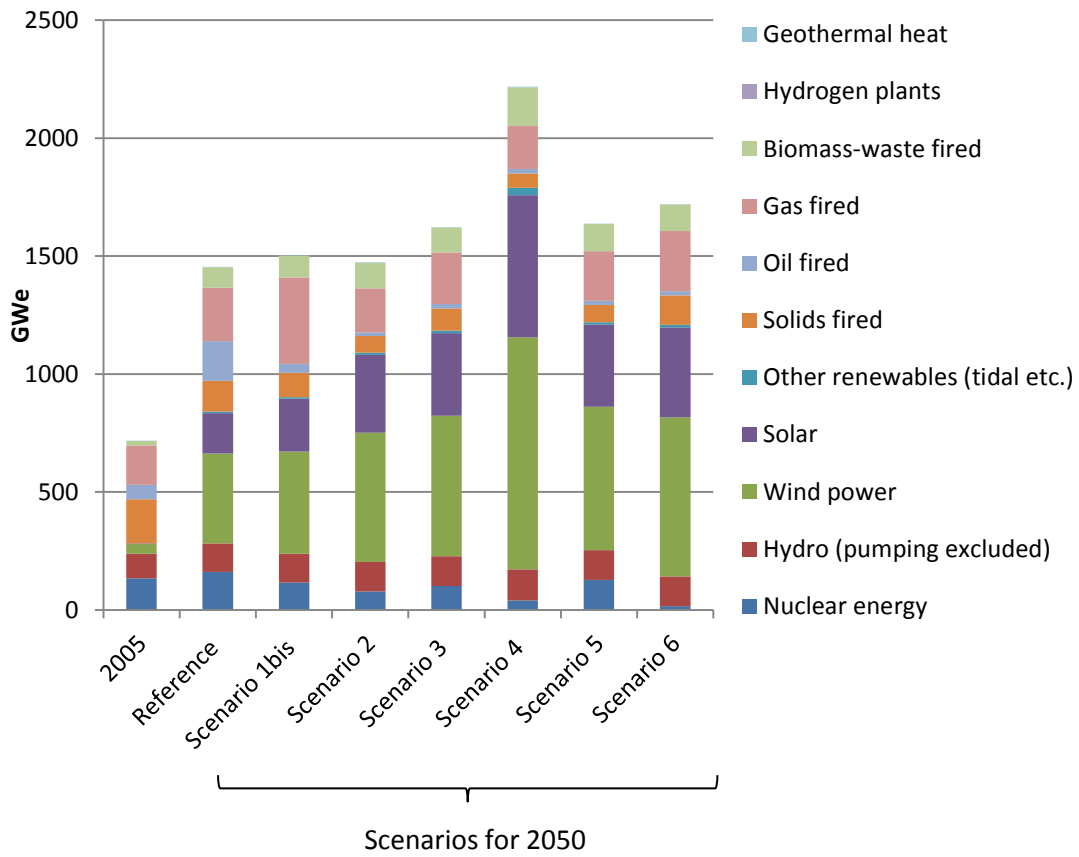


Figure 8. The Reference, Current Policy Initiatives and the five decarbonisation scenarios of the power capacity in EU in 2050. (EC 2011c)

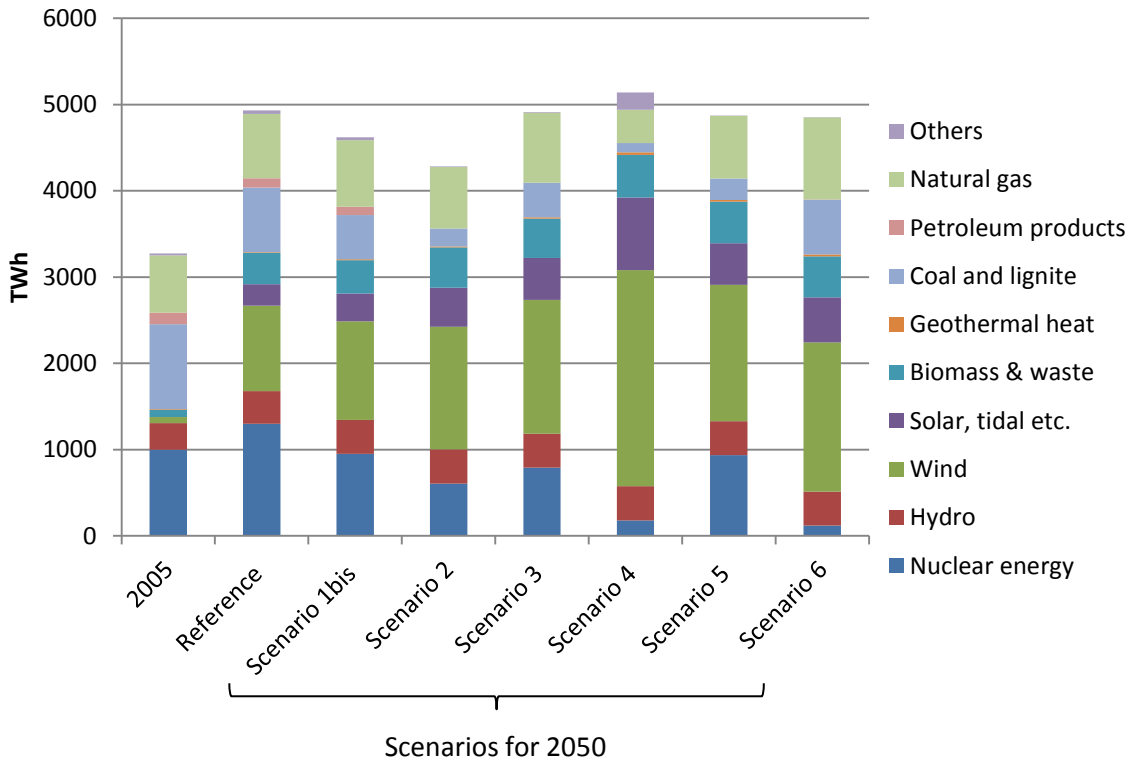


Figure 9. The Reference, Current Policy Initiatives and the five decarbonisation scenarios of the electricity production by source in EU in 2050. (EC 2011c)

3.3.2 RES-E in Europe

EU is on the way to meet the NREAP targets by 2020. Capacity development for wind and photovoltaics is shown in Figure 10. In Figure 11, the production of electricity by wind, biomass and PV is shown in relation to European Technology Platforms Visions for 2030 (PV-TRAC 2005, EWETP 2006.) Interestingly, if current growth rates can be maintained, the visions seem achievable. Current Policy Initiatives scenario assesses the solar power capacity to 224 GW in 2050, whereas the preliminary figure for photovoltaic capacity was 68 GW in 2012. Correspondingly, for wind power, the CPI scenario figure is 432 GW for 2050, whereas the realized capacity 106 GW in 2012.

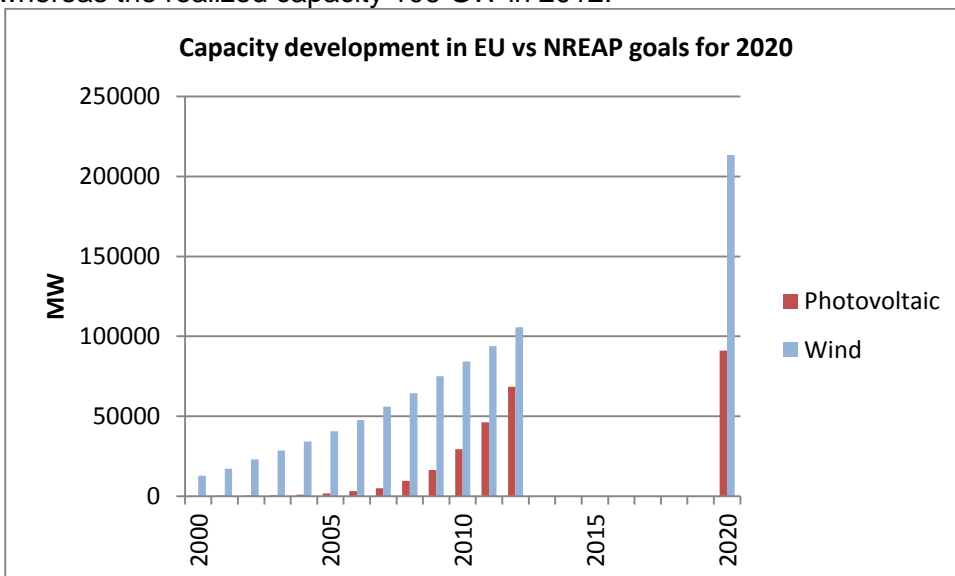


Figure 10. Capacity development of photovoltaic and wind capacity (Sources Eurostat, EurObserv'ER preliminary data for 2012)

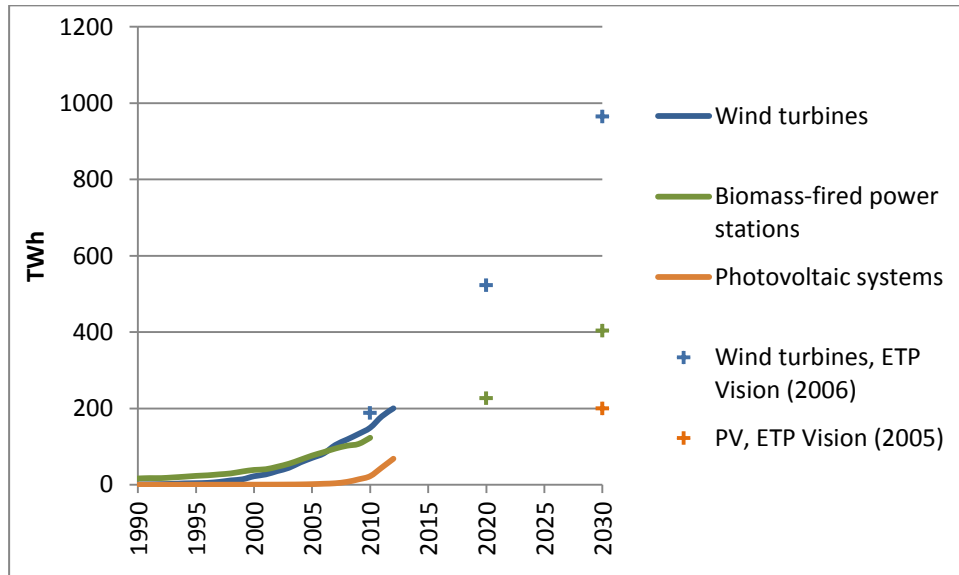


Figure 11. Electricity generation of selected renewable energy technologies and target (Sources Eurostat, EurObserv'ER preliminary data for 2012).

3.3.3 Capacity in the Nordic market

There is a large amount of new non-fossil capacity coming to the Nordic market. The Swedish-Norwegian green certificate system has a target of 26.4 TWh of new RES-E production from 2012 to 2020. Denmark has set the target of getting half the electricity from wind power in 2020 and the wind power target for Finland is at 6 TWh in 2020 and 9 TWh in 2025. New nuclear power is being built in Finland by TVO, Olkiluoto 3, by 2016 and planned by TVO, Olkiluoto 4, and Fennovoima, Hanhikivi 1, for the 2020'ies. Old plants are being heavily refurbished in Sweden this decade raising the capacity at the same time. Sweden has also a decision in principle that old nuclear power plants may be replaced with new units.

At the same time, conventional older gas and coal power plants are being retired not only because of their age, but because they are unprofitable to uphold in the long run. For example, Fortum announced in autumn 2013 that the Inkoo coal power plant, 4 * 250 MW, will be shut down for good. The EU environmental directives for SO₂, NO_x and particular emissions, beginning with the Large combustion plants directive (LCP) to the IED are forcing older plants to either costly refurbishments or early retirements.

