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# International trade with electric power

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# Problem Description

International electricity trade has been increasing lately and will probably increase in the years to come. Such trade will sometimes involve transit through a third country. For instance trade between a Norway and Finland will involve transit through Sweden. Such trade has impact on different levels/entities: It has an impact on the economic benefit (to society) in general, it has an impact on the cost and revenue for the grid companies (TSOs) involved and has an impact on costs and revenue for trading parties. The result can be influenced by so-called Inter TSO Compensation (ITC).

The following tasks are included

1. Status on international exchange in the Nordic region and continental part of Europe.

2. Description/discussion of the basic element included in the costs and benefits for the different parties. Literature survey.

3. Simulation of different solutions on an 11-node grid.

4. Evaluation/discussion of different solutions

Assignment given: 15. September 2008
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# PREFACE

This Master thesis constitutes the final work of a 5 year Master of Technology education program within the field of Energy and Environment. The work on the thesis has been carried out at the University of Science and Technology (NTNU), Trondheim.

Many thanks to my supervisor Ivar Wangensteen who has provided me with great guidance and feedback, I would also like to thank my contact at SINTEF, Gerd Solem.

Frode Årdal
February 28th 2009

## SUMMARY


In 2003 the European Commission introduced the Directive 2003/54/EC and Regulation 1228/2003/EC which increased the focus on the liberalization of the European electricity market. The international electricity trade has increased and created new challenges related to cross-border transmission and compensation mechanisms.

The focus of the report has been to discuss the development of the electricity market in Europe, and the status of international exchange. The report also discusses the concept of cross-border trade and transit, and investigates a proposed ITC model and whether correct investment incentives are given.

### *Market development*

Price data from the main power exchanges in Europe indicate that the market is experiencing increasingly integration and efficiency. There has also been a trend towards market based congestion management methods. Regional markets have successfully developed in Spain and Portugal (the Iberian market) and between France, Belgium and The Netherlands (the Trilateral Market Coupling, TLC). Further plans for regional coupling are also underway (see chapter 5).

### *Transit*

The most common definition of transit is the one adopted by ETSO (Association of European Transmission System Operators), where transit is defined as the minimum between exports and imports. This definition could create opportunities for market participants to manipulate transit income (discussed in chapter 5.3).

### *Inter-TSO compensation model*

The Inter-TSO compensation (ITC) model used in this report is based on the With-and-Without transit algorithm. The model only focuses on costs and load flow, and do not include market incentives or evaluation of benefits. The model bases the compensation calculation on the transit term, which can lead to misguided identification of network responsibility.

### *Investment Incentives*

Two scenarios were compared with a base case scenario in order to identify possible investment incentives. The first scenario included a situation where one of the cross-border lines in the network was constrained. Results from this simulation indicate that the transmission system operators involved would experience increased ITC payment, and therefore not receive investment incentives. The TSOs involved would benefit from the bottleneck in form of increased revenue (assuming Cost-Of-Service regulation).

In the second scenario an extra cross-border line was implemented, and the situation was compared to the base case. The results from this simulation show that the TSOs involved would receive a positive effect in form of reduced ITC cost. The ITC mechanism would in this case be in line with the European Commission's Regulation 1228/2003/EC, and give the involved TSOs correct investment incentives.

The lack of correlated results in these two cases indicates that the ITC mechanism (in this case modeled by the WWT algorithm) cannot be regarded as relevant from an investment incentive perspective (more information found in chapter 7.3).

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# 1. INTRODUCTION

## 1.1 Background

The European power market is going through a process of liberalization. Powered by the Directive 2003/54/EC (European Commission, 2003a) and the Regulation 1228/2003/EC (European Commission, 2003b), the European Commission is seeking to create a competitive market for electricity trade in the enlarged European Union.

## 1.2 Research objectives and methods

The research objective for this report has been to give an overview of the development of the integration process in the European electricity market, with special emphasis on the international exchange between countries. This power exchange between nations brings up many important issues that need to be addressed. Congestion management is one of these issues, and is by many considered to be the key in the integration process.

Another subject of importance is the inter-TSO compensation mechanism which deals with transit flows as a consequence of cross-border trades. The transit flows are characterised by the fact that injections and loads are outside the transit country. The question of compensation for this kind of transit is subject to much discussion and different models have been developed.

In this report the With-and-Without transit mechanism is discussed and closer investigated in order to identify some relationships between ITC allocation and investment incentives. An Optimal Power Flow algorithm is being used in the simulation process. This algorithm replicates an efficient market environment, and is in line with the ambition of the European Commission, where we preferable would have a situation with a single European power market.

## 1.3 Structure of the report

Chapter 2 introduces the reader to the European electricity market and the integration process started by the European Commission. The regulatory framework is commented and an overview of the congestion management methods is given. An overview of the main power exchanges in Europe is also given. The chapter ends with a discussion on the market development.

The pricing mechanism in an electricity market is discussed in chapter 3.

Chapter 4 concentrates on the inter-TSO compensation concept, and the framework behind this mechanism.

A general discussion about transit flows and cross-border flows is given in chapter 5.

Chapter 6 introduces the reader to the theory related to the simulations done in the report.

The results from the simulations are presented in chapter 7. These are based on a Base Case, a Bottleneck Case and an Additional cross-border line Case.

A discussion and conclusion is presented in chapter 8.

# 2. INTERNATIONAL POWER EXCHANGE

In this section some principles regarding international power exchange is discussed. With increased cross-border trade, congestions are likely to occur, a section in this chapter is set off to clarify the term congestion and discuss some of the methods utilized. The liberalization process also involves the power exchanges, and these are discussed in a later section. But first some viewpoints of an effective market should be mentioned.

## 2.1 Some viewpoints on an effective market

A well functioning and effective market is often characterized by several important attributes. First off is the ease of market entry and exit. It is important to avoid barriers of entry into the market as this would reduce the possibilities for participation, and thereby limit the extent of competition. Another sign of a well functioning market is the lack of significant monopoly power. This monopoly power restricts the participation opportunities of smaller entities and potential new market entrants. Furthermore is widespread availability of market information an essential part of an effective market, all parties in the market, including firms and consumers, must be well informed in order to make effective decisions.

The above statements are some of the foundation in an effective and liquid market environment. When these criteria are taken into account, some viewpoints on an effective electricity market can be suggested.

**Ease of market entry**
Parties should have open access and equal rights in the transportation system. As discussed in (Melody, 2003) is the need for a transparent and non-discriminatory access to the grid urgent for competition and it has been a challenge so far to establish neutral and independent system operators which arrange for open access and equal rights for transmission.

**Lack of significant monopoly power**
No participant should have a dominating position, where its in it force of size can control the market.

**Widespread availability of market information**
It is important that information about relevant market conditions are accessible at all times. This would imply that the market participants, including the exchanges and the system operators must provide information to the market.

