

Area price hedging and the Nordic market model



Energimarknadsinspektionen
Box 155, 631 03 Eskilstuna
Energimarknadsinspektionen R2016:11
Authors: Jens Lundgren and Kaj Forsberg
Copyright: Energimarknadsinspektionen
Report available at www.ei.se
Cover image: © Energimarknadsinspektionen

Foreword

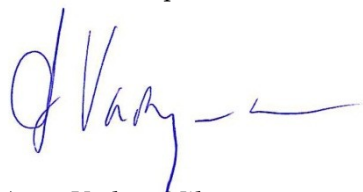
In the work to integrate the European electricity markets, a target model and common rules known as “network codes” are being developed on a central level in the European Union (EU). The target model is an overall description of how a common market will work and the network codes are intended to create uniform functioning in the markets and facilitate further integration. One of the areas which have been reviewed intensively in recent years is how the capacity for transmitting energy between different countries and bidding zones will be handled in the short and long term. Today, the network infrastructure is insufficient for balancing prices between various sub-markets both within and between countries in the EU.

One important dimension is thus which instruments the market actors have access to in order to manage the financial risks associated with cross-border trade. In the short term, the target model for the common market means that all available capacity in the network will go to the spot market and the daily market coupling mechanism in order to ensure socioeconomically optimal flows from low-price to high-price zones. In the more long-term and forward-looking trade today – the “forward market” – different instruments are used for managing area risks in different parts of the EU. The as yet incomplete network code Forward Capacity Allocation (FCA), which pertains to forward-looking capacity allocation, will regulate which instruments are permitted for managing area price risks within the EU.

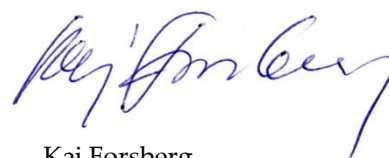
In the appropriation regulation for 2013, the Government commissioned the Energy Markets Inspectorate to perform an analysis of the various price hedging instruments mainly used to handle area risks in the EU. In the report it is described the advantages and disadvantages of the various instruments in relation to the Nordic market model and the impact the instruments have on overall competition and consumer benefit.

In the scope of the survey and in its work with the report and gathering opinions, the Energy Markets Inspectorate has collaborated with a reference group consisting of representatives from the energy sector and from other concerned organisations.

Eskilstuna, September 2013



Anne Vadasz Nilsson



Kaj Forsberg

Contents

Please note that the page numbering in the first chapter “introduction” doesn’t match the index.

Summary	6
1 Introduction	9
1.1 European integration as a catalyst for market development.....	9
1.2 Commission	10
1.3 Delimitations.....	11
1.4 Project organisation.....	11
2 Description of various price hedging instruments	12
2.1 Contracts for Differences (CfDs).....	13
2.2 Financial Transmission Rights (FTRs).....	16
2.2.1 FTR options.....	16
2.2.2 FTR obligations	18
2.3 Physical Transmission Rights (PTRs)	20
2.4 The economic effects of transmission rights on market actors.....	21
2.4.1 Fundamental actor.....	22
2.4.2 Supply and trading.....	23
2.4.3 Issuer of transmission rights	24
3 Nordic market design and area price hedging	26
3.1 Market design in the Nordics.....	26
3.1.1 Implicit trade in capacity.....	26
3.1.2 Opportunities for area price hedging today	26
3.2 What are the problems with Nordic market design from the perspective of actors outside the Nordics?	27
4 Function of the instruments in relation to Nordic market design	29
4.1 What do the market actors say?	29
4.2 Analysis of the instruments' advantages and disadvantages	31
4.2.1 Impact on actors.....	31
4.2.2 Impact on TSO.....	32
4.2.3 Liquidity.....	35
4.2.4 Impact on transparency.....	38
4.2.5 Impact on the second-hand market	39
4.2.6 Impact on competition	40
4.3 The instruments in relation to consumer benefit and the Nordic end-user market.....	43
4.3.1 Effects on consumer benefit	44
4.3.2 Effects on the work with the Nordic end-user market.....	46
4.4 Nordic market design, transmission rights and the internal market for electricity	47
5 Summary analysis, conclusions and recommendations	48
5.1 Transmission rights deviate from the established Nordic market model	48
5.2 The need for further price hedging products is limited, according to the market actors.....	49

5.3	Transmission rights entail a more complex market with very limited consumer benefit	49
5.4	Unsuitable to introduce transmission rights in Sweden.....	50
	References.....	52

Summary

In order to create common rules for the internal market for electricity, the transmission system operators in the EU are developing proposals via their cooperative organisation, the European Network of Transmission System Operators for Electricity (ENTSO-E), for common European regulations known as “network codes” for cross-border trade in electricity. The network codes will then be evaluated by the Agency for Cooperation of Energy Regulators (ACER), which is the regulator for electricity and natural gas on the EU level, and will then become legally binding following the decision of the European Commission.

The Network codes determine the Member States' options

In the proposal for the network code NC FCA, which regulates the long-term and forward-looking trade in electricity – the “forward markets” – there are three main types of contract which are intended to facilitate management of the area price risks in cross-border trade.

These are physical and financial transmission rights and financial contracts. Where transmission rights are concerned, it is proposed that the transmission system operators have an obligation to auction these off to the market. In Sweden, this means that the public utility Svenska Kraftnät (SvK) would be responsible for such auctions.

The Nordic electricity market model does not explicitly include trade in capacity

The Energy Markets Inspectorate can establish that the recommendation concerning trade in transmission rights deviates from the model which has for some time been used in the Nordic region in at least two different ways. First of all, this would involve introducing explicit trade in capacity between individual bidding zones and shift focus in the trade from the common system area to trade between individual bidding zones. Secondly, the transmission system operator would be given a role on the market which thus far has not been customary in the Nordics.

The Nordic market model is based on an integrated day-ahead market (DA market) within a number of smaller bidding zones whose exchange of energy is optimised per hour in the daily spot price auction, where the supply and demand on the DA market meet at the power market Nord Pool Spot. The prices on the DA market are related to a common system price which is a fictive price for all bidding zones. The system price shows what the price would have been if there were no physical transmission limitations between the bidding zones in the Nord Pool area. Normally, there are limited price area differences from one bidding zone to the next. In order to secure price area deviations, CfDs are employed in the Nordics. CfDs are a purely financial product traded between the market actors and are offset against the difference between the system price and the price of an individual bidding zone. These contracts have been traded continuously since 2001 and are an established product for area price hedging.

Introduction of transmission rights risks weakening the Nordic model

The Nordic market actors express no need for additional price hedging products. In fact, they feel that the instruments available today meet their needs of securing both the underlying price risk and the specific area price risk associated with the respective bidding zone. Transmission rights and CfDs are not necessarily mutually exclusive; they can be traded in parallel. If an introduction of transmission rights is to be successful, the instruments also need to function together and support one another. At present there is insufficient evidence to establish that this is the case; it is an empirical issue in case of a possible introduction. If the instruments are substitutes, an introduction would mean the splitting the liquidity between several instruments whilst the introduction of transmission rights risks weakening the current market structure. This would be very unfortunate.

One advantage of introducing additional instruments for price hedging is that this can give market actors access to more options in their risk management. At the same time, new instruments of a different type than those previously employed in the Nordics run the risk of making the market even more complex than it already is. This can result in smaller actors choosing to withdraw from the market, which in the long-term can lead to a deterioration of competition.

By means of the market's actors gaining access to instruments which secure the price risk between two bidding zones, there is potential for sellers and buyers to more easily "move across bidding zone boundaries" and thus compete in several bidding zones' "forward" products. This could lead to reduced spreads (differences between the best bids and offers on the market) in some of the contracts on the market. All else being equal, this could reduce the prices for the end-users, albeit marginally.

The Energy Markets Inspectorate's overall assessment is that the introduction of trade in transmission rights has little to offer the Nordic region in terms of consumer benefit. Introducing the transmission system operator as a market actor could also counteract potential greater consumer benefit if an increased financial risk concerning the system operator spills over onto electricity grid customers.

Unsuitable to introduce transmission rights in Sweden

As prices can differ from one bidding zone to the next, the market actors are in need of opportunities for area price hedging. In the Nordics, these needs are fulfilled by trade in CfDs. The Energy Markets Inspectorate's conclusion is that the potential advantages of introducing transmission rights in the Nordics are too small to motivate an obligation for SvK to auction off transmission rights. The risks highlighted in the report – such as trade in transmission rights risks undermining the system price as a reference price on the market, which is central to the success of the Nordic market – are greater than the potential advantages.

Through the reinforcement of the Swedish national grid with the construction of, among others, the South West Link, the conditions to issue and trade in CfDs

in Sweden is improved, wherefore the market can be expected to function even better in the future. A large majority of the market's actors also express wishes to maintain and develop today's market functioning rather than introduce new instruments. The Energy Markets Inspectorate is in agreement with this standpoint.

In a Nordic context, the Energy Markets Inspectorate considers it unsuitable for Sweden to introduce instruments in trade which other Nordic countries do not intend to introduce. As changes in the DA market also have consequences in the retail stage, it is the Energy Markets Inspectorate's opinion that the work with the Nordic retail market must also be guiding in how the Nordic regulatory authorities work together to formulate trade and available instruments in the Nordic electricity market. If this is to be possible, it is essential that the existing wordings in the as yet unfinished network code Forward Capacity Allocation (FCA), regarding the option to use financial instruments such as CfDs instead of introducing transmission rights, remains once the Member States have completed negotiations and the legislation for area price hedging instruments is in place.

1 Introduction

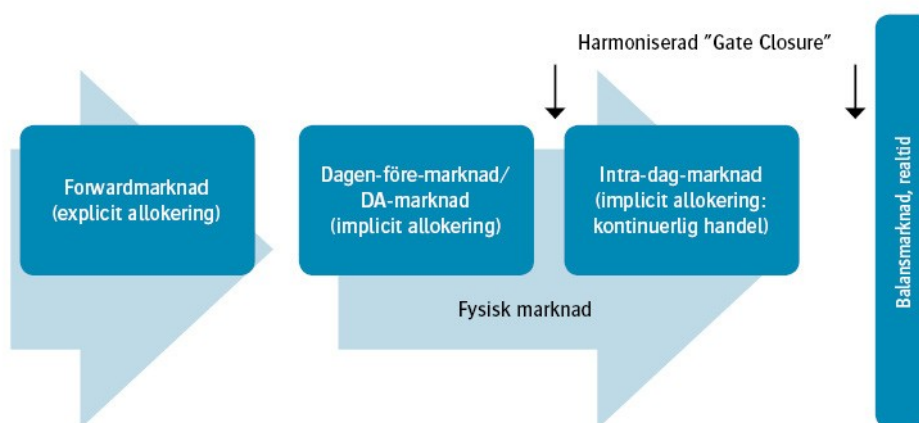
1.1 European integration as a driving force for market development

The idea of an integrated market for electricity has existed in the European Community for a long time. Already in the first electricity market directive (96/92/EG) the groundwork for common rules for the internal market for electricity was laid down. The development since then has been rapid, and today several countries, including Sweden, have implemented the third electricity market directive (09/72/EG) in their national legislation. In the work to create an internal market for electricity, common rules are required, and as grounds for producing these we have the third electricity market directive. In the work towards an internal market, what is often known as the EU's target model for the internal market for electricity has been developed. The target model which was gradually developed describes how the European electricity market shall be integrated in order to achieve efficiency gains, competitive prices and greater security of supply throughout the EU.

In order to manage the complexity of the work towards the internal market for electricity, the work has been divided into several sub-projects known as network codes. The network codes are developed by the transmission system operators (TSOs) within the EU via their cooperative organisation, the European Network of Transmission System Operators for Electricity (ENTSO-E). Each network code deals with a delimited area of the work to create a functioning internal market for electricity. The network codes are produced based on "Framework Guidelines", which was developed by the Agency for Cooperation of Energy Regulators (ACER), which is the EU-level supervisory authority for electricity and natural gas.

Figure 1 below shows a timeline for the target model based on trade in electricity. The market for electricity trade is divided into four periods of time; trade far in advance (forward market), trade the day before physical delivery (day-ahead market), trade on the delivery date (intraday trading) and the real-time balancing market (market for keeping the balance in the electricity grid in operating hours).

Figure 1 Coordinated capacity calculation



Source: ENTSO-E

The EU's target model is a description of the market design for the internal market for electricity divided into different time periods but also serves to coordinate capacity allocation. Three different network codes are being developed for how trade in the various time periods will work.

The CACM code (Capacity Allocation and Congestion Management) regulates the physical markets and the DA and intraday markets. The balancing code describes the real-time market, whilst the forward markets are regulated in the FCA code (Forward Capacity Allocation), which also applies to the trade in the time periods prior to the spot market (months, quarters and years) and is also the code which is of special interest for this study. The code develops the target model's description that the transmission capacity should first of all be allocated via explicit auctions of financial or physical transmission rights.¹

The aim of a specific code for the forward market is to create competition and facilitate trade far in advance across zone boundaries (long term cross zonal). This shall be achieved by providing the market actors with price hedging opportunities in order to manage risks for area price differences in the event of transmission limitations.

ENTSO-E's draft proposal for the network code concerning FCA from 14 August 2013 regulates how national regulators are able to exempt transmission connections from the requirement to issue transmission rights by demonstrating that the market's need for price hedging across zone boundaries is met and that the existing forward market is well-developed and has proven efficient.²

Based on FG CACM and the draft for NC FCA, there are three alternative products available for Member States to provide the market in order to manage risks of price differences arising between bid areas due to insufficient transmission capacity. It is these products which are described and whose advantages and disadvantages are analysed in this report.³

1.2 Commission

In the appropriation regulation for 2013, the Energy Markets Inspectorate (Ei) received the following commission:

“In Sweden and other Nordic countries, CfDs (Contracts for Difference) are used for price hedging in the respective bidding zone. A CfD is normally issued by producers in each zone. Unlike in the Nordics, the practice elsewhere in Europe is to employ physical or financial transmission rights. The Government commissions Ei to compare the various price hedging instruments and list the advantages and disadvantages of each instrument. The analysis shall in particular highlight the instrument's relationship to overall competition and finally

¹ It should be mentioned that the FCA network code was initially part of CACM but has been taken out and is now a separate network code. The time perspective for deciding on CACM is that the network code is in the final phase and is expected to go to comitology in 2014. The FCA network code is after CACM chronologically but is also expected to go to comitology in 2014.