Finland and Sweden both have a scheme for strategic reserves. Sweden's strategic reserve in the winter 2013/2014 is 1489 MW, of which 531 MW is demand side reductions (Svenska kraftnät 2013). Sweden (Energimyndigheten 2013d) is already planning to abandon this remuneration scheme by 2020.

3.3.4 The future supply of the Nordic power system

Capacity development is studied mainly on the basis of results from model runs in SGEM with VTT's Nordic TIMES, excluding Iceland, and scenarios presented in IEA Nordic Energy Technology Perspectives (IEA NETP 2013), including Iceland.

Nordic TIMES is a long-term, multi-period, partial equilibrium model that covers the whole energy production and consumption system of the national economies in the world with a

special emphasis on the Nordic countries excluding Iceland. It is based on the TIMES modelling framework developed in the IEA Energy Technology Systems Analysis Programme (see Loulou et al. 2005 and Loulou and Labriet 2007). It determines a solution that minimises total costs, including investments, over the study horizon.

The scenario of the future is the same as presented in Pursiheimo et al (2013). Nordic TIMES runs to determine the capacity development in the Nordic countries is presented in Figure 12. One of the main questions of the future is how well will CHP keep its competitiveness and its demand in the future. The results show that district heat CHP decreases in Finland and Denmark, but increases in Sweden. On the other hand, industrial CHP more or less increases in the time span.

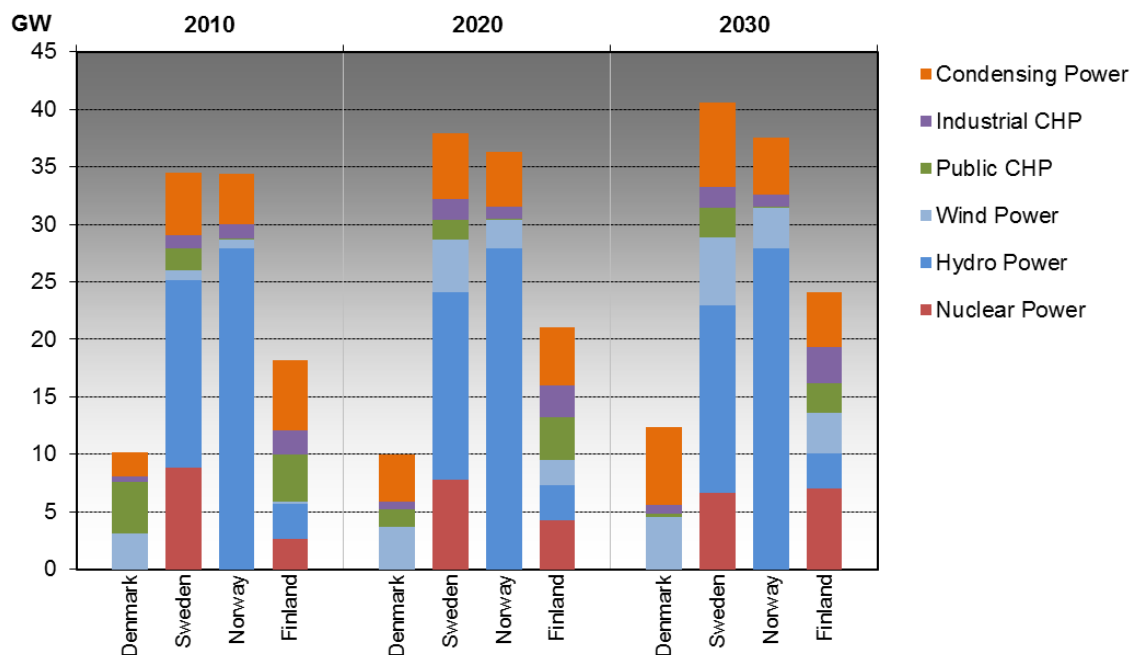


Figure 12. The power capacity development in the Nordic countries 2010-2030 according to Nordic TIMES.

Danish reduction in CHP capacity is related to the out phasing of coal, as it is coal CHP that mainly disappears. One of the interesting questions is regarding district heating: how will the demand for district heat develop taking into account the energy efficiency improvements in housing and competitive new heat sources such as heat pumps? And if the heat demand doesn't diminish noticeably, will it be produced using CHP or large scale heat pumps, solar heat, heat boilers or waste heat? Especially turning away from coal might lead to smaller CHP power productions, as gas may not be that competitively priced, alternative fuels such as biomass and waste might have locally restricted availability and the market price for electricity can turn out to be low compared to the costs. IEA NETP (2013) presents estimates for the coming decades for the development of district heating in the Nordic countries, see Figure 12.

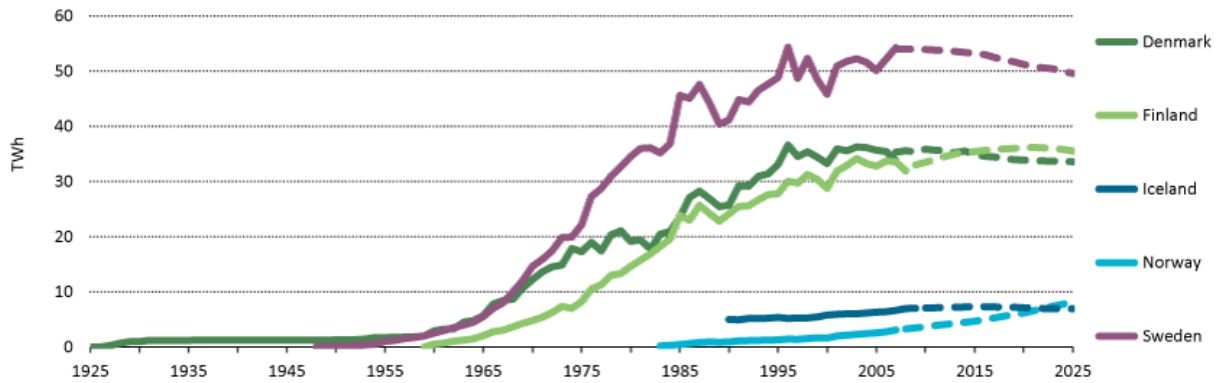


Figure 13. Development of district heating in the Nordic countries and estimates for the coming decade. Source: International Energy Agency (2013), Nordic Energy Technology Perspectives, OECD/IEA, Paris.

Sweden and Denmark experience a downward trend, while use in Norway may grow. Finland has reached saturation.

IEA NETP (2013) gives much stronger capacity development for the Nordic countries than our Nordic TIMES estimates, see Figure 14.

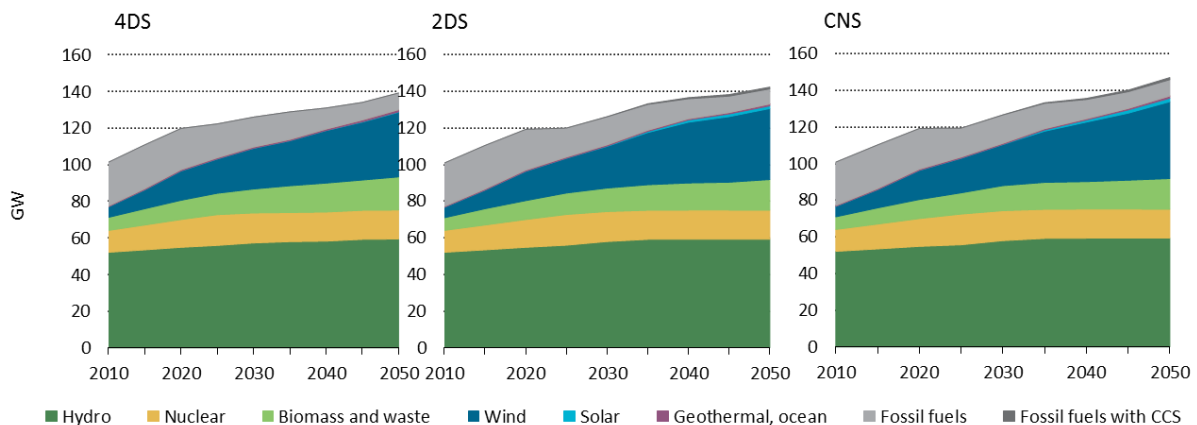


Figure 14. Nordic (including Iceland) capacity development 2010-2050 in three different scenarios. Source: International Energy Agency (2013), Nordic Energy Technology Perspectives, OECD/IEA, Paris.

Energy produced by production type according to Nordic TIMES results is presented in Figure 12. District heat CHP will decrease by 30% to 2020 and by 38% to 2030. Where the TIMES results for district heating CHP in Finland is showing a clear downward trend, the background report to the national energy and climate strategy (TEM 2013b) shows a more modest reduction, 0.6 TWh by 2020 and 1.4 TWh by 2030. SKM Market predictor (2012) estimates that Finnish DH CHP will retain its competitiveness and remain stable up to 2035.

Nordic TIMES estimates that industrial heat CHP will increase with 11% to 2020 and 17% to 2030. However, in Finland there are expectations of an increase of 16% to 2020, although (TEM 2013b) in contrast shows a decrease of 10%. The net CHP effect of the Nordic TIMES is a decrease of CHP electricity production by 11% (8 TWh) to 2020 and by 17% (10 TWh) to 2030.

The Swedish long term prognosis (Energimyndigheten 2013b) estimates 50%, mainly DH CHP, more CHP in 2020 than Nordic TIMES and 10% more in 2030.

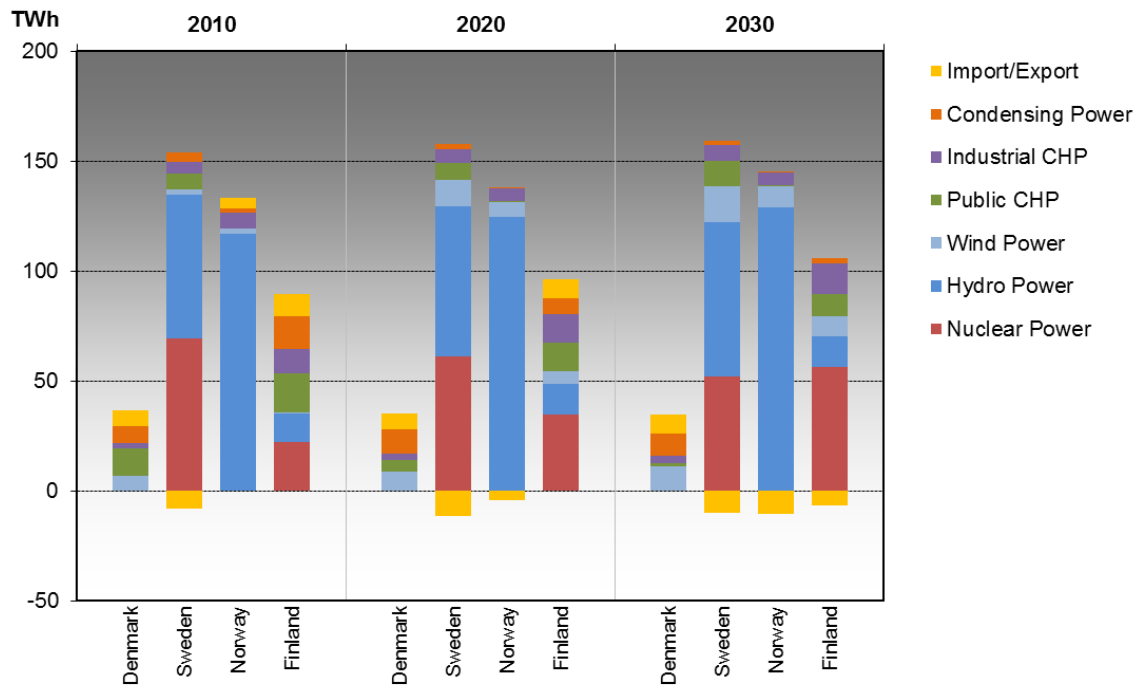


Figure 15. The development of electricity production in the Nordic countries 2010-2030 according to Nordic TIMES results.