In addition to these criteria, good market **liquidity** should be emphasized. This can be reached by having a sufficient number of participants on both supply and demand side. As the number of participants increase, the liquidity and confidence to the market price increases. One single large exchange should be favorable over a cluster of smaller exchanges as this would significantly increase the liquidity and transparency in the market.

## 2.2 Regulatory Framework

The liberalization of the electricity market has been strongly enforced by the European Commission. The goal has been to create a competitive market for electricity in EU and the rest of Europe, where customers can have a choice of supplier and where unnecessary obstructions to cross border exchanges are removed. The improved cross-border flow, would according to their strategy paper, increase the competition and the efficiency in the market and lead to an overall increase in economic growth (European Commission, Strategy Paper, 2004).

In order to reach their goal of a more competitive market, the Directive 2003/54/EC was introduced. The Directive was concerning common rules for the Internal Electricity Market (IME), and was repealing Directive 96/92/EC, which did not reach the expected results. The Directive 2003/54/EC has four main objectives,

1. *Strengthening access to the electricity transmission and distribution networks*
A nondiscriminatory access to the network is guaranteed, and thus eliminating the possibility of negotiated third party access (TPA), and only allowing the regulated TPA. This would assure all market operators a better right to access the network without discrimination.

2. *Increased level of consumer protection*
The Directive guarantees for an effective legal separation between market actors and operators working in the transmission and distribution, where the aim is to limit the risk of cross-subsidization and discrimination between current and new entrants.

3. *Strengthening independent regulation.*
The member states are obligated to establish an effective regulator, who has independence from the market operators.

4. *Accelerated market opening*
A timetable for the different market opening stages is given. The member states should ensure that non-household customers are free to purchase electricity from the suppliers of their choice by 1st July 2004, and 1st July 2007 for the non-household users (i.e. commercial, industrial and other professional customers).

To address the increased cross-border exchange, the Regulation 1228/2003/EC[1] was implemented. This regulation was aimed at setting rules for cross-border exchange of

[1] With the entry into force of the Regulation on the 1st of July 2004, the first Guidelines on Congestion Management became legally binding and on the 1st of December 2006, the amended Congestion Management Guidelines took legal effect.

electricity. In addition to this the Regulation established a framework for the Inter-TSO Compensation mechanism (ITC). This topic will be addressed later in the report.

The framework suggested by the European Commission, in form of Directive 2003/54/EC and Regulation 1228/2003/EC seems fairly in line with the criteria for an effective market discussed in section 2.1, as well as the Commissions own agenda on the development of the Internal Energy Market (IEM).

## 2.3 Congestion management in Europe

The definition adopted by The European Commission is that congestion involves a situation where interconnectors, which link national transmission networks, cannot accommodate all physical flow that results from international trade. The congested transmission line should, according to the Regulation 1228/2003/EC, be managed in such a way that the transmission capacity is utilized efficiently with as little social welfare loss as possible.

### 2.3.1 Overview

As can be seen in Figure 2.1, were earlier solutions on the continent and the rest of Europe a complete mix of various systems. These solutions included methods like; access limitation, priority list, pro-rata, explicit auction, implicit auction, first come – first served and so forth. But as can be seen in Figure 2.2, is the situation today somewhat different. There seems to be a shift towards market based solutions like implicit and explicit auctions at most national borders.

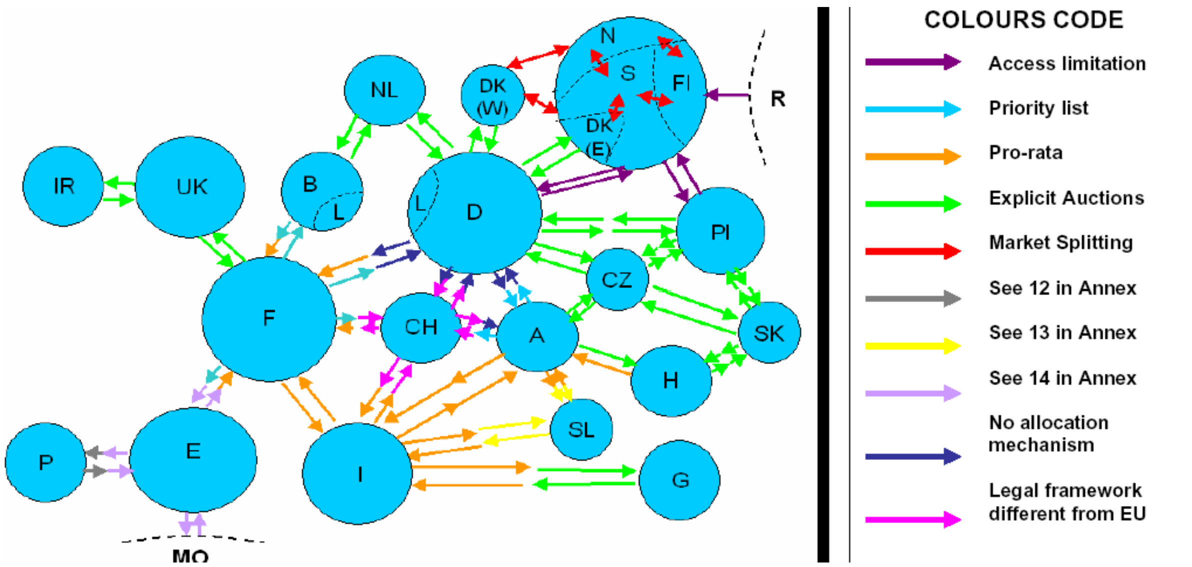


Figure 2.1 Different congestion management methods in Europe, year 2004 (ETSO, 2004)

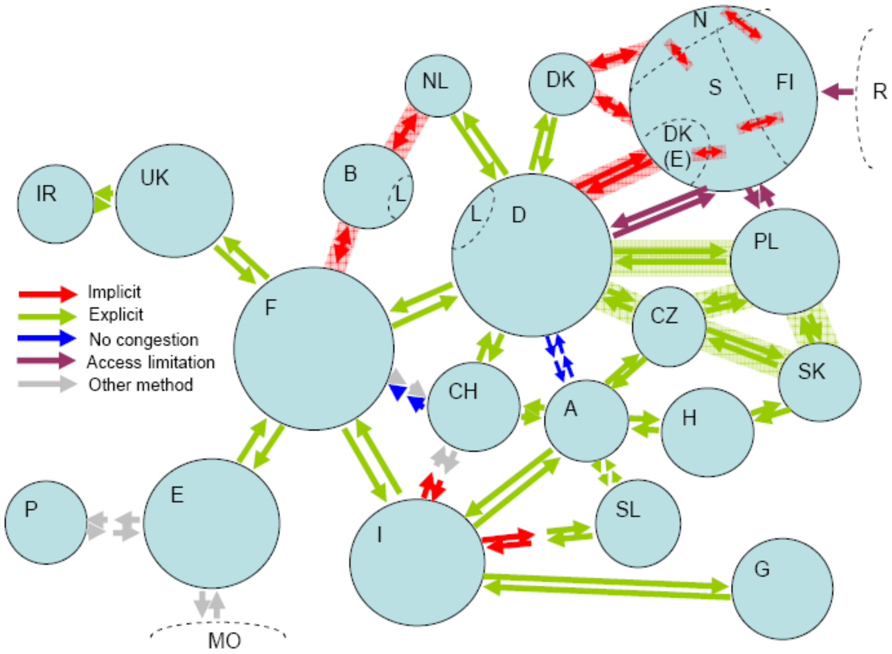


Figure 2.2 Different congestion management methods in Europe, year 2007 (ERGEG, 2007)

