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Policy Instruments for ancillary services and capacity adequacy

Master's Thesis

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Foreword

This Master's Thesis has been written in the employment of Wärtsilä Corporation. I wish to extend a warm thank you to Wärtsilä Marketing & Business Development department for making me feel welcome and for providing me with the best possible environment to write my Thesis. A special thank you goes to my instructor Mikko Syrjänen for his words of wisdom.

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AALTO UNIVERSITY SCHOOLS OF TECHNOLOGY PO Box 11000, FI-00076 AALTO http://www.aalto.fi		ABSTRACT OF THE MASTER'S THESIS
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<p>This thesis examines the needs of power systems, the different instruments used to meet those needs, and builds a framework for classifying both. The thesis starts with a look at the drawbacks of the vertically integrated power market that lead to the creation of the liberalized energy-only market, at what needs this energy-only market fulfils, and what its challenges are. The third chapter explains why the energy-only market alone is not enough for second-to-second power system operation. The needs it cannot meet are presented and determined to arise from three different levels: physical operation, network, and policy level. The fourth chapter examines the instruments used to meet these needs, often called ancillary services, and develops a framework for classifying them. This framework has four categories: frequency control, capacity, coordination and operation, as well as system backup and restoration. The fifth chapter presents a case study of the frequency control and capacity instruments in the Danish system, and the sixth chapter has case studies of the Polish and Pennsylvania-Jersey-Maryland (PJM) systems. The case studies demonstrate how the developed framework for ancillary services works in the context of real countries as well as in identifying the dimensions on which the instruments differ between the case areas, the dimensions that define the service in question and that players wishing to enter the market in question need to know. This chapter also includes some general points on what leads to the opening of ancillary and capacity markets, and examples of ways to organize the capacity market. Next, the findings chapter summarises the main facts found out during the research, including some points on what to take into consideration when designing market instruments to a system. The conclusions chapter draws it all together, and the discussion chapter evaluates what went well, what could have been done better, and points out directions for further research.</p>		
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1 Introduction

This thesis examines the needs of power systems and the instruments used to meet those needs. It builds a framework for classifying the needs and also the instruments. The ultimate goal behind this is to identify the best way to arrange a power market. However, in order to be able to give any answers to that question, it is first necessary to build the framework. This is because based on an extensive literature review and several expert interviews, no such frameworks were found. Thus, this thesis concentrates on building one and hopes to use it to draw some conclusions as to the organization of the power market, especially the ancillary and capacity markets.

This thesis starts with a look at what were the drawbacks with the vertically integrated power sector that lead to the creation of the liberalised energy-only market. The same chapter two also looks at what is, or at least should be, better with the liberalised market, and what its challenges are, as well as what tasks it performs.

The third chapter explains why the energy-only trade needs to be supplemented in order to keep the power system functioning, why the liberalised power market alone is not enough for the second to second operation of the power system. The chapter presents the needs that the energy-only trade cannot meet and determines that these arise from three levels: the physical operation, the network, and the policy level.

The fourth chapter gives some answers to how to meet these needs, what instruments can be used to meet them and introduces a framework for classifying the instruments. These instruments or services are referred to as ancillary services, and for the purposes of this thesis they are divided into four categories: frequency control, capacity, coordination and operation, and finally system backup and restoration.

The fifth chapter presents a case study of the frequency control and capacity instruments in the Danish system. The sixth chapter includes shorter cases on Poland and Pennsylvania-Jersey-Maryland (PJM) in the United States. The purpose of these cases is to see how the developed framework works in the context of real countries as well to identify the dimensions on which the instruments differ in the different countries, or which have to be known to define and buy the service in question. In other words, to identify the dimensions that players wishing to enter the markets in question need to know. The same chapter also includes some general points on what leads to the opening of ancillary and capacity markets, and some examples of ways to organize the capacity market.

Next, the findings chapter summarises the main facts found out during the research, including some points on what should be taken into consideration when designing market instruments into a system, what are the essential questions to answer before implementing an instrument. The conclusions chapter draws it all together, and the discussion chapter looks into what went well, what could have been done better, and what there is left to study.

2 Energy-only trade; its birth and functions

Traditionally, vertically integrated and regulated utilities had taken care of generation, transmission, as well as distribution. This model was based on four principles formed early in the 20th century, at the start of wider electrification. The first of these was that when customers were aggregated to form the largest possible interconnected web, i.e. grid, it was cheaper to serve them. Secondly, the economies of scale in the electricity industry meant that monopolies were deemed natural. Third, because costs went down as sales went up, the dominant marketing logic became to “sell more and charge less”. This meant that consumers were encouraged to consume more power. Fourth, because the electricity industry had decreasing costs, large needs for capital, and strong “political interaction”, a system of governmental regulation was set up to control and stabilize it. [Fox-Penner, 2010]

However, in the 1990s, many countries started to deregulate their electricity sectors and disintegrate their utilities. Generation was separated to form a competitive market of its own. For example in the US and also many other countries this was possible because transmission networks had developed far enough to make significant trade over long distances possible and “to remove the natural monopoly character of the wholesale market in many places”. [Stoft, 2002] In completely competitive markets, also transmission and distribution are unbundled, customers can choose between several suppliers, and ancillary services have their own market. [Vuorinen, 2009]

One of the needs for competition came from the fact that in the older model of regulated markets there always existed a trade-off between keeping electricity prices low and minimising costs. This is because suppliers of electricity will almost always have more and better knowledge about the market than regulators. For example with a regulatory scheme

where suppliers are allowed to recover their costs and a normal rate of return on their investment, but nothing more, prices will be low, but there will be no incentive to decrease costs. This is because if a supplier finds a way to cut costs by a certain amount, this will be taken away and given to customers. Another example is a regulatory scheme with price caps fixed according to some formula for a long time period. In such a scheme, producers do get to keep all the money they save, but as any formula for price caps that is fixed for a long period of time must allow for prices to be clearly above long-run costs, it will lead to prices being excessively high. [Stoft, 2002]

This trade-off can be softened and even made relatively satisfactory by increasing the regulators' knowledge. Still, it is always going to exist in regulated markets and the result is never going to be the same as in competitive deregulated ones, which can encourage both holding prices near marginal costs and minimisation of costs. Additionally, competitive markets also tend to produce pricing that more accurately reflects production costs through the use of real-time pricing. This real-time pricing should also decrease consumption during times when the prices of electricity are highest and generation most expensive. In theory, this in turn means that less capacity needs to be built and that thus the total cost of generating electricity will be lower too. This reduction in costs is however counteracted by the additional costs to the customers of having to shift their consumption, so that the net benefit often is just a few percent. [Stoft, 2002]

Although deregulated markets usually are more efficient than regulated ones, in reality they have their problems as well. The first major issue is that at present there is little to no real-time metering in use, and very few customers see the real-time prices, meaning that responsiveness to price changes is very small, and demand essentially inelastic. The second

problem comes from the fact that it is not possible to control the flow of power to particular customers in real time, which means that “bilateral contracts cannot be physically enforced in real time”. It also means that the system operator has to function as the real time default supplier. Due to the negligible responsiveness of demand to price changes, it is possible that the demand and supply curves fail to intersect. At such times, competitive pricing is impossible, and the system operator has to set the price for electricity. These two “flaws” on the demand-side produce high prices, and together with scarcity, create ideal conditions for use of market power to increase prices even more. [Stoft, 2002]

Another major shortcoming of the deregulated energy-only market is that it is unable to guarantee capacity adequacy on its own. The average market price does generally not reflect the true value of lost load, or energy not being delivered, and yet this price is what guides investments. This means that investing in capacity is not profitable, and thus the market will most likely not encourage adequate investment. For the market to be able to do this, the prices during the peak hours would have to be unreasonably high, resulting in high risks for both consumers and producers. [Zhao, 2010]

Additional issues with deregulation arise from complexity and local market power. Complexity here means that the power system is often very large, yet at the same time quite delicate. This means that every generator has to be synchronized with all the others, voltage has to be kept at a certain level in a large number of different locations. And the network where these goals must be reached is effectively split into two parts: the grid part that is operated “for the common good” and the generators that are operated for “hundreds of different private interests”. While this complexity may be overcome through

well thought-out market rules, the issue of local market power often requires regulatory intervention. [Stoft, 2002]

Even with these flaws and issues, it remains possible to design a market that works well. It is just essential to notice that the biggest issues with deregulating markets are to do with the market structure, not so much the market architecture. The term market structure refers to the technology and ownership properties of a market, with supplier concentration and elasticity of demand being the most common measures for the competitiveness of the structure. Market architecture, on the other hand, refers to the submarkets, parts of the larger market that are also markets, found on a market and the links between them. After grasping this difference, the problems with deregulating can be tackled, and quite good solutions can be found. The long term goal should of course be for demand to become elastic enough to “clear the market at a finite price”, with price spikes that do not need caps. Indeed, when deregulating any power market, it has been suggested that it might be cheapest to first fix the demand side before creating any market structure. [Stoft, 2002]

Many different forms of competitive power markets exist these days, with the simplest being the pure energy market, where only electricity is traded. The market in the Nordic countries has been of this type since 1998, and also the Australian market is like this. On energy-only markets, the prices for electricity for every hour of the following day are determined through daily evaluation of supply and demand curves on a spot market. The supply and demand curves themselves are based on offers to supply, which in turn are based on the variable costs of generators, and forecasts of demand by the customers. In the Nordic countries, and also in Germany, there is an additional market for intra-day trading

that can go on until one hour before the need for electricity actualises. [Vuorinen, 2009]
[Fingrid.fi]

The energy-only market fulfils several needs. First, and perhaps most fundamentally, it matches supply to demand, providing market clearance. Second, it allows power producers to recover their production costs, and hopefully also make a profit, thus enabling them to continue producing power. Third, the balance of supply and demand achieved through the energy-only market functions as the basis for dispatch planning.

Today the electricity industry faces totally different challenges from anything that has come before, and the principles on which electricity systems were built during the early 20th century are becoming at least partly obsolete. The first major global issue is the need to mitigate climate change, to limit greenhouse gas concentrations to acceptable levels. It is generally accepted that much greater energy efficiency is both the best and the cheapest way to do this, but it goes directly against the old maxim of selling as much electricity as possible as cheaply as possible and is going to require big changes to the core ideas of the power industry. [Fox-Penner, 2010]

The second issue to be addressed is the need for more energy security and economic stability. Many countries are already dependent on oil and natural gas imports from countries such as Saudi-Arabia, Iran, and Russia, and with increasing global demand these supplier countries are going to have more and more “geographical leverage”. Solving this issue is going to mean shifts in fuel sources, generation, and often also the building of new transmission capacity. [Fox-Penner, 2010]

It has been suggested that during the next decades, power systems will change from ones based on large sources and central control to ones with many smaller sources and individual control. Also the economies of scale involved in power production have already changed and will continue to. The goal of maximum consumption has already been replaced by the ones of productivity and sustainability, and old forms of regulation will become useless. The three new objectives of the power industry will be the creation of a “decentralised control paradigm, retooling the system for low-carbon supplies”, as well as discovering business models to promote greater efficiency. [Fox-Penner, 2010]

3 The need for something additional – why energy-only trade alone is not enough

The deregulated energy-only market alone is enough for neither the minute-to-minute operation of a power system, nor for the long term, there are needs that it cannot fulfil, and they are discussed in this chapter. These needs arise from three different levels; the physical operation level, the network level, and the policy level. While all three levels ultimately are inextricably linked to the physical operation of the system, the difference between them is in the scope of focus. The needs that come from the policy level are concerned for example with the benefit of the whole society or country, while the network level considers the grid as a whole, and the physical operation level concentrates on specific, momentary actions.

3.1 Physical operation level

3.1.1 Frequency stability

In order to keep the power system secure, a continuous real-time balance between supply and consumption of electricity must be maintained. Disturbances in the balance between generation and load cause the system frequency to deviate from its target value. This frequency deviation can affect the operation of electrical equipment, power plants, and even at worst lead to a total system black-out. Thus, imbalances must be dealt with immediately. [Katholieke Universiteit, 2009] [Verhaegen et al. 2006]

There are three usual causes for these imbalances between supply and demand; predictable load variations throughout the day, unpredictable fluctuations in loads and generation, and outages of lines and generators. [Stoft, 2002] With current goals to increase the percentage of wind generation significantly in many countries, imbalances due to variability in production are going to increase in the future. True, when considering the total supply at

the European level, it is not that big of a deal when the wind stops at one wind farm, as it will likely blow at another, but especially in systems where a large part of the demand is met through wind, the variability does affect system operation. [Van Hulle et al, 2010]

Trading on electricity markets produces consumption and production profiles that are broadly in balance within a certain time period. However, this is not enough for actual, physical system operation, where supply and demand must be in balance second by second in all locations of the network. [Verhaegen et al. 2006]

Refining the result of trade is usually the responsibility of the system operators. They accomplish this by obtaining incremental generation and redispatching. For this reason, the power system needs to have reserve production capacity, and due to the limits in the transmission capacity of any system, this reserve must likely be distributed throughout it. [Verhaegen et al. 2006]

Usually the system operators use several types of reserves. Fast responding reserves are used for short term issues, to avoid too big disturbances if supply or demand fails to operate according to plan and to allow others to continue producing and consuming, while longer term reserves replace these after the immediate imbalance has been dealt with. The definitions and treatment of the different reserves vary quite a lot from country to country, but in general they can be divided into primary, secondary, as well as tertiary control (regulation). The procurement and settlement of these different reserves can together be called balancing. [Verhaegen et al. 2006]

3.1.2 Voltage stability for customers

When electricity flows towards customers on the transmission lines, voltage drops on the way. If the voltage is not restored to the right level, it will affect all other loads in the area. A transformer usually corrects the voltage drop before distribution of power, but not entirely, which causes the voltage received by the customer to fluctuate. [Stoft, 2002]

By using generators, capacitors or synchronous condenser to inject real power into the grid, the drop in voltage can be compensated. Generating reactive power consumes very little fuel, so essentially a generator's only cost of producing it is the opportunity cost of a lowered ability to produce real power. Stabilising the voltage that customers receive interacts in a complex manner with the voltage limit set by transmission security explained below, and thus they should be considered together. [Stoft, 2002]

As there are externalities associated with the consumption of reactive power, setting up a bilateral market for it not feasible due to the fact that consumers of reactive power would buy too little of it. Additionally, the losses associated with transmission of reactive power are large compared to the transmission of real power. [Stoft, 2002]

3.1.3 Ensuring power quality

Broadly defined, power quality “refers to a wide variety of electromagnetic phenomena that characterize the voltage and current at a given time and at a given location on the power system”. The main phenomena causing disturbances to power quality include transients, short and long duration root-mean-square variations, imbalances, waveform distortions, as well as voltage fluctuations and power frequency variations. [IEEE, 2009]

Poor power quality disturbs power metering, can damage electrical equipment, and cause disruptions and malfunctions in process operations. These disruptions to profit-based

operations are costly, as are the possible equipment damage and repairs. Thus, the ultimate reason for monitoring power quality is economic. [IEEE, 2009]

Power quality can be monitored by the utility, end user, or a third party. Instruments used for monitoring power quality can be as simple as analogue voltmeters or as sophisticated and complex as “multiple-site, permanently installed power quality monitoring systems”. The type of instrument chosen depends on the objectives of the application. [IEEE, 2009]

Power quality can be corrected using many different methods. For example, load equipment can be designed to reduce harmonics in the load current, as well as to reduce sensitivity of loads to voltage disturbances. Also the supply system can be designed in a manner that reduces the possibility of disturbances, filters and compensators can be installed to correct the disturbances, and uninterruptible power sources can be installed to perform as the power source during disturbances in the utility power. [Kusko et al, 2007]

3.2 Network level

3.2.1 Transmission security in the national grid

To make the transmission of electricity secure, a system operator has to calculate the security limits for the transmission lines, i.e. the thermal limit and basic physical limits. Then he has to make sure that the output of generators, given the load at the moment, does not exceed the security limit of any line. The thermal limit is the total amount of real and reactive power a transmission line can handle before it is permanently damaged. Also voltage limits and stability limits, which are basic physical limits and vary more than thermal limits, may have to be taken into consideration when calculating security limits. [Stoft, 2002]

A guiding principle in transmission security is that the loss or failure of any single component must not jeopardize the operation of the whole grid. So, if for example the

largest power plant in the system fails to operate, the system must be able to produce the missing electricity by some other means. The same goes for transmission lines.

Transmission security service has to be provided by the system operator either through selling of transmission rights or controlling of the bids accepted in the day-ahead market. Both of these actions are done some time before real time, and thus in the time interval left in between, the flow of power can alter and breach a security limit, for example through an increase or decrease in load or a line or generator going out of service. [Stoft, 2002]

If a security limit is breached in real time, the system operator induces more generation in one place and less in another. The issue, in other words, is not total generation, but the location of the generation. Although a market could take care of decreasing the price of electricity where less of it is wanted, and increasing it where more is needed, this market should only be an additional tool for the system operator to use. This is because the provision of transmission security is a very complex issue, and should be handled centrally. [Stoft, 2002]

3.2.2 Transmission security in cross border transmission

In the European electricity markets, there are considerable differences in electricity prices between countries. These differences are simply the result of production cost “gaps” between countries that rely on different primary power production technologies. Of course there can also be differences in prices between countries for other reasons, for example different pricing policies, taxation, fuel prices, or cost efficiency of production. Due to the price differences, power exchanges between interconnected partners have been growing, and this together with limited existing cross border exchange capacity has made the issue of

“cross border interchange and of exchange capacity allocation” increasingly important.