The Nordic countries will turn net exporters around 2020. For Finland it will happen after the fifth and sixth nuclear reactors are ready. IEA NETP (2013) estimates that the Nordic countries will be net exporters with 20 TWh to 30 TWh by 2020 and might even be net exporting 60 TWh by 2035. The production according to fuel is presented in Figure 16. Wind is the main increase factor, but also electricity from hydro, nuclear and biomass will increase and only use of fossil fuels decrease. According to these results, PV is not seen as a large-scale Nordic solution.

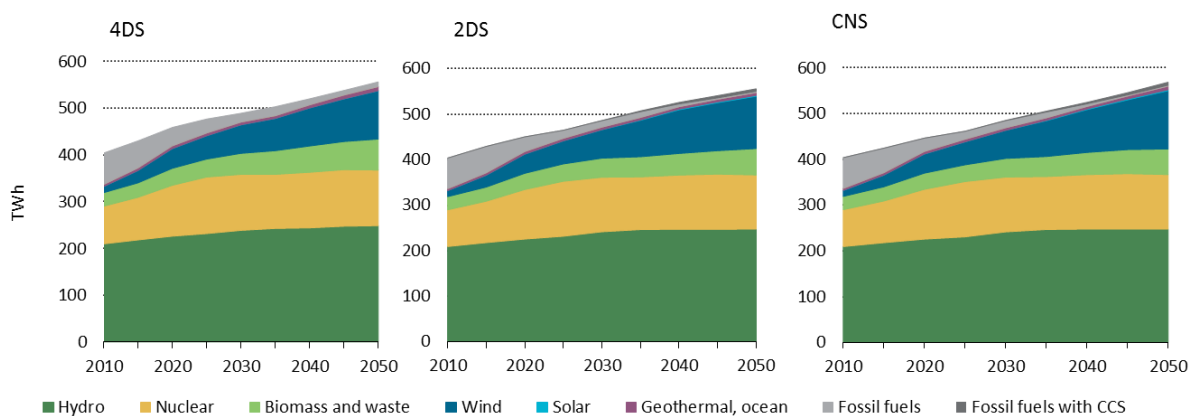


Figure 16. Nordic (including Iceland) electricity production development 2010-2050 in three different scenarios. Source: International Energy Agency (2013), Nordic Energy Technology Perspectives, OECD/IEA, Paris.

3.4 Natural gas market trends

3.4.1 Market interaction

Gas markets are regional, not global, due to the low energy density of gas. Low energy density means large infrastructure needs in the supply line: production, transportation and delivery. Infrastructures, such as long-range transportation routes both by pipeline and as LNG, are expensive and form natural barriers for mercantile interaction. Figure 17 shows the trends for regional gas prices during the last years.

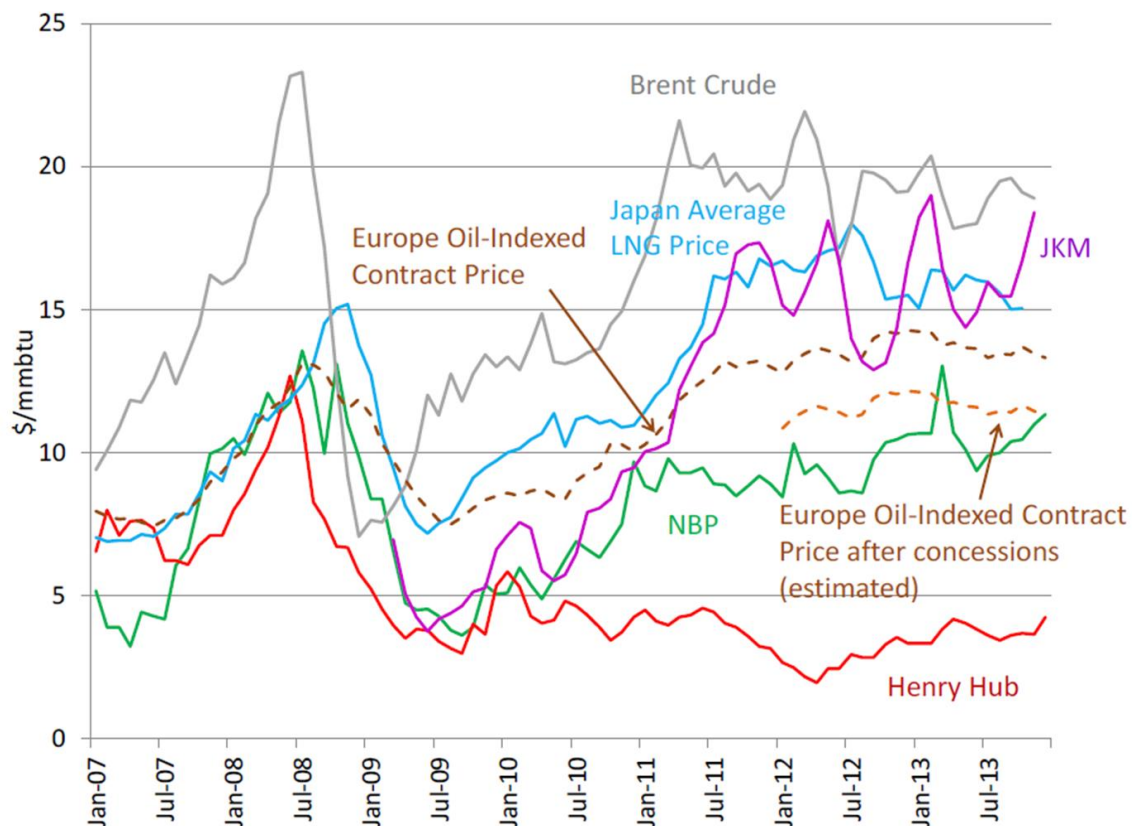


Figure 17. Regional monthly average gas prices (JKM = Japan Korea price marker. NBP= National Balancing Point in the UK). (Rogers&Stern 2014)

At the beginning of 2010 the Henry Hub⁷ price separated from the general development path. This is the consequence of the shale gas boom: abundant gas supply keeps the gas prices low in the US. There the shale gas production has reduced both the price of gas and gas imports. Natural gas has gained more market share in electricity generation by displacing coal. This in turn has led the American coal industry to increase exports of coal that would normally have been consumed within the US.

The same fuels compete for market share in electricity generation also in Europe. Coal is mainly used for electricity production in Europe. The amount of additional coal capacity being constructed or planned in Europe ranges from 10 GW to 50 GW depending on the data source. In addition to these new plants, some of the coal power plants that were expected to close are being refurbished and their lifetime extended and this constitutes a risk related to climate change mitigation.

⁷ Henry Hub is the main gas trading hub (market place for the layman) in the US of A.

But, as Figure 18 shows, the European gas price trend differs from that in the US giving coal a better competitive position in Europe when compared to natural gas. But the price ratio between gas and coal is not the only reason why coal has become an economically interesting option for power production in the EU. Other reasons are the economic crisis and the rapid increase of renewables in energy production that have contributed to the GHG emissions decrease. As a consequence of these factors, carbon prices have decreased towards €5 and below per ton of CO₂. The outcome of all this is that the EU has been the recipient of much of the US coal exports leading to increased coal consumption, Figure 18.

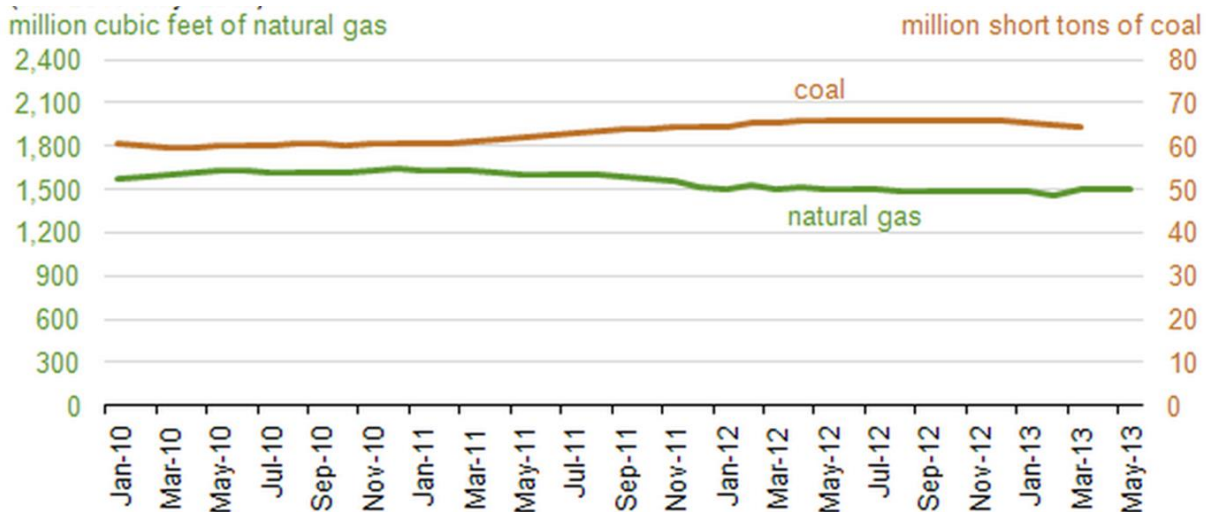


Figure 18. OECD-Europe natural gas and coal consumption, 12-month moving averages (EIA 2013).

3.4.2 LNG market trends

In this section we shall study the interplay with the market prices and the destinations of LNG cargos.

Figure 19 shows global LNG trade-flows in the period 2004-13. The green area above the axis represents Atlantic Basin-sourced LNG delivered to Atlantic Basin Markets. The blue area represents Pacific Basin LNG delivered to Pacific Basin markets. The yellow area above the axis represents Middle East LNG delivered to Atlantic Basin Markets, and the yellow area below the axis shows Middle East-sourced LNG delivered to Pacific Basin Markets. The green area below the axis represents Atlantic Basin-sourced LNG delivered to Pacific Basin markets. For the 'tight' period for Asian LNG markets from 2006-08, relatively little Middle Eastern LNG reached Atlantic Basin Markets; and significant volumes of Atlantic Basin LNG were drawn into the Pacific Basin reaching a maximum in March 2008.

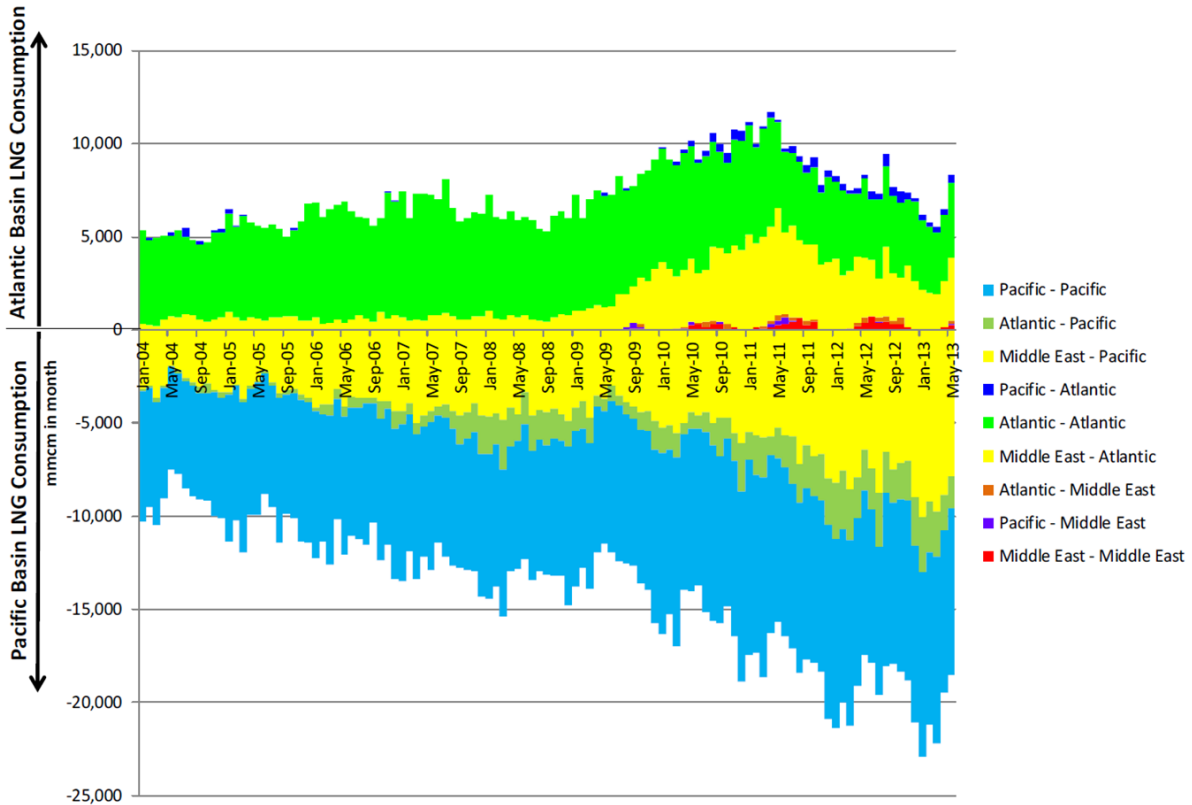


Figure 19. Regional LNG sources and destinations by month 2004-2013. (Rogers&Stern 2014).