*Explanation to Figure 2.2:*
- *Market splitting (Implicit Auction) has now been introduced in the Iberian market*
- *An interconnection with more than two different colors means that there is not a unique capacity allocation method or congestion management mechanism jointly applied by the two TSOs involved*
- *The NorNed cable is not included in the figure, the plan is to introduce market coupling on this connection*

The most attractive congestion management method in a well developed electricity market is a solution that encourages transparency and liquidity, the Regulation 1228/2003/EC Article 6, states the following:

> *"Network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals to the market participants and transmission system operators involved. Network congestion problems shall preferentially be solved with non transaction based methods, i.e. methods that do not involve a selection between the contracts of individual market participants"*

(European Commission, 2003b).

Even though a market based solution is the recommended solution, a range of non market based methods is still used in the allocation of transmission capacity throughout Europe. In the following section a selection of both market based and non market based solutions are described.

### 2.3.2 Market based solutions

These are the preferred solutions in a marked based environment, they are transparent and non-discriminatory and give a correct economic signal provided there is no exercise of market power. A simple overview of the methods can be seen in Figure 2.3.

In an **explicit auction**, transmission capacity is auctioned separately to the marketplace where trading of energy occurs. The TSO determines ex ante net transfer capacity (NTC) considering security analysis, accepts bids from potential buyers and allocates the capacity to the ones that value it the most (Kristiansen, 2007). Market players make bids for the needed NTC. The bids are stacked, with the highest first, until the NTC are completely utilized. Each participant has to pay a calculated "transmission market" clearing price. A player who has been allocated capacity is not obliged to use it, but a principle of "use-it or lose-it" should be used. The unused capacity will therefore be opened up for all players. The explicit auction is often a joint coordinated mechanism between the concerned TSOs, and includes different products with varying frequency (i.e. year, month or day).

**Implicit auction** considers energy bids in each organized market area, and based on submitted bids, supply and demand in the market areas are matched. Unlike an explicit auction, the allocation of capacity is here included in the auctions of electricity in the market. When the implicit auction method is used, the capacity between bid areas is available for all players, in addition the bid and offers in each area are known. The area prices would therefore reflect the cost of energy in each area and the cost of congestion.

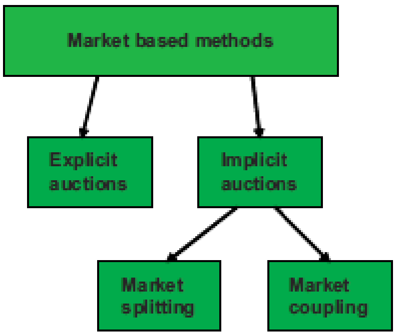


Figure 2.3 Market based congestion management methods (Kristiansen, 2007)

Market splitting and market coupling are the two marked based solutions where implicit auctions are used.

When a **market splitting** method is used, a centralized power exchange (PEX) is split into geographical bid areas with limited exchange capacities (Androcec & Wangensteen, 2006). A single system price is calculated based on the total demand and generation in the whole market area. When a congested line is expected, a bid area on each side of the transmission line is defined each having its own pool price. The price in the surplus region is lower than the price in the deficit region, and the power should flow from the low price area over in the area with a higher pool price. This congestion management method is an optimal solution regarding utilization of the defined capacity in the grid, where the market players will decide the physical flow and whether congestions would appear. This method has been used with great success in the Nordic region, and has now been implemented in the Iberian market as well.

The principle of **market coupling** is somewhat the same as the market splitting method, the capacity should be utilized with power flowing from a low price area/region towards a high price area/region. The difference here is the cooperation between two or more power exchanges.

There are several practical barriers to applying implicit auction in the EU region, the method requires a well organized electricity market. Between nations there might be different physical agreements and exchange trading agreements. Market coupling have however recently been successfully introduced between France, Belgium and The Netherlands. And on the horizon several other market coupling projects are under way, including the CWE (France, Belgium, The Netherlands and Germany) coupling and the first inter regional coupling EMCC between the Nordic region and Germany.

### 2.3.3 Non market based solutions

As can be told from the name, these solutions do not give correct economic signals from a market based viewpoint. Although some of these methods are still used at different cross-border sections, most of them should become obsolete or be altered towards a market based solution in the future. The solutions discussed here can be seen in Figure 2.4, followed by a short description of each method.

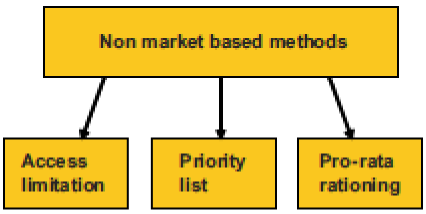


Figure 2.4 Non market based congestion management methods (Kristiansen, 2007)

**Access limitation** is a congestion management tool used for DC interconnectors with ownership that differs from the linked network. This method does not give any efficient cross border economic signal for generation/transmission investment (ETSO, 2004). And no pan European incentive for social welfare maximization and least-cost operation is given. A few users may retain benefits from this method.

For the **Priority list** method (or First come, first served), the marketer gets capacity in a priority order until the whole available transfer capacity (ATC) is allocated. The criteria used are often based on chronological order, and past use of capacity. The problem with this approach is the possibility of long-term reservations blocking the transmission capacities. Other characteristics for the method are (ETSO, 2004):

- Transparency limited by confidentiality of trade
- The market players obtaining capacity capture congestion rent and pay a capacity price which usually is very low or zero.
- The method favors exporters or importers with large portfolios of customers.

When using the **Pro-rata rationing** method, capacities are allocated in proportions to requests if they exceed the announced ATC. This allocation method is transparent and non-discriminatory. But the characteristics of this method could possible promote gaming tactics from players in the market, if a player anticipates that a congestion would occur it may possibly overestimate their capacities needs and purchase accordingly. These gaming-tactics can be avoided by making the players oblige to use the designated capacity.