[Genesi et al, 2008][Lamponen et al, 2007]

3.2.3 Economic dispatch

Economic dispatch means minimising the total cost of producing electricity by using the least costly generation at any time. The two issues that must be dealt with in economic dispatch are which plants to start up, and how much to use each. The day-ahead market is an important part of making real time dispatch efficient, as many generators are time-consuming and costly to start up. [Stoft, 2002]

Economic dispatch can be provided through bilateral trading, a centralized day-ahead power market, or power pool. Whereas in the first option suppliers of power and power traders solve the economic dispatch problem, in the second the exchange gives a public price that is used for deciding which generators to start up. The third option requires sending of complex bids, which the system operator then optimises. What all three options have in common is that in all of them the market price and the suppliers together decide on the dispatch. With a competitive market, the result should be quite close to least cost. [Stoft, 2002]

3.2.4 Imbalance settlement

Imbalance settlement consists of recording the differences between forecast demand or supply and actual consumption or generation, and then also charging for these differences. Ideally, there would be no difference but in reality this almost never is the case, as forecasts usually contain errors. Imbalance settlement is a service for the system operator to provide, because no trader has either the incentive to do this for their own trades or the possibility to do it for others'. [Stoft, 2002][Fingrid.fi][Zhang et al, 2009]

3.2.5 Emergency services and reserves

Emergency services are used to handle crisis situations, when regular regulation service is not enough to maintain the power system in balance. An example is a situation without enough offers to supply power. [Kiener, 2006]

3.2.6 Starting up an islanded part of the grid

While most outages can be repaired with the help of a neighbouring part of the grid, sometimes, for example with wider blackouts, there is no neighbour to help. At the same time, almost all generators have to have access to power from the grid to start producing it in turn. Thus, generators with the capability to start injecting active power to the grid without first receiving power from the grid are needed in case of bad system failures, and these are called black start reserves. [Stoft, 2002] [Kiener, 2006] [Feldes, 2008] [Kirby, 2010]

3.3 Policy level

3.3.1 Ensuring sufficient capacity in the long term

Supply reliability is actually a two-part concept, which includes both security and adequacy of supply. Security of supply means the ability of the power system to tolerate disturbances, while adequacy refers to the ability to match the total electricity requirement of all consumers at all times. The security aspects that have been addressed above have a more short term focus. Adequacy, on the other hand, focuses on meeting demand and preventing shortages in the long term, taking into consideration the unpredictable variations in supply and demand, that power cannot be stored and the lengthy lead times for building new capacity. [Oren, 2000] An important aspect of supply reliability is that the system must be able to withstand the loss of any single component in it, even the largest one. This principle should guide the planning of the system as well.

In theory, on a competitive market with no entry barriers supply or capacity adequacy would be guaranteed through temporary price increases, which should encourage investment in new capacity. Also, during scarcity, the price should rise high enough for voluntary load-shedding to take place. Thus, unlike security, adequacy is a private good, with customers deciding what the adequate quantity is. [Oren, 2000][Zhao, 2010]

In reality, however, markets don't function quite like that. First, the real average price of electricity on the market is usually not the same thing as the value of lost load, or energy not being delivered. Yet the price that producers actually get, i.e. the market price, is what guides investments. Second, real-time demand is almost inelastic without smart grids, meaning that the electricity market is in practice a supply-side market. Additionally, even supply can only react up to the amount of available capacity.

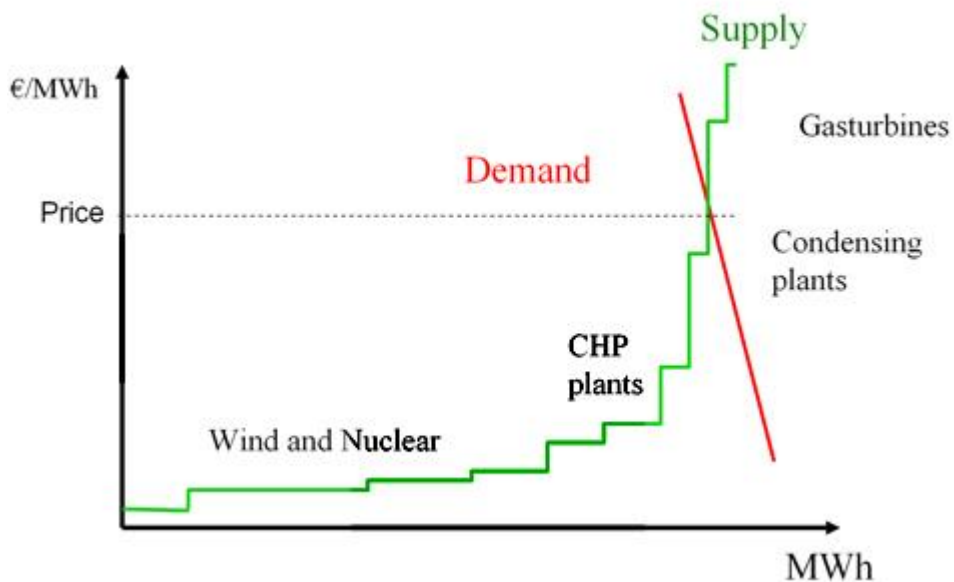


Figure 1 Supply and demand curves on the Nordpool spot market [Wind Energy the Facts, homepage]

Due to concerns of the supply-side domination on the market leading to supply-side manipulation and the fact that electricity is so critical to economies it is common for regulators to intervene, through for example imposing price caps on energy market prices. These caps are usually lower than the prices that would exist in the ideal market, resulting in loss of money for generators and distorting investment signals. The price that generators actually do receive does not fully reflect the value of lost load, or energy not being delivered. One solution to this problem is to create a capacity market, where the generators could redeem the “missing money” and also decrease the investment risk. [Zhao, 2010]

Related to, and almost impossible to separate from, the financial aspect of the missing money is the physical, or engineering, aspect of capacity adequacy. The less-than-ideal markets result in the missing money issue, which in turn causes too little investment to take place, leading to a shortage of capacity. And vice versa, as the prices on the capacity market that have been capped do not represent the actual value of reliability, the generators don't receive the prices that they would on the ideal market, which results in the missing money. Thus, missing money and adequacy are in fact two sides of the same coin. [Zhao, 2010]

3.3.2 Energy efficiency

The flipside of capacity adequacy on the consumers' side is energy efficiency. In essence, it means using less energy than before to get the same result, or in production of power using less fuel to produce to same amount of electricity. This is an idea that is mentioned in countless visions for future energy systems and also in many countries' energy policies as a way forward to meet growing demand and tightening emission standards, as well as counteract dependency from imported fossil fuels at the same time. Energy efficiency is even often seen as the “best and cheapest means of reducing carbon emissions” [Fox-Penner, 2010].

However, to be able to compare the cost-effectiveness of investment in new capacity or in energy efficiency would require present value calculations, as there is a significant difference between investing in new capacity or energy efficiency. When purchasing more energy efficient appliances or technologies, consumers have to pay 100 percent of the costs up front, before receiving any benefit. The benefits, or savings, are then realized over the lifespan of the equipment. In contrast, when a new power plant is built, consumers only pay for 1kWh at a time, no matter how expensive the plant was to build. And even if the energy efficiency investment would be better in terms of net present value, the problem is that people do not in general act on net present value calculations. [Fox-Penner, 2010]

There are several other barriers to more wide scale adoption of energy efficiency measures that would pay for themselves over their lifetime. The first of these is that it takes effort and training to keep up with the features of energy use technologies and evaluate their cost savings potential, and most consumers just do not have the knowledge needed. Related to this is the fact that it is much easier to buy more power than to consider alterations to one's home or office or factory. The second barrier is simply lack of available capital to finance the investments in energy efficiency, or unwillingness to use the scarce capital available to finance investments that take several years to pay themselves back and are not even directly related to the consumer's own business. [Fox-Penner 2010]

Yet another barrier to energy efficiency measures being adopted are the transaction costs involved in adopting them. Buying more power is simple, but energy efficiency measures require construction projects and changes to the way things are done. The fourth barrier is to do with the fact that most often decisions regarding a building's energy use are made by someone like a landlord or builder who will not be paying the electricity bills. This means

that they may see no benefit in installing more energy efficient technology. Additionally, the price of power rarely reflects the true cost of providing it, which means that the real value of saving electricity cannot be seen by consumers. [Fox-Penner, 2010]

Because of the human tendency to favour benefit today over benefit tomorrow, and the four hidden costs mentioned above it is likely that for energy efficiency to be utilised to its full potential some policies targeting these barriers will be necessary. There are several choices here, anything from adopting dynamic pricing that reflects the approximate cost of production for each hour, to including externalities in the power price to new building codes and energy efficiency standards, to offers of low-interest capital, to utilities helping with installing energy efficiency measures, to turning the responsibility over to the private firms that specialize in designing energy efficiency measures. [Fox-Penner, 2010]

Whichever method chosen to promote it, more energy efficiency would mean that the demand curve shifts to the left, distancing the intersection of demand and supply from the area where the supply curve becomes vertical.

3.3.3 Guiding the capacity mix

In recent years, concerns have arisen in Europe about excessive reliance on fossil fuels. This is mainly due to three reasons. First, burning fossil fuels produces greenhouse gases and other emissions, contributing to climate change. Second, fossil fuels are mostly located away from where they are used and often in politically unstable regions, thus reducing security of energy supply. In addition, the prices of fossil fuels are already high and quite volatile, and as the fossil fuels become more and more scarce, these effects are probably going to increase. Accordingly, many countries have been led to consider guiding their

capacity mix toward a more independent one, for example through renewable and nuclear power. [Van Hulle et al, 2010] [Mendonça, 2007]

3.3.4 Climate change mitigation

Globally greenhouse gas emissions are growing together with the population and economic output of many countries. There are several greenhouse gases, with the most important ones being carbon dioxide, nitrous oxides, methane, and chlorofluorocarbons (CFCs). When the concentrations of these gases increase in the atmosphere, they disturb the radiation energy balance of the earth by trapping energy into the atmosphere, instead of it being let into space. This warms the Earth. [VTT, 2009]

Climate change poses a serious threat to ecosystems and human life. It leads to increased temperatures, higher sea levels, often also significantly different amounts of rainfall, which can in turn lead to floods and dry spells. Climate change can also impact the humidity of the soil in many places, and thereby agriculture in general, and food production in particular, as well as water availability. Due to climate change, also extreme weather conditions are likely to become more common. Of course, the size of these impacts will depend on how far climate change will proceed; whether the temperature rise stops at two or four or six degrees will make a great difference. [VTT, 2009]

According to the largest study on the economic impact of climate change, the Stern report, the short run costs of climate change will be around 2.5 percent of GDP in Asia by 2100 and circa 2 percent in the Middle-East and Africa. The report estimates that the monetary costs will be lower in the Northern hemisphere. The long-run costs are estimated to significantly higher. However, the report estimates that the costs of mitigation will be considerably

lower. Therefore, in addition to the environmental impacts themselves, also the economic point of view encourages early action. [VTT, 2009]

Mitigation of climate change is no easy task, as “the inertia of the total system is tremendous”. The socio-economic inertia comes from the long life-times of investments, as well as slow changing attitudes and policies. Nature itself also has inertia; greenhouse gases have long life-times in the atmosphere, and the heat capacity of the “natural surface-atmosphere system is large”. Overcoming this inertia is no mean feat. Also, the reductions required to even stabilize greenhouse gas concentrations to a level that can be considered safe will require large emissions decreases; according to the IPCC for example CO₂ emissions should be cut by 50-85 % from 2000 levels by 2050 in order to limit temperature rise to about two degrees. And at present we don’t even know the precise relationship between radiative forcing and temperature increase, known as climate sensitivity. [VTT, 2009]

There are two principal ways to mitigate climate change. The first one is to reduce consumption or to at least change it to a direction with less emissions and lower energy intensity. The second way to cut emissions is to use technology better in both energy services and the generation of energy itself. In practice this means using more energy-efficient technologies as well as ones with low to zero emissions. Carbon capture and storage (CCS) as well as control of other emissions like methane, NO_x, and halocarbons also provide possibilities. Of course the consumption approach and technological approach can be coupled in order to produce truly lasting results. [VTT, 2009]

Further, it is most likely only possible to make sufficient reductions in the world GHG emissions unless all “significant emitters” participate in the effort. This means that countries

with hugely different emissions per capita, development stages, and financial means have to be able to reach some kind of consensus on climate treaties. Both policy instruments, like regulation, standards, financing, as well as other fiscal measures, and economic instruments such as emission trading and feed-in tariffs, tax exemptions, and green certificates can be used to speed the mitigation effort along. [VTT, 2009]

4 Ancillary and system services

As established in the previous chapter, power systems have needs beyond those that the energy-only market can meet. This chapter introduces the instruments used to meet those needs, called ancillary and system services, and introduces a framework for classifying them. Technically system and ancillary services are two different things; system services are provided by a SO to all users of the network, while ancillary services are provided by some users to the SO. However, the two are also interconnected as the system operator often buys ancillary services to be able to supply system services in turn. [Rebours et al, Part I, 2007] Thus, from now on they shall be referred to as ancillary services, although both are meant.

Because the liberalisation of the electricity industry has proceeded independently in different countries and because the power systems in these countries have been very different from one another to begin with, also the definitions for ancillary services, as well as their trading differ significantly from one country to another. In fact, there is such a large amount of different terms when it comes to ancillary and system services, that when comparing power systems, extreme care is necessary and confusion seems almost inevitable. [Rebours et al, Part I, 2007]

For the purposes of this thesis, the services are going to be divided into four categories; frequency control, capacity, coordination and operation, as well as system backup and restoration. The categories are used according to the article by Raineri et al, 2006, with the exception of the capacity category. Of these categories, frequency control and capacity will be examined further in the next chapters. There we will look at how the instruments in those categories are traded in the case areas of Denmark, Poland, and Pennsylvania-Jersey-

Maryland in the United States (PJM). But in this chapter, all instruments are introduced briefly. First, a short description of the dispatcher mindset is provided.

4.1 Dispatcher mindset

The consumption and production profiles and their broad balance produced by the day-ahead energy market, as well as a possible intra-day market form the basis for power dispatching. However, this broad balance is not enough for second to second system operation, and power dispatchers must refine it. During normal operation this is achieved through a combination of manual regulation and reserves that automatically respond to changes in frequency. [Verhaegen et al. 2006]

If the automatic reserves are not enough to keep the frequency within prescribed limits, further manual regulation through a balancing power market is undertaken. This is a market where power producers and consumers can submit bids to supply regulation up or down. These bids are usually used in the order of prices. Such a market does not exist in every country, however, and in these countries the manual control is done using reserves set aside for it. [www.Fingrid.fi]

If the disturbance in a system is so bad that even the balancing market or corresponding manual regulation is not enough to reinstate the balance, emergency procedures are used. These can include anything from requests for additional balancing bids, to orders to reduce consumption, to use of emergency reserves. [Kiener, 2006]

Besides frequency control, also transmission security must be taken into account in dispatching. This means that the dispatcher has to make sure that the power flowing in the grid does not breach the security limits of transmission lines, and if it does, then he has to

induce less generation in that location and more in another. The issue, in other words, is not the total generation, but rather the location of the generation. [Stoft, 2002]

	Energy-only	Other
Before the operating hour		Capacity market
	Day-ahead market	Ancillary market
	Intra-day market	
Operating hour		Regulation and disturbance restoration
After the operating hour	Imbalance settlement	Monetary settlement
	Monetary settlement	

Figure 2 Events in the energy-only market and the supporting markets with respect to one operating hour

Figure 2 is intended to clarify how the events in the energy-only market and the supporting markets relate to one operation hour, to the physical operation of the system. The events before the hour are to prepare for the hour, during the hour the plans made in advance are implemented and any deviations from them are corrected using regulation and reserves. After the hour, all monetary settlements related to the hour are carried out.

4.2 Frequency control and capacity

4.2.1 Frequency control

In order to keep the system frequency at its target level, the demand and generation must be kept in balance through controlling of production and consumption of power. This requires that a certain amount of active power reserves, or frequency control reserves, be

kept available in a power system. This reserve can usually be divided into three levels; primary, secondary, and tertiary. Figure 3 demonstrates the basic principle of power system balancing. Deployment times are the most important technical features of the frequency control services. [Rebours et al, Part I, 2007] These reserves are traded, whereas those used for system backup and restoration are usually not allowed to operate on the free market or any market.