² ENTSO-E (2013).

³ In this context, it is important to point out that ENTSO-E's proposal is simply a proposal and that the content may be amended before the network code has passed through the comitology process and been decided on.

consumer benefit. The analysis shall be set in relation to the Nordic market situation, the work with Nordic end-user markets and the upcoming network codes due to the introduction of the third internal market package for electricity and natural gas. Ei shall in an appropriate manner take advantage of the knowledge and experience found at the Swedish Competition Authority (KKV) in the area when carrying out the commission. A report on the commission is to be submitted to the Government Offices (Ministry of Enterprise, Energy and Communications) no later than 30 September 2013.”

1.3 Delimitations

This report is delimited to primarily focusing on fundamental actors' need of area price hedging. Analyses of actors that solely or primarily operate for speculation purposes will be kept brief.

The analysis in the report is also limited to the instruments named in the commission.

1.4 Project organisation

The project manager was Kaj Forsberg. Jens Lundgren has also participated.

In carrying out the commission, the Energy Markets Inspectorate has taken advantage of KKV's experience. Contact with the authority has been handled by KKV participating in the reference group.

Through the reference group, industry representatives and relevant associations have been afforded the opportunity to follow the work and provide feedback. The reference group comprised of the following:

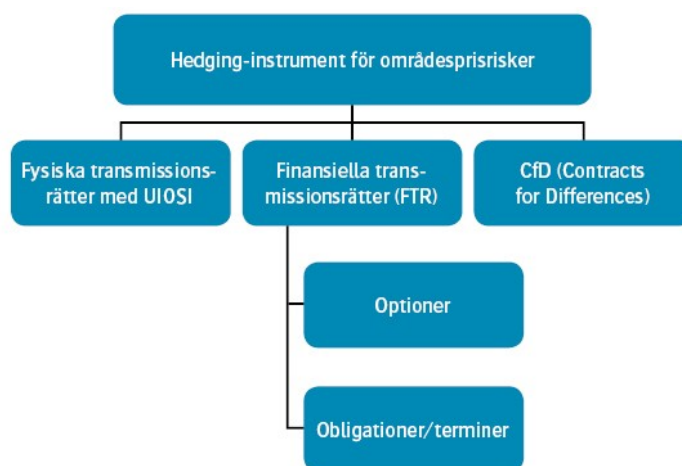
- The Swedish Competition Authority
- The public utility Svenska Kraftnät
- Svensk Energi
- Vattenfall
- E.ON
- SCA
- Södra Skogsägarna
- The Association of Independent Electricity Traders in Sweden
- Nord Pool Spot
- Markedskraft
- Nasdaq OMX

2 Description of various price hedging instruments

In electricity trade, there is a need for market actors to manage risks of prices varying both over time and between different geographical areas. There are several ways of managing and securing the price for electricity supply. For the underlying price risk, different forms of forward and future contracts are used in most markets. These may cover different time periods (e.g., weeks, months and years) and even have a varying profile (e.g., base and peak load contracts). For price hedging of the specific area price risk, different instruments are used in different parts of the EU. The most common instruments in continental Europe are financial and physical transmission rights whilst the Nordics use financial contracts known as Contracts for Differences (CfDs). Trade in transmission rights is taking place today via primary auctions on the common marketplace Casc.eu⁴, whilst CfDs are traded via Nasdaq OMX or bilaterally between actors.

In FG CACM it is determined that financial or physical transmission rights should be used for area price risk management. The guidelines also mention that if there are financial instruments on liquid markets on both sides of the transmission connection, these may be used for area price risk management instead of transmission rights. In the draft of NC FCA, it is maintained that these three instruments are the alternatives.⁵ Even if CfDs are not mentioned explicitly, it can be said that the three instruments recommended are those found in Figure 2. These are also the instruments mentioned in the mission statement for this report.

Figure 2 Price hedging instruments according to proposals for NC FCA



Source: ENTSO-E

⁴ For an exhaustive description of which instruments are available and between which areas, see www.casc.eu. On Casc's website, it is also possible to search for information on volumes, the number of actors, etc., for each auction and product.

⁵ ENTSO-E (2013).

The common function of the instruments is to manage area price risks. At the same time, the instruments function in different ways and also have different effects for actors and for the market as a whole. The fact that the instruments have different impacts on actors and markets means that it is important to analyse whether they still fulfil the functional requirements to which the instrument can be subjected. The primary requirement for an instrument for area price hedging is that it provides an effective price hedging for the actors. This means that the contract entered into must be constructed in such a way as to manage the financial risk and limit uncertainty in future cash flows for producers, suppliers and consumers. Apart from this basic function, instruments should contribute to socioeconomic efficiency by, for example, facilitating good competition and stimulating market integration by improving opportunities for trade across national borders.

This chapter reports on how the various instruments function and what economic effects the instruments have on different actors.

2.1 Contracts for Differences (CfDs)

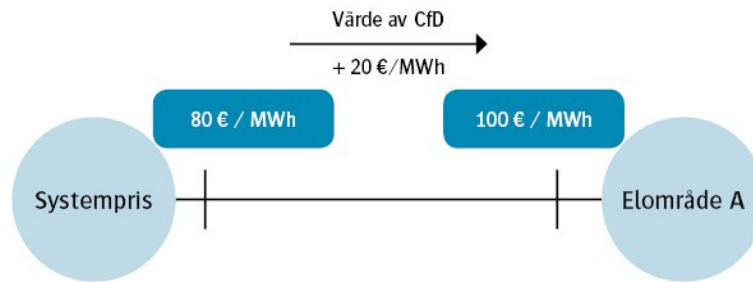
Nordic electricity trade is built around a common market and trade with a system price (which is the price that would prevail if there were no transmission limitations in the region). The system price is used as a reference price for trading in electricity in the Nordic region and is also used as a reference price for the majority of price hedging products there.

The Nordic electricity grid is essentially well-developed, but transmission limitation mean that the Nordic area is divided up into different bidding zones from time to time.

It is in the local bidding zones that the physical input from the production source and the actual consumption of electricity are priced. As the prices in the bidding zones can differ from the system price, it is necessary for actors to protect themselves against this area price risk as well.

In the Nordics, CfDs have been traded, since 2001, as a financial product for managing the risk of differences in electricity price from one bidding zone to the next. A CfD is essentially a contract between two parties whereby the underlying value is the price difference between two reference prices. The way the instrument is used in the Nordic region, the reference prices are the Nordic system price and the prices in the various bidding zones (several bidding zones can form one price area but one bidding zone can be a price area if there are bottlenecks with all adjacent bidding zones). The use of CfDs is explained by the examples below.

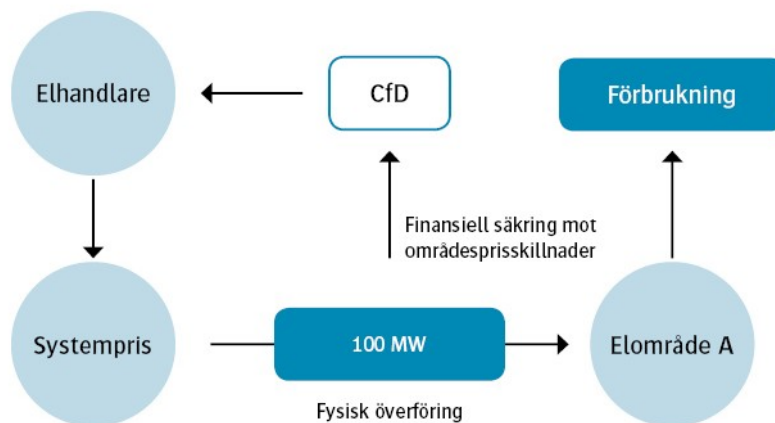
Figure 3 Value of CfDs



Source: ENTSO-E

In Figure 3 it is assumed that the system price for a given hour is EUR 80/MWh. For the same hour, the price in bidding zone A is EUR 100/MWh due to transmission limitations between surplus zones and deficit zones, in the electricity system. Figure 4 shows the electricity supplier's activity on the market.

Figure 4 Function of CfDs for hedging price area risk



Source: The Swedish Energy Markets Inspectorate

For an electricity supplier which has an obligation to supply at a fixed price to customers in bidding zone A, but which has only protected itself against the system price risk by purchasing system price contracts and has not purchased a CfD to protect itself against the area price risk, the loss is EUR 20/MWh. The value of the CfD is in this case EUR 20/MWh. These EUR 20/MWh are settled financially between seller and buyer.

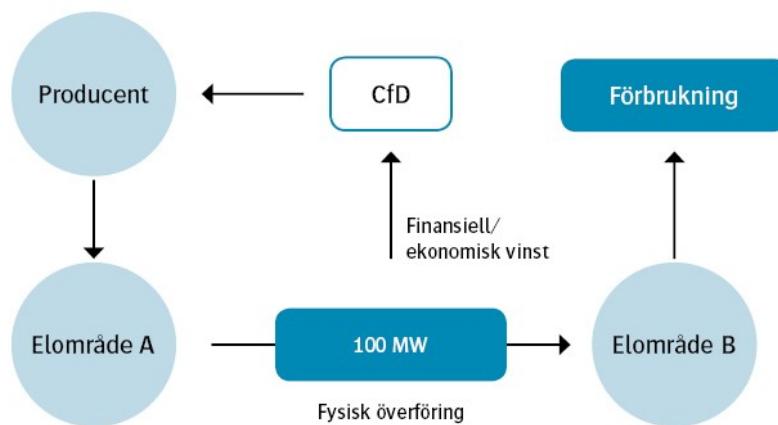
A CfD is structured like an obligation⁶, which means that a person who buys a CfD can either receive payment from or make payment to the issuer of the CfD, depending on the outcome of the settlement between both reference prices during the settlement period in relation to the agreed price of the contract. The example in Figure 3 shows when the difference between the system price and the area price is positive and the seller of the CfD has to compensate the buyer. Had the price difference gone the other way, the buyer would instead be liable to compensate the seller of the CfD.

⁶ Here, the word "obligation" refers to a commitment which is binding.

The fact that a CfD is a purely financial product means that the remaining volume of CfD is not directly linked to the transmission capacity between different bidding zones. The price (or valuation) of the CfD is however linked to the market actors' assessment of the future physical transmission capacity between zones, as it is limitations in the transmission capacity which create the price differences that actors wish to protect themselves against.

Even if a CfD offers protection against the risk of deviations between a bidding zone's price and the system price, CfD contracts can also be combined in pairs in order to protect against the price difference between two or more bidding zones. This is illustrated in Figure 5 below.

Figure 5 Function of CfDs when a producer in Bidding zone A sells to consumers in Bidding zone B



Source: The Swedish Energy Markets Inspectorate

In order to hedge the price in A against the price in B, the producer can use two CfDs. By selling a CfD in zone A and buying in zone B, both the selling price in zone A and the buying price in zone B are secured and the producer thereby has the necessary security to offer a buyer in zone B a fixed price.

It is also possible to show the effects of such a transaction

$$\text{mathematically. } CfD_{\text{sell}}: EO_A - SYS \quad (1)$$

$$CfD_{\text{buy}}: SYS - EO_B \quad (2)$$

By combining equations (1) and (2), we get the following: $CfD_{\text{sell}} +$

$$CfD_{\text{buy}} = (EO_A - SYS) + (SYS - EO_B) \quad (3) \text{ If we}$$

Through shortening the equation (3), we get the following:

$$CfD_{\text{sell}} + CfD_{\text{buy}} = EO_A - EO_B. \quad (4)$$

A combination of buying a CfD in a bidding zone and selling in an adjacent bidding zone thus results in the system price disappearing from the equation, and instead we get an instrument which corresponds to an area price hedging between two bidding zones.⁷

Unlike other price hedging instruments discussed in the report, trade in CfDs normally does not involve transmission system operators (TSOs); but only market actors. A CfD can in principle be traded by anyone, but the natural candidate for a seller is a producer with base production capacity in a bidding zone⁸. Buyers can for example be electricity suppliers with sales commitments in the bidding zone in question or a customer consuming in the same. CfDs are primarily used by fundamental actors (with physical commitments/positions in the market) in order to manage area price risk, but just as with many other financial contracts, the instrument can also be used by traders⁹ for speculation purposes. That the instrument is primarily used as a risk management product and not as much as a trading product is evident from the fact that the turnover is lower than for system price products, for example.

In this context, it should be mentioned that although the above description is based on how CfDs are used in the Nordic market, the Nordics are not alone in Europe in using CfD instruments for risk management. Today, there are functioning CfD markets between Spain and Portugal as well, and Nasdaq OMX has recently introduced CfDs between Germany and the Netherlands, Belgium, France and the Czech Republic.¹⁰

2.2 Financial Transmission Rights (FTRs)

A financial transmission right is, according to the definition in the draft of NC FCA, “a right purchased in a transmission rights auction¹¹ and which is based on the transmission capacity between two bidding zones. The right gives the owner the entitlement to receive or pay out (depending on whether it is an option or obligation) financial compensation which is based on the outcome on the spot market for the two bidding zones in which the right originates. The right applies to a specific period of time and in a given direction”. The definition is general, and the contract type “financial transmission rights” can in turn be divided into FTR options and FTR obligations.

2.2.1 FTR options

A financial transmission right in option form is designed so as to give the holder the right to part of the revenue created by trade on the transmission connection in a given direction. The revenue that the FTR gives the owner is the difference between the market price on the various sides of the transmission connection, hour for hour, multiplied by the volume that the right concerns. This is known as the “bottleneck revenue”, which otherwise goes to the owners of the transmission capacity; normally TSOs.

⁷ As shown in Chapter 2.2.2, this corresponds to an FTR obligation.

⁸ The reason these are considered to be natural candidates for sellers of CfDs is that they have the natural position/security to take on the risk entailed in issuing the contract (which is settled hour by hour during the contract period). In this context, “baseload power” refers to production units that are in more or less continuous operation.