## 2.4 European Power Markets

In the process of integrating the electricity market in Europe, a number of power exchanges have evolved. A few words on the basics behind a power exchange are shared, followed by a brief overview of the existing exchanges.

### 2.4.1 The exchange

The basic idea of a power exchange is the possibility of having a centralized and transparent market place where competitive trading can take place, and where market participants can accurately monitor the market price. Most power exchanges originated as auction-based spot markets, reflecting market participants need to optimize day-ahead scheduling decisions in the delivery of a non-storable commodity over an integrated transmission network (OMEL, Annual Report , 2007). The exchanges have however, with increasingly competition in the power market, evolved into a more traditional role of exchange including standardized and freely tradable power derivatives.

Spot market trade at a power exchange is completed the day before delivery. This is done in order to allow both market participants and system operator a reasonable timeframe for arranging physical aspects of the delivery.

The spot market in the Nordic region calculates the price as the balance between bids and offers from all market participants, i.e. the intersection point between the markets supply curve and demand curve. This method is often referred to as equilibrium point trading, auction trading, or simultaneous price setting (NordPool, The Elspot market, 2008). In a situation with market splitting, the mechanism of the spot market trade adjusts the flow of power across interconnectors in the grid accordingly the capacities set by the TSOs. And thus works as an implicit capacity auction on the interconnectors between the bidding areas.

Trading in electricity derivatives is a cost-effective, liquid and convenient method for participants to manage their price delivery of electricity. When trading in the derivative market the settlement and delivery are carried out as financial price hedging settlements without any physical delivery of electricity (Solem, 2003).

### 2.4.2 European power exchanges

An overview of the current power exchanges in Europe can be seen in Figure 2.5 followed by a short description of a selected few exchanges.

Figure 2.5 Power exchanges in Europe (EEX & Powernext, 2008)

***Nord Pool***

A power exchange does not need to be limited by national borders, an example of this is the Nord Pool exchange, which is a collaboration between four Nordic countries. The exchange is the largest physical and financial power exchange in Europe, and organizes the physical trade of electricity in the Nordic region and the KONTEK area in Germany.

Nord Pool also provides a market place where participants can trade derivative contracts in the financial market[2]. The duration of the contracts vary from days, weeks, months, quarters and years, with the longest contract reaching 6 years of length.

Turnover in the financial market at Nord Pool increased with 38,3 % from 2006 (765,9 TWh) to 2007 (1059,9 TWh). The traded volume at the spot market increased from 249,8 TWh in 2006 to 290,6 TWh in 2007, an increase of 16,3% (NordPool, Key Figures, 2008).

[2] The Nordic derivative products are owned by Nord Pool ASA. All international contracts are owed by NASDAQ OMX Commodities.

Nord Pool has currently over 420 members in total, including exchange members, clearing clients, members and representatives in 22 countries (NordPool, About Nord Pool, 2009)

***EEX***[3]

The European Energy Exchange (EEX) emerged as a result of a merger between LPX Leipzig Power Exchange and the Frankfurt-based EEX in 2002. Since then it has evolved into the leading power exchange at the continental part of Europe. EEX offers opportunities for trading in the spot market (day ahead and intraday) and electricity derivatives. The derivatives have a maturity of up to six years.

Since EEXs inception in 2002, the volume for the power spot market has increased from 31,45 TWh in 2002, to 154,4 TWh in 2008. The increase in the traded spot volume displayed a particularly good development recently with an increase of 24,8 % from 2007 to 2008. The trade volume on the power derivative market increased at the same time from 1150 TWh in 2007 to 1165 TWh in 2008[4].

As of January 2009, EEX has 218 trading participants from 19 countries (EEX, European Energy Exchange, 2009).

***IPEX***

The Italian power exchange (IPEX) was launched in 2004 and marked the start of the first regulated electricity market in Italy. The exchange is organized and managed by Gestore del Mercato Elettrico S.p.A (GME) and enables producers, consumers and wholesale customers to enter into electricity purchase and sale contracts. The exchange consists of the spot market, MPE, (day ahead, adjustment market and ancillary service market) and the forward electricity market, MTE. The tradable forwards consist of Base-Load and Peak-Load contracts, with daily, weekly and monthly delivery periods.

From the launch in 2004, the exchange volume (both MPE and MTE) increased from 231,5 TWh in 2004 to 336,0 TWh in 2008. The liquidity in the same period increased from 29,1% in 2004 to 69% in 2008. As of January 2009 there are 149 market participants listed at the exchange.(GME, Summary Data, 2009).

[3] On September 19, 2008 EEX and Powernext announced the incorporation of the new Spot Trading Company under the name EPEX Spot SE – European Power Exchange (EEX & Powernext, Press Release, 2008).
[4] The volume for derivatives trading also comprises 887 TWh from OTC clearing (EEX, Press release , 2009)

### *Powernext*[5]

Powernext was launched in July 2001 as a direct response to the opening up of the European electricity markets, and is the French power exchange for spot (day ahead and intraday) and future trading. The exchange offers derivatives in form of power futures with maturity up to 3 years.

The volume traded on the Powernext exchange increased from 2,6 TWh in 2002 to 44,2 TWh in 2007 (Rademaekers, Slingenberg, & Mosy, 2008). The exchange had 80 trading members in January 2009.

### *APX and BELPEX*

The Amsterdam Power Exchange (APX) was established in 1999 as an independent exchange for anonymous trading on the spot market offering market participants a spot market trading platform in the form of day-ahead transactions (APX, 2008). The exchange provides markets for short term trading (no derivatives[6]) in the Netherlands (APX Power NL), the United Kingdom (APX Power UK) and Belgium.

In November 2008 the second anniversary of the Trilateral Market Coupling (TLC) was celebrated. This market coupling was initiated by APX in 2004, and set into action two years later. The TLC is linking the Belgian, Dutch and French electricity markets closer together.

The APX Power NL exchange had a traded volume of 24,9 TWh in 2008, this is an 19% increase from 2007 and is the highest ever traded volume on the APX NL exchange. The number of participants on the exchange was 56 by the end of 2008.

The Belgian power exchange BELPEX was introduced simultaneously as the market coupling was introduced in 2006. The exchange provides short term power trades through the day-ahead market segment, through a continuous day-ahead market segment and a continuous intraday market segment (BELPEX, 2008). BELPEX does not currently offer any derivatives products.

In BELPEXs first full year of service, the exchange reached a total trade volume of 7,5 TWh, and by the end of the same year counted 24 members.