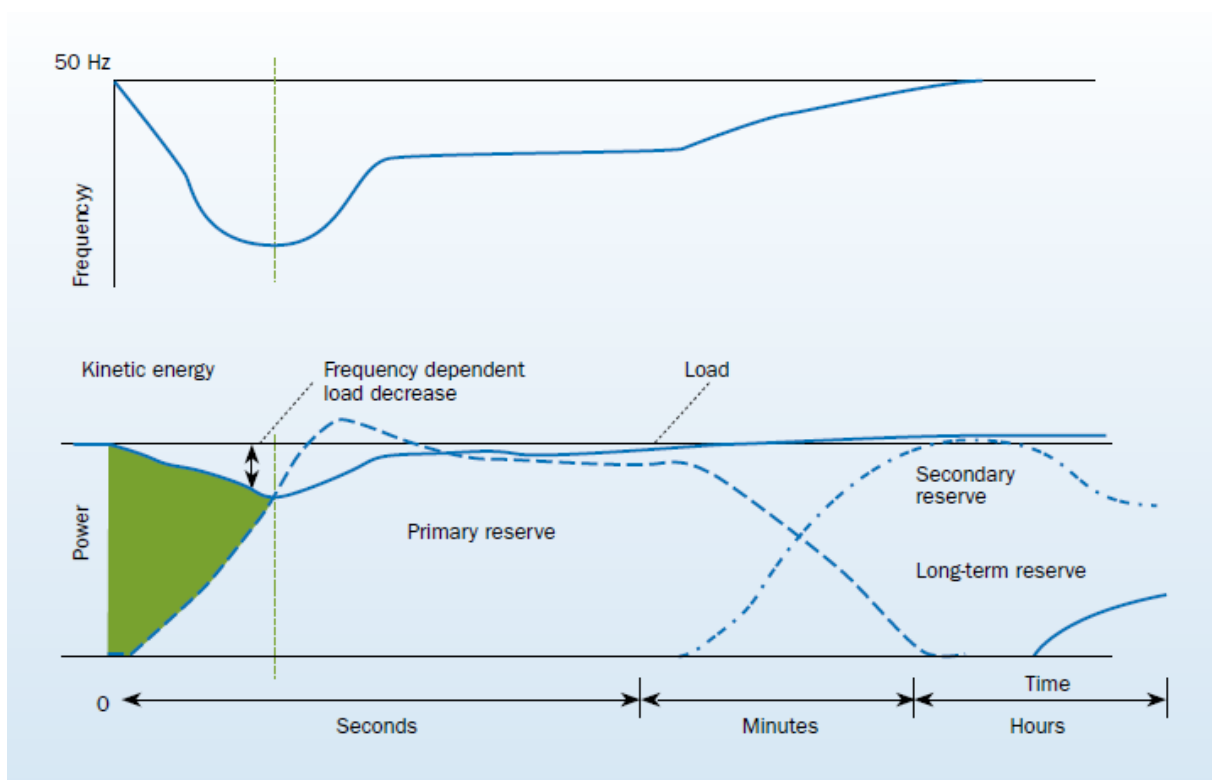


Figure 3 Principle of power system balancing [Van Hulle et al, 2010]

4.2.1.1 Primary frequency control reserve

Primary frequency control is local control that automatically adjusts the active power output of generators as well as the amount of consumption of controllable loads in order to reinstate balance between production and consumption of power and offset variations in frequency. In other words, it is used to deliver reserve power in the opposite direction of a frequency deviation. [Rebours et al, Part I, 2007]

Aside from being used to maintain the continuous balance in normal system operation together with manual adjustments, primary frequency control is also designed to stabilize frequency after large outages, and it is thus vital for the power system's stable operation. "All the generators that are located in a synchronous zone and are fitted with a speed governor perform this control automatically." Also loads can take part in this control by for example self-regulating or disconnecting. However, this demand-side contribution is not always included in calculating the primary frequency control response. [Rebours et al, Part I, 2007]

There are a couple of limitations to the provision of primary frequency control. First, many of the generators that increase their output upon a frequency drop can only maintain this higher output level for a given time. Thus, they must be replaced after a while. Another important point is that the primary reserve should be divided evenly throughout the network, in order to minimise unplanned electricity transmission across the system in case of outages and to improve security. [Rebours et al, Part I, 2007]

4.2.1.2 Secondary frequency control reserve

Whereas primary control limits and stops frequency deviations, secondary control brings the frequency back to its target level. Secondary control is automatic, centralised control that adjusts the active power output of generators so as to bring both frequency and interchanges with other systems to their intended values following a disturbance. Demand-side participation is not common in secondary control. [Rebours et al, Part I, 2007]

Secondary control is not vital to the operation of the power system, and thus some systems use only automatic primary control and manual tertiary control. However, all "large interconnected systems" have implemented also secondary control, as the manual tertiary

control isn't capable of removing overloads on tie lines fast enough. In the (former) UCTE, secondary frequency control is known as load-frequency control (LFD), and in the USA the preferred term is automatic generation control (AGC). The term AGC in the UCTE, on the other hand, means both dispatching and secondary frequency control. [Rebours et al, Part I, 2007]

4.2.1.3 Tertiary frequency control reserve

Manual changes in dispatching and unit-commitment are called tertiary control. It is used for restoring the primary and secondary reserves, for managing congestion in the network, as well as for returning the frequency and interchanges to the right levels, if secondary control has been unable to do this. [Rebours et al, Part I, 2007]

4.2.1.4 Demand response

Demand response can be defined as end-customers changing their electricity consumption from the nominal level in response to price changes or incentives or dispatch orders. It is used to decrease demand at times when the price of electricity is high, or when reliability of the system is at risk. It can also be used to induce more demand when electricity price is low. [Singh et al, 2010] [Mohagheghi et al, 2010] The programs for realising demand response can be divided into three groups, based on where the initiative for the demand response comes from. [Mohagheghi et al, 2010]

Closely related to demand response is load shedding, also called demand side or load side management. It consists of disconnecting parts of the distribution network when the power demand exceeds the maximum possible generation. For example in many developing countries it is common practice to have rotating regular periods or even times of day when power is not available.

Incentive based programs

In incentive based DR programs, a utility or other instance responsible for demand response, often called an aggregator, sends out either request or commands for demand reduction to the participating customers. Both directly controllable loads and loads that can be interrupted or reduced when they receive a signal can be used in these types of programs. Typical applications for the direct control are residential appliances or other residential loads. The loads that can be interrupted or reduced are usually larger, for example lighting, air conditioning, or heating and cooling in industrial processes as well as process scheduling. The notification time for demand response of this type can vary between some minutes to a couple of hours. [Mohagheghi et al, 2010]

Rate based programs

In rate based demand response, the price of electricity is changed either at intervals determined beforehand or dynamically, based on the time of day or week or year and the amount of currently available reserve margin. The idea is for the price of electricity to be highest during peak times and lowest off-peak, and for customers to voluntarily respond to the price changes. “The prices can be set a day in advance on a daily or hourly basis, or in real-time.” [Mohagheghi et al, 2010]

Demand reduction bids

Demand reduction bids are sent by the participating customers to the utility or aggregator, at the customers’ own initiative. In these bids the customers announce how much demand reduction capacity they have, as well as the price they want for it. “This program encourages mainly large customers to provide load reductions at prices for which they are willing to be

curtailed, or to identify how much load they are willing to curtail at the posted price.”

[Mohagheghi et al, 2010]

4.2.2 Capacity

4.2.2.1 Approaches to ensuring adequacy of capacity

The traditional vertically integrated utilities used to ensure adequacy of supply by considering forecasts of demand and estimates of the value of lost load (VOLL), and then building extra planning reserves based on these. The cost of this capacity was covered by a rate increase. Nowadays, many electricity markets have been restructured and there are three newer basic methods to ensuring adequacy. [Oren, 2000]

Energy only markets

In energy only markets, generators bid purely energy prices and if there are no constraints, all their bids that are lower than the market-clearing price of the current hour get dispatched and paid the market-clearing price. Capacity cost is recovered mainly through the difference between the market-clearing price and the marginal cost of the generator. An additional source of revenue can come from possible separated ancillary markets. [Oren, 2000]

Capacity payments

In a system where capacity payments are in use, generators receive the normal market-clearing price, but also an additional per MW payment for available capacity, regardless of whether that capacity is actually dispatched or not. This additional payment can also be based on generated energy. These capacity payments are collected from customers like other “uplift charges”, such as the transmission charge. “In some cases such as in Spain capacity payments are indistinguishable from stranded investment compensation, which are

viewed as an additional source of revenue for the generators that is needed in addition to the competitive energy revenues in order to guarantee their profitability.” [Oren, 2000]

Planning reserves requirement

The third approach to guaranteeing generation adequacy is in use in the eastern pools of the United States, for example PJM, NYPP, and New England. In these systems, “load serving entities” must either have or contract a prescribed amount of reserve capacity above their peak demand within a certain time period. What form this reserve requirement has and what the time frame is varies from system to system. [Oren, 2000]

Where reserve capacity requirements have been implemented, capacity markets to allow the trading of the capacity obligations have often emerged. The capacity markets together with the reserve requirement give generators the possibility of making additional revenue for their unutilized reserve capacity and also give an incentive to invest in reserves beyond what is required in the short term for ancillary services. [Oren, 2000]

The product on capacity markets can be defined as a certain amount of capacity being available at a certain place when requested within a certain reliability. [Zhao, 2010]

4.2.2.2 Support instruments for renewable power

Although renewable energy sources can potentially deliver many benefits, their market development has been relatively slow due to barriers in the existing market structures of countries. Examples of these barriers are public subsidies to fossil and nuclear power, coupled with no evaluations of their costs in the future, resistance from existing utilities not wanting new competition, governments preferring big, centralized power production solutions, as well as perceived investment risk and uncertainty. Other barriers are the often high costs of developing renewable power, difficulties in finding a “stable market” for the

generated power, and costs like environmental impact analyses, consent hearings, etc.

[Mendonça, 2007] [Barry et al, 2009]

To overcome these and other barriers to renewables development, many countries are adopting policies to support renewables. The main policy types in use globally are feed-in tariffs and quantity-based systems. Also other mechanisms like investment subsidies and tax instruments are used.

Feed-in tariffs

A feed-in tariff is a guarantee to producers of renewable power that their output will be bought, and at a predetermined price independent of the current market price. This guarantee price is designed to ensure that the renewable investment will be profitable, and is usually only in use for a certain time period; long enough to guarantee adequate profit and an acceptable level of risk for the investment. [Mendonça, 2007] [Barry et al, 2009]

Quantity-based systems

Quantity-based systems use governmental quotas or targets to guarantee market share for renewable power, thus ensuring that a certain minimum amount of it is produced. Internationally, quantity-based systems are about as popular as feed-in tariffs, at least in supporting wind generation. However, quantity-based systems tend to encourage the selection of least cost projects and for example in wind generation that means large scale wind farms in places with the best resources. At promoting small-scale generation they are less effective. Also, quantity-based systems are not well suited to small investors, as both the transaction costs and investment risk are quite high under these schemes. The risk comes from the fluctuation in power prices and “the need to negotiate power purchase agreements with utilities”. [Barry et al, 2009]

An example of quantity based methods is green certificates, which are widely used in for example in Europe. Green certificates are given as proof that a certain amount of electricity has been produced using renewable sources. A power producer gets as many certificates as he has produced renewable power; one certificate for every megawatt hour. Green certificates are a market-based method for supporting renewable power. With the certificates, energy sale and environmental values represented by the certificates have been separated and are sold on different markets. [Motiva website]

Investment subsidies and tax instruments

Investment subsidies are government help in paying for the initial investment costs of renewable power. They are attractive in particular to smaller developers with limited financing of their own, and they are also one of the most popular support mechanisms globally. Their size varies from country to country, for example in 2005 in Finland 30% was common for wind, and in Sweden it varied between 15 to 35%. [Barry et al, 2009]

Tax instruments in many forms can also be used to support renewables. Examples are tax credits, exemptions, accelerated depreciation, and carbon taxes. Accelerated depreciation has been used successfully in promoting small-scale wind generation; in Sweden and Denmark one of the main reasons that individual farmers started to build turbines on their land was the introduction of accelerated depreciation rate of 30%. [Barry et al, 2009]

Easing the consents process

Yet another way of encouraging more renewable generation is to “streamline” the process of obtaining the required consents; to lower the costs and the amount of time associated with it. This can e.g. mean making small-scale projects exempt from environmental impact analyses. [Barry et al, 2009]

Other instruments

Emission trading systems can aid in promoting renewable power, but usually they are not the primary source of support for it. They may make thermal generation relatively more expensive than renewable, but emission trading systems do not remove the issue of “finding a stable and economic market for the electricity generated; i.e. power purchase agreements will still need to be negotiated with retailers or large energy users”. Additionally, the carbon price in for example the EU emission trading scheme is volatile, meaning that it may not provide a reliable incentive for investment. [Barry et al, 2009]

4.2.2.3 Emission trading

The Kyoto Protocol from 2002 set specific greenhouse gas emission reduction targets for each participating country. The countries can participate in emission trading, which is the buying and selling of part of their emission allowances, in order to reduce their costs of meeting their targets. If a country’s emissions are below its allowed annual amount, it can sell the excess and get profit from it. Emission trading transactions, according to the Kyoto Protocol, can take place on four levels: international, national, industry, and project level. [Kurkovsky, 2006]

Emission trading schemes had been in place already before the Kyoto Protocol, so it is not a totally new concept. The systems are usually implemented either based on credits or on allowances. [Kurkovsky, 2006]

4.3 Other instruments

4.3.1 Coordination and operation

4.3.1.1 Voltage control through injection and absorption of reactive power

Maintaining the correct voltage in the grid is achieved by injecting or absorbing reactive power. [Kirby, 2010] Voltage control, like frequency control, is often divided into three

parts. Primary voltage control is automatic and keeps the voltage at a certain point, secondary voltage control is also automatic, but it “coordinates the actions of local regulators in order to manage the injection of reactive power within a regional voltage zone”. Tertiary voltage control is the manual optimising of the flow of reactive power in the network. Power producers may also wish to divide the voltage control into the basic part that they have to do in order to be a part of the grid and to the enhanced part that is not mandatory. Unlike for frequency control, the terminology for voltage control is quite unified across countries. [Rebours et al, Part I, 2007]

4.3.1.2 Imbalance settlement

How imbalance settlement is handled in a country or region depends on the market and network structures. For example in the UK, “cash-out prices” are determined for every hour of the day, and these are used to settle the imbalances between actual and contracted consumption and generation. In Austria, something called balance groups are used. Each group has a representative who is commercially responsible for the group and also manages and represents the group. [Zhang et al, 2009]

4.3.1.3 Nodal Marginal Pricing (NMP)

In Nodal Marginal Pricing, there is a different electricity price at every node in the power system. It is sometimes referred to as the “ideal pricing system”, because it can be used to produce a dispatch that takes the physical laws of transmission as well as the resulting limits and losses into consideration, unlike uniform pricing over the entire grid or even zonal pricing. On the other hand, it has been critiqued on the large number of prices being confusing. This criticism has led to some resistance in adopting it, as the large number of prices means that it is, among other things, harder to trace why an offer is not accepted, and also more complicated data handling and financial settlements. [Ding & Fuller, 2005]

4.3.1.4 Cross border transmission capacity allocation

There are many different ways of allocating cross border transmission capacity. These include auctioning, market coupling, and unifying the electricity markets of neighbouring countries. “Coordinated auctioning” was the method suggested by the European Transmission System Operators (ETSO) in 2001. This explicit auctioning of cross border exchange capacities has the advantage of being able to take the differences in the organisation of national markets as well as the structure of the larger grid formed by the national ones into consideration. Later, ETSO suggested an implicit auctioning approach, called “Decentralised Market Coupling”, which essentially consists of decentralised national power markets and a centralised market for the cross border transmission capacities that regulates the interactions between these national markets. [Genesi et al, 2008]

In market coupling, national markets are integrated and there are no explicit auctions for cross border transmission capacities. Instead, the capacities are assigned implicitly with the goal of maximising the combined economic surplus of everyone involved. [Genesi et al, 2008]

4.3.2 System backup and restoration

4.3.2.1 Emergency services

Emergency services are usually used according to a predetermined priority order. For example, the SO can first ask for new balancing offers, followed by orders to change generation output, asking for international help, disconnecting loads or lines, asking for emergency services that do not follow the usual technical requirements, and as a last resort using the emergency reserves that must be available to the SO at all times. For example if France, all of the technically available active power not being used for scheduled production has to be available for the SO to use as emergency reserve. [Kiener, 2006]

4.3.2.2 Black start capability

These are generators with the ability to start up by themselves, without the grid or any other “off-site power”, and enough real as well as reactive power capacity to aid in either energising a part of the grid or starting other generators. Usually, several black start generators are used at the same time, in order to restore the system faster, and the “independent islands of generation and load” are then later synchronized. [Feltes, 2008]

[Kirby, 2010]

Most often, the generators used for black start are hydroelectric units, diesel generator sets, aero-derivative gas turbine generator sets, or larger gas turbines together with diesel generator sets. [Feltes, 2008]

5 Frequency control and capacity instruments in Denmark

Denmark is located in Northern Europe, and has circa 5.5 million inhabitants. In 2009, Denmark produced 34,290 GWh of electricity, and consumed 33,872 GWh. In the same year, the country's exports of power came in at 10,930 GWh and imports at 11,264 GWh. The country is also a net exporter of oil, as well as of natural gas. [CIA, 2011][Energinet.dk]

Circa 48 percent of the electricity in 2008 was produced from coal, 19 % from wind, another 19% from gas, and 6 % from biomass, 5 from waste, and 3 from oil, and a very small amount from hydropower. Thus, the percentage of renewable generation in Denmark is quite high. [IEA.org]