The financial crisis of 2008 and its impact on economic development reduced gas consumption. US LNG imports, which had been expected to reach 70 bcm by 2010, were reduced from nearly 18 bcm in 2005 to 4.2 bcm in 2012 due to the unforeseen growth in shale gas production. The new Qatari trains came on stream in mid-2009, reaching full capacity in 2011 in addition to projects in Yemen, Sakhalin and Indonesia. Some of these volumes were originally intended for the US market where 183 bcma of LNG import capacity had been built. The net consequence was a boost in LNG deliveries to Europe during 2009-11. Gas demand was low in both 2009 and 2011, so that these European LNG imports resulted in a reduction in pipeline imports mainly from Russia, despite the increase in the demand 2010 due to abnormally cold weather.

From Figure 19 it is apparent that from 2011 onwards, growth in Asian LNG consumption (NB: Japanese shut down of nuclear power plants in the wake of Fukushima) has resulted in LNG being re-directed away from Europe. Price of course is the prime motivator which provides the incentive for new supply development, and for LNG arbitrage between different markets (OIES NG-58).

3.4.3 The evolution of natural gas price formation

North America

In the 1980s, the US was the first country in the world to move to spot (market) pricing at a hub by removing regulation of upstream and midstream pricing and liberalising access to pipelines. Once market pricing had been established, on the basis of Henry Hub spot and after 1990 NYMEX futures prices, it was not commercially feasible for any supplies to be delivered on any other price basis. This meant the end of long term contracts and currently that term applies in North America to any commercial agreement in excess of one year.

North American gas deregulation led to more than a decade of low, market-related prices in the \$2-3/MMBtu range which finished at the end of the 1990s. From then until the mid-2000s, US gas prices fluctuated wildly, exceeding \$12/MMBtu in early 2006 and again in early 2008, until the unconventional (principally shale) gas era, ushered in a period of lower prices which during 2012-13 were in the range of \$2-4.20/MMBtu.

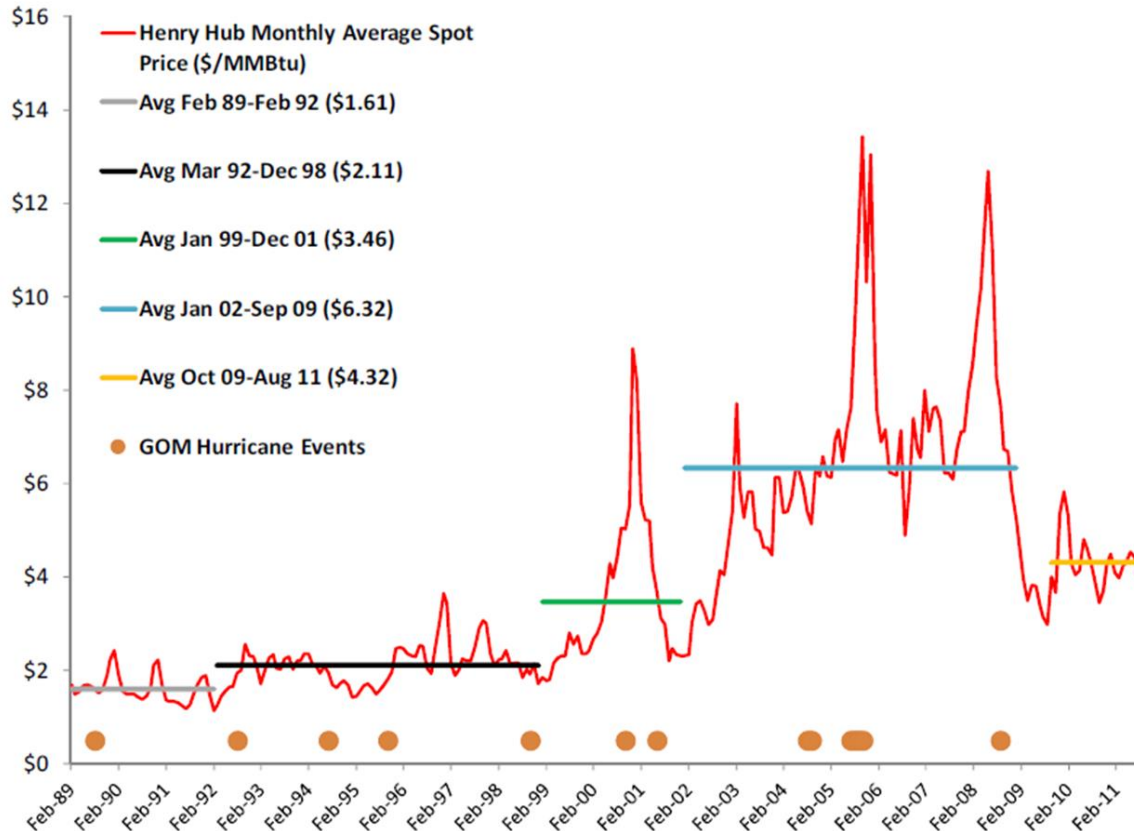


Figure 20. Henry Hub price eras. (Foss 2013).

North American gas prices are driven primarily by the supply and demand fundamentals of the domestic gas market. In anticipation of US LNG export projects from 2015 onwards, there has been much discussion of the future impact on domestic US prices due to varying export volumes. Whilst this has generated much debate and analysis it should be recognised that forecasts of the speed and extent of any associated price rise are the subject of many assumptions. Even with no LNG exports from the US, gas prices would eventually have to rise to the long run marginal cost of dry shale gas production to meet demand requirements, estimated to be in the range \$5-7/MMBtu.

Europe

The UK market was liberalised during the 1990s and by the end of that decade it had created the National Balancing Point (NBP), a hub with a reference price across the whole country. In the UK, as in North America, traditional long term take or pay contracts disappeared as liberalisation advanced. In general contracts are of short duration and are priced at the NBP.

Continental Europe began the 2000s with a commercial structure dominated by long-term (15-25 year) oil indexed contracts for pipeline and LNG imports, and also for domestic production. The price of pipeline gas purchased under long term contracts was typically based on gasoil and fuel oil prices and indexed to a lagged six to nine month average of those prices. The buyer committed to purchase the 'Take or Pay' (TOP) quantity within a

contract year. The TOP level was typically 85% of the Annual Contract Quantity (ACQ). Similar approach was taken in long term LNG contracts in Continental Europe.

The impact on European gas demand of the post 2008 recession, coupled with an increase in renewable energy generation, and the arrival of significant volumes of LNG created severe financial problems for the European mid-stream utilities who were obliged to purchase gas under long term contracts priced on a formula linked to oil products. The development, and increase in liquidity, of trading hubs across the Continent was boosted by the arrival of large volumes of hub-priced LNG imports, the impact of unbundling and third party pipeline access and court rulings which ended the obligation of end-users to buy gas from midstream utilities on a multi-year, oil-linked pricing basis.

With European hub prices 25-35% below oil-indexed contract levels during 2011-13, mid-stream utilities were faced with unsustainable financial exposure in their gas trading operations, and a series of price re-negotiations with upstream sellers and international arbitrations ensued. Although in late 2013 this process was still ongoing, Gastera (Netherlands) and Statoil (Norway) have largely accepted that a move to a hub-priced business model is inevitable. Gazprom (Russia) has introduced a system of base price reductions and rebates to customers which have brought their prices down to hub levels in competitive markets. Sonatrach (Algeria) is believed to have made few concessions and is in arbitration with many of its customers.

In 2012, different regions of Europe had very different price formation mechanisms. In the north west which represents 50% of European gas demand, nearly three quarters of gas was priced at hub levels, while Mediterranean and South-East Europe remain dominated by oil-linked and regulated pricing. Nevertheless time series analysis of the data suggests that hub pricing is spreading across Europe and, with further development of interconnectors and the new EU network codes, this process will continue.

3.4.4 Shale gas from US to Europe?

Shale gas refers to natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States. (EIA 2012)

Although the prospects for shale gas production in the US are promising, there remains considerable uncertainty regarding the size and economics of this resource. Many shale formations, particularly the Marcellus, are so large that only a limited portion of the entire formation has been extensively production-tested. Most of the shale gas wells have been drilled in the last few years, so there is considerable uncertainty regarding their long-term productivity. Another uncertainty is the future development of well drilling and completion technology that could substantially increase well productivity and reduce production costs.

The low gas price level in US has created speculations about the possibility to import gas from US to Europe. When estimating how realistic this opportunity would be one has to replace the present Henry-Hub price with a sustainable long-term price level. It has been estimated that a price level of 5-7 \$/mmbtu could be a suitable figure. Using this estimate the break-even destination market prices for US LNG for Europe and Asia are shown in Figure 21.

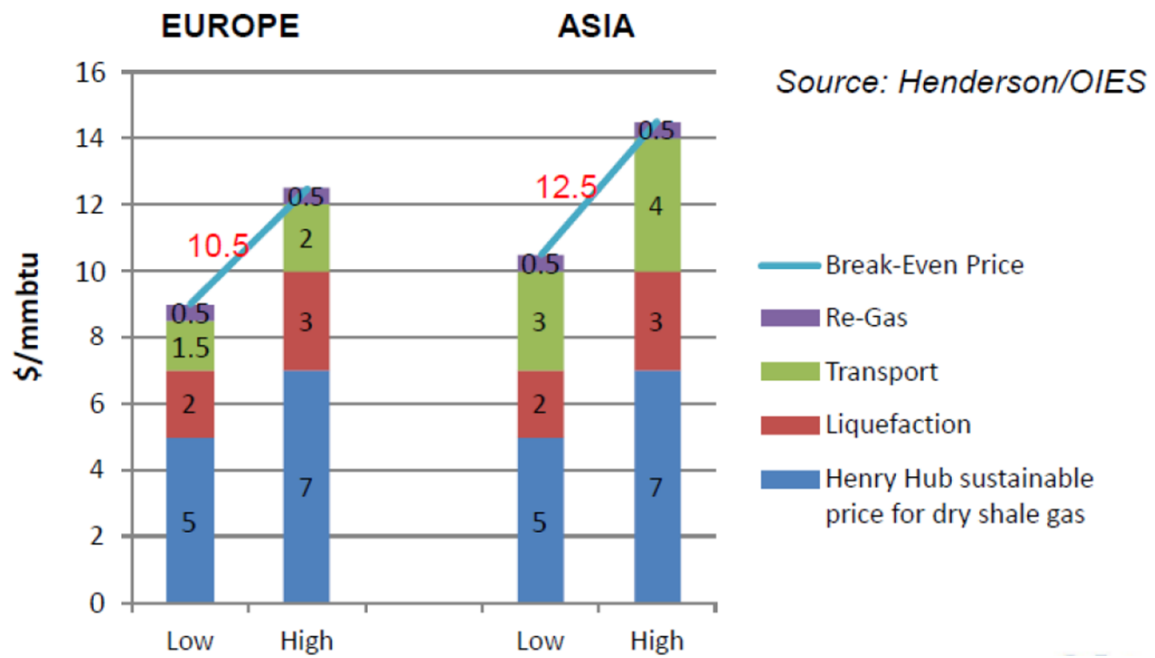


Figure 21. Break-even destination market prices for US LNG to Europe and Asia (Henderson 2012).