[5] See footnote number 2

[6] As per 12 December 2008, ENDEX, the Amsterdam-based European Energy Derivatives Exchange, is part of APX Group. ENDEX offers trading and clearing services for power and natural gas futures (APX, APX Continues to grow, 2008)

***OMEL and OMIP***

Spain`s operator for the power market is OMEL, which is responsible for the technical management of the national power system. OMEL offers daily trading in The Iberian Electricity Market (Mercado Iberico de Electriciade, MIBEL). The futures market is organized by OMIP, which is the managing entity responsible for the organization of the Portuguese division of MIBEL. Throughout 2008 the traded volume in the daily market at OMEL was 266 TWh. (OMEL, Market Results, 2009). Per January 2009, OMIP had 30 participants.

### 2.4.3 OTC trading in the power market

Over-the-Counter (OTC) trading occurs when players trade power directly between themselves and not through an exchange. These trades are often managed by large brokerage firms, and the method thus involves the use of a decentralized market approach. There are no centralized exchanges for these trades, and the trades are often referred to happen in the "OTC market". Unlike trades on an exchange is OTC trades not logged and published, the trades are a deal between the involved players and the broker used. This leads to limited price transparency, limited liquidity, an ex ante restricted number of potential market partners and often substantial transaction costs (Rademaekers, Slingenberg, & Mosy, 2008).

This limited transparency makes it difficult to accurately estimate the size of the OTC market, but it is obviously the preferred method for power trading in Europe. This can be confirmed by estimates from (Fortis, 2008) which suggest that the volume of OTC trades in the EEX region during 2007 was twice the size that was traded at the exchange.

## 2.5 Market development

The agenda of the European Commission has been to create a single electricity market in Europe. The market development in terms of congestion management, price development and market integration is briefly commented in the following sections.

### 2.5.1 Congestion management

It is important to promote market based solution on congestion management as this would enable an economic value being placed to the product being traded, i.e. transmission capacity. A non market based method would work in an environment with no competition, but in a fully competitive market cross border exchanges should be managed under market rules.

The Regulation 1228/2003/EC requires that market based solutions are adopted for congestion management. Methods other than implicit and explicit auction should therefore be less common in the future. It should however be mentioned that explicit auctions have one major disadvantage as they do not allow the netting of imports and exports, this is a requirement of the Regulation 1228/2003/EC.

Some work has recently been done to a Flow-based Market Coupling (FMC) solution. According to the ETSO-EuroPEX Joint Working Group, this method meets the needs of both the market and system operation. The result is a model with regional price areas, with inter-regional trading facilitated by market coupling subject to simplified transmission constraints. The model describes arrangements for day-ahead trading (EuroPEX, 2004). The model can be seen as a compromise between the market splitting approach and the more detailed Locational Marginal Pricing (LMP) method used in the PJM-area in the US. The method might be a possible solution in a future single electricity market across Europe (Gerd Solem, 2007)

A flow-based allocation scheme is a supra-national approach, where all bids for energy and the related cross-border capacity are optimized by a centralized entity that is responsible of the allocation. The flow-based solution could be a promising approach as the commercial transactions are no longer limited to the interconnections where they are reported, but instead converted into physical power flows using a simplified network representation. Impacts on third interconnections can thus be considered in order to ensure overall security (Energy Community Secretariat, 2007).

At the moment, no flow based capacity allocation mechanism is implemented in Europe.

### 2.5.2 Market Prices

A good indicator to measure the efficiency and integration level of the power market is the market price development at the different exchanges. In Figure 2.5.1 the price variation from February 2008 until January 2009 can be seen. The prices at the various exchanges are somewhat correlative, the prices seems to be following the same price trends with a price top during September 2008 and a bottom during may 2008. There is however very large volatility at some exchanges, this is especially true for the APX, EEX, Powernext and GME exchanges. It is very interesting to see the low price volatility at the Nord Pool and OMEL-E exchanges. These markets are based on implicit auctions with market splitting, and it is somewhat clear that this could be a preferred solution as a future congestion management method at the continent.

Even with the relatively large volatility in prices at some of the exchanges, the correlative nature of the prices indicates that the market has reached some degree of efficiency.

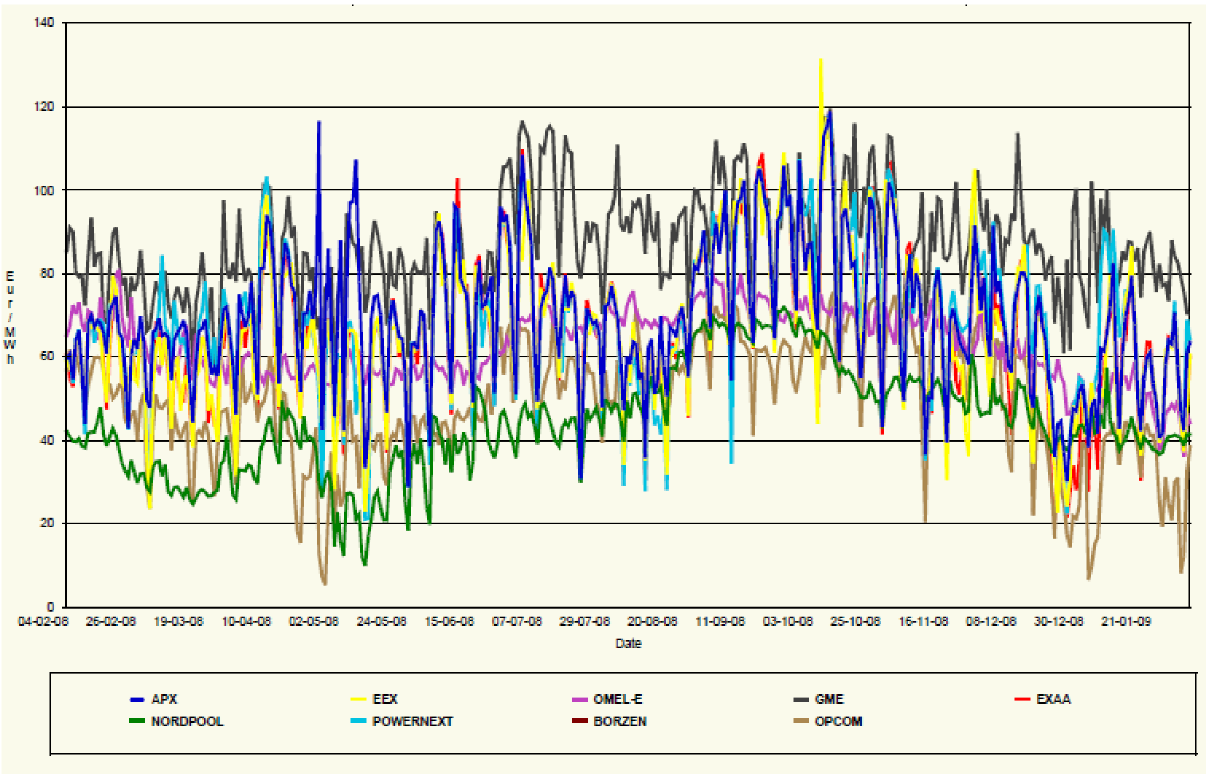


Figure 2.6 Price development at various power exchanges during 2008 (OMEL, 2009)

### 2.5.3 Regional markets

The development of potential regional markets has been proposed as a necessary interim stage in the integration process. An overview of possible regional markets was introduced by the European Commission in 2004, see Figure 2.7. As can be seen from this figure, the Commission expected 8 regional markets to develop by 2009. Including the already well established Nordic marked.