5.1 Structure of the Danish power market

In Denmark, the power market has three separate parts; a day-ahead spot market, an intra-day market, and a market for reserves and regulating power. There is also a balancing market, but this is not so much a market in the traditional sense as it is the basis for settling imbalances. The electricity market of Denmark is part of the common Nordic market, Nordpool. Nordpool is owned by the Nordic TSOs, and most of the wholesale power trade in Denmark goes through it. Nordpool has two parts: Elspot and Elbas. [Energinet.dk]

Elspot is where the day-ahead spot trade takes place. It operates on an auction principle, where once a day a market price for each bidding area is formed by matching supply and purchase bids. Denmark is separated into two different bidding areas by the Great Belt. The auction mechanism used on Elspot is of implicit type, as transfer capacity is allocated at the same time as power is traded. In case of congestion, the market is split up into various price areas. [Energinet.dk]

Elbas is the market that market players can use for reaching a balance after the closing of Elspot. In Denmark, intraday trade is possible on all transmission interconnections to neighbour areas as well as on the Great Belt Power Link. This trade takes place on Elbas, where players can modify the result of trade reached on the Elspot market from after the closing of Elspot until one hour before delivery. [Energinet.dk][Nordpoolspot.com]

The Jutland-Germany border differs from the other interconnections: intraday trade there takes place via a capacity platform. “On the capacity platform access to a transport channel is given; the access is necessary in order to be able to make use of the intraday trade. Buying and selling energy cannot be affected through the capacity platform, but must be done through bilateral trade or through an intraday trading platform like e.g. Elbas.” [Energinet.dk]

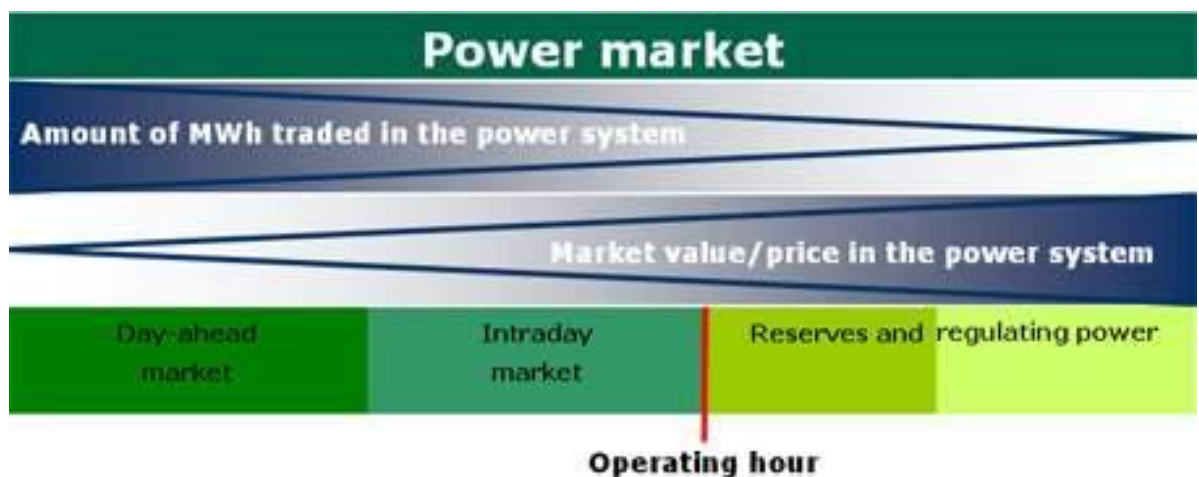


Figure 4. The structure of the Danish power market. [Energinet.dk]

The Danish Electricity Supply Act together with provisions from the TSO, Energinet.dk, determines the roles of the different market players. The TSO is responsible for the physical transmission system and for maintaining the supply-demand balance. The TSO also develops

market rules aimed at making both the wholesale and retail electricity markets well functioning. [Energinet.dk]

Balance responsible parties have agreed with the Danish TSO to bear the responsibility for production, consumption, and trade activities in a certain responsibility area. This means that they are also financially responsible for any possible imbalances in their responsibility area. [Energinet.dk]

Other roles in the power market are those of electricity supplier, companies with supply obligations, grid companies, producers, and end users with grid access as well as Nordpool power exchange. Electricity suppliers buy power from the exchange, directly from the producer, or another supplier and sells this power to end users. Customers can freely switch suppliers. Companies with supply obligation are "authorised companies supplying end users who have not exercised their right to choose an electricity supplier". The Danish Competition Authority regulates the prices they can collect from consumers. Grid companies are responsible for the management of the distribution grid and for metering both production and consumption. Producers sell their power either to Nordpool or directly to suppliers, and also sell power to and buy it from Energinet.dk in the regulating power market. Likewise also consumption can be used in the regulating market in keeping the power system in balance and secure. [Energinet.dk]

5.1.1 Regulating power market and balancing power market

The balancing market has two parts: a regulating power market and a balancing power market. The regulating power market is where the TSO buys power from or sells it to players during the delivery hour, based on bids for upward or downward regulation reserves made earlier. The balancing power market, on the other hand, is where the TSO buys power from

the players and sells it to them in order to “neutralize imbalances incurred by them”. The difference between these two markets is that the results of the balancing power trades cannot be calculated until after the delivery hour, when metering data is available and the size of the imbalances known. [Energinet.dk, 2008]

5.1.1.1 Regulating power

Energinet.dk is as the TSO of Denmark responsible for the balance of the total power system, and is a part of the Nordic regulating power market, NOIS. This market functions much like the spot market does, and the market price for regulating power is formed hourly, and is the same in all of the spot market areas if no bottlenecks exist. This regulating power (RP) price is also a determining factor in forming the price for balancing power. [Energinet.dk, 2008]

Players can enter the regulating power market in two different ways. They can respond to the TSO’s invitation to tender for ancillary services and regulating reserves by committing to keeping manual reserves available for use through entering bids for a certain amount of regulating power for a certain time period. If these bids are activated, then the player gets an availability payment in addition to the usual energy payment. [Energinet.dk, 2008]

The other way for players to enter the regulating power market is to make no specific agreement, or bilateral contract with the TSO about bidding, but rather just enter bids when they wish. However, using this method means that the players will not get an availability payment upon activation of their bids. [Energinet.dk, 2008]

In both methods, the bids can range from 10 to 50MW in size, and the player must be able to fully activate the bids within a maximum of 15 minutes of the activation order. The bids can cover one day of operation, and can be adjusted in terms of both price and volume until

45 minutes before delivery hour. The bids must specify separate prices and quantities for upward and downward regulation hour by hour. For upward regulation, the minimum price will be the spot price in the given area, and the maximum price for downward regulation will also be the spot price of that hour in the given area. Energinet.dk has defined a total maximum price for upward regulation of 37,500 DKK/MWh. [Energinet.dk, 2008]

The activation of regulation bids normally starts with the one with the lowest price. Sometimes some bids are bypassed, if their activation is prevented by a bottleneck or if they cannot be activated in a manner that complies with the Nordic system operators' conditions, or if there is some sort of special situation with the regulation. In special situations where there are not enough bids for regulating power, the TSO may ask for more bids. The activation orders are communicated to players either through power schedules "at 5-minute intervals" sent by the TSO to them, or through direct activation without schedules. [Energinet.dk, 2008]

In both cases, the commitment of the player is broken down into a schedule of many 24MWh/h commitments, and settlement is then based on this "supplementary schedule" together with the bid that was approved for regulation. Thanks to the supplementary schedule, there is available a time series of the commitments of players' activated regulating bids. The next day, the TSO sends the player a "statement" of the volumes activated and prices involved. The player then has some hours to comment on this statement, on for example possible discrepancies. Possible differences have to be settled the same day, but if this is not possible they are settled outside the normal procedure at a later date. Billing and paying for regulating power takes place a month at a time. [Energinet.dk, 2008]

The RP price on the Nordic regulating power market is calculated every hour based on a marginal price principle, meaning that it most is often set at the level of the most recent bid to be activated on the common list. This is of course true only if bottlenecks or anything else don't prevent the free flow of power between the different spot market areas. In case bottlenecks do exist, the regulating power market area is split, and the area with a bottleneck will have a separate price. [Energinet.dk, 2008]

If both upward and downward regulation bids are activated in the same hour, then the price is determined differently. For example, when the aggregate regulation is upward, the price for activated downward regulation is the one in the bid ("pay-as-bid") and the upward regulation price is the common RP price. And this applies also vice versa.

In some cases, Energinet.dk selects regulation bids for upward or downward regulation in another order than the price order. This is called special regulation, and it may be required in case of bottlenecks or restrictions in the Danish grid or in the transmission grids of neighbour areas. Another possible reason is announced or unannounced tests of reserve plants. [Energinet.dk, 2008]

5.1.1.2 Balancing power

The balancing power market is where the TSO manages the unforeseen imbalances between production and consumption in its area. [Nordpool Spot web page]

Balancing power settlement is based on notifications and power schedules sent by the balance responsible parties, in practice retailers of power, as well as their metered production and consumption. The notification comprises at most three things; the original BRP notification sent the day before and approved by the TSO, adjustments made during the day of operation, and the supplementary schedule. [Energinet.dk, 2008]

After the day of operation, grid companies or “their metering point administrators” send metered time series of production and consumption to the TSO in order that purchase and sale of balancing power can be calculated. This calculation of imbalances between trade and actual consumption and production is done separately for Eastern and Western Denmark. Also the imbalances between actual production and notifications as well as actual consumption and notifications of it are calculated separately, and thus BRPs receive two hour-by-hour balance calculations for every 24 hours. [Energinet.dk, 2008]

The balancing market has active and passive participants, the active ones being those producers and consumers that can regulate their production or consumption on request from the TSO. The passive participants, on the other hand, are all of the companies that are connected to the grid and have balance agreements with a TSO. All of their production and consumption is measured and the difference between planned and measured generation is settled at the prices that are established during real time balancing. [Nordpool Spot web page]

Retailers estimate the consumption of their end customers, and buy the required amount of power before delivery hour. Then after the delivery hour, the accounts are settled. In case customers have used less power than estimated initially, the retailer “has per definition sold the excess power to the system operator”, and the system operator pays the retailer for the power. If, on the other hand, the customers have used more power than was estimated, the “retailer automatically buys power from the system operator”. As a result of this trading with the system operator, the retailer reaches a balance between his net purchases and consumption, thus the name balancing power. In essence then the balancing power market is a market between the TSO and retailers of power. [Nordpool Spot web page]

If for example a retailer's customers have used less power than the retailer has bought from the supplier before delivery hour, this means that the retailer has in effect sold power to the TSO. This power is what is called the balancing power. The TSO then pays the retailer for this power. If the TSO had to buy up-regulation during the hour in question, the retailer gets paid the same up-regulating price that the producers that sold the up-regulation to the TSO during that hour. This price will most often be higher than the market price. If the TSO had to buy down-regulation during the hour in question, the retailer gets paid the down-regulating price, usually lower than the market price. [Houmøller, A. 2009]

In the opposite case, where the retailer's customers have used more power than the retailer purchased in beforehand, the retailer has to purchase this extra amount from the TSO who then charges the retailer for it. Again, if the TSO has had to buy up-regulation during this hour, then the TSO charges also the retailer the up-regulating price, and if he has had to purchase down-regulation he charges the down-regulating price. [Houmøller, A. 2009]

Also producers may have to settle balancing energy with the TSO using this market, in case they fail to produce according to plan. This can happen for example if a plant breaks down ten minutes before operation hour, when it is no longer possible to purchase power from another producer. "The retailer has to pay the producer, even though the producer has not produced anything. In this instance, the TSO sells balancing energy to the producer, and the producer resells the energy to the retailer." [Houmøller, A. 2009]

Although the basic procedure for settling the balancing energy with the TSO is the same for the producer as well, the price is determined somewhat differently. During an hour with up-regulation, the producer who produces too much does not get the up-regulating price but instead the market price. Those producing too little will be charged the up-regulating price.

During hours with down-regulation, producers who produce too much get the down-regulating price and those producing too little are invoiced the market price. [Houmøller, A. 2009]

Even if no active regulation has been used, players still have imbalances to be settled. This is also done by Energinet.dk, and the balancing power is traded between players at the spot market price, thus yielding no profit to the TSO. [Energinet.dk, 2008]

5.2 Market arrangements for frequency control and capacity instruments

5.2.1 Ancillary services in Denmark in general

In order to ensure secure and reliable power system operation, Energinet.dk buys ancillary services. The volume and type of ancillary services needed varies dynamically throughout the year, and there are also some regional differences between Eastern and Western Denmark. Ancillary services are bought from electricity consumers and producers in Denmark and neighbouring countries, and used for various purposes. Thus also the requirements for their supply vary, and there are some differences in the supplier requirements also between Eastern Denmark (DK2), and Western Denmark (DK1). The Great Belt divides Denmark into these two parts. [Energinet.dk]

The services that Energinet.dk buys in Western Denmark include primary reserves, secondary reserves, Load Frequency Control (LFC), black-start capability, manual reserves, and short-circuit power, reactive reserves as well as voltage control. In Eastern Denmark, Energinet.dk buys services called frequency-controlled disturbance reserve, frequency-controlled normal operation reserve, manual reserves, and short-circuit power, reactive reserves as well as voltage control. Of these, frequency controlled disturbance reserves are

the only reserves, for which only upward regulation bids are invited. All other reserves are used for both upward and downward regulation. [Energinet.dk]

In order to supply ancillary services to the TSO, a supplier has to sign a main agreement. These are only signed with balance responsible parties for production and consumption. Additionally, all the plants that supply the ancillary services have to be approved by Energinet.dk. A main agreement simplifies the process of further transactions, as those suppliers that are parties to one don't have to send bids to the daily reserve auctions. [Energinet.dk] [Energinet.dk, 2010]

5.2.2 Primary reserve, Western Denmark (DK1)

Primary reserve is used for stopping frequency deviations. It is automatic, and supplied by production or consumption that automatically responds to frequency deviations in the grid, by means of regulating equipment. Denmark is part of the ENTSO-E RG Continental Europe synchronous grid, where all TSOs are responsible for providing a certain share of the combined primary reserve requirement. Denmark's share is determined based on the share of Western Denmark's power production of the total ENTSO-E RG Continental Europe group production. In 2011, the Danish share of the combined requirement is +/- 27MW. The Danish TSO buys the primary reserve in daily auctions. [Energinet.dk, 2010]

Western Denmark can also import and export primary reserves from other TSOs in the Continental Europe group, but as these transfers are limited to neighbour TSOs in the same "control block", this in practice means Germany. Before such transfers can take place, an agreement has to be made between the TSOs involved, and the maximum transfers allowed are +/- 90 MW. But it is also possible to import reserves up to several hundred MW from

Sweden, Norway, Finland, and DK2, i.e. Eastern Denmark, provided that transmission capacity is sufficient. [Energinet.dk, 2010]

The primary reserve “must as a minimum be supplied linearly at frequency deviations of between 20 and 200 MHz”, this is relative to the goal frequency of 50Hz. Half of the reserve has to be supplied within 15 seconds, and the rest in full within 30 seconds, at a frequency deviation of +/- 200 MHz. The reserve must be possible to maintain until subsequent automatic or manual reserves are activated, but the maximum time is 15 minutes. After use, the reserve has to be “re-established” after 15 minutes. [Energinet.dk, 2010]

The auction for primary reserve is held once daily, for the next 24 hours at a time. The 24-hour period is divided into four-hour blocks for the auction. Bids are sent to the TSO via Ediel, which is a communication tool. All bids must be with Energinet.dk by 3 pm the day before the 24-hour period, and must include volumes and prices per MW for reserve power for each four-hour block of the following 24-hour period. The minimum bid is 0.3 MW. Bids are selected by Energinet.dk in their entirety or not at all, and they are accepted in the order of increasing prices. In case there are not enough bids, Energinet.dk emails all players with a request for bids. [Energinet.dk, 2010]

All accepted bids receive an availability payment that corresponds to the price of the highest priced bid accepted. If it turns out at a later time that the reserve offered was not actually available, the availability payment is cancelled. “No calculation is made of energy volumes supplied from primary reserves.” [Energinet.dk, 2010]

5.2.3 Secondary reserve/ LFC, Western Denmark (DK1)

Secondary reserve is used to restore frequency to 50 Hz after a major disturbance, following the stabilisation done using the primary reserve. Secondary reserve actually has two tasks;

first, it releases the primary reserves, and second, it restores possible imbalances on interconnections. Secondary reserve production and consumption units respond automatically to signals from the TSO. The response is possible by means of regulating equipment. The signal from Energinet.dk is sent online as an output value with a reference to the bid made by the player. [Energinet.dk, 2010]

Energinet.dk buys the secondary reserve once a month, according to requirements published on its web pages at the latest on the 10th day of the prior month. The ENTSO-E RG Continental Europe group recommends a secondary reserve of circa +/- 90 MW. However, this recommendation is not binding as an upper limit, and in Denmark an additional consideration is the uncertainty in the forecasts of wind power availability. ENTSO-E RG is also about to make it possible to purchase up to one third of the secondary reserve outside of DK1, and to respectively sell secondary reserve to outside DK1, up to one third of the buying TSO's reserve requirements. These are of course subject to whether there is enough transmission capacity available. [Energinet.dk, 2010]

The secondary reserve requested must be supplied within 15 minutes. It can be supplied either through "in-service" plants exclusively or through a combination of in-service and fast start-up plants. However, "the reserve to be supplied within any coming five-minute period must be supplied by in-service units". An added requirement is that it has to be possible to continuously maintain the regulation. [Energinet.dk, 2010]