⁹ Here, the term “trader” refers to a trade actor with no underlying energy flows for which to handle price risks. A trader buys and sells transmission rights and other financial instruments based on future price prognoses and speculation in price fluctuations in order to maximise the profit from their portfolio.

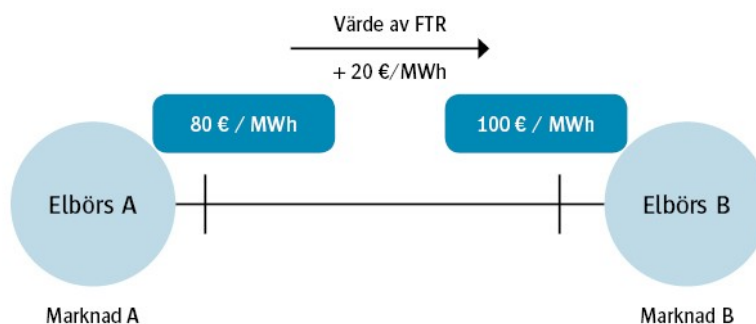
¹⁰ The CfD offered by Nasdaq OMX has the German system price (Phelix) as a reference price. <http://www.nasdaqomx.com/commodities/markets/products/power/cfds/>.

¹¹ Forward Capacity Allocation.

Use of FTRs requires the existence of a functioning spot market on which various bidding zones are interlinked via market couplings. If there is a functioning market coupling, it is guaranteed that the capacity on the connections between zones is allocated in an effective way on the spot market, as the energy flow is always moving from low to high-price areas so as to even out the prices between areas as far as possible.

In order to show the effects of FTR options, we provide a short example below. We assume that a producer in zone A has a sales commitment in zone B and that the transmission connection is sometimes limited. If the producer is to fulfil its commitments, it must be active on the spot markets on both sides of the transmission connection; selling in zone A and buying in zone B.

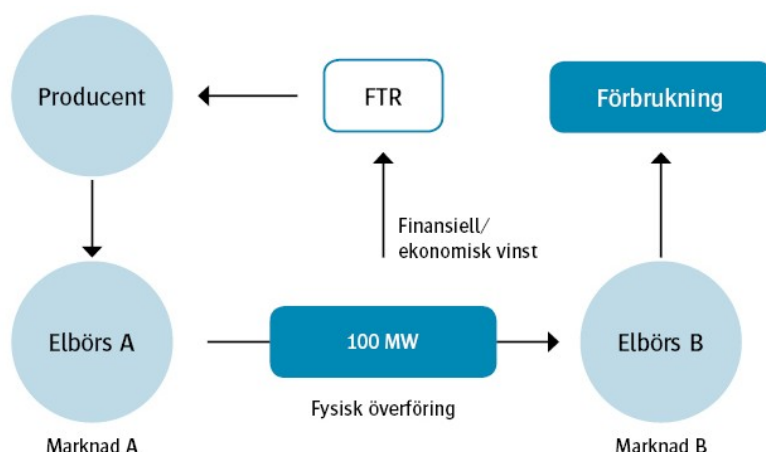
Figure 6 Value of an FTR option



Source: ENTSO-E

Figure 6 shows the results of the trade in one hour where the prices are EUR 80 /MWh in zone A and EUR 100/MWh in zone B. Figure 7 shows that, for the producer, this means that they sell in zone A for EUR 80/MWh but have to buy at EUR 100 /MWh in zone B, which means a loss of EUR 20/MWh. In order to protect itself against this cost difference, the producer can purchase FTR options, which entitles it to financial compensation to the value of the area price difference, in this case amounting to EUR 20/MWh. By buying FTRs, the producer gains the security that the price (offset by the FTR option) in zone B is the same as what the producer is paid for their production in zone A. The FTR is thus a secure price hedging against price differences between the areas.

Figure 7 Function of an FTR option.



Source: ENTSO-E

Responsibility for how much of the capacity on a transmission connection is allocated to transmission rights lies with the TSO. In accordance with the draft of the FCA network code, the allocation procedure is to be harmonised between the Member States so as to increase transparency.¹² Normally, the TSOs are also responsible for the auction of FTRs.

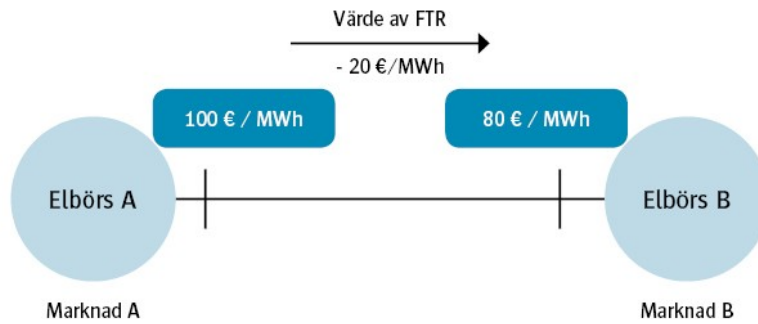
2.2.2 FTR obligations

Unlike the option, the owner of an obligation is not just entitled to compensation in the form of the hourly price difference between two bidding zones for a specific period in a given direction; they are also obligated to pay compensation if the price difference goes in the other direction. This means that an FTR obligation can provide the holder with financial remuneration, but may also entail a cost that the holder would not have had if they had not buy the transmission right.

To explain the difference when compared with the FTR option, we continue with the example above. For the producer in zone A, the outcome of an FTR obligation is the same as with the option – provided the price difference between zone A and zone B is as it is in the example. It is if the price difference goes in the other direction that the difference between instruments arises. In the example shown in Figure 8, we switch the area prices around, thus making the price in zone A EUR 100/MWh and in zone B EUR 80/MWh.

¹² ENTSO-E (2013).

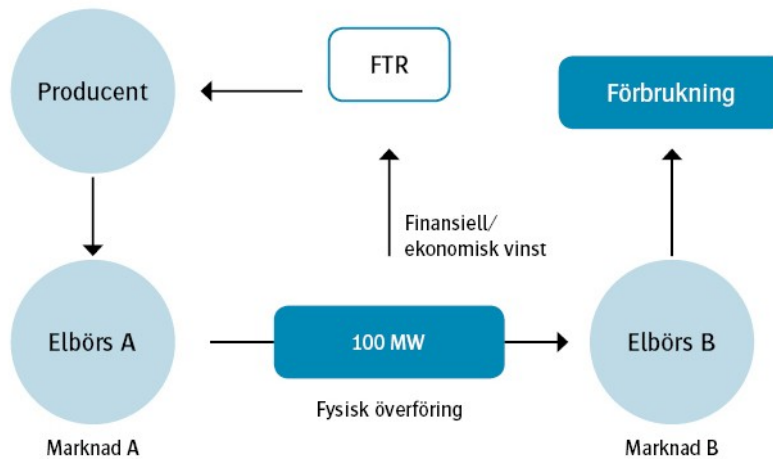
Figure 8 Value of an FTR obligation



Source: ENTSO-E

With an option such as the one in the previous example with the direction A to B, no payment is made by the time it reaches maturity (apart from the compensation paid by the buyer at the time of buying). Figure 9 shows that a producer in zone A which has a commitment in zone B and which has purchased an obligation will sell energy in zone A for EUR 100/MWh and buy energy in zone B for EUR 80/MWh. This transaction thus provides a profit of EUR 20/MWh. If the producer purchased an FTR obligation instead, however, the producer is liable to pay the negative price difference of EUR 20/MWh to the issuer of the obligation, which is normally the TSO. Overall, an FTR obligation means that the producer in A always (irrespective of the direction of the price difference) knows what margin they gain in a business transaction and gains a perfect price hedging for their commitment in zone B.

Figure 9 Function of an FTR obligation



Source: ENTSO-E

In this context, it can also be said that an FTR obligation has the same function as CfDs in the Nordics. The main difference is that FTRs are issued for transmission connections and are offset against the price differences between two bidding zones (and are auctioned off by TSOs), whilst CfDs are settled between the system price and a specific bidding zone. The CfD-design can therefore be said to support and maintain that of the system price in the DA market, whilst the transmission rights have a tendency to steer attention away from the system price to the area price.

2.3 Physical Transmission Rights (PTRs)

A physical transmission right (PTR) can be described as the right to transmit a certain quantity of energy across a given cable in a given direction and during a given period of time. PTRs in the form discussed in Europe have a similar structure to options, with the addition of “use or sell” (UIOSI - Use It Or Sell It).

The transmission right can be used to channel energy from one market to another, irrespective of whether the energy is bought on an established power exchange or outside of it, so called OTC-trade (over-the-counter) trade. An actor with physical positions on both sides of the cable can also use the transmission right to optimise its own portfolio.

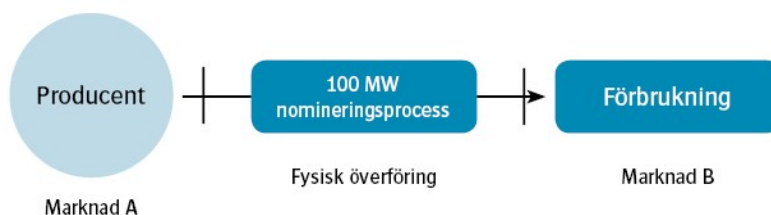
An actor which has purchased a transmission right can use it in two ways. First of all, the holder can use the right to transfer the energy (Use It) and thereby utilise its share of the transmission connection. For this, a nomination procedure is adopted whereby the holder of the right informs the TSO of its intention to utilise its transmission right. In this case, no other actor, nor the DA market can use the nominated/reserved part of the transmission connection. Alternatively, the holder may choose not to use the right to transmit energy. If this alternative is chosen, i.e., not to nominate the right, it is instead sold back to the spot market (Sell It) and the holder is then compensated in the amount that the DA market valued the sold capacity at (i.e., the volume multiplied by the price difference between the two areas).

Just as for FTRs, it is the TSOs that are responsible for calculating how many PTRs can or should be sold for each transfer connection. It is also the TSO that is responsible for issuing and auctioning PTRs. The TSO is also responsible for the nomination procedure, in which the TSO receives and compiles the PTR holder's nominations. Before the TSO hands over available capacity to the DA market, the nominated capacity is drawn from the total technical available capacity.

The use of PTRs is best illustrated via two examples. Assume we have a producer in zone A that has a commitment to sell energy in zone B. Between the zones, there is a transmission connection and the zones have a market coupling, but the transmission connection is periodically insufficient and the zones thus have different prices.

With physical transmission rights, the producer needs to ensure it is in fact able to transport the energy to zone B and thereby fulfil its commitments. The producer can secure future transmission rights by purchasing the required number of rights in a PTR auction. Figure 10 shows an example whereby the producer purchases the physical right to transmit 100 MW from zone A to zone B. The producer nominates (informs the TSO that the right is to be used) and thereby transmits 100 MW to zone B, thus fulfilling its commitment to the buyer in zone B without needing to become involved in the spot market.

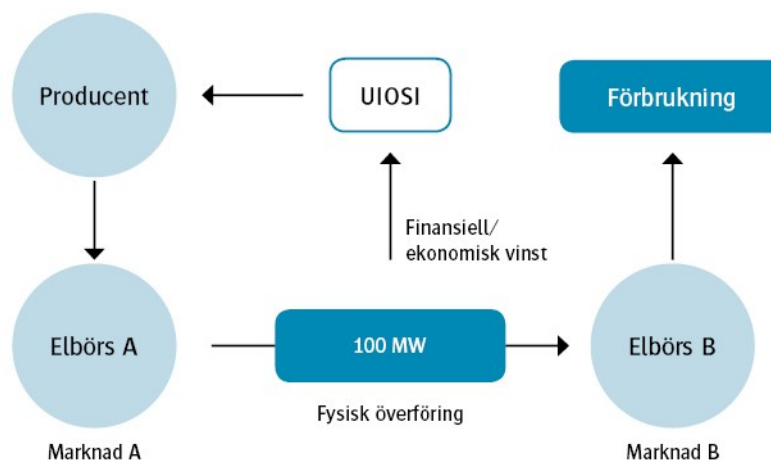
Figure 10 Function of a PTR



Source: ENTSO-E

The alternative for the producer in zone A is to not utilise their physical transmission right at all and instead sell it back to the spot market as in Figure 11. In this case, the right goes from being a physical right to instead functioning as a financial transmission right option, where the owner is compensated in an amount corresponding to the price difference between the areas multiplied by the contracted volume.

Figure 11 Function of a PTR with the addition "use or sell"



Source: ENTSO-E

If the producer in zone A acts in this way, they must instead act on the spot market on either side of the connection. The producer must act as seller in zone A (assuming they choose to produce at all) and as buyer in zone B in order to fulfil their commitments in zone B.

2.4 The economic effects of transmission rights for market actors

Primarily, the "fundamental actors", i.e., actors with physical commitments or resources on the market (producers or sellers) and pure trade actors, i.e. traders, are the market actors who are likely to use transmission rights. In addition, the issuer of the transmission rights, normally the TSO, is also an actor on the market.

The fundamental actors' utilisation of transmission rights is mainly intended for managing risks tied to contracts entered (buy or sell) in two or more

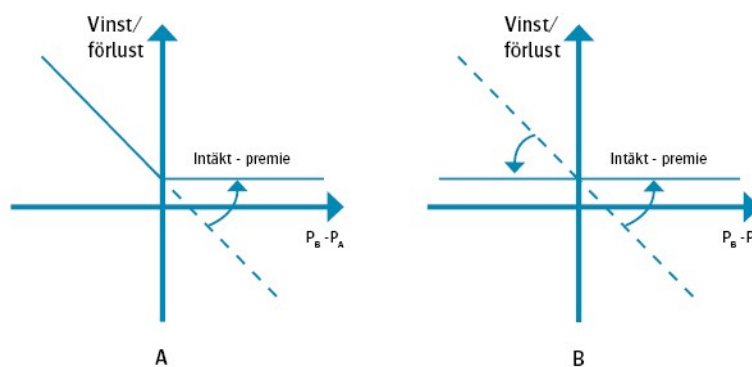
bidding zones that may have differences in price. A trade actor primarily uses transmission rights as a financial product in their trade portfolio which they will attempt to maximise the return on.