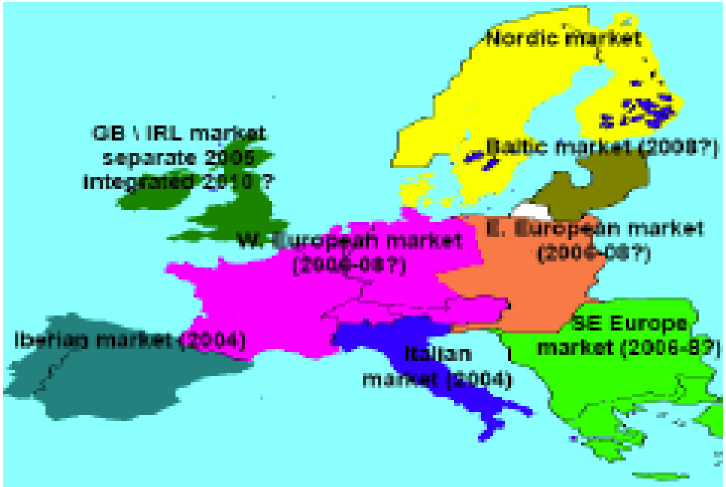


Figure 2.7  Strategy by the European Commission, year 2004 (European Commission, 2004)

Since this time, an additional three regional markets have successfully developed. The TLC market between Belgium, The Netherlands and France was launched in 2006, while the Iberian market (MIBEL) was opened in 2007. In addition to these three, has an intraregional market become operational in Central Eastern Europe, where coordinated explicit auction is utilized.

Further plans involving regional market development includes a market coupling in Central Western Europe, namely between France, Belgium, The Netherlands and Germany. This regional market is planned for launch during the first quarter of 2009 (Zecchini, 2008).  A coupling between the Nordic market and Germany is also underway, this project is undertaken by The European Market Coupling Company (EMCC). The coupling was initially launched in September 2008 but was suspended later the same year due to unexpected deviations in power flow and price. The coupling is planned for re-launch during first quarter of 2009 (EMCC, 2008).

# 3. PRICING MECHANISM

In this chapter some principles regarding pricing mechanism in an electricity market is discussed, the example is valid for a situation where market splitting is used to create different price areas[7]. But first let us take a look at what makes the electricity market somewhat different than other commodity markets.

## 3.1 Properties of the electricity market

Electricity is essential to the community, the society depends on electricity and it is taken for granted that power is available at all times. Technical characteristics of the power supply can however lead to a breakdown, and it is estimated that the price on loss of power sometimes can cost society over 100 times higher than ordinary price of electricity (Wangensteen, 2007).

Electricity differs from most products in several aspects. As discussed in (McDermott & Peterson, 2002) is there bound to be some volatility in the power market. Supply and demand varies during the day, week and year. This combined with the fact that electricity cannot be stored, at least not in a large scale efficient way, will lead to fluctuation in the market.

It is a common fact that upgrade or investment in new generation capacity in the power grid could be a time consuming and expensive task. The same can be said for the transmission grid, where the consequence at times with high load could be insufficient transmission capacity. Lack of transmission capacity can create constraints in the grid, which in turn could increase market power for participants when regions are separated.

Another factor that increases the concerns regarding market power is the rather inelastic demand for electricity. This means that variation in the price of electricity has little effect on a consumers demand for electricity.

As for the transmission and distribution of electricity, the industry is considered to be naturally monopolistic.

The electricity system can overall be regarded as a very complex system, where instant balance in production and consumption is essential. The need for instant balance in the system makes a real time price mechanism practically impossible, hence the pricing of the market needs to be done ex ante or ex post. In the following sections, a discussion of the price formation in the electricity market is done.

[7] With an underlying assumption of perfect foresight and perfect competition, the dispatch outcomes for the explicit auction are identical to those of the implicit auction. Price outcomes and welfare distribution are also identical in the two cases (CONSENTEC, 2004).

## 3.2 Pricing mechanism and congestion management

### 3.2.1 Socio economic welfare

Let's first take a look at the pricing mechanism in a perfectively competitive market, and how social welfare can be identified by a simple approach.

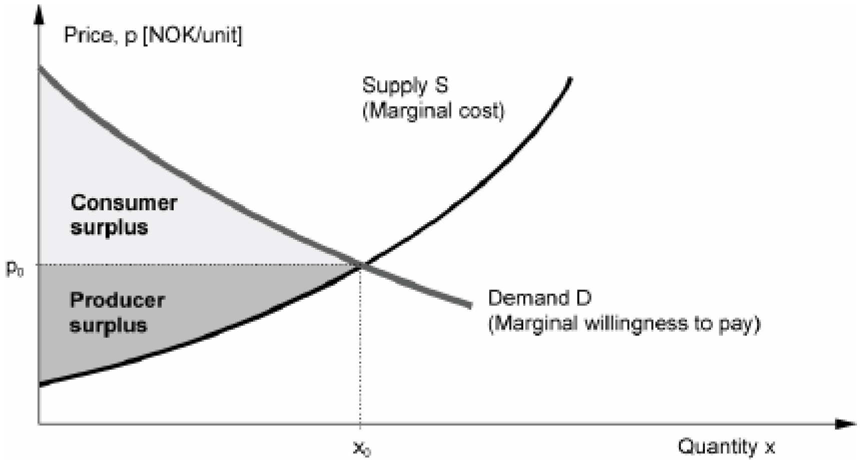


Figure 3.1 Producer and consumer surplus in optimal market environment (Wangensteen, 2007)

Figure 3.1 show a standard supply and demand curve in a liberalized market environment, the intersection between these curves is the equilibrium of the market, in other words the point where the marginal cost equals the marginal willingness to pay a price $p_0$ at volume $x_0$. When this intersection is located, the producer and consumer surplus can be identified. The shaded area between the demand curve D and the price $p_0$ is the consumer surplus, while the producer surplus is the shaded area between the supply curve S and the price $p_0$. The socio economic welfare is defined as the product of these two areas.

### 3.2.2 A simple example[8]

The following section tries to clarify how the pricing mechanism works in an environment where constraints in the transmission capacity have lead to market splitting[9].