As with primary reserve, a regulation delivery can be a combined delivery of several production or consumption units with different properties, provided that the combined system is verified to Energinet.dk and certain conditions are met. These conditions include

rules on balance responsibility in such cases and also on how the bids are handled by Energinet.dk. [Energinet.dk, 2010]

All bids for secondary reserve must be sent by email to Energinet.dk by a deadline, after which Energinet.dk reviews the bids and negotiates with “relevant” bidders. The bids are evaluated based on, in order of importance, the price of service offered, place of service delivery, as well as the technical characteristics of the production or consumption unit that has made the bid. Unlike with primary reserve, here the selection of bids is not based only on price, and neither does Energinet.dk have to accept the bids as they are. Energinet.dk may for example accept parts of bids, order other volumes than those offered, and also after agreement with the reserve supplier alter the agreement periods. [Energinet.dk, 2010]

Also the price of secondary reserves is determined in individual negotiations between the bidder and Energinet.dk. If it is later shown that the capacity was not actually available, the capacity payment is cancelled. “Deliveries of energy from secondary upward regulation reserves are settled per MWh at the DK1 electricity spot price plus DKK 100/MWh, however based at least on the regulating power price for upward regulation. Deliveries of energy from secondary downward regulation reserves are settled per MWh at the DK1 electricity spot price less DKK 100/MWh, however not exceeding the regulating power price for downward regulation. The energy delivered is calculated on the basis of registrations in Energinet.dk’s SCADA system as an integrated value of expected activated output per quarter.” [Energinet.dk, 2010]

5.2.4 Frequency-controlled normal operation reserve, Eastern Denmark (DK2)

Frequency-controlled normal operation reserve is used in Eastern Denmark to restore frequency to the 50Hz level after frequency deviations. Like primary reserve in Western

Denmark, frequency-controlled normal operation reserve is also automatic. It is provided by production and consumption units that respond to frequency deviations in the grid by means of regulating equipment. [Energinet.dk, 2010]

The TSOs in the ENTSO-E RG Nordic synchronous area have joint responsibility for providing enough frequency-controlled normal operation reserve for the area. The total requirement for this reserve in the area is 600MW, and DK2 has to provide an amount of this proportional to its power production in relation to the entire Nordic area. This amount is determined once every year, and for 2011 the DK2 requirement is 23 MW. [Energinet.dk, 2010]

ENTSO-E RG rules allow the purchasing and selling of this reserve from and to outside the Danish TSO's area, so long as two thirds of the reserve are supplied within the area. The reserve must be supplied within +/- 100 mHz of the reference frequency of 50 Hz. Regardless of the size of the frequency deviation, the activated reserve has to be supplied within 150 seconds. It also has to be possible to maintain the regulation continuously. Deliveries can also here be combined deliveries of several production or consumption units that together can produce the response in the required time, so long as this arrangement has been agreed upon with the TSO. [Energinet.dk, 2010]

The frequency-controlled normal operation reserve is bought at daily auctions. The auctions periods of 24-hours are divided into six four-hour blocks, and bids for the auction must be sent via Ediel to Energinet.dk by 3 pm on the day before operation, at the latest. The bids must include the volume of megawatts offered for each block, as well as the price requested for it. The minimum bid is 0.3 MW. [Energinet.dk, 2010]

Bids are accepted in the order of increasing price per megawatt, and they are accepted in whole or not at all. In case there are too little bids, Energinet.dk requests more by e-mail. All accepted bids receive an availability payment that corresponds to the price of the highest priced bid accepted. Again, unless the capacity is actually available, the availability payment will be cancelled. “No calculation is made of amounts of energy supplied from frequency-controlled normal operation reserves.” [Energinet.dk, 2010]

5.2.5 Frequency-controlled disturbance reserve (DK2)

The frequency-controlled disturbance reserve is used in case of major disturbances, such as outages of major plants or lines. It is fast, automatic upward regulation supplied by either production units or consumption units that respond to frequency drops through the use of regulating equipment. When the system frequency drops under 49.9 Hz, this reserve becomes active and stays so until the frequency has been restored or manual reserves take over. [Energinet.dk, 2010]

In the ENTSO-E RG Nordic grid, there is a combined requirement for frequency-controlled disturbance reserves, and the TSOs of the area are jointly responsible for providing this. This requirement is the size of the single largest contingency in the grid, minus 200 MW. Eastern Denmark’s share of this is determined based on the largest contingency in DK2, and is determined once a week. For 2011, the total share of DK2 is 150 MW. [Energinet.dk, 2010]

A minimum of two thirds of the reserve has to be supplied from within the TSO’s own area, but the rest can be imported. Part of the disturbance reserve of the ENTSO-E RG Nordic area comes via HVDC connections from Germany and DK1 via Sweden. [Energinet.dk, 2010]

Frequency-controlled disturbance reserves have to be capable of supplying non-linear power in the frequency range of 49.5 to 49.9 Hz, supplying half of their response within five

seconds, and also supplying the rest of the response within another 25 seconds. Production or consumption units with different properties can make combined deliveries, provided that this arrangement has been agreed upon with Energinet.dk. [Energinet.dk, 2010]

Energinet.dk buys also frequency-controlled disturbance reserves at daily auctions for the coming 24-hour period. Like with the above discussed reserve types, the 24-hour period is for the purposes of the auction divided into four-hour blocks. Players' bids must show the volume they are willing to offer within each block, and the price at which they are willing to offer it. These bids are sent to the TSO via Ediel by 3 pm on the day before operation. Again the minimum bid size is 0.3 MW, and bids are accepted in the order of increasing price per MW. Bids are accepted in total or not at all, and when there is a shortage of bids, the TSO requests more via email. All accepted bids get an availability payment that corresponds to the price of the highest bid accepted. "No calculation is made of energy volumes supplied from frequency-controlled disturbance reserves." [Energinet.dk, 2010]

5.2.6 Manual reserve, DK1 and DK2

Manual reserve is activated manually by Energinet.dk from its Control Centre, through orders to relevant suppliers. In case of minor imbalances, manual reserve relieves the LFC and frequency-controlled normal operation reserve, and it is also used to ensure balance in case of possible outages and limitations in generation or interconnections. [Energinet.dk, 2010]

"The reserve is requested at daily auctions, to meet the demand during individual hours." Within 15 minutes of activation, the reserve has to be fully supplied. In activating the reserve, production schedules and consumption forecasts previously agreed upon by the supplier and Energinet.dk are amended. Several production or consumption units can make

combined deliveries, after agreeing on the arrangement with Energinet.dk. [Energinet.dk, 2010]

The Danish TSO buys both upward and downward manual regulation via auctions held once a day for “each of the hours of the coming 24-hour period”. Final bids are sent to the TSO via Ediel by 9.30 am on the day before the 24-hour operation period. The bids must have the volume the supplier is willing to offer and the price per MW at which he is willing to offer it for each hour of the 24-hour period. Bids can vary in size between 10 and 50 MW. [Energinet.dk, 2010]

In the basic scenario, the TSO covers his need of manual reserves with bids starting from the lowest priced ones, and proceeding to the more expensive ones. However, in special cases when the TSO needs reserves in some particular geographic location, he will disregard the price order and consider the locations of the bids instead. Bids are accepted in total, or not at all. In case of insufficient bids, Energinet.dk asks for more via email. [Energinet.dk, 2010]

All accepted bids get an availability payment that corresponds to the price of the highest priced accepted bid. This availability payment is subject to two rules. First, the player has to “subsequently submit a bid for activating all the capacity in respect of which an availability payment is obtained”; this applies for the hours that the player receives the availability payment for. Second, the capacity must really be available for use, and if shown otherwise, the availability payment is cancelled. Deliveries are checked on a test basis [Energinet.dk, 2010]

In some cases, the Great Belt connection from DK2 to DK1 can be fully loaded and then Energinet.dk will need more manual reserve than what it bought in DK1 in the morning. It

will then have an additional auction in the afternoon, just like the one held in the morning, but with separate bid IDs for the bids in this auction. [Energinet.dk, 2010]

5.2.7 Short-circuit power, reactive reserves, and voltage regulation, DK1 and DK2

Short-circuit power, reactive reserves, and voltage regulation are used for ensuring safe and stable operation in the power system. After Energinet.dk has received the operational schedules for the next day, it checks them for load flow, short-circuit power, n-1 situations, and reactive reserves. If there are any changes within the 24-hour operation period, these are checked again. [Energinet.dk, 2010]

Only “primary” units that are connected to the high-voltage grid can provide short-circuit power and reactive reserves at present. Energinet.dk states that three primary power stations must be operative in both Western and Eastern Denmark, and in Western Denmark these units have to be at three different locations. [Energinet.dk, 2010]

In order to ensure the short-circuit power, reactive reserves, and voltage regulation, the Danish TSO can request forced operation of units at various times. For example, on a monthly or weekly basis, early the day before, after the close of the spot market, after receiving first operational schedules, and during the 24-hour operation period. If there is not enough of any of the three capacities, then the “balance” watch of Energinet.dk can undertake special regulation or forced operation in order to ensure system security. [Energinet.dk, 2010]

If it is in any way possible, bids will be requested in advance for the solving of the problem, and this means that players may be asked to bid at quite short notice. Forced operation is

settled as billed, and separate payment is made for short-circuit power volumes, MVA, reactive power, and MVAr that are supplied. [Energinet.dk, 2010]

In the weekly or monthly case, bids are sent to Energinet.dk via mail or email, and after possible negotiations, Energinet.dk orders these services using a purchase order. Payment is made for keeping the plants in operation, and cancelled if it turns out that they were not really in operation. This does not apply in the case of possible breakdowns, when the TSO will take on the responsibility for starting up a new plant. [Energinet.dk, 2010]

5.2.7.1 Neighbouring TSOs

When it comes to interconnections with neighbouring TSOs, Energinet.dk must fulfil the approved 24-hour notifications. There are slightly different rules for the settlement of possible imbalances for each interconnection. [Energinet.dk, 2008]

5.2.7.2 Force majeure situations

In situations where there is a threat to the security of supply, and which can leave large areas without access to power, for example large or extreme weather, Energinet.dk can declare force majeure. In such a situation, Energinet.dk can use all resources in the system, within their individual technical limitations, in order to restore or secure “normal operational reliability”. At the same time, rules as to settlement of balancing power are suspended and balancing power is settled at the area price, while market players pay each other according to contracts, as in any other situation. [Energinet.dk]

5.2.8 Ensuring capacity adequacy

Energinet.dk is “legally responsible for ensuring enough capacity”. At the moment there are no capacity payments or obligations in use, but they are apparently in the pipeline; there is “work in progress within this area”. At present, a producer has to send an application to the Danish Energy Agency if he wants to take a generating unit out of operation. Then

Energinet.dk delivers a statement, in which it either opposes or approves of the removal of the unit. There is no exchange of money involved in this process. [Henning Parbo, Energinet.dk]

A new generating unit can be installed after an investor first receives necessary local permissions. In the years 2006-2009, circa 280 MW of capacity has been built to serve solely as manual reserves. [Henning Parbo, Energinet.dk]

5.2.9 Guiding the capacity mix

In guiding the capacity mix, the government plays the main role. The political wish is to “bring forward investments” in both on- and offshore wind power, and there are several subsidy schemes in use for this purpose. [Henning Parbo, Energinet.dk]

In Denmark the generation of power from renewable sources is supported using price premiums and fixed feed in tariffs. As a general rule, the support scheme in place when a plant is connected to the grid applies for the life time of the plant. Yet historically, the level of support has varied a lot, meaning that there is a high level of uncertainty about the support amount at the time of investment. [Danish Energy Agency web site]

In 2008, the level of support that power from wind, biomass, and biogas receive was increased. The support level for solar PV, wave power, fuel cells, and other renewables remained the same, but a fund that supports the adoption of these technologies at the sum of 25 million DKK per year for a time period of four years, was founded. Another fund, EUDP, gives out one billion DKK worth of funds annually to support the development and demonstration of new energy technologies. [Danish Energy Agency web site]

The funds for the support for renewable energy are collected by Energinet.dk, as a so called Public Service Obligation (PSO) on all consumers’ electricity bills. This PSO is the tariff

charged by Energinet.dk on behalf of the society in order to finance subsidies for renewable energy production and development. In the last quarter of 2010, the PSO was 8.5 ore/kWh in DK1, and 7.7 ore/kWh in DK2. The funds gathered with the PSO tariff are used for various purposes, including as subsidies for environmentally-friendly power production, to pay for connection of said generation to the grid, to ensure security of supply, to perform environmental investigations with regard to offshore wind, and R&D of environmentally-friendly generation. [Energinet.dk homepage]

The goal of the Danish government is for Denmark to in the long term become totally independent of fossil fuels, which at present account for 85 percent of the country's energy need. There are two quite obvious reasons for this goal; the GHG emissions of fossil fuels and the constantly decreasing security of supply due to supplier concentration in often unstable areas and increasing prices brought on by the gradual decreasing of reserves. [Danish Energy Authority, 2007] Of course there are differences between the fossil fuels; for example coal is a readily available fuel and the risks in terms of its price and availability are small when compared to natural gas or oil.

Denmark can be thought of as being in quite a good position to handle these challenges, as it already has experience with "developing new and efficient energy technologies and applying them in practice". At the same time, it is stated that any new energy policy adopted has to be cost effective and help in maintaining growth, high employment, as well as competitive advantage. Also international cooperation, particularly with the EU is mentioned to be essential. These are the reasons behind the government adopting a long-term energy policy until 2025. [Danish Energy Authority, 2007]

By 2025, the Danish government has stated that it will reduce the use of fossils in the country by 15 percent, as well as “effectively counteract the rises in overall energy consumption, which must remain static”. The policy names three crucial areas, where the goals are to be reached. These are efficient energy generation and consumption, renewable energy, as well as new and more efficient energy technologies. [Danish Energy Authority, 2007]

The area of efficient energy generation pertains to the goal that Denmark needs to continue to be able to have significant economic growth without this increasing overall energy consumption as has been the case since 1972, and that this must be accomplished through the use of “market-based initiatives”. As an example of a specific goal, it is mentioned that initiatives in energy saving have to grow by 1.25 percent per annum. [Danish Energy Authority, 2007]

In the crucial area of renewable energy, the government is going to provide “effective market-based initiatives which in time with the development of new technology will increase the share of renewable energy consumed while ousting fossil fuels”. By 2025, the target is to cover at least 30 percent of energy consumption with renewable sources. By 2020, the share of bio fuels in transportation is to be increased to 10 percent. It is possible that partial targets will be set also before 2020, if technologies that are both economically competitive and environmentally sustainable are developed before then. [Danish Energy Authority, 2007]

The final crucial area of new and more efficient energy technologies pertains to the goal of providing optimal conditions for research into energy technology for the Danish researchers. This is in order to make it possible to develop new technologies, and already known

technologies to the point where they can be brought to the market. By 2010, the goal was to establish annual support of DKK 1 billion to research, development, and demonstration of energy technology. The technologies that are seen as the most promising in terms of the Danish objectives are second generation bio fuels, hydrogen and fuel cells, wind power, and energy efficiency, in buildings especially. [Danish Energy Authority, 2007]

In more detail, the government's proposals include a reform of the subsidy system to renewables (PSO) to get a lower unit cost for renewable energy, increased use of biogas, more wind energy, more waste usage in central power stations for CHP, rationalisation of the tax system to support renewable adoption and fossil fuel decrease, more heat pumps in households to replace old oil boilers, and more flexibility in the choice of fuels for electricity generation and heating with the goal of promoting gradual increases in the use of bio fuels in CHP. [Danish Energy Authority, 2007]

Increased amounts of large scale wind and other, more local, renewables mean that the grid will have to be expanded. Also the natural gas infrastructure will have to be renewed, in order to get access to Russian and Norwegian natural gas, when production from the reserves in the North Sea starts to drop off and Denmark will have to start importing gas. It is predicted this will happen in 2015. Aside from expansion, another important issue is clarifying which geographical areas will be suitable for offshore wind turbines, and how many wind farms each area could accommodate. [Danish Energy Authority, 2007]

5.3 Challenges in the Danish power system/ in realising the energy policy 2025

The Danish Energy Association states that one of the biggest challenges in the Danish system is the improvement of energy efficiency. According to the Energy Association this is due to the fact that there is at the moment no proper control over energy consumption and

GHG emissions in the transport, agriculture, non-energy-intensive industry sectors, as well as individual heating in private homes and the public sector. In other words, all other areas except power generation and energy-intensive industry covered by the European emission trading system. It is further stated that unless something “drastic” is done about energy efficiency in these areas, the emissions will soon “threaten the carbon account”. The prediction is that if no action is taken, Denmark will face a deficit of minimum four million tonnes in the carbon account. [DanskEnergi website]

The present consumption of fossil fuels in the Danish system is undesirable, as it makes Denmark dependent on producer countries and the insecurities of transport routes, as well as contributing to GHG emissions. Also their increasing prices are a threat, in that to remain competitive the Danish industry must also have access to competitively priced electricity. These reasons have led to the ambitious goal of Denmark ultimately producing all its energy through renewable sources. Keeping energy consumption from increasing will be a large part of reaching this goal. [Danish Energy Authority, 2007]

Also the Great Belt Power Link that was taken into operation on the 20th of August 2010 has brought some challenges. The DC link has a capacity of 600 MW and unites Western and Eastern Denmark. The two still remain separate bidding areas, but the link can be used for spot market, Elbas, and the regulating power market, and off-setting imbalances in both areas, as well as sharing reserves between DK1 and DK2. [nordpoolspot.com] [Birkebæk, 2009] The link has taken electricity prices down, which means that the owners of previously built reserve plants are not terribly happy as their plants are no longer feasible. [Iversen, Bent]

A large challenge to the whole system is the “volatility in the market due to interconnections and the large amount of wind”. This volatility makes it difficult to plan investments (“price a big plant”), when you “don’t even know the price for the next day”.