Before an analysis of transmission rights and CfDs is made, it is necessary to discuss the economic effects that the concerned actors are faced with when using the various instruments. The focus of this paragraph is primarily financial transmission rights. Physical transmission rights which are not nominated and are instead sold back to the DA market have a financial outcome similar to that of FTR options, which means that PTRs are not discussed explicitly.

2.4.1 Fundamental actor

In order to describe the effects to which fundamental actors are subjected, Figure 12 provides the example of a producer in zone A which has a sales commitment in zone B. To the left we see the outcome of options and to the right the outcome of obligations.

Figure 12 Profit function for a producer with an FTR option and an FTR obligation respectively



Source: ENTSO-E

In Figure 12, the vertical axis shows the company's profit and the horizontal axis shows the price difference between zone A and zone B. The left side of Figure 12 shows the effects when the producer buys an FTR option from zone A for zone B in order to protect itself against price differences between the areas. The downward sloping line shows the producer's profit function without FTRs. In the illustration, we can see that the producer's profit declines when the price in zone B approaches that of zone A. If the producer does not buy an FTR, the dotted line shows that the profit will become a loss once the price in zone B is higher than in zone A. In order to protect itself against this loss, the producer buys an FTR option, which gives it rights to part of the bottleneck revenue if the price in zone B is higher than in zone A. Figure 12 shows this in terms of the producer's profit function breaking and becoming a horizontal function when the price difference between the zones is zero. The distance between this horizontal line and the x axis illustrates the size of the premium that the producer pays for the option. In this case, the producer has a price hedging against the area price difference. We can also note that if the price in zone A is higher than in zone B, the producer will make a greater profit as FTRs do not hedge the price difference on that side.

The right side of Figure 12 shows the outcome if the producer instead purchases an FTR obligation. Here, the same conditions apply as with an option if the price in zone B is higher than in zone A, i.e., the producer receives compensation corresponding to their part of the bottleneck revenue in the same way as with an FTR option. The difference with the obligation instrument is that the producer has also undertaken to pay the issuer of the obligation in an amount corresponding to the area price differences if the price difference goes in the opposite direction; i.e., if the price in zone A is higher than in zone B. The effects of this position for the producer are that both losses and profits have been limited and that the producer knows exactly what their revenue will be, irrespective of area price differences.

2.4.2 Trading

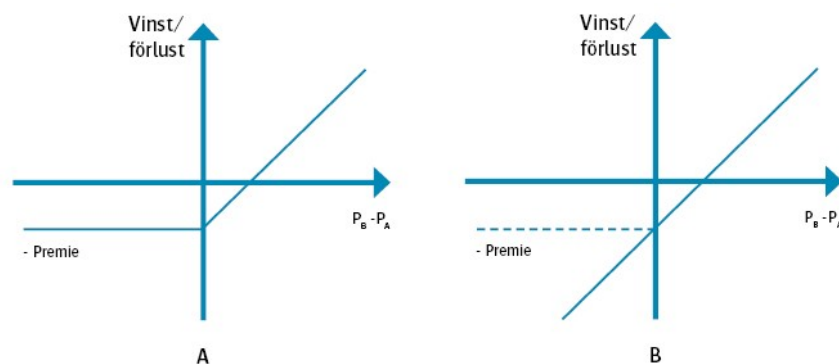
The second type of market actor that is interested in trading in transmission rights is pure trading companies; traders. Traders have no underlying energy flows for which they need to manage price risks; rather, they buy and sell transmission rights and other financial instruments based on future price prognoses and speculation in price fluctuations.

A typical trader with interest in transmission rights analyses and makes prognoses for price differences between two areas. If the company's analysis shows that the price will be higher on average in one area than in another, there are grounds for purchasing transmission rights for speculation purposes in this expected price difference.

Provided that the expected profit is greater than the cost of the transmission right, the purchase of the transmission right means an expected profit for the company. One alternative trading strategy is of course to trade on the price fluctuations, i.e., buy when the market is perceived to be generally undervaluing the instrument and sell at a later stage once the price has risen.

The word speculation sometimes has somewhat negative connotations, but in this case the effect on the market's function is quite the opposite. Through traders' participation in the market, the number of actors increases, which can lead to higher liquidity and higher credibility in the determination of prices for transmission rights and other instruments.

Figure 13 Profit function for a trader with an FTR option and an FTR obligation respectively



Source: ENTSO-E

Figure 13 shows the economic situation facing a trader who is active in the market for transmission rights with no underlying physical commitments. The left side of Figure 13 shows an option that gives the trading company a positive return if the price in zone B is higher than in zone A. The risk the company takes is to lose what the transmission rights would cost if their price forecast proves inaccurate.

The right side of the figure shows the outcome of an obligation. Unlike the option, the company must pay the corresponding bottleneck revenue if the price is contrary to expectations. In a comparison with fundamental actors, however, traders have no production at the base that they feel is worth price hedging. The downside in the outcome of the obligation, where the actor in the example is identical, is that there is only an increased financial risk, because in an unfavourable outcome it has undertaken to pay the area price difference to the issuer of the transmission right. Overall, financial transmission rights in the form of an obligation entail a higher risk for a trade actor than if the transmission rights were structured like an option.

2.4.3 Issuer of transmission rights

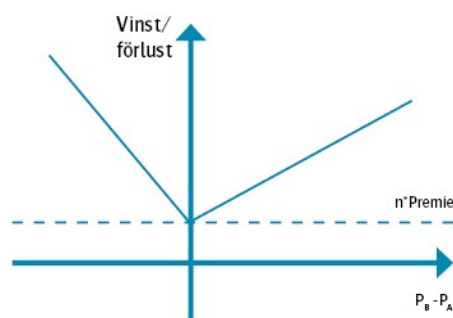
The natural issuer of transmission rights is the owner of the transmission capacity; normally the TSO. In accordance with FG CACM, it is also the TSO who takes care of auctioning off and payments to the holder of transmission rights.

The settlement of transmission rights also has economic effects for the TSO. In order to show these effects, we start with an example from a situation in which TSO auctions off FTRs from zone A to zone B. The outcome of the auction means that TSO has sold off any future rights to bottleneck revenues¹³ for this transmission connection. For this, the TSO receives the proceeds of the auction, which are the number of transmission rights sold multiplied by the auction price for the rights ($n \cdot \text{premium}$).

The transmission rights are settled in the DA market at the time they mature. Following the sale of transmission rights, the TSO's revenues depend on both area prices and the number of transmission rights auctioned out. If the area price difference is zero, the TSO retains the proceeds of the auction but does not need to pay any compensation to the holder of the transmission right. Furthermore, the TSO has no bottleneck revenues as the area price difference is zero. If the area price difference is positive, the TSO must pay the holder the proportion of the bottleneck revenue that the holder purchased the right to. If the area price difference is negative, the TSO receives bottleneck revenues, but if no transmission rights have been sold in this direction, there is no counterparty that is due payment; the TSO retains the entire bottleneck revenue.

¹³ The bottleneck revenue is based on area price differences and is calculated as the available capacity for the market coupling between zone A and zone B, multiplied by the absolute price difference between the areas.

Figure14 Profit function of the TSO when auctioning off FTRs



Source: ENTSO-E

Figure 14 shows the TSO's profit function when selling transmission rights as options for transmitting from zone A to zone B. What can be seen is that to the right, when the price in zone B is higher than in zone A, the revenue function is flatter than for negative area price differences. This is because the TSO has sold transmission rights in that direction and is thereby unable to retain the bottleneck revenue, which they can if the price difference goes in the opposite direction. If the TSO has instead auctioned off obligations, they would also have had additional revenues when the area price difference was the opposite, i.e., area A would have higher prices than zone B.

Provided there is a functioning market for the TSO, there is no financial risk involved in auctioning off transmission rights, whether options or obligations, as long as the physical transmission capacity available in the DA market is greater than the volume of transmission rights sold. This applies if the bottleneck revenues can be used for settling transmission rights. Provided the capacity available in the DA market is greater than the number of transmission rights, the bottleneck revenues will always suffice for paying the holders of the transmission rights. If the transmission capacity available in the DA market for some reason, such as a broken transmission connection, proves to be lower than the number of transmission rights sold, however, there is a financial risk ("firmness risk") for the TSO. This is because the bottleneck revenues will be insufficient to compensate the transmission rights holders in the event of an area price difference.

Regarding the TSO's financial risk, the same reasoning applies to both options and obligations. One important difference between both types of FTR is that with FTR obligations there is an opportunity for the TSO to net off the sale of capacity in one direction against the sale of capacity in the other. As an obligation provides an income for the TSO when the price difference is negative, the cash flow can be used to cover commitments when selling an obligation on the same transmission connection, but in the opposite direction. Under certain conditions involving FTR contracts structured like obligations, the TSO can issue significantly larger volumes (which also exceed physical capacity available on the connection) of transmission rights without increasing their economic risk¹⁴. Naturally, this requires the market to demand transmission rights in both directions.

¹⁴ This reasoning is based on the assumption that the TSO's counterparties are creditworthy and in all situations manage to meet the commitments to the TSO, or that there is a clearing house which functions as a counterparty.

3 Nordic market design and area price hedging

3.1 Market design in the Nordics

Nordic market design is built on a common physical wholesale market, Nord Pool Spot, with a common system price as a reference price. Participants in the trade on Nord Pool Spot are electricity producers, electricity suppliers and portfolio administrators. However, the market model has also gained a high level of confidence among larger consumers such as industrial enterprises, real-estate companies, and municipalities and county councils which themselves (or via a representative) follow the market and make independent decisions concerning their own running purchases directly on Nord Pool Spot .

Participation in trade on Nord Pool Spot is voluntary, but all cross-border trade on the day-ahead (DA) market must take place via Nord Pool Spot. The market share for Nord Pool Spot comes to almost 80 per cent of the electricity produced in the Nordic region. The remaining 20 per cent is traded bilaterally or within companies. Participation in physical and financial stock exchange trading in the Nordics is high compared with other comparable countries in Europe, where, just as in the Nordic region, stock exchange trading is not obligatory.

3.1.1 Implicit trade in capacity

The capacities for transferring energy between bidding zones are calculated and coordinated between the Nordic TSOs and are handed over to Nord Pool Spot before prices are calculated. The prices for the bidding zones and flows between these are calculated at a later stage. The applied algorithm ensures that electricity will flow from low-price area to high-price area. If the transmission capacity is sufficient, the prices are balanced out between the areas. If not, price differences between the areas arise.

This implicit trade in capacity is one of the characteristics of the liberalised Nordic market. Via this, the available transmission capacity is used to integrate spot trade in the various bidding zones with the purpose of maximising the total societal benefit. In the Nordics, the spot market is thus allocated all of the available capacity (according to the TSO) and at present there is no separate trade in transmission rights. The flows on the cables are determined by the bid from the market actors in the different areas.

3.1.2 Opportunities for area price hedging today

The Nordic market is based on a combination of a liquid spot market and a liquid financial forward market which relates to the system price. The system price is the hourly spot price that would be calculated for the Nord Pool area as a whole if there are no transmission restrictions. By structuring the system price in this way, a larger and more stable market is achieved, one which more actors can relate to, instead of a fragmented market divided into a number of areas with fewer actors each and thereby a risk of worse liquidity in each individual area.

There are two main steps for an actor that wishes to cover their price risk in the Nordic market.

The first is to purchase a financial forward contract which refers to the system price.¹⁵ The forward contract means that a person who wishes to buy electricity for future needs buys “in the future”. The actor signs an agreement concerning the supply of electricity, in which the volume and price are established in advance. With this method, the price for the volume of electricity to be delivered will be fixed, but as the contract is financial, it is also settled financially. The contract must thus be supplemented with an agreement concerning physical delivery. This often originates from the DA market. In the Nordic forward market, a total of 1,747 TWh was traded in 2011 and 1,663 TWh in 2012 at Nasdaq OMX Commodities. The underlying physical volume traded at Nord Pool Spot amounted to 334 TWh in 2012¹⁶. The financial trade is thus considerably larger than the physical.

Other than buying forwards which are offset against the Nordic system price, buyers and sellers also need to hedge risks linked to bottlenecks in the transfer system in the Nordics in order to have full certainty of the future price. The method employed for this in the Nordic system is the CfD. As described in Chapter 2.1, a CfD is a means of price hedging between the system price and a specific area price. The purchase and sale of CfDs for different areas can be combined to create a hedging of the price difference between two areas. The total volume of CfDs traded on the Nordic market has in recent years amounted to around 130-170 TWh annually.¹⁷ Trade in CfDs is thus more limited than in system price forwards, which is also a sign that the CfD is used primarily for price hedging and not for trading.¹⁸

3.2 What are the problems with Nordic market design from the perspective of actors outside the Nordics?

The Nordic market design has been highlighted as successful in many contexts and has also largely acted as a model for the target model adopted for the internal market. There are however areas where the Nordic and continental views are not aligned. Examples of such areas are instruments for cross-border trade and methods of area price hedging. The criticism targeted at the Nordic market design from other parts of Europe is linked to two matters:

1. A general problem put forward is that the Nordic and the continental trade function in different ways. As transmission rights (in different forms) are the most common product for managing area price risks in Europe, the need for continental actors to use other products and another means of trading when they arrive at the Nordic border is perceived as highly inconvenient. A number of continental actors have pointed out that they

¹⁵ This is done in the financial forward market, where Nasdaq OMX Commodities is the dominant marketplace for system price contracts. For CfDs, OTC trade still dominates.

¹⁶ Nord Pool Spot (2012).

¹⁷ www.nasdaqomx.com.

¹⁸ Hagman & Björndalen (2011).

perceive this way of trading as a barrier to competition on the Nordic market.

2. Based on the requirement in FG CACM for the existence of instruments which can be traded on liquid financial markets on both sides of a cross-border connection, it has been discussed whether this is the case when for example entering Sweden from the south. It is thus referred to here that it is not enough to have good opportunities to both buy and sell system price contracts with good liquidity. The discussion has also applied to the supply of CfDs in e.g., bidding zone four (SE4). The lack of transmission rights or a greater supply of CfDs can be considered a barrier to competition on the forward market.