**No interconnection**

As can be seen in Figure 3.2, we start with two areas with different supply and demand properties which lead to two independent area prices. In relation to each other the area A is a surplus area, while area B is a deficit area. This can be identified by the price difference between the cases. The socio economic welfare has already been defined, and in this situation the total surplus for both areas are 32 500 NOK.

[8] The data for this example is provided by (Wangensteen, 2007).
[9] For simplicity the example here involves two areas. Market splitting can however certainly involve more than two areas which would increase the complexity of the pricing mechanism.

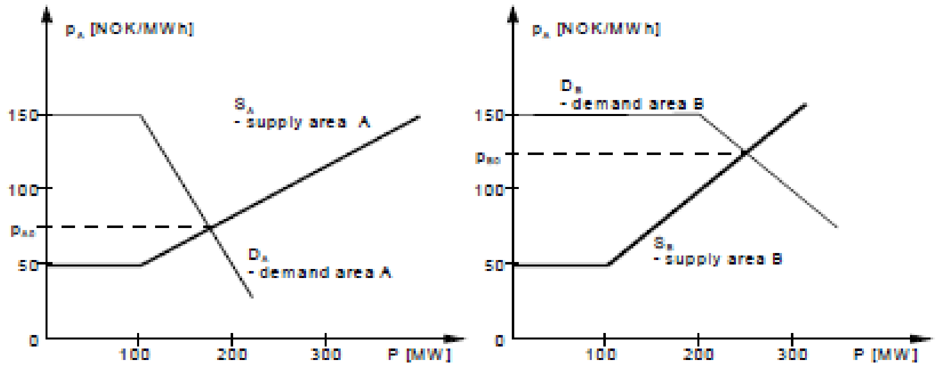


Figure 3.2 Demand and supply curves for the two areas (Wangensteen, 2007)

Furthermore let us analyze what would happened if these two areas where connected via a unconstrained transmission line. As can be seen from Figure 3.3, the market now has one demand curve and one supply curve, and acts as one integrated market. What happened to the socio economic surplus? Well the total surplus sums up to a total of 35000 NOK, which means that the integration of the market has a value of 2500 NOK.

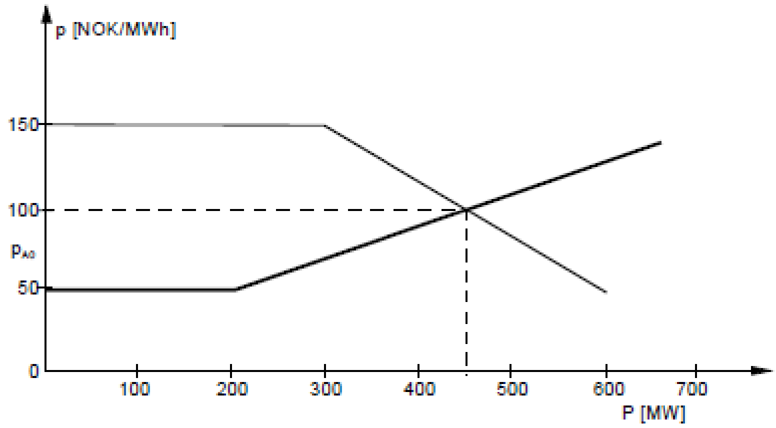


Figure 3.3 Supply and demand curves for the integrated market (Wangensteen, 2007)

### ***Impact of transmission capacity constraints***

The capacity of the transmission line used to connect the two areas in the above was assumed to be unconstrained. If the transmission line connecting the areas was congested this would have impact on the prices in the areas. For the surplus area (A) the price will be reduced, for the deficit area (B) the price will increase. As a consequence of this alternation in prices, consumers in area A would increase their benefit, and producers in the same region would experience a reduction in surplus and vice versa for area B. The system operator in the market would receive a profit in form of congestion rent from the market players. Overall the benefit in form of socio economic consequence to society would be reduced.

The situation with a constrained transmission line can be illustrated in Figure 3.4. The surplus line (A) is found when subtracting supply from demand in area A, while the deficit line (B) is found by subtracting demand from supply in area B. The required transmission capacity between the two areas can be located in the intersection point from the supply and demand lines. This is the transmission capacity which is needed in order to avoid congestion. The congestion rent received by the TSO(s) involved is found by multiplying the price difference between the two areas with the capacity of the transmission line. In the figure this rent is represented by the square. Furthermore the welfare gain for the market participants can be seen, which together with the congestion rent represents the socio economic welfare to society is. The welfare loss when transmission capacity is less than 100 MW is also represented in the figure.

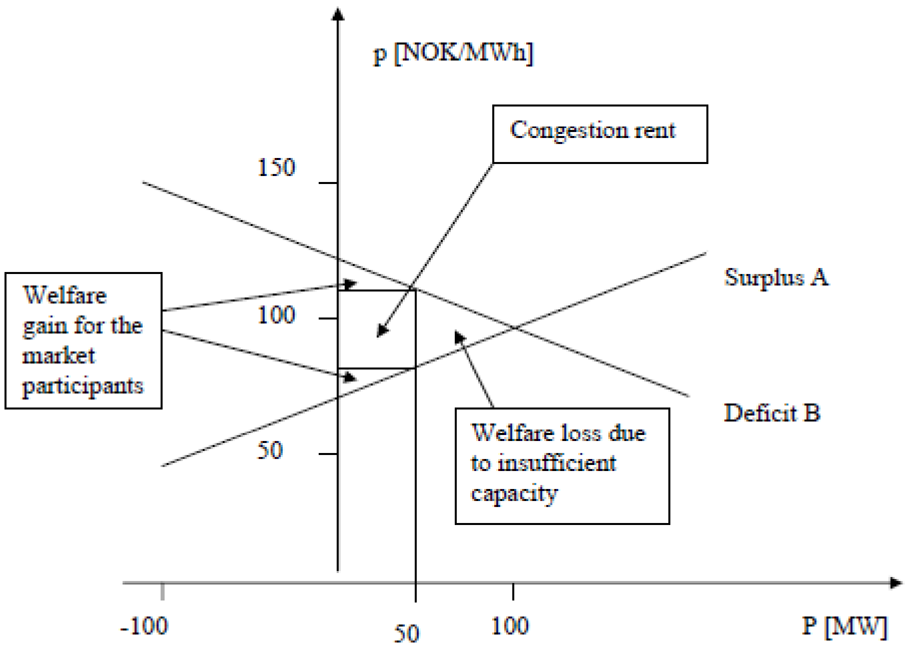


Figure 3.4 Welfare gain/loss and congestion rent in a situation with constrained tranmssion capacity (Wangensteen, 2007)

# 4. INTER-TSO COMPENSATION

With the introduction of Regulation 1228/2003/EC the European Commission aimed at setting fair rules for cross-border exchanges in electricity. This included the establishment of a compensation mechanism for cross-border trade, the Inter-Transmission System Operator Compensation (ITC) mechanism. The Regulation is presented in this chapter, followed by a short discussion. Later some criteria for a compensation scheme are discussed.