[Iversen, Bent]

6 Summary of instruments in Denmark, Poland, and Pennsylvania-Jersey-Maryland (PJM) in the United States

The previous chapter on Denmark was an in-depth look at how the developed framework for frequency control and capacity adequacy functions in the case of a specific country. This chapter will include similar surveys of two further power systems; Poland and Pennsylvania-Jersey-Maryland (PJM) in the United States. However, here we will not go into so much detail, but rather stay on the general level of identifying the different instruments used for frequency control and capacity adequacy assurance.

The main purpose of this chapter is to identify the dimensions on which the instruments differ between the power systems in question. To determine the dimensions that need to be specified in order that an instrument is defined, that it can be bought; in other words the dimensions that are essential in terms of market design. These are the parameters that players wishing to enter said markets need to be aware of.

The tables below describe the instruments used for controlling frequency and ensuring capacity adequacy in Denmark, Poland, and PJM. Table 1 shows the frequency control instruments used in Denmark. These have already been discussed in the previous chapter, so here just a brief recapitulation.

6.1 Summary of instruments

In DK1, in other words Western Denmark, primary reserve is the reserve that automatically responds to frequency deviations. The response has to start in 15 seconds, and the reserve has to be in full operation within 30 seconds. The maximum time that the reserve is used is 15 minutes, but after use it has to be re-established, i.e. ready for use again, in another 15 minutes. Primary reserve is traded in a daily auction, where bids are selected in the order of increasing prices. Bids are selected in total or not at all. Both production and consumption

units can offer primary reserve in the auction, and all accepted bids get an availability payment corresponding to the value of the highest priced bid accepted. [Energinet.dk, 2010]

Secondary reserve in DK1 is also automatic, but full operation is only required in 15 minutes. However, it must be possible to supply the reserve continuously. The TSO buys this reserve based on bids from production or consumption units and negotiations with them. Bids are selected based on multiple criteria, not just price. During the negotiations, the bids can be modified; they don't have to be accepted as is. The providers of secondary reserve are paid the spot market price plus an additional payment per MWh. [Energinet.dk, 2010]

In DK2, the frequency-controlled normal operation reserve is an automatic reserve that has to be supplied in 150 seconds, regardless of the size of the frequency deviation. Continuous supply must be possible, and the reserve can be provided by either production or consumption units. The TSO buys the reserve on daily auctions, where bids are accepted in the order of increasing prices. Accepted bids receive an availability payment, corresponding to the price of the highest bid accepted. The other automatic reserve in use in DK2, the frequency-controlled disturbance reserve, differs from the normal operation reserve only in terms of response time. The disturbance reserve has to provide 50 percent of the response in five seconds, and the rest in another 25 seconds. [Energinet.dk, 2010]

Manual reserve has the same conditions in both DK1 and DK2. It is activated manually by the TSO, must provide full response in 15 minutes, and is traded on daily auctions, where bids are accepted in the order of increasing prices, in total or not at all. Accepted bids get an availability payment corresponding to the highest priced bid accepted. [Energinet.dk, 2010]

Table 2 describes the capacity instruments in use in Denmark. There are no actual capacity markets, payments, or obligations in use in Denmark, but all consumers have to pay a Public Service Obligation (PSO) tariff on their power bills, and this is used to support new renewable power generation in various ways, as established in the table below. [Danish Energy Agency, 2008] [Danish Energy Agency, website]

Poland is part of the European Network of Transmission System Operators for Electricity (ENTSO-E), and as such it should in principle follow their regulation in terms of frequency control. Based on research and some interviews, it is quite certain that Poland has in one way or another at least implemented primary and secondary reserve with the specifications of the ENTSO-E Policy 1 on frequency control. However, there are no specific reserve plants in the country, and the reserve need is fulfilled using some spinning plants, some pumped storage, as well as some flow-of-river hydro. According to interviewees, the reserves are traded on a balancing market, of which there was no information readily available. [ENTSO-E, 2009][Rajewski, 2011]

According to the ENTSO-E Policy 1, the primary reserve has to be automatic and respond in a few seconds, provide half of the response in 15 seconds, and the total response in 30 seconds. The minimum time that the reserve has to be able to deliver is 15 minutes, however it must be able to produce until secondary or tertiary reserve has completely offset the frequency deviation. The compensation for this reserve is the form of PLN/MWh. [ENTSO-E, 2009]

Secondary reserve differs only in that it has to respond within 15 minutes and operate until tertiary takes over. Tertiary reserve, on the other hand, is a manual reserve, that operates until frequency is restored to the proper level. [ENTSO-E, 2009]

Instrument	Signal	Response time	Duration	Trading	Buyer	Seller	Compensation	Special
Primary reserve DK1	Automatic response to frequency deviation	Start in 15 sec, full operation in 30 sec.	Maximum use 15 minutes, re-established in 15 minutes	Auction, bids selected in the order of increasing prices, in their entirety or not at all	TSO	Production or consumption unit	Availability payment corresponding to the price of the highest priced bid accepted, capacity €/MW	
Secondary reserve DK1	Automatic response to manual signal	Full operation within 15 minutes	Continuous supply must be possible	Bidding and negotiation, selection based on multiple criteria, bids not necessarily accepted as is_2	TSO	Production or consumption unit	Spot price +/- additional €/MWh ₁	Regulation for next five min must come from spinning reserve
Frequency-controlled normal operation reserve DK2	Automatic response to frequency deviation	150 seconds	Continuous supply must be possible	Auction, bids accepted in the order of increasing price per MW, in total or not at all	TSO	Production or consumption unit	Availability payment, corresponding to the price of the highest bid accepted.	
Frequency-controlled disturbance reserve DK2	Automatic response to frequency deviation	50 percent within five sec, rest within additional 25 sec.	Active until frequency restored, or manual reserve activated	Auction, bids accepted in the order of increasing price per MW, in total or not at all	TSO	Production or consumption unit	Availability payment, corresponding to the highest priced accepted bid, €/MW	
Manual reserve DK1 and DK2	Manual activation by TSO	Full operation within 15 minutes of activation		Auction, bids accepted in order of increasing prices, in total or not at all ₃	TSO	Production or consumption unit	Availability payment, corresponding to the highest bid accepted, €/MW	

Table 1 Frequency stability instruments in Denmark

Instrument	Use	Payer	Collected by	Payment method	Amount	Special
Public Service Obligation (PSO)	To finance all of the below support mechanisms to renewable power	All power consumers	Energine t.dk	Charged on consumers' power bills	Varies annually; calculated by dividing the PSO expenses by the total electricity consumption.	In the third quarter of 2010, the PSO tariff was 8.5 ore/kWh in DK1 and 7.7 ore(kWh in DK2
Price premium for new wind turbines at land and sea	To support new wind generation	All power consumers via PSO	Energine t.dk	Via PSO	25 ore/KWh for 22,000 full load hours plus an additional 2.3 ore/KWh for the entire lifetime of the turbine	
Special tenders for wind parks at sea	To support off shore wind parks	All power consumers via PSO	Energine t.dk	Via PSO	Depends on the wind park in question; Horns Rev II Wind park of 200 MW got a fixed feed in tariff of 51.8 ore/KWh for 50,000 full load hours, while Rodsand II wind park of 200 MW got 62.9 ore/KWh for 50,000 full load hours.	
Support for household wind turbines	Support for turbines below 25 kW connected to the installation in the home of the owner	All power consumers via PSO	Energine t.dk	Via PSO	Fixed feed in tariff of 60 ore/KWh	
New biomass fired units	Support for new units that produce power using biomass	All power consumers via PSO	Energine t.dk	Via PSO	15 ore/KWh electricity	In CHP plants, the heat produced using biomass is exempt from the energy tax
New biogas fired units	Support for new units producing power only from biologically or thermally gasified biomass	All power consumers via PSO	Energine t.dk	Via PSO	Fixed feed in tariff of 74.5 ore/KWh.	If there are other fuels mixed with the biogas, the portion of the power produced using biogas gets a premium of 40.5 ore/KWh
Special renewable energy technologies that are of importance to future generation of renewable energy	Support for technologies such as wave power, solar PV, fuel cells running on renewable fuels etc.	All power consumers via PSO	Energine t.dk	Via PSO	Fixed feed in tariff of 60 ore/Kwh for ten years, and 40 ore/KWh for the following ten years	
Small solar PV units in private installations	Solar PV units below 6 kW connected to the installation in private homes	All power consumers via PSO	Energine t.dk	Via PSO	Exempt from energy tax, no tariff or price premium	

Table 2 Capacity instruments Denmark

Instrument	Signal	Response time	Duration	Trading	Buyer	Seller	Compensation	Special
Primary reserve	Automatic response	Start in a few seconds, 50 percent in 15 seconds, full operation in 30 seconds	Minimum duration for the capability to deliver is 15 minutes; however, must delivered until power deviation completely offset by secondary/tertiary reserve	Balancing market	TSO	Production units	PLN/MWh	No separate reserve plants, just some spinning reserve units, some pumped storage, and flow-of-river hydro
Secondary reserve	Automatic response	Within 15 minutes at the most	Until tertiary takes over	Balancing market	TSO	Production units	PLN/MWh	No separate reserve plants, just some spinning reserve units, some pumped storage, and flow-of-river hydro
Tertiary reserve	Manual response	N/A	Until frequency is restored	Balancing market	TSO	Production units	PLN/MWh	No separate reserve plants, just some spinning reserve units, some pumped storage, and flow-

Table 3 Frequency stability instruments in Poland

Instrument	Use	Issuer	Who responsible/ buyer	Basis for issuance	Trading	Special
Green certificates	Renewable energy sources	Energy Regulatory Office issues to plant	Power retailers (=distributors)	MWh of energy produced	Certificates can be traded on the free market, do not have to "follow" the power for which issued. No special pricing for power produced under certificates.	Certain percentage of power has to be generated using red, green, yellow sources. Penalty fee for missing certificates.
Yellow certificates	High-efficiency cogeneration with heat in either a plant with less than 1MWe capacity or in a gas-fired plant	Energy Regulatory Office	Power retailers (=distributors)	MWh of energy produced	Certificates can be traded on the free market, do not have to "follow" the power for which issued. No special pricing for power produced under certificates.	Certain percentage of power has to be generated using red, green, yellow sources. Penalty fee for missing certificates.
Red certificates	High-efficiency cogeneration in plants that do not fulfill the yellow certificate criteria	Energy Regulatory Office	Power retailers (=distributors)	MWh of energy produced	Certificates can be traded on the free market, do not have to "follow" the power for which issued. No special pricing for power produced under certificates.	Certain percentage of power has to be generated using red, green, yellow sources. Penalty fee for missing certificates.

Table 4 Capacity instruments in Poland

Instrument	Mechanism/ Ways to fulfill obligation	Signal	Response time and duration	Trading	Seller/ Provider	Charges	Compensation to provider of generation	Special
LSE regulation requirement (pro rata share of PJM regulation requirement ₄)	Self-schedule of own resources/ i.e. using own resources	Automatic response to regulation signal	Full operation within five minutes		Production units/ DR (limited to 25% of regulation requirement)		Self-schedulers are price takers; paid the regulation market clearing price (\$/MWh) times the number of MWs they scheduled for; opportunity cost not compensated here	These resources are guaranteed to run. Their merit order price is set to zero, and thus when the set of resources with the lowest merit order prices are selected to run, self-scheduled resources are always included in that set.
	Bilateral transactions with other market participants	Automatic response to regulation signal	Full operation within five minutes	Bilateral transactions reported by the buyer to PJM's electronic system and confirmed by the seller		Arranged between the parties of the transaction	Arranged between the parties of the transaction	These must be for the physical transfer of regulation
	Purchases from the PJM regulation market	Automatic response to regulation signal	Full operation within five minutes	Regulation market run by PJM, bids accepted in the order of increasing price (merit order price = regulation offer + opportunity cost)	Production units/ DR (limited to 25% of regulation requirement)	LSEs charged the RMCP for the regulation they purchase, plus their share of opportunity cost credits	The higher of the regulation market clearing price (\$/MWh) or their respective merit order price. The RMCP is the highest merit order price awarded regulation. Merit order prices are determined for each offer; they are the bid price plus the estimated opportunity cost to run. (Estimated opportunity cost of demand resources is zero.)	In addition to market-based offer, also a cost-based offer must be submitted, as well as the relevant data to support the cost-based offer.

Table 5 Frequency stability instruments in PJM, part I

Instrument	Mechanism/ Ways to fulfill obligation	Signal	Response time and duration	Trading	Seller/ Provider	Charges	Compensation to provider of generation	Special
LSE Synchronized reserve requirement ₅	Owning Tier 1 resources from which the synchronized reserve zone obtains synchronized reserve ₆	Manual response to a call from the dispatcher	10 minutes to respond, continue until dispatcher directs to stop	A company's estimated Tier 1 resources will be counted towards its obligation, but cannot make it negative. Excess Tier 1 will be allocated to companies with remaining obligations, based on load ratio share. Tier 1 calculated hourly.	Synchronized generators or demand response (limited to 25 percent of the synchronized reserve requirement of the reserve zone)		SRMCP, \$/MW and Tier 1 credits	
	Self-schedule of owned Tier 2 resources	Manual response to a call from the dispatcher	10 minutes to respond, continue until dispatcher directs to stop	Resources may self-schedule for Tier 2 synchronized reserve until 60 minutes before each hour.			Resources self-scheduled or PJM scheduled paid SRMCP, \$/MW.	If tier 1 resources enough to meet synchronized reserve requirement, no Tier 2 resources will be assigned, and the clearing price for them will be zero
	Bilateral arrangements with other market participants	Manual response to a call from the dispatcher	10 minutes to respond, continue until dispatcher directs to stop	Offers entered by seller and accepted by buyer electronically		Charges arranged between parties	Payments arranged between parties	
	Purchases of synchronized reserves from the market	Manual response to a call from the dispatcher	10 minutes to respond, continue until dispatcher directs to stop	Any remaining obligation fulfilled using the synchronized reserve market, at the market clearing price	Synchronized generators or demand response (limited to 25 percent of the synchronized reserve requirement of the reserve zone)	LSEs charged SRMCP plus their percentage share of opportunity costs and Tier 1 credits	The higher of SRMCP (\$/MW) or respective merit order price. The SRMCP is the highest merit order price of the lowest cost set of resources awarded Tier 2 synchronized reserve. The merit order price equals the synchronized reserve bid price plus estimated opportunity cost for the resource.	

Table 6 Frequency control instruments in PJM, part II

Instrument	Mechanism/ Ways to fulfill obligation	Signal	Response time and duration	Trading	Seller/ Provider	Charges	Compensation to provider of generation
	Quick-start reserve	Specifically requested by PJM, if needed in addition to synchronized reserve. This reserve not synchronized to the system	Generation available within ten minutes		Generally run-of-river hydro, pumped hydro, combustion turbines, and diesel type units		
LSE supplemental reserve requirement	Self-schedule of own resources	PJM request, does not need to be synchronized to the system	Full response within interval of 10 to 30 minutes				Market clearing price, \$/MWh
	Bilateral arrangements with other market participants	PJM request, does not need to be synchronized to the system	Full response within interval of 10 to 30 minutes	Bilateral transactions reported to PJM by buyer and confirmed by seller electronically		Arranged between the parties based on index provided by PJM	Arranged between the parties based on index provided by PJM
	Purchases from the supplemental reserve market	PJM request, does not need to be synchronized to the system	Full response within interval of 10 to 30 minutes	Voluntary, offer-based market that clears reserve requirements on a day- ahead, forward basis. Results in hourly prices.	Generally unsynchronized run-of- river hydro, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels OR generating capacity synchronized to the system and operating at a point deviating from economic dispatch OR load resources	Hourly supplemental reserve market clearing price times the number of MW purchased and a share of those costs that supplemental reserve resource providers were unable to cover via market clearing price.	The higher or the market clearing price (\$/MWh) or respective merit order price. The clearing price is the merit order price of the most expensive resource allocated. The merit order price equals bid plus opportunity cost.