This criticism emphasises different aspects of the Nordic situation, but is also linked to the lack of experience and knowledge about how the Nordic market actually works.

However, in a continental European context, where transmission connections between countries have in many cases been weak, a structure with a system price, and forwards which are offset against this, is not common. The tradition of reserving physical capacity between the domestic market and the “export market” is strong. Likewise, the market on the continent has been largely characterised by bilateral contracts, physically settled contracts and a comparatively limited financial trade.

The Nordic model has developed with a clear focus on transparency, a liquid and functioning DA market and exchange-traded financial contracts. This has also provided space for a rather large number of actors without their own production to act as electricity traders with relatively good opportunities for competition.

On the continent, the markets have more tangibly continued to be dominated by the larger integrated companies, i.e., companies which have both production and electricity trade in their activities.

4 Function of the instruments in relation to Nordic market design

A natural point of departure in an analysis of different area price hedging instruments is how the Nordic market functions today and how it should be expected to develop in the event of a change such as the introduction of trade in transmission rights. For this report, this means that the point of departure is the existing Nordic market model described in Chapter 3, where the foundation is trade in system prices and area price hedging with CfDs.

Initially, we report on what the actors in the Nordic market have expressed concerning the function of the market with the instruments of today versus transmission rights.

4.1 What do the market actors say?

The majority of actors in the Nordic market, who have been interviewed in various contexts over the past few years¹⁹, have expressed doubt in face of the introduction of transmission rights in the Nordic system.

Hagman & Björndalen (2011) interviewed sixteen market actors, including fundamental actors, traders and authorities, in Sweden, Norway and Finland. All fundamental market actors wished for greater liquidity in CfDs. Some believed that the introduction of FTRs would increase the liquidity in CfDs whilst others believed the opposite.

Several of the actors who have trading as their primary activity were interested in FTRs as a complementary product. Some of the fundamental market actors expressed that FTRs as a complementary product to CfDs could provide better hedging for vertically integrated companies with production in one zone and sales to customers in another. At the same time, it was pointed out that the majority of Nordic actors use gross bidding, whereby all sales and purchases of electricity are handled separately via Nord Pool Spot, which means that their trade is not managed in this way. Other actors were satisfied with using current systems with system price contracts complemented with CfDs for hedging.

The majority of the actors interviewed in the study of Hagman & Björndalen (2011) predicted that the introduction of FTRs would affect the transmission system operator's (TSO) behaviour in the short-term regarding the planning of maintenance work and managing disruptions in the grid. With FTRs, there is greater incentive for TSOs to minimise the impact of problems in the grid-side of the market.

¹⁹ Hagman & Björndalen (2011), NordREG (2012), the Swedish Energy Markets Inspectorate (2012).

Via their cooperative organisation NordREG, the Nordic regulatory authorities have responded to ACER concerning how the Nordic actors perceive that long-term price hedging in the Nordic region works²⁰. In a questionnaire, actors in Norway, Denmark, Sweden and Finland had the opportunity to answer the question of what they think about transmission rights. The answers are in line with those received by Hagman & Björndalen (2011) in their series of interviews, but NordREG's study also included Denmark. The Danish actors generally have a view of transmission rights that differs from that of other Nordic countries. In the responses, the actors write that the liquidity in CfDs is far too low in both Danish bidding zones, and without effective price hedging opportunities, Danish actors are left with the area price risk. In summary, the Danish actors that responded to the survey were in favour of the introduction of transmission rights with the purpose of providing Danish actors with good instruments for managing area price risks.

Norwegian actors are almost completely unanimous in their responses; that they wish to continue with the current arrangement with CfDs. The Swedish actors are also in agreement that the CfD is the product that should be used for area price hedging and that the product should not be replaced. Some actors, however, put forward the view that transmission rights could be introduced as a complement to CfDs. Just as with the Norwegian actors, the Finnish actors were of the opinion that CfDs are the method they need to hedge against area price differences. The Finnish actors also expressed that liquidity in CfDs is important and that measures for improving liquidity can further improve the function of the CfD.

The Swedish Energy Market Inspectorate's analysis (2012) looks at the effect of dividing Sweden into four bidding zones. In the report, Ei interviewed a number of Swedish actors with the purpose of finding out their opinion on the CfD market's functionality. The actors interviewed maintained that the financial market works well in the Nordic region. Regarding the CfD market, concern was expressed over the risk that the Swedish regional division will create small bidding zones, which can be a challenge in terms of liquidity in CfDs. However, dividing Sweden in this way can also make it more complicated to trade in electricity. Regarding liquidity, it was bidding zone SE4 that they were especially concerned over. Concern was primarily on the situation involving production deficit and the lack of natural candidates for issuers of CfDs in SE4. At the same time, a number of actors expressed that the CfD market was immature at the time of the study and that it was important that the market was given time to mature without further political intervention.²¹

In a report on potential alternatives to area price hedging on the NorNed cable between Norway and the Netherlands, Norwegian and Dutch actors were also interviewed.²²

Fifteen actors were interviewed regarding their current strategies and their preferences and needs.²³ Overall, the report finds that none of the actors see the need for area price hedging over NorNed. Two of the producers, however, saw

²⁰ NordREG (2012).

²¹ It can be noted that in the subsequent consultation, several market actors pointed out the problem with a lack of natural candidates for issuers of CfDs in SE4. Suggestions were also received that TSOs should be involved in the markets by issuing CfDs.

²² Redpoint (2013).

²³ The group of actors interviewed was made up of two TSOs, a trader, three exchanges, five producers and four large industries.

the potential to move their position to a more liquid financial market with the help of transmission rights as an opportunity.²⁴

4.2 Analysis of the instruments' advantages and disadvantages

Access to transmission capacity between the different zones affects the value of production resources (the revenues vary with the price area constellations) and also affect the prices which the consumers in different areas are faced with on the DA market. Also via financial trade in CfDs, the market's actors today take positions based on the expected accessibility of transmission capacity, whilst they themselves do not have the tools to influence this.

4.2.1 Impact on actors

Apart from Denmark, there is no tradition on the electricity market in the Nordic region of trading in either financial or physical transmission rights. This means that it is difficult to say with any certainty which actors will trade in transmission rights in the Nordic region, if such trade is introduced. However, regardless of whether or not an actor itself trades in instruments, the effects of these will affect it via changes in the market in terms of e.g., competition, liquidity and transparency. Such general changes are discussed later in the text.

Producers

Based on the compilation of previous interviews with the market actors in the Nordic region in Chapter 4.1, it is primarily vertically integrated companies which are also involved in trade to end users which would be interested in transmission rights. It is also this group of actors which, together with trading companies, have the largest area of application, theoretically speaking, for the instrument.

A vertically integrated company²⁵ with capacity in zone A and a customer in zone B sells its production in zone A (financially, this can be achieved with CfDs for zone A) and then buys back the corresponding volume in zone B (this time by purchasing CfDs – if we want to have the volume subject to price hedging). If instead there were transmission rights that the company could purchase in order to hedge the price of the transfer between both areas, these could be used instead of CfD-contracts.

For a vertically integrated company with production in one zone and a destination market in another zone, it is clear that transmission rights would create additional options for how the company conducts its business. For pure production companies, the advantage of greater choice is not as obvious. On the contrary, it is often difficult to perceive. The producer sells in the zone in which they operate. Buying transmission rights to then sell electricity in another bidding zone should as a rule constitute speculation in the mispricing of rights.

Electricity suppliers without their own production

An electricity supplier with their own production is a vertically integrated company and the effects for such companies are discussed in the previous section. An electricity supplier without their own production does not have the same needs or interest in using

²⁴ In the report, they refer to this use of the instrument as "bridge to liquidity".

²⁵ Applies to companies that do not manage their business via gross bidding on NPS.

transmission rights in their price hedging. It can of course be said that transmission rights open up for these to make their purchases in a cheap area, “transmit” the energy to a more expensive one and sell it there instead in order to make purchases and sales in the same area. For this to be profitable, however, it would be necessary to assume that the market does not function efficiently and that similar arbitrage opportunities would be available on a continual basis. Otherwise, trade strategies of this type would be of a speculative nature and could also result in significant losses. In a low margin business such as trading in electricity, it is not likely that this is an activity many would wish to engage in.

Electricity consumers

The situation for a large electricity consumer (industrial company or similar) is in many ways like the situation for an electricity supplier without their own production. There are however situations in which it is conceivable that an industrial customer would have interest in transmitting energy from one zone to another. This is in cases where an industrial company makes redistributions in their production plans between their supply points situated in different bidding zones. In such situations, it could be appropriate to use volumes which were previously subjected to price hedging in one area for a facility in the other. To make this move without creating new price risks, a transmission right could be used between both areas.

However, these scenarios would likely be both relatively uncommon and also occur at relatively short notice and with great irregularity, which is why regular trade interest from this type of actor is limited. It should also be noted that an electricity consumer can resolve problems of this nature with the instruments already available on the market. The effect of introducing transmission rights in this case is thereby solely to create an additional choice.

Summary: impact on the market actors

Overall, it seems likely that, at least initially, it is the actors which on a group level sell the largest volumes that would see the greatest value in gaining an additional instrument in the portfolio. It is also here we find the largest resources for handling and analysing additional contracts and, in some cases, experience from other markets regarding how instruments work and provide returns in a business.

It is worth noting that the majority of actors on the Nordic market today regard trade in system prices and CfD products as satisfactory. No-one has expressed a desire to switch the current system with one whereby trade is established based on individual bidding zones with direct trade between these. One reason for this is that for an actor with a fundamental position to hedge, today's financial instruments meet the primary needs – provided the pricing in existing products works efficiently. Both as a seller and a buyer, it is possible to gain certainty of the future sale or purchasing price. The need to hedge the price difference between two zones with transmission rights arises when a party trades directly between two bidding zones with potentially different prices.

4.2.2 Impact on TSOs

The introduction of transmission rights can affect the issuer (the TSO) in a number of ways. When the TSO auctions off future bottleneck revenues, this provides a guaranteed income in the

form of the premium. Fees paid to the holder of the right are the bottleneck revenue for the given hour. As long as the volumes of rights auctioned off by the TSO do not exceed the available transmission capacity, the TSO runs no risk with the auction. If the volume of issued rights does exceed the available capacity, however, or if available capacity is for some reason reduced so that it falls short of the volume of issued transmission rights, the revenues from the auction will not cover the TSO's costs. This is normally referred to as firmness risk.

An issuer of transmission rights having a firmness risk can be seen from two sides. First of all, it can be said that by auctioning off transmission rights, the TSO subjects themselves to a financial risk. If the revenues from the bottleneck revenues and the auction together are insufficient to compensate the buyers of transmission rights, the TSO must still, as an issuer of transmission rights, cover the cost, which can be described as a financial risk. As an owner of a national grid, the TSO receives revenues from users of the grid.²⁶ If the costs to compensate the owners of transmission rights become large enough to affect the TSO's financial situation, there may be a need to increase the tariffs in order to compensate the losses. The firmness risk can thus be said to be a risk that is finally backed up by all grid customers; i.e., the public.

It is also possible to turn this reasoning on its head and say that the firmness risk can be somewhat positive in terms of efficiency for the TSO and in the long term for society. Even if the TSOs work today with the aim of conducting business as efficiently as possible, the TSO would via the sale of transmission rights be able to have greater incentive to ensure maximal transmission capacity is available when it is valued most. The TSO is the actor best able to influence the risk of the transmission capacity being reduced. By auctioning off transmission rights, the risk of transmission limitations is moved to the TSO, whose costs will exceed the revenue if the available transmission capacity is lower than the volume of sold transmission rights. By keeping the service and repair of cables and secondary substations to points in time when the risk of affecting the market is lowest, the TSO can reduce their own firmness risk.²⁷

Regarding the firmness risk, there is further argumentation for how it will affect the TSO's behaviour, that greater incentive for making capacity available does not lead to more capacity, but instead has other effects. A possible alternative measure which the TSO could take would be to reduce the designated maximum capacity (NTC²⁸) on transmission connections in order to reduce their own exposure. If the TSO acts in this way, the result is that the transmission capacity allocated to the market will be reduced and the potential advantages created by transferring the risk to the TSO will be less. This is especially true if requirements are made for the TSO to issue transmission rights corresponding to a large proportion of the transmission capacity. If the requirements stipulate that only a small proportion of the transmission capacity be auctioned off, the potential risk is less for the TSO.

²⁶ The TSO's total revenues are regulated by the national regulatory authority, in Sweden's case Ei.

²⁷ Firmness problems beyond the TSO's control may also arise. One example from Sweden is if available nuclear power capacity is reduced in SE3, which affects the TSO's opportunity to allocate capacity to SE4 due to the fact that there is insufficient reactive effect for maintaining the transmission capacity. Another example could be external damage to transmission cables, which reduces their availability. Thus, there are also risks which the TSO cannot influence, irrespective of firmness requirements and incentive.

²⁸ NTC is an abbreviation of Net Transfer Capacity.

In order to minimise economic impact for the TSO, there is also a theoretical opportunity for them, on occasions when there is a risk that the bottleneck revenues are insufficient to compensate the holders of transmission rights, to reduce the margins found in the regulations concerning operation. In this way, the capacity available to the DA market is increased, though at the cost of the grid's operational security.

Sometimes, the question of counterparty risks arises in auctions of transmission rights. There is a risk that buyers of transmission rights will become bankrupt and be unable to meet their commitments. The fact that the counterparty cannot fulfil their commitments is however nothing unique in the area of transmission rights; it is a risk that arises in all types of business agreement. This kind of risk can be minimised by introducing a clearing house as a counterparty. Another alternative is to impose credit requirements on the buyer.

Apart from the argument that auctioning off transmission rights leads to greater incentive for the TSO to provide transmission capacity when the capacity is most highly valued, it is often argued that this auctioning provides the TSO with predictable revenues instead of depending on the area price differences in the DA market, as is the case today. This type of argumentation is of course relevant for companies seeking predictability in their activities. For example, market actors buy transmission right for exactly this reason, among others. For TSOs, the situation is somewhat different, as the use of bottleneck revenues is regulated in EU regulations and limited to countertrade or grid investments. This means that the bottleneck revenues do not directly affect the TSO's results and therefore entail that there is also no importance in whether or not the bottleneck revenues are hedged.