In Europe the minimum price ranges from 9 to 13 \$/mmbtu and in Asia it is a bit higher. Compared to the present gas price levels (Figure 17) the US LNG seems competitive. It is clear that the Asian market with its higher gas price level is the prime market for US LNG if the US starts the LNG export.

3.4.5 Shale gas production in Europe

In Europe, the largest shale gas resources are situated in Poland and in France. According to recent estimates, the deployable amount of shale gas in Europe amounts to 18 Tcm, three times that of the conventional gas.

The geological characteristics of the shale gas deposits are not as favourable as those in the US: The deposits are deeper in the ground, they contain more clay being less suitable for hydraulic fracturing and field data on these deposits is restricted.

It is not only the geology but also the institutions that form barriers for shale-gas development in Europe. Firstly, from the shale gas production point of view it is the lack of both the legal framework and general regulation on the shale-gas deployment that makes it difficult to go forward quickly. The legislation on land use and resource ownership is challenging with regard to shale-gas production. Europe is densely populated area and shale gas production is a large-scale industrial activity requiring vast areas for operations. Political acceptance varies from country to country: Countries including Poland, the U.K., Ukraine and Romania are keen to develop shale gas resources as a way to lower energy costs and reduce imports. Recent news tells that Poland is near a commercial shale gas production (Strzelecki 2014).

Secondly, the market institutions in Europe favour the incumbents rather than the new agents to enter the market compared to the US. Even if the EU strives for the new natural gas market structure, The Gas Target Model (ACER 2013), the development has been slow thus far. Table 4 below shows the natural gas reserves in Europe.

Table 4. Natural gas production, use and reserves in Europe. bcm=10⁹ m³; tcm=1000 bcm. (Forsström & Koljonen 2013)

	Statistics 2011		Reserves	Shale
	Production	Use		resources
	bcm		tcm	tcm
Poland	4.3	15.4	0.16	5.3
France		40.3	0.01	5.1
Norway	101.4	4	2.04	2.4
Ukraine	18.2	53.7	1.1	1.2
Sweden		1.3		1.2
Denmark	7.1	4.2	0.06	0.7
UK	45.2	80.2	0.25	0.6
Netherlands	64.2	38.1	1.39	0.5
Turkey		45.7	0.01	0.4
Germany	10	72.5	0.18	0.2
Lithuania		3.4		0.1
Others				0.5
Europe	250.4	358.8	5.2	18.2

3.5 Fuel and emission right prices

3.5.1 CO₂ Emissions and EU ETS

The EU Roadmap Impact assessment estimates that the price of EU Emission Unit Allowances (EU EUA) in the Emission Trade Scheme (ETS) in different decarbonisation scenarios rise to very high, as can be seen in Table 5.

Table 5. ETS price development 2020 to 2050 in different IA scenarios (EC 2011b.)

	2020	2030	2040	2050
Reference	18	40	52	50
CPI	15	32	49	51
High Energy Efficiency	15	25	87	234
Diversified supply technologies	25	52	95	265
High RES	25	35	92	285
Delayed CCS	25	55	190	270
Low nuclear	20	63	100	310

Figure 22 presents the CO₂ price in European Commission's decarbonisation scenarios and in IEA World Energy Outlook 2012 (IEA WEO 2012). We see that the variance in development in EC's scenarios quite neatly fits to that of IEA WEO until 2035, which is the last year in IEA WEO (2012). It is also seen that in the end of the period, the CO₂ price in decarbonisation scenarios reaches very high level.

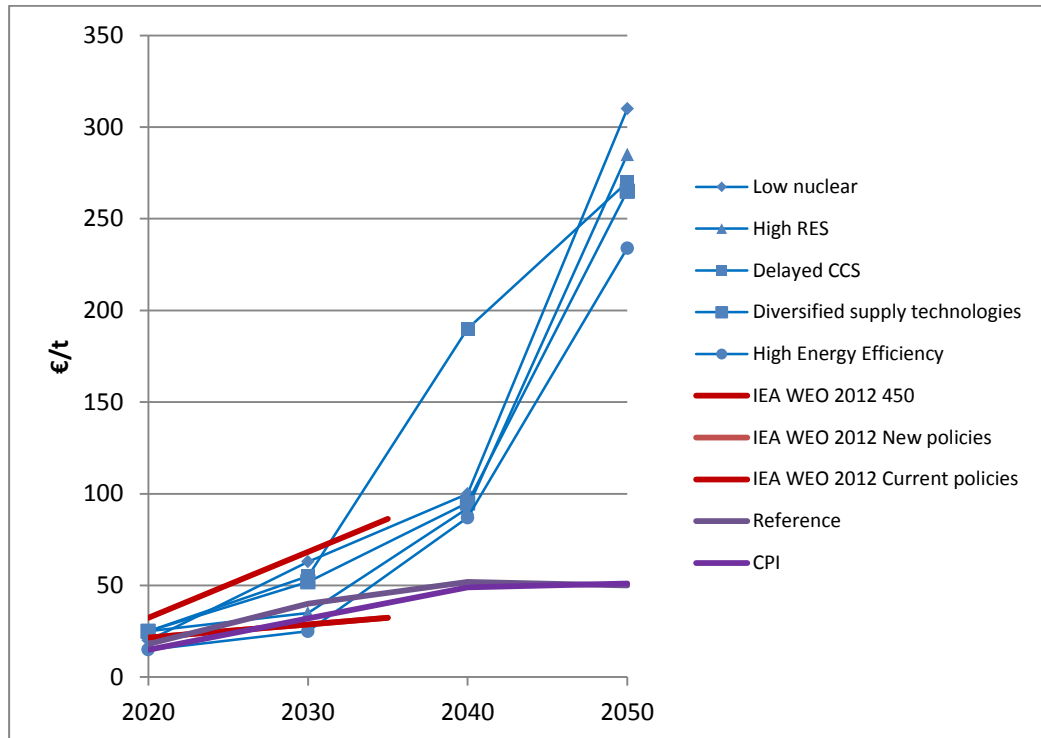


Figure 22. The development of the CO₂ price in IEA WEO (2012) and the EC (2011) scenarios (Data sources: EC 2011c, IEA WEO 2012). Please note that estimates from different years present the nominal value.

Regarding the development of the CO₂ prices, EU Roadmap Impact assessment also includes comparisons of assumptions and results of different scenario studies (Figure 23). Depending on scenario, according to these studies we can see CO₂ prices reaching a level of 100 €/t by 2050.

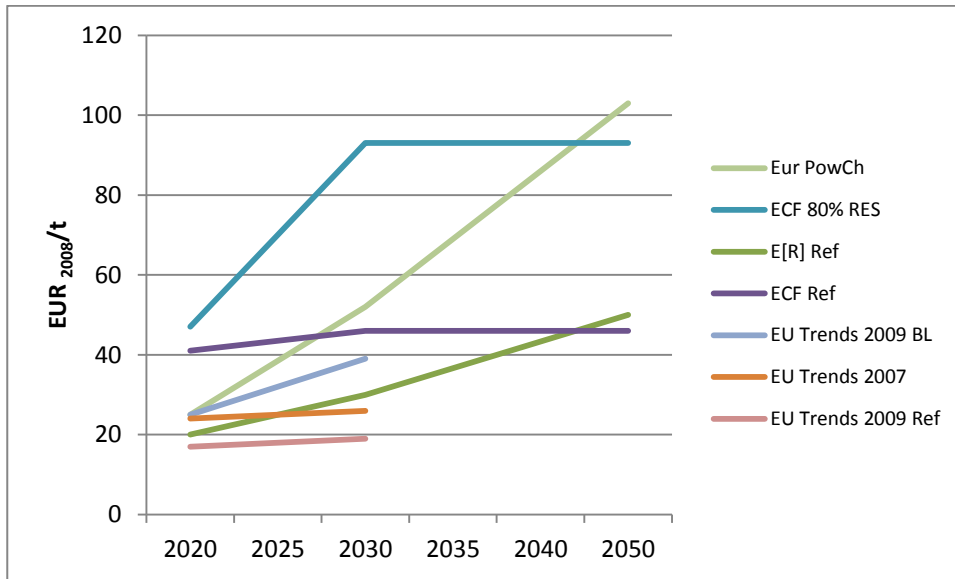


Figure 23. The development of the CO₂ price in EUR₂₀₀₈/tCO₂ according to selected different sources. (Data source: EC 2011c).

3.5.2 Fuel prices

The IA also gives price estimates for fuels. The price development in the Reference case is shown in Figure 24, which also shows more recent assessment from Current policies scenario in IEA WEO (2012) in comparison. Coal is assumed to remain cheap compared to oil and gas.

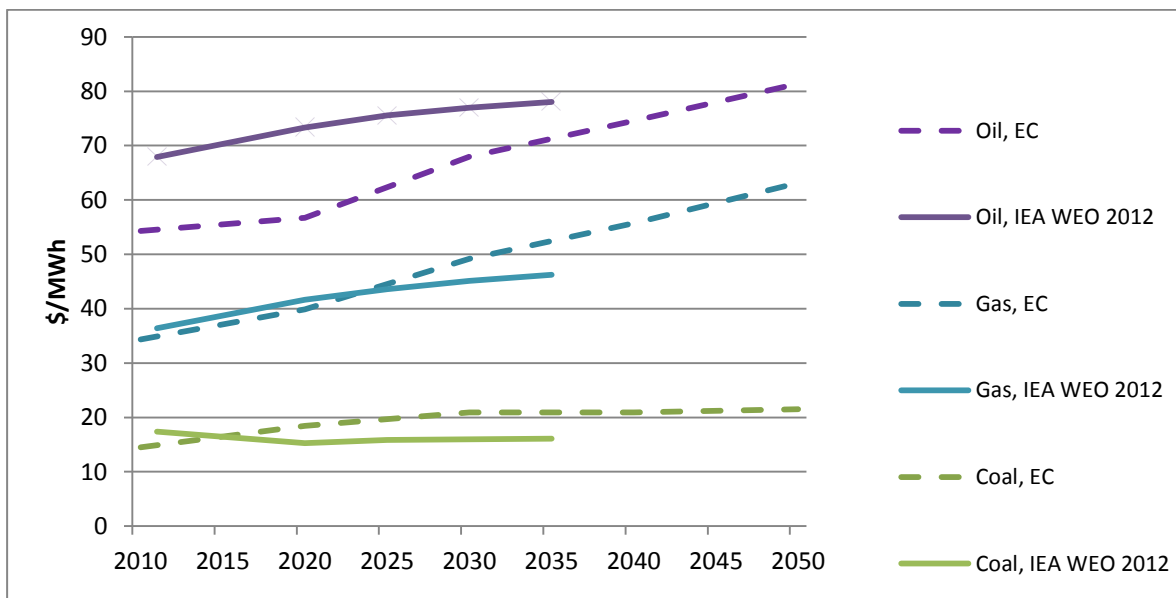


Figure 24. The price development in the Reference scenario of the Energy roadmap 2050 Impact Assessment and in Current policies scenario in IEA WEO (2012) (Data sources: EC 2011b, IEA WEO 2012). Please note that estimates from different years present the nominal value.