Table 7 Frequency control instruments in PJM, part III

Method of participation	Activity	Use	Cost/ payment	Buyer	Provider	What is traded	Special
Reliability Pricing Model (RPM)	Base Residual Auction	Procurement of RTO obligation minus amount reserved for short lead time resources minus FRR obligation	Cost allocated to load serving entities through Locational Reliability Charge	PJM	Generati on units of demand response	Resource commitments to meet system peak load three years in advance	Variable resource requirement
Reliability Pricing Model (RPM)	1st Incremental Auction	Allow a) replacement resource procurement b) increasing or decreasing resource commitments due to reliability requirement adjustments c)deferred short-term resource procurement	Cost allocated to resource providers that purchased resources as well as load serving entities through Locational Reliability Charge	PJM	Generati on units of demand response	Resource commitments to meet system peak load 20 months prior to delivery year	Variable resource requirement
Reliability Pricing Model (RPM)	2nd Incremental Auction			PJM	Generati on units of demand response	Resource commitments to meet system peak load 10 months prior to delivery year	Variable resource requirement
Reliability Pricing Model (RPM)	3rd Incremental Auction			PJM	Generati on units of demand response	Resource commitments to meet system peak load three months prior to delivery year	Variable resource requirement
Reliability Pricing Model (RPM)	Conditional Incremental Auction			Procurement of additional capacity in a Load Deliverability Area (LDA) to address reliability problem cause by significant transmission line delay	Cost allocated to load serving entities through Locational Reliability Charge	PJM	Generati on units of demand response
Reliability Pricing Model (RPM)	Interruptible load for reliability	ILR option eliminated starting with 12/13 DY					
Fixed Resource Requirement (FRR)	FRR Capacity Plan	LSE secures capacity to satisfy their load obligation	LSE does not pay Locational Reliability Charge, and does not receive RPM resource clearing prices for capacity included in the fixed capacity plan.				Only LSEs that meet eligibility requirements can participate in FRR. LSE submits a fixed capacity plan to PJM and thus meets a fixed resource requirement (=unforced capacity obligation)

Table 8 Capacity instruments in PJM

There is no capacity market in Poland, but there are three different kinds of tariffs in use; green, yellow, and red. They are all awarded by the Energy Regulatory Office to power retailers, who at the end of each year must present a certain amount of them to the Energy Regulatory Office. The amount is a predetermined share of their total sales volume in MWh. If they fall short of this amount, they have to pay a penalty. The size of the penalty is also determined in advance, at least one year to be exact, by the Ministry of Economy. The certificates can be traded on the free market, and they do not have to “follow” the power they were issued for. Thus, the power trade is totally separate from the trade of the certificates. [Rajewski, 2011][Pöyry, 2009]

The green certificates are used for supporting renewable energy sources, and the yellow ones are for high-efficiency cogeneration in either a plant with less than 1MWe capacity or in a gas-fired plant. The red certificates support high-efficiency cogeneration that does not fulfil the criteria of the yellow certificates. [Pöyry, 2009]

As there is at present a shortage of the “coloured” types of electricity, the price of the certificate stays close to the penalty fees, a little bit below it. The Energy Regulatory Office determines the penalty fee each year, and it is different for each type of coloured electricity. It is expected that the required share of coloured power is going to rise, and that the next amendment of the Energy Law will allow combining two certificate types. [Rajewski, 2011]

Since the certificates were established in 2005 as a response to a European Union directive in 2005, the quota has been set higher each year. In 2008 it was 7 % of all power sold, in 2009 it was 8.9 %, and in the years 2010-2012 it is 10.4 %. The gradual increases are planned to continue, and in 2017 the goal is to have the percentage at 12.9 %. [IEA homepage]

If someone doesn't want to buy the certificates, they can pay a substitution fee, the amount of which is determined annually by the Energy Regulatory Office and tied to the average price of electricity produced from coal. If neither option is used, then there is a financial penalty. [IEA homepage]

PJM has by far the most complicated market structure of the three cases. When it comes to frequency stability, there are two different obligations: the regulation obligation and the synchronized reserve obligation. There are also quick-start reserves and a supplemental reserve requirement. Together the synchronized reserve and quick-start reserve form the contingency, or primary reserve and the supplemental reserves are the secondary reserve. All of the reserves together are called the operating reserve. [pjm.com][PJM, 2010 (2)]

The regulation obligation is determined based on the total regulation requirement of the TSO (=PJM), which during on-peak hours is one percent of the forecasted load for the day, and during off-peak one percent of forecasted valley load for the operating day in question. Regulation reserve is used for correcting for "the short-term changes in electricity use that might affect the stability of the power system", in other words to help match production and load by adjusting generation output to maintain the target frequency, while synchronized reserve provides power if there is "an unexpected need for more power on a short notice". Synchronized reserve can be provided by generators whose production can be increased rapidly, or by demand units that can drop load on short notice. [PJM, 2010][Zhenyu et al, 2008][pjm.com]

Load serving entities (LSE) can fulfil their obligation in a couple of ways. Whichever way an LSE chooses to fulfil their obligation, the regulation reserve must always respond automatically to a frequency drop, reaching full operation within five minutes. An LSE can

either use their own resources, or purchase the required resources from the regulation market, or make bilateral arrangements with other market participants. Any self-scheduled, i.e. an LSE's own resources are always guaranteed to run. This is due to the nature of the resource selection process; all resources offered for regulation are put in order based on their "merit order price", which is basically the bid price plus opportunity cost, and the resources with the lowest merit order prices are selected to fulfil the regulation need. The opportunity cost for self-scheduled resources is set to zero, and thus they are always selected to run. Self-schedulers are compensated the regulating market price (\$/MWh) times their commitment. [PJM, 2010][PJM, website]

LSEs can also buy resources from the regulating market, at the regulation market clearing price plus a share of the opportunity costs compensated to the generators providing the resources. The generators are compensated the higher of the regulation market clearing price or their respective merit order price. The details of bilateral arrangements are agreed between the parties involved, the transaction just needs to be for physical transfer of regulation and they need to be reported to PJM. [PJM, 2010]

The synchronized reserve obligation is different. This reserve has to provide a manual response within ten minutes of the dispatcher's signal. The reserve has to be capable of operating until the dispatcher directs it to stop. As with the regulation obligation, also the synchronized reserve obligation can be fulfilled in a number of ways. [PJM, 2010]

An LSE can own Tier 1 resources and use these to fulfil its obligation. Tier 1 resources are so-called "economic" resources; they are partially loaded units online following economic dispatch and able to increase output in ten minutes in response to a spinning event. Aside

from the synchronized reserve market clearing price, these reserves also get special Tier 1 credits.

Tier 2 resources are those that are online, but operating at a point deviating from economic dispatch. If Tier 1 resources are enough to meet the reserve requirement, no Tier 2 will be assigned, and the clearing price for it will be zero. Normally Tier 2 reserves get the synchronized reserve market clearing price, \$/MW. [PJM, 2010]

If an entity with a synchronized reserve obligation does not have own resources, then it can purchase them from the synchronized reserve market. Also if an entity is not capable of fulfilling its entire obligation using its own reserves, it has to buy the rest from the market. They have to pay the market clearing price and their share of opportunity costs as well as Tier 1 credits. Those who provide generation to the market are compensated the higher of the market clearing price and their merit order price. The final option to fulfil the synchronized reserve obligation is to enter into bilateral agreements with other market participants. The clearing of the synchronized reserve market is a joint optimization between the regulation and synchronized reserves, where the goal is to minimise the total cost of producing power. The clearing price is determined from bid plus opportunity cost of Tier 2 resources committed to meet the reserve requirement. [PJM, 2010]

Demand response can take part in both regulation and synchronized reserve, but it is limited to 25 percent of the each of the reserve requirements of the entire area. The opportunity cost for demand response is also always assumed to be zero. Further, when synchronized reserve is needed units that are providing regulation can be taken off regulation to provide synchronized reserve for a maximum of 20 minutes. [PJM, 2010]

Aside from regulation and synchronized reserves, PJM has also quick-start reserves. During the research undertaken for this thesis, it was not possible to find out all of their details, like whether there is a separate market of obligation for these reserves. Nevertheless, the quick-start reserves are not synchronized to the system. They are specifically requested by PJM, if needed in addition to synchronized reserve, and their generation is available within ten minutes. This reserve is generally provided by run-of-river hydro, pumped hydro, combustion turbines, or diesel type units. [PJM, 2010 (2)]

The final reserve obligation in PJM is for supplemental reserves. These are reserves that do not need to be synchronized to the system, are requested by PJM when needed, and provide their full response within 10 to 30 minutes. Each LSE's obligation is equal to the LSE's load ration share of the total PJM RTO requirement of this reserve. An LSE can fulfil its obligation in the three ways familiar from above; it can self-schedule its own resources, it can enter into bilateral agreements with other market players, or it can use the supplemental reserve market to purchase the required amount of reserve. [PJM, 2007]

Those reserves that self-schedule are paid the supplemental reserve market clearing price of dollars per MWh, in bilateral arrangements payments are agreed between the parties. The supplemental reserve market is cleared in a joint optimisation of the day-ahead market, with a separate price for each hour. Those that purchase their reserve from the supplemental reserve market have to pay the clearing price for the reserves times the amount of MW they purchased, and in addition their share of those costs that the providers of supplemental reserve were unable to cover by the market clearing price alone. The clearing price equals the merit order price of the most expensive unit assigned generation. The providers of generation are paid the higher of the market clearing price, or their

respective merit order price. Supplemental reserve capacity is in general provided by unsynchronized hydro, industrial combustion turbines, jet engine turbines, combined cycle, and diesels. It can also be provided by synchronized generation that is operating at a point deviating from economic dispatch, or by load resources. [PJM, 2007]

The PJM capacity market is designed to ensure the adequate availability of resources that can be called upon to ensure the reliability of the grid. The capacity market is formed by two parts: the Reliability Pricing Model (RPM) and Fixed Resource Requirement (FRR). These are alternatives, and their difference is in that in RPM the TSO procures capacity on behalf of LSEs in order to fulfil load obligations that are not satisfied through LSE self-supply, and FRR is used by those LSEs that opt not to take part in RPM, but instead to obtain the capacity to satisfy their load obligation themselves. RPM and the capacity market in general, are meant to ensure long-term adequacy and competitively priced energy, and to take into consideration as well as quantify both the locational and operational value of capacity. The capacity market is also designed to produce forward investment signals. The capacity resources acquired through RPM include both existing and planned generation resources, existing and planned demand resources, as well as energy efficiency resources. [PJM, 2011]

RPM is based on auctions, the first of which takes place three years before delivery year, and is called the Base Residual Auction. Here the main part of the resource commitments to meet the peak load three years in the future is obtained. After this, there are further auctions that enable refining of the resource commitments and the procuring of more resources. The cost of procuring the capacity through these auctions is allocated to the load serving entities through a locational reliability charge. In the basic scenario, the other

auctions are at 20, 10, and three months prior to delivery year, but there is also the possibility of holding one more auction at any time prior to delivery year. [PJM, 2011]

FRR is the alternative to those LSEs that do not want to take part in RPM. In essence, this means that the LSE will send a fixed capacity plant to PJM, and thus meet a fixed resource requirement, whereas in RPM the resource requirement is variable. An LSE that chooses FRR does not pay the locational reliability charge, but neither does he get the market clearing price for the resources he includes in the plan that the resource providers in the RPM model get. [PJM, 2011]

6.2 Frequency control instruments – some general points

All power systems have to take care of frequency control one way or another. However, it is not nearly always the case that there is an open market for the frequency control reserves. Often the trade is based on bilateral agreements.

There are three separate parts in power markets; generation, transmission, and distribution. In the case of a monopoly, all of these are owned and operated by a single market participant; a company, or a state. Often the progress towards a competitive market starts with the formation of separate distribution companies, with generation and transmission being left to one or a few large, many times state-owned, utilities. [Vuorinen, 2009]

This situation is not much different from a total monopoly, as the utilities tend to own the transmission system and can thus control the power sold through it for example by using large transmission tariffs. In such a system, there is not a whole lot of competition, and thus planning an “optimal system” is relatively easy. This is because without competition there is no risk of electricity contracts being given to someone else, and thus little risk in making even large investments in capacity. That being said, the difference between a system with

virtually no competition that is well planned and a totally competitive system can be marginal and there is no way of saying with absolute certainty whether the liberalisation of power markets is actually better for the power customer. [Vuorinen, 2009]

However, if the desire is to make a power market totally competitive, the next stage is to separate also generation and transmission. Customers are allowed to choose between several different suppliers. In these unbundled markets, electricity generation is the responsibility of separate generation companies, transmission is the responsibility of a transmission system operator, and distribution that of separate distribution companies. [Vuorinen, 2009]

After a power market has proceeded this far, there can be a (natural) push to build a free market also for ancillary services. In a way, this completes the transition to a market that is entirely free, open, and competitive. Ancillary services can be defined as “services that should be offered as separate products form transmission services”. These include scheduling, system control, dispatching, reactive supply, voltage control, regulation, frequency response, imbalance, spinning reserves, and supplementary reserves. [Vuorinen, 2009]

There are differences between the specific implementation of ancillary service and the in this thesis examined frequency control markets in different countries, although as both Poland and Denmark are members of ENTSO-E, and as such required to follow the same policy when it comes to frequency control, the countries chosen as cases for this thesis do perhaps not highlight the differences so well in spite of the very different system in use in PJM. However, the dimensions that are essential for a player wishing to enter a frequency control market are almost always the same. One needs to be aware of the required

response time, whether the response needs to be automatic or manual, how long the response must last, and how the response is compensated. Although it is of course essential to know many other more practical things, like how the trading is done, the dimensions mentioned above will determine whether a participant is capable of providing the service and whether it will be lucrative for them.

6.3 Capacity adequacy instruments – some general points

On liberalised markets, or energy-only markets, the biggest problem is usually the fact that maintaining peaking and reserve capacity is not profitable, if they only get paid for the energy generated during the few peak hours annually. On the traditional electricity markets of vertically integrated utilities and next to zero competition, adequacy of capacity wasn't most often even an issue. This is because there was little risk of utilities not being able to sell enough electricity to cover their costs, and because there also often were capacity fees in place for covering the capacity costs. [Vuorinen, 2009]

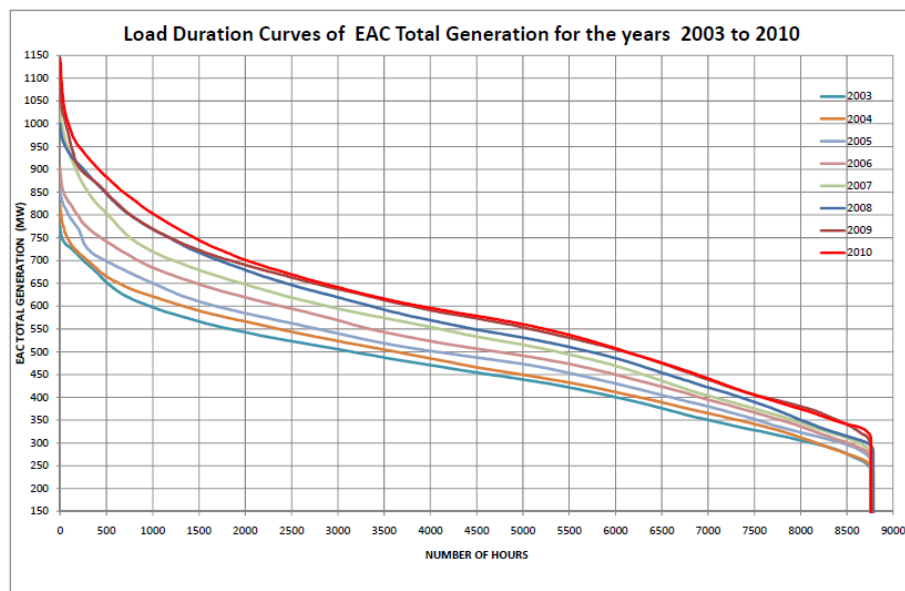


Figure 5 Load duration curve of Cyprus to illustrate peak hours [Cyprus Transmission System Operator webpage]

The liberalisation of markets has led to the fact that the capacity costs of peaking and reserve plants are paid only if there actually is a deficit of power annually. This means that the risk in building these plants is very high, and without a separate scheme to motivate the building of adequate capacity to meet the power demand at any time, it will probably not be built. Thus it is necessary to have some kind of obligation requiring utilities to either build or hire new capacity. It is also necessary from the consumer point of view; for the energy-only market to cover the costs of peaking plants, the price of power during the peak hours would have to be unacceptably high, especially if the peak is relatively thin like in the figure above. [Vuorinen, 2009]

There are a couple of ways to handle this capacity conundrum. For example in the UK, there was in use a capacity pricing system based on value of lost load (VOLL) until the New Electricity Trading Arrangements (NETA) liberalisation phase. In this model, capacity was priced according to a theoretical calculation of the VOLL. Generators were paid per MW or based on the availability of capacity. These payments were collected from the customers. The problem with this system was in the evaluation of the loss of load probability (LOLP). Also, the system was relatively easy to manipulate; when a plant operator informed the market that a plant was not available, the price of capacity went up. This was one of the factors behind the decision to change the UK system to NETA. [Vuorinen, 2009]

Another option to tackle the capacity adequacy issue is to create installed capacity obligations (ICAP) and separate capacity markets. This solution is in use in PJM and New England power systems. The ICAP obligations require market participants to have enough installed capacity to meet forecasted peak loads. If an LSE does not own or cannot hire

enough to cover its obligation, it has to buy the capacity from the market. It is also possible to have obligations for available capacity (ACAP), instead of installed. [Vuorinen, 2009]

In the UK there is at present another electricity market reform underway, in the consultation phase and with plans to implement after 2012. In this reform, the goal is to “achieve secure, low carbon, affordable electricity”. By 2020, UK will have to replace at least a quarter of its current installed capacity as it is ageing and unlikely to meet environmental requirements, and this replacement has to be done at the least possible cost to consumers. The plan to tackle this goal has four points: carbon price support, emissions performance standard, long term contracts for low carbon generation, and a “targeted capacity mechanism”. The goal of this capacity mechanism is to lower the investment cost associated with building new capacity, thus reducing the cost of capital, which in turn should result in more investment from both existing and new investors. The ultimate result is hoped to be enough capacity to meet the demand at all times, and this at the lowest possible cost to consumers. At this point it is not yet clear, what the design of the mechanism is going to look like more specifically. [Brearley, 2010]

As another example, in Russia there is also a power sector reform underway. The reasons for the reform are the same that induced many countries with vertically integrated, state-controlled monopolies to reform their power sectors in the 1990s: “ageing infrastructure, large distribution losses, very low retail tariffs, inefficient management, and increasing tightness of supply”. The new wholesale electricity market is “gradually taking shape”, and it will include separate markets for electric energy and capacity. The idea is that the electric energy market would cover the operating costs of power generation, and the capacity market would cover the fixed operation costs. The capacity market’s purpose is to

guarantee power generators an income independent of energy price fluctuations. Anyone taking part in the wholesale market has to buy both power and capacity. The basic principle is that generators offer capacity in a monthly uniform price auction, where the system operator accepts bids starting with the lowest priced ones. [Solanko, 2011]

It must be said that as the Russian capacity market is in reality heavily regulated, and thus its ability to produce correct market signals can be put into question. For instance, all the generating companies already have legally binding capacity obligations for the period of 2008 to 2012. Additionally, all new capacity built after 2006 and included in the general plan of the power sector get capacity payments, the value of which is determined in capacity delivery agreements. And the new capacity that is not included in the general plan cannot even take part in the capacity market. All of this means that the ability of the capacity prices to truly produce new investment is highly questionable, and that only old and existing capacity ends up being traded on the market. Finally, authorities can introduce price caps on the capacity market if they wish. [Solanko, 2011]

Though the Russian capacity market seems to rely more on regulation than on market forces, perhaps it serves to demonstrate that designing a well-functioning capacity market is not a small task. [Solanko, 2011] This might be one of the reasons that in spite of the many alternative ways to go about it, in most countries and power systems there is at present no separate capacity market. The countries and areas cited as examples are at present the exception, not the rule. This is probably likely to change in the future, as more and more countries start to open their power sectors to form liberalised markets and have to face the inability of the free market to provide capacity adequacy.