In this context, it should also be mentioned that there is a discussion surrounding whether auctions of transmission rights really do give the TSO returns in the form of future expected bottleneck revenues or if the auction provides lower revenues. Hagman & Björndalen (2011) discuss how requirements on risk premiums among traders mean that transmission rights will never result in a price which corresponds to the expected bottleneck revenues; that the price in fact becomes systematically lower. In a theoretical discussion, it could be asserted that if there were only actors with interest in speculation and poor competition prevails at the time of the auction, the result would be a lower price than the expected bottleneck revenues. If on the other hand a large number of actors participate, this arbitrage opportunity will likely be traded away. If in addition there are fundamental actors in the auction (which are there to hedge an area risk), it is difficult to see that an underpricing would endure in the long term. Finally, the answer to this question is empirical.

One of the TSO's duties today is to provide transmission capacity. If we look at the economic effects alone, it is not conclusive that the TSO's revenues are always maximised by maintaining high availability. This is because the bottleneck revenues are a function of the price difference between two areas multiplied by the volume transmitted. In certain situations, a lower availability can thus result in a higher revenue. It should be noted, however, that there are no strong reasons to expect that Nordic TSOs would systematically prevent the maintaining of good accessibility in the transmission capacity with the purpose of gaining a greater revenue. First of all, as discussed above, the bottleneck revenues do not contribute to the TSOs' profits as their use is regulated. Secondly,

their overall task is still not to generate profit without maximising the socioeconomic benefit of the jointly owned national grid.

The entire discussion surrounding the idea that the TSO will be commissioned to auction off transmission rights assumes that the TSO is able to use bottleneck revenues as security for payment to the buyers of rights. If this is not possible, the TSO has no natural security and bears the entire risk. It should be mentioned here that Regulation (EC) No 714/2009 of the European Parliament and of the Council, which regulates the use of capacity charges, is not entirely clear on the matter of what purposes the TSO may use the bottleneck revenues for. Article 16, point 6 explicitly mentions countertrade and grid investments, but there is also a formulation in the same paragraph which says that national regulatory authorities can allow the TSO to use the revenues for other purposes. From a Swedish point of view, the interpretation of this regulation would need to be reviewed if Svenska Kraftnät should begin auctioning off transmission rights.

Finally, it is important to emphasise that the TSO does not have full freedom in all decisions concerning what is discussed above. FG CACM describes the TSO's duties, as well as the framework that the TSO has to work within. Two examples that can be mentioned are how large a proportion of the transmission capacity shall be auctioned off and how firmness risks should be managed. The proposals are however not fully negotiated and final documents are not available. FG CACM also describes how the TSO should be monitored by national regulatory authorities. Here too, proposals are being developed and final documents will arrive once the comitology procedure is over and the network code has become law.

4.2.3 Liquidity

In discussions on functioning financial markets, the term “liquidity” frequently come up. Liquidity is a multifaceted term which can have a number of meanings. Normal usage of the word essentially equates it to “turnover”, where a higher turnover always entails a better liquidity. There is another aspect to liquidity (which is primarily used in financial contexts), where the number of available buyers and sellers of a certain instrument in a given moment is also included in the assessment. If there are always several actors who are willing to do business in the instrument, it is easier for an actor to go in and out of a position, and the liquidity is thus considered better than if it were a “thin” market that was encountered, with only a few potential counterparties. In general, the size of the spreads is less in a market with good liquidity, where many actors with different interests in the market are continuously renegotiating the price. In this report, the term liquidity is used with both of these meanings.

Impact on volumes in the DA market

Liquidity in the DA market is the same, irrespective of whether it is FTRs or CfDs that are used. In both cases, the DA market is allocated all available capacity. It is only in the case of PTR contracts that liquidity in the DA market can potentially be affected negatively. When nominating PTRs in the right direction, the available capacity reduces for the DA market, as the owner of PTRs uses part of the existing capacity themselves. The proportion of transmission capacity that the PTR holder uses is thereby reserved and cannot be used by another party, nor by the DA market. However, it is still guaranteed that the entire

capacity will be used for flows in the right direction, i.e., from low-price to high-price areas. This is achieved via the market coupling in the DA market.

Impact on potential volume for area price hedging

The volume that can be provided to the market varies from one instrument to the next and depending on how emitted volume leads to the TSO incurring a firmness risk.

For CfD-contracts, the volume is theoretically unlimited, as the number of issued CfDs does not need to be linked to the physically installed capacity on any transfer in the system. Nor is the CfD fundamentally burdened by any kind of firmness risk.

Under certain circumstances, FTR obligations can be issued in both directions on a cable. This provides the opportunity to net off the outstanding commitments against each other, which also affords the TSO the opportunity to issue obligations in volumes which are not necessarily linked to installed effect on the transmission connections. For FTR options and PTRs (UIOSI), however, the issuable volume of capacity on the connections between the affected zones is limited.

Impact on OTC trade

Trade on OTC platforms or bilateral trade, as it is also known, is on many financial markets a natural complement to the organised and dominating exchanges. It can also be mentioned that the majority of trade in the Nordic CfDs today takes place via OTC trade. OTC trade can be partly likened to stock exchange trade, but there are also elements of OTC trade which differ from established stock exchange trade. Some of these are:

- Requirements to provide securities for taken positions are reduced as there is no clearing house which requires securities to clear the trade (the actors often have set trading limits against each other on a bilateral basis), though there may be an opportunity to clear the contract.
- The purchased contracts can be more uniquely designed for both parties compared with the standard contract, which is traded in large volumes on the exchanges. In the electricity market, for example, this may be a matter of different types of structured products and contracts with a non-standard profile (a varying offset volume per unit of time).
- Volume, prices, etc. do not need to be revealed in full to the rest of the market if companies have not desired it to be so; i.e., the transparency of the OTC trade is lower than the stock exchange trade.

The bilateral trade can create a value for the market actors, primarily because the contract can be tailored to match outstanding positions, for example, with those of a third party. In order to achieve greater transparency in the market, it has traditionally been considered essential for the proportion of bilateral/OTC trade not to be too large, as this reduces the reliability of price indications and increases the transaction cost for everyone seeking a price on the market.²⁹

²⁹ The Swedish Energy Markets Inspectorate (2010).

The different types of transmission rights are used in different ways for bilateral trade. FTRs are settled financially and entails that actors in different bidding zones that wish to trade with one another must do so via the exchange. In light of this, there is no reason to expect that the proportion of bilateral trade would increase.

If the actors instead use physical transmission rights, capacity can be nominated and bilateral trade can be conducted without power exchanges needing to become involved, which makes it easier to trade in bilateral agreements. As these volumes do not need to be bid into the DA market, transparency in this stage decreases. It could also affect participation in the financial market, as the bilateral contract may also contain elements of long-term price hedging. All else being equal, a reduction in the use of the exchange as a marketplace leads to a reduction in the reliability of the exchange prices and entails the risk of a downward spiral in the degree of openness in the trade.

Impact on the CfD market

In Sweden, discussion has been underway for some time concerning the impact of transmission rights on CfD trade. An important matter in this discussion is whether the instruments are complementary or substitutive in relation to one another.³⁰

Theoretically speaking, trade in transmission rights has the potential to provide a wider range of issuers of CfDs if the instruments are complementary. This could for example be visible in areas where there is a deficit of fundamental sellers in relation to the number of buyers. The logic behind this is that the possibility to buy transmission rights from an adjacent zone with a surplus to an zone with a deficit also gives producers in zones with a surplus the security they need to issue CfDs in an zone where they otherwise have no underlying physical access for hedging of the position they take on the CfD market. Many believe this is exactly what happened in the zone DK1 (Jylland, Denmark), where PTR contracts with Germany are traded. The conditions in zones DK1 and DK2 (Sjælland, Denmark) are similar in many respects. In both regions, there are limited quantities of baseload power production, wherefore the number of natural candidates for sellers of CfDs is also limited. Despite the similar conditions in both Danish regions, however, we can see that the trade in CfDs for DK1 generally exceeds that in DK2. In some of the current futures contracts (e.g., quarterly contract Q4-13 and annual contract YR-14), the commercial interest in products for DK1, measured as Open Interest³¹, is 30-100% higher than for DK2.³² Historical values for 2011 and 2012 also show a higher level of trade activity in the contract for DK1, even when considering the fact that the underlying consumption in DK1 is greater than in DK2.³³

There are also objections to transmission rights being given a wider range on the CfD market. Hagman & Björndalen (2011) claim that the arrival of FTRs could

³⁰ If two instruments are complementary, this means that they can be used together in order to strengthen one another, whilst goods that are substitutive compete with and displace one another.

³¹ Open Interest is the total number of outstanding contracts which have not been closed by the market actors.

³² Market data obtained from Montel, 11 September 2013.

³³ Anders Houmøller, "Hedging in Denmark and SE4", <http://www.houmollerconsulting.dk/facts-and-findings>.

just as well cause actors in zones with a deficit to choose price hedging in the zone with excess instead. Should this prove to be the case, there is a risk that liquidity would decrease in the CfDs that are at present difficult to trade.

Another argument against introducing new instruments on the market is that there is a limited amount of money among the market actors to invest in financial instruments. If the number of instruments to trade with decreases, the capital is spread out across this larger number of products, which consequently reduces the capital on average per product. If this is the case, it does not matter whether the instruments are complementary or substitutive; the liquidity in each instrument will still decrease.

Overall, the question of what effects the introduction of transmission rights will have on CfDs depends largely on whether these are substitutive of one another or complementary. Practical experience of introducing transmission rights in a well-established electricity market which is based on a strong system price with CfD trade for area hedging is very limited, and thus it is in principle not possible to provide an unequivocal response to the question of whether FTR contracts and CfDs are complementary or a substitute for one another. . The experience which can be gained from PTR trade on the border between western Denmark (DK1) and Germany provides no clear indications in any direction. Nor do the theoretical arguments provide any clear answer, which makes it difficult at the present time to comment on the outcome.

Impact on prices and price formation

Trade in transmission rights should not have a major impact on the general pricing structure in the Nordic region in the short term. As long as we have a market and a pricing structure which is based on fundamental margin cost levels for the production of electricity with different technologies, the changes that the introduction of transmission rights can entail are relatively marginal.

This does not necessarily need to mean that money cannot be gained or lost via trading in transmission rights. However, the impact on the electricity price is probably negligible from an end-user perspective.

The cost parameters which may change are primarily costs for traders to introduce new components in their trading systems and changes in spreads (for better or worse, depending on the assessment of transmission rights' impact on the CfD market) in existing CfD products.

4.2.4 Impact on transparency

Transparency in a market primarily concerns access to information on equal terms.

With physical transmission rights (PTRs), it is more difficult for the market actors to predict the capacity that will be allocated to the DA market day by day and hour by hour. As the holder of a transmission right can choose to nominate their capacity or not, adds a degree of uncertainty to the upcoming publication of available capacities and the daily bidding. Actors on the DA market already feel that it is at times difficult to predict the capacity the TSO's will calculate. In a market with transmission rights shall, in addition to this uncertainty, s, a

previously unknown pattern of nominations over the hours of the day and on different connections be weighed in. Holders of transmission rights (especially where these consist of large items) gain a potential information superiority over other actors. Overall, the risk is that transparency will decrease in the market. As rights to parts of the bottleneck revenue lie with actors who have production interests, there is a risk that it will be difficult for the market actors to analyse the incentive and bidding strategies of their industry peers in the short term.

Despite the fact that financial transmission rights do not provide the same direct effect in the DA market and allocated capacities, it can be argued that transparency in the DA market can potentially decrease, even with FTRs. Access to part of the bottleneck revenue thus gives the holders of transmission rights a slightly different point of departure in the bidding compared with other actors. There are no actors today (other than the TSO, perhaps) that gain from the emergence of bottlenecks in the system. However, with entitlement to bottleneck revenues, some of the market's trading actors will end up in the situation that they can also earn money from bottlenecks. This situation can be perceived as problematic, not least in relation to the position for dominant actors with production on both sides of a connection.

The effect of this should not be overestimated, but should the "mixed incentives" and reduced transparency be perceived as inconvenient for other actors, it is conceivable that they would be less interested in issuing CfDs in future. The outcome of these contracts will thus not only depend on the TSO's allocated capacities and the market's bid in the DA market, but also on the competitors' strategic exploitation of opportunities for nomination and altered strategies so as to optimise the value of the portfolio as a whole.

4.2.5 Impact on the second-hand market

Physical and financial transmission rights are auctioned off by TSOs based on set conditions in terms of times and volumes. Market actors that participate in the auctions do so based on the needs they have and the conditions they are aware of at the time of the auction. However, as the auction concerns transmission rights for future use, new information can mean that the actors need to adjust their positions by buying or selling transmission rights. For this to be possible, a second-hand market needs to be available. It is also discussed in FG CACM that such a market should be set up. Exactly how this will be done, however, is still being analysed; whether trade will be regulated as a common European platform or the existing platforms are to be retained.

The impact of the instruments as far as the second-hand market is concerned is more a matter of differences between options and obligations than differences between PTRs and FTRs. PTR (UIOSI) and FTR options work the same in terms of trade on a second-hand market, whilst the liquidity on second-hand markets will likely be higher for FTR obligations than for options. The reason for this is that there are possibilities for TSO to sell more FTR obligations than options. Presuming there is a demand for obligations in both directions, TSOs are able to net off FTR obligations and thereby issue more rights per MW cable than for options.

If a second-hand market is to function without TSO involvement, it is necessary in cases of FTR obligations to involve a clearing house. Without this function, which can manage credit risks for the TSO, the TSO must approve every purchase on the second-hand market. However, regardless of which instrument is concerned, the TSO must be informed of who the holder is. Without this information, the TSO is unable to compensate actors who are due compensation when the instrument comes to be used, or claim compensation from FTR obligation holders if area prices show that this is the case.

CfDs, on the other hand, are traded without a primary auction procedure, as previously mentioned. From this perspective, a first or second-hand market cannot be said to exist.