Interestingly, the gas price rise seems more modest in the more recent IEA New Policies and Current Policies scenarios. Thus, taking also into account that the IEA scenarios present the variance in EC's scenarios quite nicely until 2035, we use fuel and CO₂ prices forecasts according to IEA World Energy Outlook (IEA WEO 2012) as model inputs in order to assess the Nordic electricity market price for 2020/2035 (see Chapter 4).

4. Nordic electricity market price estimates 2020/2035

The price scenarios are done using VTT's Electricity market model, VTT-EMM.

4.1 Assumptions

We look at the future price development in Nordic electricity market with the help of scenarios. For that, we have to make some assumptions about the demand and supply capacity development as well as about interconnections, fuel prices and the price of EU EUA's.

4.1.1 Demand

The main estimates for Nordic net demand (= net production + imports – exports), in normal climate conditions, in the SGEM calculations are shown in Table 6. These can be compared to estimates by SKM Market Predictor (2012) and IEA NETP (2013) in Figure 25. SKM Market Predictor estimates the Nordic demand to be 436 TWh in 2035 whereas IEA NETP⁸ (2013) calculates with 429 TWh in the 2 degrees scenario (2DS), 454 TWh in the 4 degrees scenario (4DS) and 421 TWh in the Carbon neutral scenario (CNS). SKM Market Predictor has, however, higher estimates for Finland than the most recent Finnish Energy and climate strategy (TEM 2013 b) assumes and the estimates already for 2020 for both Norway and Denmark exceed the national renewable energy allocations plans (NREAP Norway 2012, NREAP Denmark 2010).

The estimates for 2020 are derived from national estimates (NREAP Sweden 2010, NREAP Denmark 2010, NREAP Norway 2012, TEM 2013a). The estimates for 2030 and 2035 are partly based on national sources (TEM 2013b, Pursiheimo et al. 2013, Energimyndigheten 2013 b) and partly on adjustment of 2010-2020 trends as well as of trends for 2020-2035 as seen in more general estimates (SKM Market Predictor 2012, IEA NETP 2013).

Table 6. Main Nordic net demand estimates⁹ as used in the SGEM calculations in this report.

Demand TWh	2010	2020	2030	2035
Finland	87	93	99	102
Sweden	144	147	150	150
Denmark	35	36	37	37
Norway	128	126	129	130
SUM Nordic	394	402	415	419

⁸ IEA NETP (2013) estimates the development of the final energy demand. This has been converted net demand as used in this report.

⁹ The climate adjusted data for 2010 is mainly from national sources (Sveriges riksdag 2012, Energiategollisuus 2011, NVE 2011, DEA 2012) with or without help from EU statistics (2013). The estimates for 2020 are derived from national estimates (NREAP Sweden 2010, NREAP Denmark 2010, NREAP Norway 2012, TEM 2013a). The estimates for 2030 and 2035 are partly based on national sources (TEM 2013b, Pursiheimo 2013, Energimyndigheten 2013 b) and partly on adjustment of 2010-2020 trends as well as of trends for 2020-2035 as seen in more general estimates (SKM Market Predictor 2012, IEA NETP 2013).

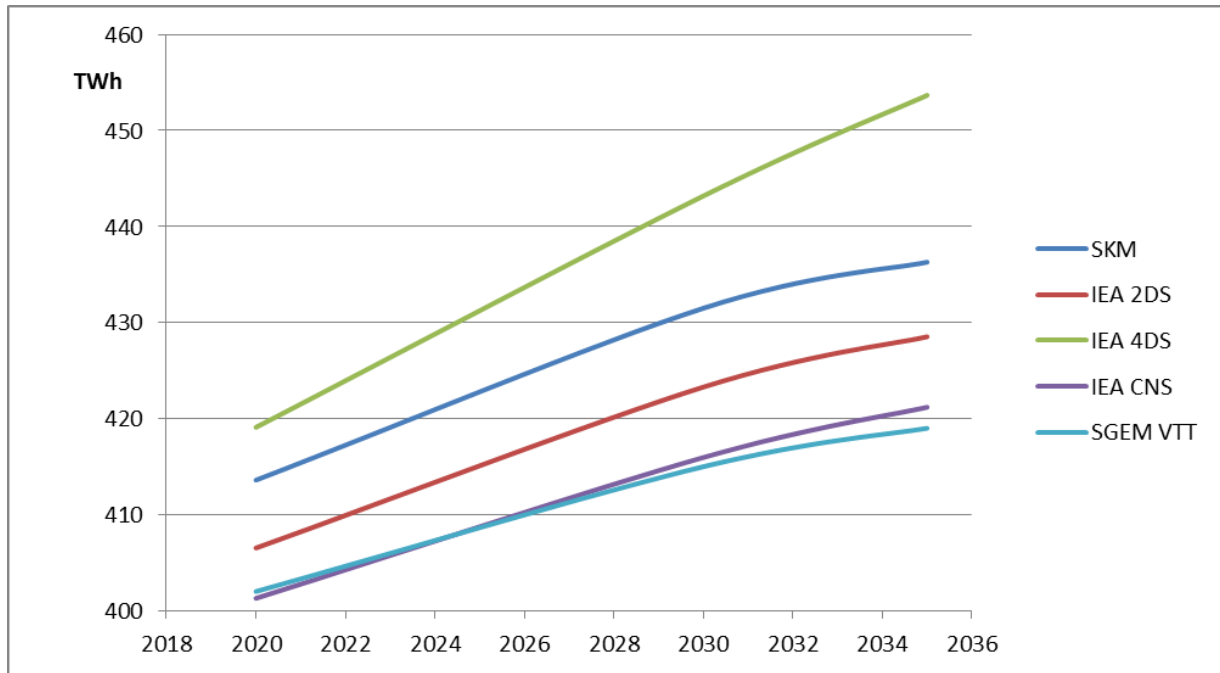


Figure 25. Estimates for the Nordic demand development between 2020 and 2035 of this report and by different sources (IEA NETP 2013, SKM Market Predictor 2012). The IEA estimates in this figure are assessments by the author, as IEA only estimated the final energy use in their report.

4.1.2 Capacity

We assume in these scenarios that from 2014 the Nordic countries will have roughly 30 TWh new renewable electricity production by 2020 and 55 TWh by 2035. Up to 2020 there will be

- 6 TWh new hydro power
- 7 TWh new biomass and waste based power production
- 17 TWh new wind power

These estimates are to a certain degree conservative, but on the other hand, the infrastructure will take time to adjust to the strong increase in intermittent or variable power production. The Nordic countries have generally been economically and market oriented and especially mindful of their heavy, energy intensive industry. Smart grids with active end-users with distributed energy resources (distributed generation, energy storages, demand response) is the main cost-efficient tool after the hydro resources have been used up.

As for nuclear power, we here assume that 3600 MW of new Swedish nuclear power will be built to replace the outgoing plants. The range of new nuclear power is from 0 MW to 16 000 MW, as there always is some uncertainty to both the economics of the plants and the political milieu. The current situation is that Swedish nuclear plants may be replaced by new ones, but the amount of ten may not be exceeded. There is no restriction on the size of new nuclear power plants, so the capacity may well reach 16 000 – 17 000 MW. As for Finland, we assume that only one of the two plants under consideration will be constructed. Especially as the energy intensive industry is a major player behind both undertakings, it might well be that both will be built although their profitability is not as good as nuclear power plants used to have earlier. The lower variable cost of power production, the lower the

market price and thus the better for end-users such as the aforementioned energy intensive industry.

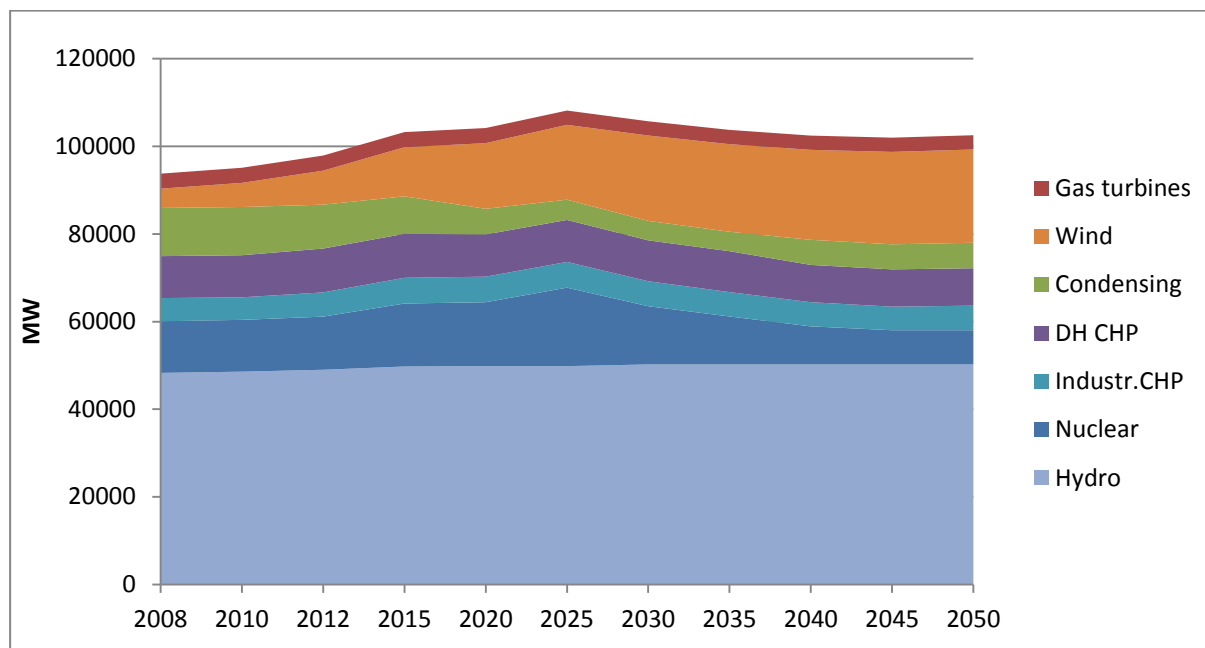


Figure 26. The assumed Nordic Electricity production in capacity development 2008-2050.

4.1.3 Fuel and CO₂ price development

The main source for the price estimates is the international Energy Agency (IEA). IEA assumes in its World Energy Outlook (IEA WEO 2012) the fuel price development shown in Table 7, although \$/MBtu, \$/tonne and \$/barrel have been converted to €/MWh by the authors.

Table 7. IEA estimate of fuel price development in Europe converted to €/MWh with a currency exchange rate of 0.72 \$ to €. Data source: IEA WEO 2012.

		2011	2015	2020	2025	2030	2035
Natural gas €/MWh	IEA New Policies	26.2	30.0	31.4	32.5	33.3	34.1
	IEA Current Policies	26.2	30.6	33.0	35.2	36.6	37.4
	IEA 450	26.2	29.7	29.5	28.4	27.3	26.2
Oil €/MWh	IEA New Policies	48.9	52.8	54.4	55.4	56.2	56.9
	IEA Current Policies	48.9	53.9	58.4	61.7	64.2	66.0
	IEA 450	48.9	52.4	51.5	49.6	47.6	45.5
Coal €/MWh	IEA New Policies	12.5	11.0	11.4	11.5	11.6	11.7
	IEA Current Policies	12.5	11.2	11.7	12.1	12.5	12.7
	IEA 450	12.5	10.7	9.9	9.1	7.9	7.1
CO₂ €/t	IEA New Policies			21.6	25.2	28.8	32.4
	IEA Current Policies			21.6	25.2	28.8	32.4
	IEA 450			32.4	50.4	68.4	86.4

4.1.4 Cross-border transmission

The Finnish-Russian trade will turn bidirectional in 2014. Imports from Russia have decreased substantially from the beginning of the millennia due to the capacity market fees for exports during peak load times. A second cable, 650 MW, from Finland to Estonia will start in 2014.

A 600 MW cable from Sweden to Lithuania will be in operation in a couple of years.