However, today many developing countries, and others without a free market, still use power purchase agreements (PPA) for the task. In essence, a PPA is a legal contract between a power producer and a buyer. The seller is often an independent power producer (IPP). The contract is most often formed for a limited time period, and can include the purchase of just power or also capacity and even ancillary services. Brazil is an example of a country that uses PPAs.

Of the case areas in this thesis, only PJM has a functioning capacity market. Thus, it is not possible to draw any far-reaching consequences that one could generalize. Denmark and Poland have capacity instruments that reward certain types of generation. These systems make it more viable to build renewable generation that perhaps without them would be unprofitable. In Poland especially, the certificates function as a sort of insurance that it is safe to invest in generation at all, even though they have raised certain generation types above others by giving them more compensation.

Also, there aren't even that many countries in the world at present that have had to face the capacity issue brought on by free energy markets. This means that any common methods of handling the situation have not been established yet, which makes generalisations difficult. The mechanisms used vary a lot there is no established standard yet.

A market player, or producer, wishing to enter a market or build new generation relying on support from certificates, needs to know three things. First, how long the support will be available. This is because if the certificates or other support are essential in making the project financially viable, and without them it might lead to losses, then the player has to be able to rely on the support coming for a certain period of time. Another, related, concern is

how large the support will be, and how often the level of support will change. If the compensation were to change without warning, and at irregular intervals to boot, it would be impossible to base investment decisions on it. The third essential thing to know is for how much of the power sold certificates must be bought. These three apply for feed-in-tariffs as well as certificates and capacity payments.

7 Findings

The first clear finding, or result, of this thesis is that the information required to do a survey such as this one has not been gathered together before. There are no global studies on ancillary services and capacity adequacy from the perspective of this thesis. This means that in order for one to get a good picture of the different ways of organising ancillary services and trading them, it is to investigate one country or trading area at a time. At least for the countries featured as cases in this thesis this meant that it was necessary to delve into detailed policy documents and TSO websites in order to understand the systems of the countries.

Also an important finding is that it was possible by combining concepts and ideas from different sources to establish a framework for power system needs and the instruments used to respond to them. The needs were categorised into three categories in chapter three: physical operation, network level, and policy level. All of these levels are of course ultimately inextricably linked to the physical operation of the system, but their difference is in the scope of focus. The needs that come from the policy level are concerned for example with the benefit of the whole society or country, while the network level considers the grid as a whole, and the physical operation level concentrates on specific, momentary actions.

On the physical operation level, the needs are frequency and voltage stability, as well as power quality. The network level gives rise to needs for transmission security, economic dispatch, imbalance management, and procedures for handling emergencies and black starts. The policy level needs include capacity adequacy, energy efficiency, methods to guide the capacity mix and climate change mitigation.

A framework was established for the instruments used to respond to these needs as well. This was done in chapter four, and the categories of the framework are frequency control, capacity, coordination and operation, as well as system backup and restoration. This framework was adapted from Raineri et al 2006, with the additional category of capacity.

To take care of frequency control, reserves of different types and demand response are used. The capacity category includes different ways to ensure adequacy of capacity, and to guide the capacity mix. Coordination and operation refers to voltage control, imbalance settlement, nodal marginal pricing, and transmission capacity allocation. The final category of system backup and restoration contains emergency services and black start capability.

Another finding is that the framework established for the instruments works quite well for looking at different countries' power systems. That is, it seems to function satisfactorily as a guide to finding and recognizing the different elements of a power system, at least in terms of frequency control and capacity. Although the instruments in individual countries may not be divided in exactly the same manner as in the framework, it seems to be possible to use the framework for detecting them.

After generation, transmission, and distribution have been unbundled, the next step on the way towards a truly competitive market can often be the creation of an ancillary services market. Although the ancillary services and frequency control markets of different countries vary in how they are organized, the basic parameters that a player needs to be aware of when entering the market were found to often be the same ones. These are the dimensions that are most important in defining the service. In terms of frequency control, the most essential dimensions are the required response time, whether the response needs to be automatic or manual, how long it has to be possible to maintain the response, and how the

service is compensated. Of course there are many other practical dimensions that are important, like how the trading is done, but those mentioned determine whether providing the service is possible and lucrative for a market player.

After the energy market has been liberalised, there can often arise a problem with the adequacy of capacity. This is because on pure energy-only markets, there are no payments for capacity, and reserve and peaking plants are only able to cover their costs if there are a sufficient number of peak hours or hours during which there is a power deficit annually. This means that the risk in building capacity becomes a lot higher than in regulated markets, and it is most likely necessary to have some separate mechanism to encourage its building. There are several methods to handle the capacity issue, as established in chapter six. These include VOLL-pricing, ACAP or ICAP payments, and the creation of a capacity market. Many countries without free markets or with regulated markets use PPAs to guarantee capacity.

Of the case countries, only PJM had a functioning capacity market, so to generalise based on that what the essential dimensions of capacity markets are, would be difficult. And because not that many countries in the world have yet had to face the capacity issue brought on by free markets, there is not a whole lot of experience of capacity markets in general, and no standard or established ways of organizing one yet.

However, both Denmark and Poland have capacity instruments that make it more profitable to build certain types of generation, in Denmark this is the PSO and in Poland the certificates, as described in chapter 6. Based on examining these instruments, as well as the PJM capacity market, it was found that a player who wants to build generation or enter a market relying on support from certificates or capacity payments needs to be aware of a few key dimensions. First, he needs to know how long the support will be available. Second,

it he needs to know what the size of the support will be and how often it will change. The third crucial dimension in terms of certificates especially is how large the volume of the certificates is in the area; for how much of the power sold must certificates be bought. These dimensions determine, whether the support level offered is high enough, and stable enough, and whether it will be forthcoming for long enough to make investment profitable.

8 Conclusions

The starting point of the whole thesis was that the energy-only market alone is not enough for the operation of the system, and that if the market is used for trading solely energy there is a need for separate mechanisms to take care of the other needs on the physical operation, network, and policy levels. As presented in the previous chapter, the focus of this thesis became to build a framework for these mechanisms or instruments.

There appear to be three reasons why the energy-only market alone cannot deliver. First, on open energy markets nobody is really able to take care of the coordination of the whole system, of overseeing everything needed to keep it going strong. True, the system operator is most often charged with this responsibility but in most cases has limited ability to carry it out. This is due to many reasons; one major reason being that the system operator is most often not even allowed to own the generation that would be needed for the continuous balancing of the system.

The second reason something in addition to the energy-only market is required is that as established in chapter two, the nature of the deregulated market is such that bilateral contracts cannot be enforced in real time, as it is at present not possible to control the flow of power to a particular customer or from a particular producer in real time. This means that the inability of one supplier to supply can in theory topple the whole system, and that the system operator has to function as the default supplier.

Third, in the short term both supply and demand are to a certain degree inelastic. There is at present little real-time metering in use, and customers don't usually even see the real-time price for electricity, let alone change their consumption accordingly. Also supply can only react up to the amount of available capacity, after which it becomes inelastic. And it is not

even desirable to have to operate near the area where the supply becomes inelastic, as there both prices and associated risks to producers and consumers become very high.

When it comes to the ancillary services, the research undertaken and reported in chapters five and six implies that it seems not to matter so much how the practical details of it like the number of reserve types or division of response times are organized, so long as the requirement for frequency stability is fulfilled and balance achieved.

For example, the exact amount of time after which the secondary reserve replaces the primary reserve, or the amount of reserve types are secondary considerations compared to the frequency being restored. This leads one to believe that the ancillary service market is relatively easy to arrange or set up; the system operator just uses some separate market mechanism, either a market or bilateral arrangements, to buy the required services. The only issue is to reimburse the producers for the opportunity cost of not being able to sell to the market, of lost production.

The conclusion that the ancillary market is relatively easy to arrange, or that it does not so much matter how the practical details are arranged, of course only applies if there is enough capacity in the system. However, if there is not enough capacity, ancillary services cannot be maintained. An example of this is India; there the capacity deficit is such that regular power cuts are the norm. Of course if there is not sufficient capacity, the energy-only market will not function smoothly either. This is true especially if the ancillary and energy-only markets use a common capacity pool for bidding.

In general, bidding on both ancillary and energy-only markets is based on short term marginal costs and plants are assigned operation according to their merit order price. This

means that the market price is determined according to the marginal costs of the most expensive plant assigned operation. Only those plants, for which the market price is higher than their marginal costs are able to cover their costs and even make a profit. Thus, the most expensive plants that define the price don't get any profit. Additionally, they are typically in operation for only a few peak hours during the year, which makes it even more difficult for them to cover their fixed costs let alone be profitable investments.

Although it is in theory possible, as discussed earlier, in practice an open market cannot in the long term guarantee capacity adequacy through the energy-only market alone, if the load duration curve has a relatively thin peak. This is because it would lead to unacceptable price peaks; the price would have to be unreasonably high during the few peak hours to cover generation costs. This would be a big risk for both producers and consumers. For consumers the risk is that these peak prices would be realized, for producers the risk is the opposite; that they would not be realised and that production costs would not be covered. The size of the risk would lead to unacceptably high risk premiums. Thus, one can presume that the issue of capacity adequacy will not be solved in an open market environment without a separate mechanism.

There are several mechanisms for tackling the capacity adequacy issue; from creating a full-blown capacity market to using different kinds of capacity payments or obligations, or indirect means like certificates that favour and encourage the building of one type of capacity over another. Since the liberalisation of power markets is a relatively new phenomenon, there are not many countries or areas in the world that have had to deal with the inadequacy of capacity brought on by the free market. Thus, there is not a lot of experience yet in the world with capacity markets. This is reflected in the fact that in this

thesis, the only case area with a functioning capacity market was PJM. Denmark and Poland each have mechanisms that prefer certain type of capacity over others, but there is no actual capacity market or capacity obligations or payments in either one of them.

The survey undertaken for this thesis also gave some insight into a couple of major points that ought to be considered when designing market instruments to a system. The first one of these is that the instruments implemented actually function together. For example, if one is planning a capacity payment, it should be taken into consideration what else has been done to intervene on the market, and that these different support mechanisms do not contradict one another.

A second point is the division of responsibility and risk between the TSOs and single market players; how much responsibility should the TSO carry and what should be common responsibility, what the individual market players'. There are a number of ways to transfer responsibility from one party to another. One example is nodal marginal pricing; when every node has its own price, then the cost of congestion management fall onto single consumers and producers. This is different from the current situation e.g. in Finland, where there is only one area price and if ancillary services have to be used somewhere everyone in the whole country pays the higher price. If it is not possible due to congestion to transfer electricity to a certain area or consumer, then the Finnish TSO shoulders the costs of using the reserves, the costs are "socialized" into the power price of all consumers. With nodal marginal pricing, however, the costs are transferred directly to the consumers in the affected area, affecting only their power price.

Another way of moving the line of responsibility between the TSO and consumers and producers is the length of the operating period, the time period that is the basic unit of the

energy market. For example in the Nordic countries, the operation period is now 60 minutes, which means that while producers have to plan their production schedules at the resolution of one hour, the TSO is responsible for guaranteeing balance within the hour. If the operation hour were shorter, then the responsibility would lie more with the producers; they would have to send production schedules for say 15 minutes periods, and be held accountable to them. This would mean that they would also have to make sure they have or purchase the requisite reserves to manage balance, to remain within their reported operation.

Another, related, question is what to include in the market, what not? As an example; in terms of reserves this division is visible in which reserves are bought using the open market, in many cases primary, secondary, and tertiary, and which ones are outside of the market, emergency reserves that are never actually traded but only used in case of large system disturbances. Here one has to face the inevitable question of whether it is sensible in the first place for the SO to have to pay for plants that stand cold most of the time and cannot operate on the free market. This leads to the question of who actually should have the capacity and which mechanism should be used to acquire it.

A third issue when designing market instruments for frequency control and capacity adequacy is whether the instrument will be taking care of a problem or issue that already exists or whether it will be more of a pre-emptive measure. It is probably most common that there is some problem that needs to be addressed, for example the creation of the capacity mechanisms in Spain and Russia were responses to capacity inadequacy. An example of a pre-emptive measure is the ongoing process to form a capacity market to the UK and Poland in order to prevent capacity running out.

A major point to consider is also how the different markets are connected to each other, for example the energy market and the capacity market. Should the capacity market or obligations be made such that they only influence or have requirements for the amount of capacity? And leave the determination of the capacity type to the energy market? Or should the capacity market in and of itself already take care of the selection of the type of capacity, for instance by favouring or rewarding certain types of capacity? These are questions with far-reaching consequences, and answering them is certainly not possible based on the research carried out for this thesis. However, in the design of markets they cannot or at least should not be ignored.

9 Discussion

It turned out that the attempt to build a framework for ancillary services was a very relevant one. Although the initial idea was to find such a framework ready, and to use it to classify different countries' market instruments and to display the variation in them, it quickly became clear that no such frameworks could be found and the direction of the research shifted.

The case areas were selected for level of general interest. PJM and Denmark were chosen due to their systems being quite advanced with many components and were thought to show good variation. Poland was chosen as an example of a country whose power market is just developing. However, when considering the goal of this thesis to highlight as many different market instruments as possible, the better way to select the areas could have been to look at whether they have interesting mechanisms for taking care of frequency control and capacity, not so much whether their whole system or market is interesting. This could have produced a better understanding of the variation in especially the methods of taking care of capacity adequacy.

As there was very limited general level information or research on these subjects from this viewpoint, it was necessary to resort to reading through policy documents and TSO reports. Additionally, it was not an easy task to find interviewees with broad knowledge of the area. These together meant that it was time consuming to dig for information, and easy to get bogged down with details. Thus, it would require a much larger study with a lot longer time to do it to get to understand all the different options, or even the case markets completely. The research done for this thesis demonstrated clearly that this is an area with a lot of possibilities for further research. It would be easy to delve into a single country, or market area, and make a thesis or two from that alone.

A very interesting direction to go in further research would be to look into the theory of electricity markets. As there were no general descriptions of what mechanisms exist, this thesis is out of necessity a descriptive one. But one way to go deeper into this subject would be look at what the theory of economics says about electricity markets. What would be the ideal way to arrange capacity and ancillary markets according to economic theory, what should work best? And then to contrast this with what exists in reality, how it really goes. And then to try to synthesize and find an arrangement that is a combination of the best of both worlds.

Due to the extensive amount of research required, it was chosen to limit this thesis to include only frequency control and capacity adequacy in more detail. Of course, one could argue that the division between frequency control and system backup and restoration is artificial but it was necessary in order to complete this work. The same goes for capacity adequacy; based on this study it is really not possible to say what are all of the elements that in truth affect how the capacity is determined in a country or area. Further, it is most likely not possible to make broad generalisations of the organisation of frequency control or capacity instruments based on the few cases included in this thesis.

In order to draw the conclusions in the previous chapter with absolute certainty, it would be necessary to examine what economics has to say, to review more countries as cases, and to do these reviews in more detail. As already stated above, it was necessary in this thesis to approach the subject though the viewpoint of the instruments, as there was no framework for them ready, or other general level information. The next stage would be to use the framework to examine the questions presented in the conclusions chapter.

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