4.2.6 Impact on competition

The main reason for introducing transmission rights is, in accordance with FG CACM, to improve competition in the forward market by making available efficient instruments in order to manage risks that prices will differ from one bidding zone to the next. Analysis of the instruments' impact on overall competition must be performed in three parts: competition in the initial auction process, effects on the competition in the DA market and the same effects on the forward market.

Competition in the auction process

Where competition in the auction process itself is concerned, there are a number of matters which need to be investigated.

1. How many actors are interested in participating in the auction?
2. What types of actors are involved in the auction?
3. Which actors are willing to pay most for transmission rights?

It is not entirely simple to know in advance how many and which actors would be interested in trading in transmission rights. Hagman & Björndalen's report (2011) includes an analysis of which actors are most interested in the introduction of transmission rights into the Nordic market. The conclusion of the report is that it is primarily financial actors (traders), large industrial customers with consumption in several bidding zones and vertically integrated energy companies with production and consumption in different bidding zones that would be interested in transmission rights. Another conclusion they arrived at is that the majority of Nordic actors will likely retain the model used today and not use transmission rights; i.e., there is a risk that the number of actors that trade in transmission rights will be few.

This conclusion is supported by ENTSO-E, which concludes that it is possible that only a small number of actors are interested in participating in auctions of transmission rights.³⁴ NordREG³⁵ conducted a public consultation in the work to answer questions on transmission rights to ACER, in which Nordic actors were asked about their opinions on transmission rights. Apart from Danish actors, the

³⁴ ENTSO-E (2012).

³⁵ NordREG (2012).

general consensus was that it was the Nordic system of CfDs that was desirable to retain. Overall, the Nordic actors, excluding a small number, do not appear to be interested in transmission rights as a complement. Based on this, however, it cannot with any certainty be concluded that only a few actors will participate in auctions of transmission rights, as it is possible that actors choose to use the instrument when it is available for trade. There is however a potential risk that only a few actors will participate, and if this becomes the case, this can create potential competition problems in that it will facilitate price fixing.

In a comparison of the auction process between PTRs and FTRs, it can be established that a PTR, which is a physical transmission right, requires a nomination process for use. From an administrative perspective, an FTR is less complex, which means that it has an advantage as it reduces obstacles to the actors becoming involved and trading.

A question relevant to the above is whether auctions of transmission rights provide advantages to specific actors. In Sweden, it has previously been discussed that it is large actors who have shown interest in buying transmission rights and that in the long term this leads to distortion of competition on the DA market, with consolidation as a consequence.³⁶ The question is not easy to analyse because, as far as we are aware, there is no empirical evidence on the subject. Instead, the analysis must be based on theory and interviews with potential actors. According to the findings of Hagman & Björndalen (2011) in their questioning of actors, it is actors with commitments in several bidding zones that are interested in transmission rights. These actors are often relatively large. However, the fact that they are large and interested in transmission rights does not necessarily mean that this benefits them at the expense of smaller companies.

In a theoretical perspective, ENTSO-E reveals that actors with market power on the DA market can buy PTRs/FTRs and thereby increase their market power. They also show that such a company has a greater willingness to pay for transmission rights than other actors and will thereby win the auctions at the cost of smaller actors.³⁷

Booz&Co (2011) argue instead that where PTRs are concerned, the monopolists will not have the highest willingness to pay. It is rather traders that have the highest willingness to pay and who will thereby bid the highest.³⁸

In other words, exactly which actors will benefit from different instruments is uncertain. If they benefit large companies, there is of course a potential risk of consolidation, greater market concentration and potentially poorer competition³⁹. If additional instruments are added to the existing ones, the market's complexity also increases, which is normally not an advantage for smaller companies with more limited opportunities to

³⁶ The Association of Independent Electricity Traders in Sweden (2011).

³⁷ ENTSO-E (2012).

³⁸ Booz&Co (2011) builds its argument on that the producer will only retain the domestic marginal revenue by using the PTR, whilst the trading company will retain the full market price of the PTR, which by definition is higher than the marginal revenue.

³⁹ It should be emphasised that a consolidation does not in itself result in worse competition in a market.

participate in many different marketplaces and to maintain the critical mass of knowledge required to compete in the market.

Unlike transmission rights in their most common form, CfDs are traded continuously and by the market actors themselves, i.e., there is no initial auction of a limited number of rights as is normal for FTRs and PTRs. Based on this, there is nothing to say about competition in the auction process. Instead it could be discussed how CfDs are issued and what terms affect the competition in this. A CfD is a financial instrument whose price is decided, just as with other instruments, based on supply and demand. The supply depends on the number of issuers and CfDs are normally issued by producers with baseload power in the area that the CfD covers. The value of a CfD is in turn based on expected price differences between the system price and the area price. In order to affect the value of the CfD, the actors must affect the expected price difference experienced by other actors. This can for example be done by limiting the supply of CfDs or setting a higher price on CfDs. In an area with few issuers of CfDs, they could thus potentially affect the price of CfDs.

Competition in the forward market

One of the purposes of FG CACM prescribing that TSOs issue transmission rights on the connections where there is a lack of liquid financial markets on both sides of the connection is to improve the functioning of the financial markets.

By means of the transmission rights providing the opportunity for an actor on one side of the connection to also trade on the other side, the potential competition in the forward market increases.

Applied to the situation in the Nordic market, the primary consequence would not be improved competition in forwards offset by the system price – even if this is also possible. It is first and foremost the trade in products for individual bidding zones that could increase. This would thus facilitate a stronger CfD trade with a balancing of the number of buyers and sellers in areas with regional imbalances.

Competition in the DA market

The effects on competition in the DA market depend on which instrument is concerned. Above all, it is a matter of differences between physical and financial transmission rights.

According to a number of advocates of transmission rights, there is a positive effect from the TSO having to sell transmission rights on transmission connections in that it creates an incentive for the TSO to put the capacity at the market's disposal.

The current model, in which the TSO receives bottleneck revenues when there are limitations in the transmission capacity, means in practice that TSOs receive a revenue from something that is a cost to the market. By auctioning off transmission rights, the TSO auctions off future bottleneck revenues which are to be paid with bottleneck revenues from the DA market. If a TSO performs maintenance and repairs in the system during hours of high load and thereby removes capacity from the market, the TSO runs the risk of causing the costs of compensating the holder of the transmission right to be higher than the revenues from the bottleneck. The TSO should be interested in

minimising this risk and thereby attempt to allocate as much capacity to the market as possible

– not least during periods when the price is high and the value of availability at its peak. This means that available transmission capacity can be higher than it is in the current situation, which will benefit the DA market and is positive for the overall conditions for competition.

As a counter argument to this, it can be said that the TSO may, for the purpose of reducing their firmness risk, be interested in allocating a smaller part of the transmission capacity to the auctions of transmission rights or, if the proportion to be auctioned off is harmonised in EU regulations, attempt to decrease the transmission connection's official capacity.

Where physical transmission rights with UIOSI are concerned, these can have a negative impact on the overall conditions for competition on the DA market. This is because PTRs nominated (in the right direction) means that nominated capacity is taken from the DA market's implicit auction. As the capacity available to the DA market is reduced, the conditions for competition on the DA market also becomes worse. If the conditions for competition deteriorate, there is also a risk that actors will choose to leave the DA market and instead trade bilaterally.

Unlike PTRs, FTRs do not affect the physical flow on the DA market as FTRs are settled financially. In this way, it is also true that FTRs cannot affect the physical conditions for competition. There are, however, cases in which FTRs could be used for the purpose of limiting competition on the DA market. One concern which has arisen is that producers who hold FTRs use market power and invite unreasonable bids on the DA market as they have FTRs as a security against large price differences (they move their revenues from their sales virtually from one area to another). Indeed, an actor with an FTR can put in an extremely low bid so as to be sure to gain a footing on the DA market and thereby create an instrument that is similar to a PTR. As the producer in a Nordic context is paid in the zone where production takes place, this could lower the price in the zone and likely be a strategy for forcing competitors out of the zone. Whether or not this is a sustainable strategy will likely prove to be an empirical matter, just as it is a legal matter as to whether the action is permitted under competition law.

In this context, it should be noted that based on research into the exercising of market power on the Nordic electricity market, Tangerås & Fridolfsson (2009) establish that both the Nordic market model and competition within it have functioned well thus far.

4.3 The instruments in relation to consumer benefit and the Nordic end-user market

Those who will eventually use the electricity produced and pay for the electricity are the end-users. It is therefore important to remember that all changes, irrespective of which ones are discussed, will affect customer benefit.

4.3.1 Effects on consumer benefit

When the term “consumer benefit” is discussed in the report, the point of departure is that the consumer can generally be considered to benefit from higher levels of competition, choice, lower prices and market conditions which build credibility and reliability.⁴⁰

Thus, should the market primarily develop in this direction, consumer benefit will increase.

In Chapter 4.2, we discussed the effects on competition in different contexts when introducing transmission rights. There nothing was mentioned about the effects on the end-users apart from the fact that competition effects spill over and impact the customers. The likelihood of spillover effects from the DA market and the forward markets is high as it is the customers who ultimately pay for the electricity, and it is the prices set on these markets that most customer agreements refer to. If the introduction of transmission rights improves competition, this benefits customers, and vice-versa.

As described in Chapter 4.2.6, an introduction of PTRs in the Nordic system runs the risk of having a negative impact on competition in the DA market, as a nominated PTR takes transmission capacity from the DA market. However, even if the holder does not consistently nominate the PTR, the instrument creates a higher degree of uncertainty for other actors in terms of the transmission capacity which will be available on the following day. PTRs can also help to increase bilateral trade, which in turn decreases transparency and liquidity on the DA market. A lesser degree of transparency and lower liquidity do not increase consumer benefit. Overall, it is difficult to find positive effects for consumer benefit entailed by the introduction of PTRs as a complement to CfDs on the Nordic electricity market. One potential positive effect would be if PTRs and CfDs were complementary products and the introduction of PTRs gave more actors the opportunity and incentive to offer CfDs in bidding zones with a deficit of baseload production. However, this potential effect is not unique for PTRs; it is general for transmission rights and is discussed in greater detail below when the effects of FTRs are discussed.

The introduction of FTRs as a complement to CfDs does not affect liquidity on the DA market in the short term as an FTR is a financially settled product which does not affect physical flows. As described in Chapter 2.2, CfDs and FTRs are different in that CfDs maintain the system price structure and associated area prices whilst FTRs are based on and serve to promote trade between different bidding zones. Since this is the case, it means there is a risk that the introduction of FTRs could lead to a shift from the current model towards a model based on trade between bidding zones. This kind of development entails the risk of reducing liquidity in system price trade and, ultimately, in the DA market as well. Decreased liquidity can affect actors' trust in the market and get them to trade more bilaterally than in today's system.

For a positive impact on consumer benefit, CfDs and FTRs need to be complementary products. If this is the case, the number of issuers of CfDs in zones with production deficits may rise, as discussed in Chapter 4.2.3. This is a result of producers in neighbouring zones with a surplus gaining the area price hedging they need –

⁴⁰ For a discussion on how consumers benefit from competition, choice, etc., see e.g. Carlton & Perloff (1994).

by purchasing FTRs – to issue CfDs in the zone with a deficit without having their own baseload production as security there. If this is the result of the products' complementarity, there is a possibility that the competition in the forward market will increase in the zones with deficits. Increased competition could potentially increase the spreads in trade in CfDs and in the long term reduce the price paid by the consumers for the area price risk in zones with deficits.

In Chapter 4.1, we also discussed which actors potentially benefit from the introduction of transmission rights. Based on interviews and previous studies, it is difficult to determine in advance who has the highest willingness to pay for the transmission rights. There are both experiences from interviews⁴¹ and theoretical arguments⁴² that favour the view that it is large market actors with the potential to influence the market outcome that have the highest willingness to pay. At the same time, there are also arguments in the opposite direction; that fundamental actors will never have a higher willingness to pay than traders⁴³. If the results from previously conducted interviews with the market actors in the Nordic region are correct and it is primarily larger and financially stronger actors that will have the willingness as well as the opportunity to professionally and continuously trade successfully in transmission rights, the introduction of these instruments will likely lead to a decrease in competition. This is because the introduction of transmission rights creates an imbalance between large and small actors and increases barriers to entry in parts of the market. In the long term, this will probably lead to a risk of decreased competition and higher prices for end-users.

Even if CfDs and transmission rights are complementary products and the consumer benefit in zones with deficits thereby decreases in zones with deficits, there is a risk that the net result of an introduction will be negative for society. The effects of increased competition and better spreads in areas with deficits occur via the system operator entering the market and taking an active role as well as a different risk from that of today. The system operator's "firmness risk" can potentially generate losses for the TSO in certain periods; losses which it cannot cover with bottleneck revenues. If this is the case, there is a risk that the system operator will need to cover its losses by increasing the network tariffs for its customers; i.e., consumers throughout the nation. This means therefore that a potential profit for some consumers must be set in relation to the transferral of costs to society as a whole and the transfer of assets that can take place from society in the form of the system operator and consumers to the actors that have purchased transmission rights.

Taking the Nordic market model as a basis, there are certain risks entailed in introducing additional products. One of the characteristics of the Nordic market has been a high degree of transparency and strong confidence in the pricing structure on both Nord Pool Spot and Nasdaq OMX. Complementing the market with an additional instrument is good from the perspective that the market actors gain a broader choice but negative in that the market becomes more complex and more difficult for the actors to understand and analyse. The fact that the market becomes harder to understand means that the actors think about how and in which market they will act. If confidence in the market reduces, there is a risk that they will instead move to increased bilateral trade, which is a market form with lower transparency and higher

⁴¹ Hagman & Björndalen (2011).

⁴² ENTSO-E (2012).

⁴³ Booz&Co (2012).

transaction costs. This development is negative for the Nordic model but also for overall competition, in that increased bilateral trade reduces transparency and increases the transaction costs.

The overall assessment is that the effects on customers entailed by an introduction of transmission rights as a complement to CfDs are marginal. There are a number of potential disadvantages, such as a risk of decreased transparency. Potential advantages of introducing transmission rights as a supplement to CfDs are dependent on whether CfDs and transmission rights are complementary or substitutive. As there is no clear empirical evidence pointing in a particular direction, and as theoretical reasoning on the matter is also ambiguous, it is difficult to say whether consumer benefit will increase when introducing transmission rights.