Denmark will have a cable of 700 MW to the Netherlands up and running in 2016.

Norway will be connected to Germany with a 1000 MW cable early next decade and nearer 2030 also double the transmission capacity to the Netherlands. There have been discussions and plans for a cable to Great Britain on and off for years, but they have always been abandoned or postponed. At the moment, the connection to Germany is competing with a connection to Great Britain. A commercial cable to the UK has also been mentioned, but it is not in the Regional Investment Plan for the Baltic Sea (ENTSO-E 2012)

4.2 Nordic market price scenarios

4.2.1 The production mix

The power production is estimated to develop as shown in Figure 27. Condensing power production doesn't have a big share in the Nordic countries even today, when compared to most European countries, and it is assumed to diminish. It will still be important as the price setter most of the time and especially during dry spells.

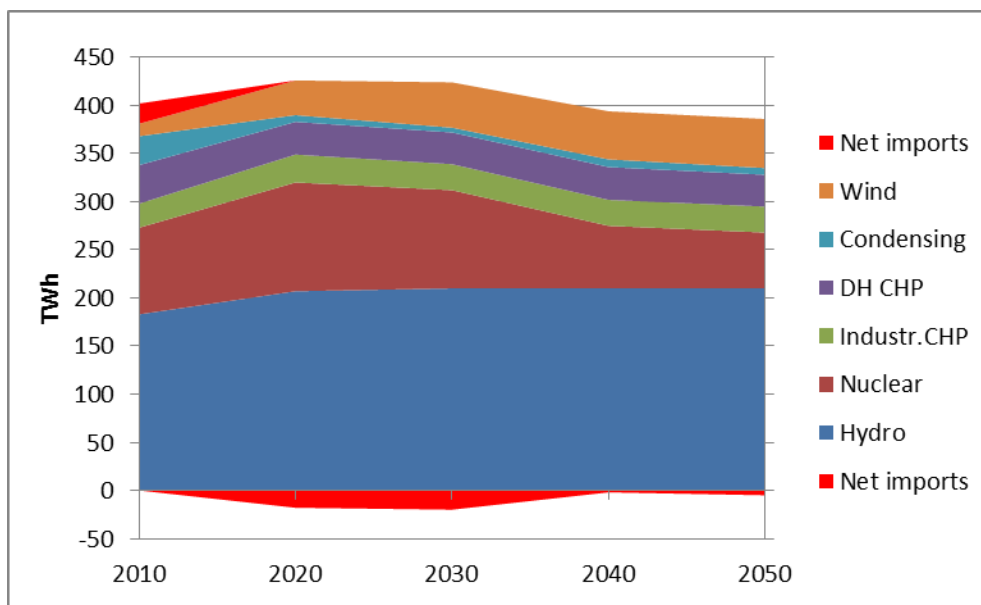


Figure 27. Nordic electricity production 2010-2050 according to VTT-EMM in the IEA New policies price scenario.

According to results, the Nordic countries will change from being net importers to being net exporters in the 2020's. Even if a lot of new cross-border transmission lines may be built to continental Europe and England, their main function will be to provide cost efficient and hydro based balancing to north-western Europe's wind (and other variable) production.

4.2.2 Market price and its sensitivities

The future Nordic market price is not one deterministic graph, but a variety of graphs that depend on input assumptions. Fuel prices' and emission costs' influence on the Nordic market price 2010 – 2050 is of course quite strong, as can be seen in Figure 28. The prices are calculated in ten year steps, but nevertheless, a price dip in 2020 can clearly be seen in the IEA Current policy and New policy scenarios. The introduction of such large amounts of

power production with low variable cost is more than enough to compensate for the increases in fuel and emission rights prices.

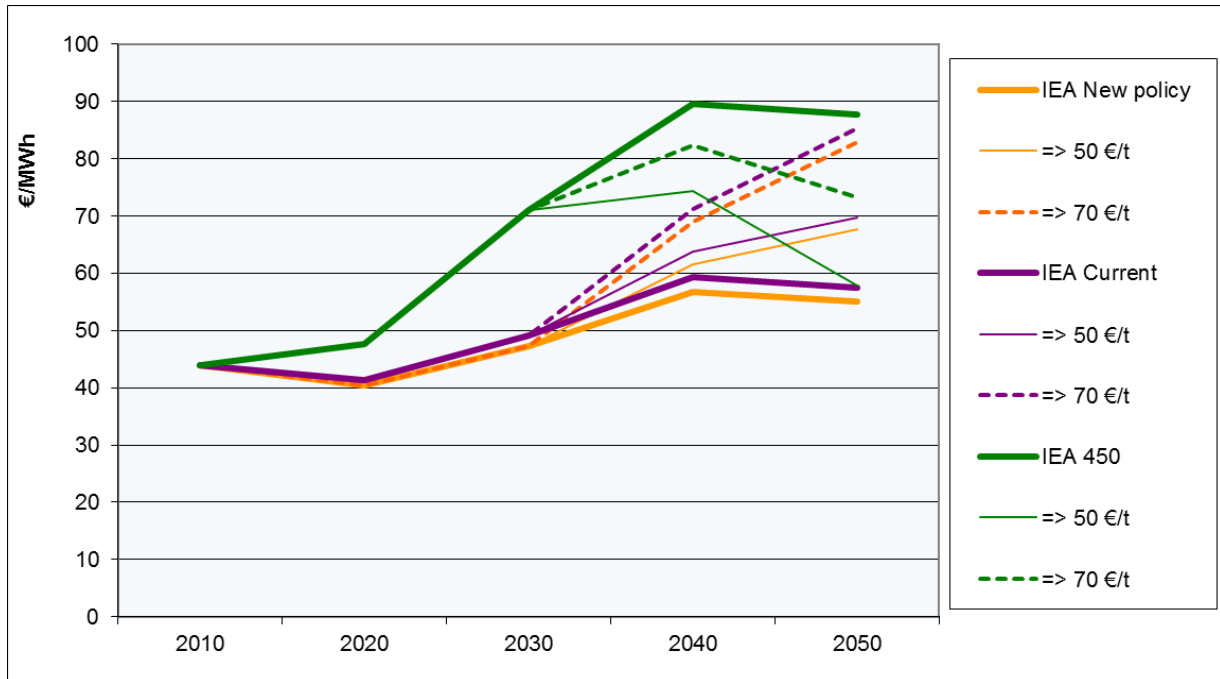


Figure 28, The Nordic market price fluctuates quite heavily depending on the fuel prices and emission costs 2010 – 2050, The thin line in each price scenario shows the extrapolation of the CO₂ price to 50 €/t_{CO2} in 2050 (IEA estimates stop 2035), and the dotted line the extrapolation to 70 €/t_{CO2}.

In Figure 29, the market price behaviour is shown in relation to demand. The comparison demands are from IEA Nordic energy technology perspective (IEA NETP 2013) representing a global target of 2 degrees warming (2DS) or 4 degrees (4DS) by 2050, as well as the scenario of carbon neutral Nordic countries (CNS), which best represents actual Nordic targets. The fuel prices etc. are according to the IEA New policy scenario.

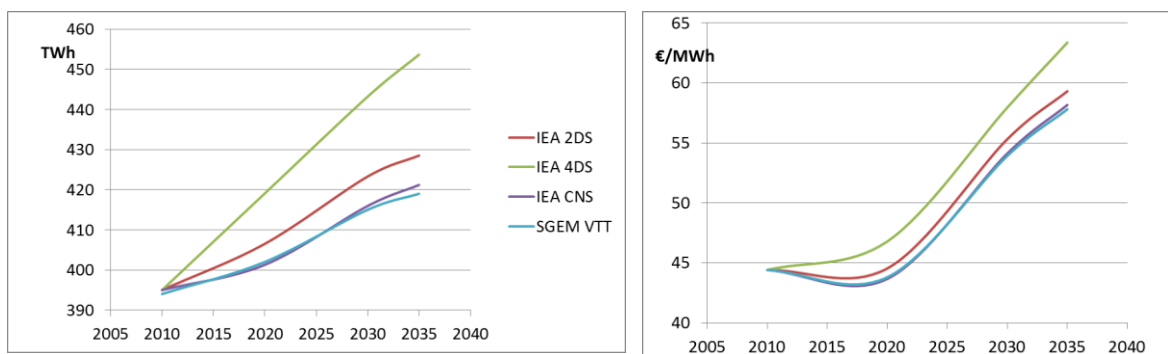


Figure 29. The effect that demand has on the Nordic market price. To the left, four demand scenarios, and to the right, their respective market prices. The IEA demand scenarios are derived from IEA NETP 2013.

What happens, if the Swedish nuclear industry takes another course than the replacement of 3600 MW while old units are shut down at an age of 50 years? We look at two scenarios in comparison to the basic IEA New policies scenario for 2010-2050, one where the nuclear capacity is assumed to remain status quo after 2020 and one where all are shut down at the age of 50 years and none is replaced, see Figure 30.

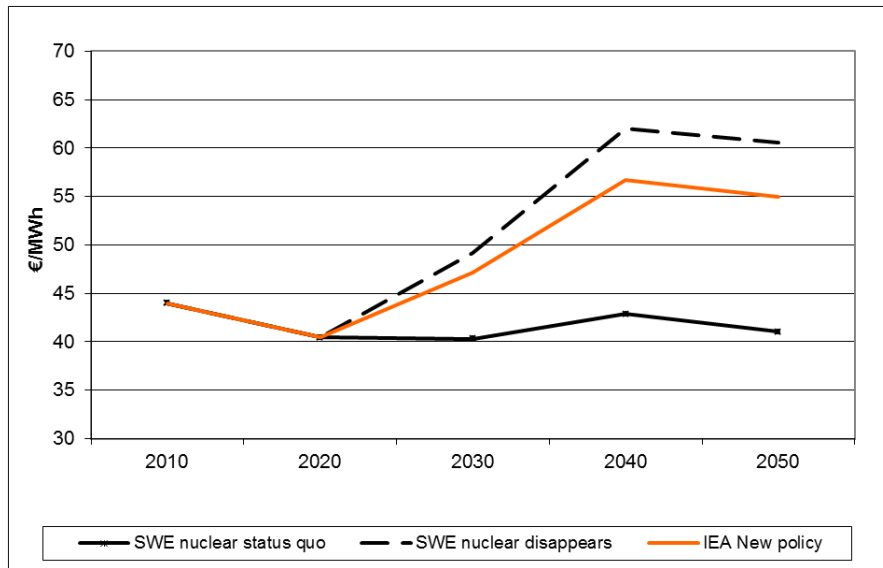


Figure 30. Swedish nuclear scenario analyses: the base assumption, where 3600 MW new nuclear capacity is introduced (IEA New policy), one scenario, where the current status (after the refurbishments in the 2010's) is kept as is, and one where all reactors are turned off after 50 years of service and none is built.

5. Summary and conclusions

More intermittent renewables, more real-time measurements, and more active demand side are expected in the future electricity markets. This is very relevant from a SGEM point of view as, generally, Smart Grid technologies have potential to move electricity markets in the direction of ideal markets.

In this report, the question of an existence of any 'best-practice' market design is approached. That is, can any design ensure generation adequacy in the long run at least cost while minimising regulatory interference with the market (Roques 2007), especially taking into account the changes arising by Smart Grids?

The role of after-spot markets strengthens as flexibility is called for in evolving European electricity markets. However, there is improvement still to do in order to achieve efficient and harmonized intraday and balancing market designs in the EU. In addition to the market integration, there is considerable room to improve market design and accuracy of market signals in Europe.

Capacity mechanisms – at least traditional implementations – can be seen as alternative or additional methods to tackle the imperfections in a electricity market and to ensure long-term generation adequacy. For example, Roques (2007) discusses the issue of increasing demand side and capacity mechanisms as a dilemma of between healing causes and symptoms. From a theoretical viewpoint, the topic of adequate investments in liberalized electricity markets has been widely discussed even for decades. The effects of increasing renewable electricity on the electricity system and on the profitability of conventional plants seem to be the main driver for the current discussion in the EU.

Capacity mechanisms have been criticized for their potential favouring of (fossil) capacity and for concentrating on the generation side at an expense of the demand-side, as well as for their distortion of the market signals, with national mechanisms creating a barrier for market integration, and for imposing a regulatory risk on the market participants. International experiences and research show, however, examples of capacity mechanisms, where

demand-side can also be included. This is of particular relevance when smart technology approaches, with increasing real-time information and demand response, are considered.

From market integration of point of view, a European-wide solution is desirable over national mechanisms, even though there seems to be practical challenges in the implementation of such a scheme due to dispersed system operations etc. and differing local practices and conditions. Modern approaches in design, such as reliability contracts and forward capacity mechanisms, are often referred to as potential directions of further consideration in the EU, while strategic reserves are seen as a more easily implementable option. The modern innovation of capacity subscriptions becomes an interesting option with enhanced real-time metering, a characteristic widely discussed among SG concepts. Generally, the lack of experiences of innovative capacity mechanisms can be seen as limiting their use in practice.

Generally, if a market-based and integrated European approach chosen as target for the future, market interventions and national support mechanisms should be implemented only using utter care and after stringent consideration. However, integrating demand side and associated market mechanisms, together with real-time data utilisation, as effectively and widely as possible can be seen supporting the target. When considering market mechanisms, local circumstances should always be taken into account. What suits one market doesn't have to suit another.

Renewable electricity production is increasing rapidly, and will do so also in the future. Whereas PV is one of the large power factors in Europe, its importance appears smaller in the Nordic countries, where hydro, wind power and biomass are the most important renewables. Conventional fossil condensing power will have a hard time in the future in the Nordic, as new nuclear and renewable capacity pushes it farther and farther up on the merit-order list. Even CHP might experience more serious blows to its profitability.

Whereas the demand for electricity will continue to rise, our results suggest the slope will be smaller than it has been. Compared to the EU analysis, Nordic demand seems to increase slower than the EU demand as a whole. Heat pumps, auxiliary heating, and later electric vehicles will be Nordic drivers.

Fuel prices are expected to rise. Here the shale gas revolution in the USA has led to large momentum shift with lower inland prices. This has pushed the price of coal down, which has led to its increased use in Europe, and a decrease in gas usage. Now, gas plant owners in Continental Europe are demanding subsidies, especially as their profitability is additionally being eaten by the renewables and the low price of CO₂ emissions.

Nordic market prices show a tendency to come down in the next ten years. Of course, this conclusion has a high dependency on policy – the more the EU puts efforts on climate change mitigation, the higher the price of CO₂ emissions and the higher the market price. The electricity prices are expected to rise when we approach the 2030's. Although renewables have a big role in the formation of the future prices, Swedish nuclear will perhaps have a bigger role. Will the units be renewed or not, is the vital question.

Extensive feed-in tariffs and other subsidies can at worst destroy the basic operational premisses of the energy-only markets. Some might ask what the point is in having markets, if politicians want to determine the exact capacity composition, however cost-ineffective it is, and want to regulate the end-user prices. The result is a suboptimal market with heavy subsidies, including feed-in tariffs, to almost all producers. And as markets are more and more integrated, this leads to unbalanced conditions. Luckily, the Nordic market has still been quite well functioning and although there are danger signs, there is a possibility it will continue so.

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Appendix: A practical approach to solving the adequacy problem: reliability options¹⁰

Reliability option approach is a result of a design process targeted to solve the market power and risk problems of the electricity markets while maintaining incentives for capacity investments using clear economic principles. The market coordinates new entry through the forward procurement of reliability options: physical capacity is bundled with a financial option to supply energy above a strike price.

The new type of capacity market is designed to coordinate new entry through the forward procurement of reliability options: physical capacity bundled with a financial option to supply energy at spot prices above a strike price. Two major advantages reliability options are the following: (i) they hedge demand from high spot prices; and (ii) they reduce suppliers' risk by replacing uncertain scarcity price based revenues by constant capacity payment.

Spot prices can still be volatile if market clearance cannot otherwise be achieved, as all parties are exposed to the spot price on the margin. Market power is relieved because major part of the load offered to the spot market is connected to the strike price that defines the price for supplier revenue when the spot price exceeds the strike price.

The reliability options are introduced into the market by requiring every generator to sell a reliability option for K megawatts of capacity as a prerequisite for receiving a payment for K megawatts of capacity. The specific form of reliability options that has been implemented in practice is the *load following* reliability options (source).

If we assume that the energy price stays low except when there is a blackout due to a shortage of capacity (an adequacy problem), at which time it rises to the price cap, P_{CAP} . Load may be at various levels when such a blackout occurs because the amount of generation out of service varies. So a reliability option assigns generators a capacity "load share", K_{LS} , which is the same fraction of total load as their capacity is of total capacity.

$$K_{LS} = (K_{BID} / \sum K_{BID}) \times \text{Load Served} \quad (1)$$

K_{BID} is the capacity bid of a generator. We will assume that all generators in the energy market have had their bids accepted and so $\sum K_{BID}$ is the sum of the designated capacity value of all generators in market. This means that

$$\sum K_{BID} = \text{Load Served}. \quad (2)$$

The financial option associated with a reliability option specifies that during a blackout, a generator must pay K_{LS} times $(P_{CAP} - P_{STRIKE})$ to load, but the energy market pays the generator its output, K times P_{CAP} . In an energy market capped at P_{CAP} without the option pays the generator simply K times P_{CAP} . Comparing these two results goes as the following (R revenue):

¹⁰ This appendix is based on Cramton et al., 2013.

$$\text{Without the option: } R_1 = P_{\text{STRIKE}} K \quad (3a)$$

$$\text{With the option: } R_2 = P_{\text{CAP}} K - (P_{\text{CAP}} - P_{\text{STRIKE}}) K_{\text{LS}} \quad (3b)$$

$$R_2 - R_1 = P_{\text{CAP}} K - (P_{\text{CAP}} - P_{\text{STRIKE}}) K_{\text{LS}} - P_{\text{STRIKE}} K \quad (3b)$$

$$= (P_{\text{CAP}} - P_{\text{STRIKE}})(K - K_{\text{LS}}) \quad (3)$$

Summing this over all generators, the last term becomes (Total Output – Load Served), which is exactly zero because of physics as noted by equation (2). Consequently, relative to a market capped at P_{STRIKE} , energy payments in such a capacity market are exactly zero. This means load and total generation are both perfectly hedged relative to a market with a low price cap. Reliability options not only reduce risk but also market power without damaging the dispatch incentives on the generation side.

If the supplier provides 80 MW of power for the hour in question, then it is paid €80,000 for this, but it must pay $(90 \text{ MW}) \times (\$1000 - 300) = €63,000$ as a hedge payment. If it provides 90 MW of power, it is paid €90,000 and is obliged to make the same €63,000 option payment. If it produces 100 MW it is paid €100,000, and again makes the same hedge payment. For every megawatt it increases or decreases its production, its net revenue increases or decreases by €1,000. Note that when the spot price equals the strike price or is above it, it is profitable for virtually every generator to be producing, since marginal cost typically is less than the strike price. As long as the suppliers produce their share of load, they will earn the strike price for all of their output. In other words, a generator with average performance is nearly fully hedged against spot prices above the strike price by its physical generator. Also load is 100% hedged from energy prices in excess of the strike price.

Suppose that an generator with 1000 MW of capacity with the short-run marginal cost of 50 €/MWh can withhold 100 MW and drive the spot price from 350 €/MWh to 3050 €/MWh. In this case his profit increases from $1000 \text{ MW} \times 300 \text{ €/MWh}$ to $900 \text{ MW} \times 3000 \text{ €/MWh}$, from 0.3 M€ to 2.7 M€, a huge 2.3 M€ per hour.

With reliability option, having a strike price of 350 €/MWh, and a load-share option of 1000 MW, the outcome of the withhold operation is the following: $R = 3050 \times (900 - 1000) + 350 \times 1000 = -50,000 \text{ €}$. A huge profit has changed to substantial loss, meaning that the market power has been eliminated by the reliability option and turned into a disincentive. What a reliability option does is that insures that a generator will sell its on-peak energy forward at a competitive price that is determined in the capacity auction and through this process eliminates the market power during times of scarcity.

In an energy-only market generators experience a great risk because the number of scarcity hours when the price is at the price cap varies a lot from year to year. With reliability options the capacity payments do not vary with the number of annual scarcity hours so the risk of the scarcity payments from the energy market will almost entirely be hedged away.

Capacity acquisition is carried out by an annual auction. These auctions determine the price of reliability options that is just sufficient to induce the required entry. For example, with a strike price of €300/MWh this might result in the average annual loss of €40,000 of revenue per MW of capacity relative to the optimal spot market without reliability options. In this case, new entrants will bid the price of reliability options down to €40,000/MW-year. If the cost of constructing new capacity increases or decreases, due to environmental restrictions or new technology, new entrants will bid just enough higher or lower to maintain a normal rate of return.

The result is that the regulator fully controls the level of capacity, but the market controls the price of capacity and the type and quality of capacity built. Hence the regulatory intervention is limited to the determination of the one factor the market cannot control - the adequate level of capacity.

There is confusion around giving capacity payments to generators that would remain in the market without such payments. Why are they being paid to do what they would do anyway? Existing plants are paid because that is what an ideal energy-only market would do. An energy-only market pays for peak capacity with scarcity prices that rise above the variable cost of a peaker. But when there is scarcity, every operable plant is running, and all are paid the same scarcity price - even though they would stay in the market without such payments. One could imagine inducing new plants to enter the market with long-term contracts that pay for both variable and fixed costs, but paying existing plants only a tiny bit more than their variable costs. They would not close, because some profit is better than none. This can work effectively if investors are surprised. But once the policy is known, new plants will demand contracts that protect them from this in the future and likely charge a significant risk premium as well. (source: Crampton, Ockenfels, Stoff, 2013)

It is the end-users of electricity who have to pay costs of capacity acquisition. If the total acquisition costs are divided by the (expected) yearly energy it can form a basic level of the spot price.

European markets can be thought of as having two settlement systems consisting of day-ahead spot market and a balancing market that prices the deviations from the forward sale. A generator sells an amount Q_{spot} in the spot market and delivers an amount Q_t in real time. The deviation from the forward sale, $Q_t - Q_{spot}$, is valued at the balancing market price $P_{Balance}$. Without reliability options or when the balancing price is below the strike price, the settlement works as follows: (R=generator's revenue)

$$R = P_{spot} * Q_{spot} + P_{Balance} * (Q_t - Q_{spot})$$

With reliability options and the balancing price above the strike price, the settlement step consists of three parts. Each supplier is responsible for a share (LS) of the real time load that is proportional to the quantity of reliability options it has sold. The settlement goes as follows:

$$R = P_{spot} * Q_{spot} + P_{strike} * (Q_{LS} - Q_{spot}) + P_{Balance} * (Q_t - Q_{LS})$$

If the generator supplies exactly its load share so that $Q_t = Q_{LS}$ then it is fully hedged against the balancing price. However, if it deviates it must pay or it is paid the balancing price. The incentives for performance have not changed and the balancing market operates as before. There is no reason why generators should not sell all the capacity in forward markets and sell reliability options for all of their capacity in the capacity market.

When summing up over all generators the total power delivered, Q_t , equals the total load which equals the sum over all generators of Q_{LS} . This means that summing over generators the term $P_{Balance} * (Q_t - Q_{LS})$ equals exactly zero, because this is determined afterwards. The summed terms are the incentive payments for under and over production relative to Q_{LS} . So these payments do not affect load but are simply payments from poorly performing generators to the better performers. Because of this the system operator organizing the capacity auction does not have an incentive to acquire too little capacity. Under-procurement of capacity will increase the number of hours when there is a capacity shortage and then the generators are paid the strike price.