4.3.2 Effects on the work with the Nordic end-user market

The effects of different area price hedging instruments for the introduction of a common Nordic end-user market should be limited, given that the Nordic countries act in a similar way where the introduction of instruments is concerned. With continued use of CfDs alone, we are in the same situation as today, where Nordic actors know how the instruments work.

Even if the effects can be assumed to be small, there is a risk that the introduction of transmission rights in the Nordic region, which will complement CfDs, will affect the Nordic end-user market. This holds true even if the countries introduce instruments in the same way.

The introduction of an additional instrument provides the actors with greater choice but also a more complicated market. A more complicated market benefits actors with financial strength and competence; normally large actors. A more complicated market runs the risk of deterring actors (for example a number of the larger end-users which are currently represented as actors at Nord Pool Spot and/or Nasdaq OMX) from trading on the exchange and causing them to move to bilateral trade. Overall there is therefore a risk that introducing transmission rights in the Nordic region will affect companies in a way which means there are fewer active parties in the trade on the Nordic end-user market. As described in Chapter 4.2, increased bilateral trade also runs the risk of decreasing liquidity on the open marketplaces and of decreasing transparency. Should this be the case, the likely outcome would be a reduced possibility for the Nordic end-user market to function optimally.

If the Nordic countries introduce different types of instruments, trade between the countries will be made more difficult and it will thereby become more difficult for actors who have the intention of acting as retailers in a number of Nordic countries.

In a comparison between the introduction of FTRs and PTRs as a complement to CfDs, PTRs entail a greater risk of impact on the Nordic end-user market. As previously discussed, the reason for this is that nominated PTRs take capacity from the DA market, which has a negative impact on the DA market in the form of lower liquidity and potentially reduced credibility. The extent to which credibility is affected depends to a certain degree on how large a proportion of the total volume is traded via the DA

market and whether it will decrease drastically upon the introduction of PTRs due to more actors choosing to trade bilaterally.

4.4 Nordic market design, transmission rights and the internal market for electricity

FG CACM and the draft of NC FCA mention financial and physical transmission rights as the instruments which should primarily be used to manage area price risks. The regulations also mention that financial instruments may be used. In FG CACM it is written that the requirement is that there are liquid financial markets on both sides of the transmission connection. From a Swedish and Nordic perspective, the current question is whether transmission rights will be introduced in the Nordic region via regulation in network codes or whether the Nordic model will continue to be developed without regulated introduction of transmission rights. As described in Chapter 4.1, the Nordic actors have indicated that the Nordic model of system price contracts and financial area price hedging with CfDs works well for their needs of area price hedging. In general, the actors feel that additional instruments for hedging area prices are unnecessary. Within the scope of NordREG, the Nordic supervisory authorities also stated, in an official letter to ACER in 2012, that the Nordic model functions well and that there is no need to additionally introduce transmission rights in the Nordic region.⁴⁴

Based on this, and the discussion on transmission rights in Chapter 4.2, it is uncertain as to whether an introduction of transmission rights would benefit the Nordic market model. The Nordic model with system prices and area price hedging against bidding zones differs from how transmission rights function with area price hedging from one bidding zone to the next. From this perspective, the introduction of transmission rights would run the risk of undermining the Nordic market model.

As described above, it is difficult to foresee how the wording of NC FCA will develop over time. Before the network code passes ACER and goes through the comitology process, many discussions and negotiations remain in which changes can take place. In a Nordic context, it is important to point out that CfDs function well and are an effective instrument for fundamental actors to manage area price differences in the Nordic region. CfDs as a financial instrument in the Nordics also function as an area risk management instrument, based on what is prescribed in the Third Energy Package and the target model for an internal market for electricity.

As the Nordic market model works well for actors with area price hedging needs, and as there is no convincing evidence in favour of transmission rights, it is crucial that Sweden and the Nordic region work to retain the opportunity to use financial instruments for area price hedging. It is important that there are clear and transparent criteria for the grounds on which area price hedging instruments are to be introduced.

⁴⁴ NordREG (2012).

5 Summary analysis, conclusions and recommendations

In accordance with Directive 2009/72/EC concerning common rules for the internal market in electricity, ENTSO-E is developing proposals for a common EU regulatory framework, known as “network codes”, for cross-border trade in electricity. The network codes shall then be evaluated by ACER and become legally binding following a decision from the European Commission.

In the network code that regulates the forward markets (NC FCA), it is recommended that the European system operators be obligated to auction off transmission rights with the purpose of facilitating the market actors' management of area price risks and competing on the forward market via cross-border trade.

The final content of the network codes is not yet decided, but current proposals contain three main contract types which are intended to facilitate trade across market boundaries. These are physical and financial transmission rights and financial contracts (in the Nordics, CfDs – Contracts for Differences – are used).

It is apparent that in many areas there is a lack of clear theoretical arguments or empirical evidence that could unequivocally confirm or dismiss the possibility of a successful and socioeconomically beneficial use of transmission rights in the Nordic region. The Energy Markets Inspectorate's conclusions are therefore based on an overall assessment of the indications provided by previous studies on the subject, as well as the situation of the Nordic market and the implementation of the Third Internal Energy Market Package.

It is important to point out that whilst the definition of transmission rights is unambiguous, they are implemented in different ways on different markets. They can take different forms in different markets and the methods for how they are provided to the market can also vary. Such design choices can be expected to produce different effects on the functioning of the market, its degree of transparency, competition, etc.

5.1 Transmission rights deviate from the established Nordic market model

The Energy Markets Inspectorate can initially establish that the recommendation concerning trade in transmission rights deviates from the model which has for some time been in use in the Nordic region in at least two different ways. Firstly, the introduction of transmission rights would mean the introduction of explicit trade in capacity between individual bidding zones, whereas the Nordic model has been built on implicit trade in capacity based on the energy trading bids within the common system area. Secondly, the transmission system operator (TSO) would be given a role in the market which thus far has not been customary in the Nordics.

The Nordic market model is based on an integrated DA market with a common system price. The market consists of a number of smaller bidding zones whose exchange of energy is optimised per hour in the daily spot price clearance at Nord Pool Spot. Normally, there are limited price area differences from one bidding zone to the next. The structure of the system price has been crucial in getting several smaller sub-markets to form a credible and stable common market which could provide a foundation for physical and financial trade. All available capacity in the network, as calculated by the TSOs, is available to the spot market and allows for the largest possible socioeconomic benefit to be achieved in the daily energy flows. A system with transmission rights would to a greater extent be built around trade between individual bidding zones and thus weaken the system price structure.

The common system price has great confidence among the market actors, which is for example illustrated by the fact that the turnover on the financial market amounts to 5-6 times the underlying physical market. In order to financially secure price area deviations, CfDs are employed in the Nordics. These have been traded continuously since 2001 and are an established product for price hedging, even if they are not used at all as frequently for trading purposes as for system price contracts.

5.2 The need for further price hedging products is limited, according to market actors

The Nordic market actors have expressed no need for additional price hedging products. On the contrary, the actors favour the current structure with a well-established system price and a liquid and functioning financial market that they prefer to develop rather than change. One proposal put forward in a number of contexts in recent years is to allow Nordic TSOs to sell CfDs in order to increase the liquidity in these. An additional purpose of the proposal is to give the TSO a role in the market and take responsibility for ensuring actors from several areas can participate in the competition on the forward market.

The instruments available today meet the actors' needs of securing both the underlying price risk and the specific price risk associated with the respective bidding zone. Transmission rights and CfDs are not necessarily mutually exclusive; they can be traded in parallel. In order for an introduction of transmission rights to be successful, the instruments must be complementary. At present, there is insufficient evidence to establish whether the instruments are substitutive or complementary. This is a matter of empirical evidence which will present itself if such an introduction takes place. If the instruments are substitutes, an introduction would mean the splitting of liquidity between several instruments whilst the introduction of transmission rights risks weakening the current market structure. This would be very unfortunate.

5.3 Transmission rights entail a more complex market with very limited consumer benefit

Introducing additional instruments would give the market actors access to more choice in their risk management. This in itself is positive. At the same time, new instruments of an entirely different type to what the Nordic region has previously had will make the market even more complex than it already is. This can have a negative impact on smaller actors

first and foremost; electricity grid operators and electricity consumers alike see a decrease in the opportunities to continue their activities, which means that they choose to maintain a more passive relationship to the market. This would also be unfortunate, as the Nordic market has traditionally managed to attract a variety of actors outside of the traditional and more narrowly defined energy sector to be active.

There is an area in which transmission rights could potential increase consumer benefit in the Nordic market, provided transmission rights and CfDs are complementary products. This primarily concerns the situation in the bidding zones characterised by an imbalance between buyers and sellers in the financial market. By means of the market actors gaining access to instruments which secure the price risk between two bidding zones, there is potential for sellers and buyers to more easily “move across bidding zone boundaries” and thus compete in several bidding zones' forward products. This could result in reduced spreads in some of the forward contracts on the market. All else being equal, this could reduce the prices for the end-users, albeit marginally. The Energy Markets Inspectorate's overall assessment is that the introduction of trade in transmission rights has little to offer the Nordic region in terms of consumer benefit. Introducing the transmission system operator as a market actor could also counteract the potential for greater consumer benefit if the transmission system operator's risk spills over onto its customers; the electricity grid customers.

There may be functions in the market that can be supported by trade in transmission rights. These functions include primarily some of the market actors gaining more choices in their risk management, which can lead to greater competition over zone boundaries in the forward market. This development would primarily be useful in zones in which there is an imbalance between consumption and production or where insufficient transmission capacity means that price deviations between areas are common.

5.4 Unsuitable to introduce transmission rights in Sweden

It cannot be determined that transmission rights would improve the function in the Nordic market. It is therefore not justified to anticipate potential demands for the introduction of transmission rights in the Nordic electricity market, which could be the result of network code FCA. The exception which provides the opportunity to use functioning financial markets for area price hedging instead of introducing transmission rights, which has been found in FG CACM, should be kept in the upcoming network codes. It is thereby the function in the respective European sub-market which determines whether or not trade in transmission rights shall apply.

There are risks associated with the introduction of transmission rights in the established Nordic market model. These are primarily associated with the market becoming more complex and less transparent and with the stability in the system price structure being undermined. This entails a risk that the electricity market will not function as well on the whole, which affects all actors and, ultimately, the end-users.

In Sweden's case, the problem of having insufficient capacity to transmit energy from the north of the country to the south will be further mitigated already within just a few years as the South West Link is ready for commissioning. This will increase the capacity between SE3 and SE4 by over 1,200 MW and make price

differences between the country's northern and southern parts more uncommon and smaller in general. Through the reinforcement of the Swedish national grid, the conditions for issuing and trading in CfDs are also improved, wherefore the market can be expected to function even better in the future. A large majority of the market's actors also express wishes to maintain and develop today's market function rather than introduce new instruments; a standpoint which the Energy Markets Inspectorate is in agreement with.

From a Nordic context, it is unsuitable for Sweden alone to introduce instruments into the trade in electricity which other Nordic countries (apart from Denmark) have chosen not to introduce. As changes in the DA market also have consequences in the retail stage, the work with the Nordic end-user market must be guiding in how the Nordic regulatory authorities work together to formulate trade and available instruments in the Nordic electricity market. If this is to be possible, it is essential that the existing wording in FG CACM, which concerns the possibility to use financial instruments such as CfDs instead of introducing transmission rights, remains once the Member States have completed negotiations and the legislation for area price hedging instruments is in place.

References

Articles and reports

Booz&Co (2011), *Physical and Financial Capacity Rights for Cross-Border Trade*, Report prepared for Directorate-General Energy European Commission, R011071 Booz & Company, London.

Carlton, D. W & J.M Perloff (1994), *Modern Industrial Organization*, HarperCollinsCollegePublisher, New York.

Swedish Energy Markets Inspectorate (2010), *Övervakning och transparens på elmarknaden*, EIR 2010:21.

Swedish Energy Markets Inspectorate (2012), *Elområden i Sverige. Analys av utveckling och konsekvenser på marknaden*, EIR 2012:06.

ENTSO-E (2012), *Transmission Risk Hedging Products –An ENTSO-E Educational Paper*, updated version 20.06.2012.

ENTSO-E (2013), *Draft Network Code on Forward Capacity Allocation*, updated version 04.08.2013.

Hagman, B & J Björndalen (2011), *FTRs in the Nordic electricity market –Pros and cons compared to the present system with CfDs*, Elforsk report 11:16.

Nord Pool Spot (2012), *Annual Report 2012*.

NordREG (2012), *Long Term Hedging within the Nordic – NordREG response to ACER*, 20th of June 2012.

Redpoint (2013), *Long-term cross-border hedging between Norway and Netherlands*, Redpoint Energy Ltd.

Tangerås, T & S-O Fridolfsson (2009), *Market power in the Nordic electricity wholesale market: A survey of the empirical evidence*, *Energy Policy*, Vol. 37, Issue 9, September 2009, 3681-3692.

THEMA (2012), *Efficiency of cross-border forward products and the role of TSOs*, THEMA report 2013-01.

Directives and regulations

Directive 96/92/EC of the European Parliament and of the Council *concerning common rules for the internal market in electricity*.

Directive 2004/39/EC of the European Parliament and of the Council *on markets in financial instruments*.

Directive 2009/72/EC of the European Parliament and of the Council *concerning common rules for the internal market in electricity.*

Regulation 2009/72/EC of the European Parliament and of the Council *on conditions for access to the network for cross-border exchanges in electricity.*

Web publications

Framework Guidelines on Capacity Allocation and Congestion Management for Electricity,

The Association of Independent Electricity Traders in Sweden (2011),
www.elforsk.se/Documents/Market%20Design/projects/2011_P1_FTR/3_OberoendeElhandlare.pdf

www.houmollerconsulting.dk/facts-and-findings, (15 September 2013).

www.montel.no, Market data obtained from Montel, (11 September 2013).

Websites

www.casc.eu

www.nasdaqomx.com