## 4.1 The ITC framework

The ITC mechanism plays an important role in the development of the internal electricity market. In a liberalized electricity market, power should flow across national borders as easy as it would flow within borders. Meaning market participants all across the network could be involved in cross-border trades. The cross-border flows from these trades have an impact on foreign networks, and would lead to increased costs for TSOs. The idea behind the ITC scheme is that these costs should be compensated for. With this being done, there should in reality be no extra cost involved with cross-border trades and the market would be more in line with the European Commission's definition of a single market.

The framework for the compensation mechanism is given in Article 3 of Regulation 1228/2003/EC, and is quoted bellow:

1. *Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their networks.*

2. *The compensation referred to in paragraph 1 shall be paid by the operators of national transmission systems from which cross-border flows originate and the systems where those flows end.*

3. *Compensation payments shall be made on a regular basis with regard to a given period of time in the past. Ex-post adjustments of compensation paid shall be made where necessary to reflect costs actually incurred. The first period of time for which compensation payments shall be made shall be determined in the guidelines referred to in Article 8.*

4. *Acting in accordance with the procedure referred to in Article 13(2), the Commission shall decide on the amounts of compensation payments payable.*

5. *The magnitude of cross-border flows hosted and the magnitude of cross-border flows designated as originating and/or ending in national*

*transmission systems shall be determined on the basis of the physical flows of electricity actually measured in a given period of time.*

6. *The costs incurred as a result of hosting cross-border flows shall be established on the basis of the forward looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure, as far as infrastructure is used for the transmission of cross-border flows, in particular taking into account the need to guarantee security of supply. When establishing the costs incurred, recognized standard-costing methodologies shall be used. Benefits that a network incurs as a result of hosting cross-border flows shall be taken into account to reduce the compensation received.*

(European Commission, 2003b)

Transit as defined in Regulation 1228/2003/EC:

> *'Declared transit' of electricity means a circumstance where a 'declared export' of electricity occurs and where the nominated path for the transaction involves a country in which neither the dispatch nor the simultaneous corresponding take-up of the electricity will take place.*

(European Commission, 2003b)

## 4.2 Comments to the framework

The inter-TSO compensation framework set forth in Article 3 of Regulation 1228/2003/EC aims to compensate infrastructure and network losses for TSOs affected by transits. The framework has however been criticized for having some vague definitions relating to the rule set.

Paragraph 1 and 2 in the article states TSOs *hosting* cross-border flows should be compensated for by those TSOs cross-border flows *originate* and *ends*. This seems like a reasonable statement, but there is one problem, the path of a power flow in an electricity network is based on physical laws and is dependent on transmission lines impedances.

Let us assume there has been a bilateral trade agreement between a producer in France and a consumer in The Netherlands, one would assume that the path of the energy would go straight north through Belgium. Most of this energy will actually follow this path, but certainly not all. Some of the energy would possibly flow through the German transmission lines and thus create loop flows (cf. section 5.3) between these countries. This could create a dilemma, because of the physical laws, a declared transit flow would not correspond to an actual bilateral contract.

Paragraph 5 in the article suggests the use of national borders in case of measuring of cross-border flows. It can however be discussed whether national borders/TSO-regions are the right terms to use when defining the origin and end of cross-border flows, since these flows are so difficult to map. Another reason for why national borders should not be the part of the measuring of cross-border flows is the fact that the smaller a country is, the larger will generally the ratio of transits to internal consumption become. Smaller countries will therefore in general have a larger fraction of their horizontal networks attributable to external users. Research proves that a smaller country is more prone to experience larger effects of inter-TSO payments than larger countries (COMILLAS, 2002).

It is stated in paragraph 6 that "*benefits that a network incurs as a result of hosting cross-border flows shall be taken into account to reduce the compensation received*". There is however no clear definition of what benefit is.

The benefit concept is further discussed in section 5.2.

## 4.3 General properties for a cost allocation method

As can be seen from the framework above is the objective of the ITC compensation scheme quite general, and thus makes it a challenge to create sound solution. There are however some properties that are essential in this process.

An ITC model should comply with the rules of physics, and therefore be accurate in terms of cost reflectivity. From the discussion above the identification of cross-border flows can be challenging, therefore a load flow algorithm should be the desired method for this task.

According to the Regulation 1228/2003/EC should the ITC mechanism determine costs that results from hosting cross-border flows. Some ITC models define compensation based on transit flows, which per definition[10] can lead to less sensible results. For example would a country with export on all transmission lines be defined to not have transits, and shall thus not receive any compensation. The same goes for a country with import on all lines. An ITC model using the transit definition is therefore lacking accuracy compared to a model which do not use the transit term in the allocation calculation[11].

[10] ETSO defines transit as the minimum between total import and total export of a county, i.e. Min $(\sum import, \sum export)$

[11] An example can be the Average Participation and the Marginal Participation methods, which detects the responsibilities of flow on network elements on node levels in order to explicitly consider flows (not only transits) between neighboring countries (COMILLAS, 2002).

An additional way of increasing accuracy for an ITC model is to consider a variety of load flow situations throughout the year. This is important since load flow pattern will vary during day, week and month.

Transparency is also essential when dealing with ITC models. An allocation method should produce results that are trusted, and trusted results depend on the transparency and how easy the model is to comprehend.

Benefits should also be included in a future ITC mechanism, not only benefits related to the physical conditions in the grid. As pointed out in (Gerd Solem, 2007) could countries buy at a low price at one side of the border, and sell at a higher price on the other side and this way create a benefit.

## 4.4 Voluntary agreement

Although the ITC concept was introduced with the 1228/2003 Regulation, work on a compensation scheme regarding cross-border trade already begun in 2002, when eight members of the ETSO (Association of European Transmission System Operators) signed the first voluntary compensation agreement (ETSO, 2002).

Since then there has been a number of suggested compensation methods, and a range of analyses have been done in order to find a suitable method that is in line with the Regulation. Some of these methods are; With-and-Without Transit (WWT), Average Participations (AP), Marginal Participations (MP) and Improved Model for Infrastructure Cost Allocation (IMICA).

The latest signed agreement for 2008/09 is based on the principle applied for the Interim ITC Agreement June – December 2007, where losses are based on the WWT model, i.e. losses are calculated based on a scenario with transit and a scenario without transit and then compared (for details see section 6.1). According to this agreement all ITC participants get fully compensated for losses caused by transit flows. They will also get compensation for infrastructure cost, in addition to this will the model allow less volatility, and hence guarantee stable ex post net results (ETSO, 2007).

The agreement has so far been signed by 39 European TSOs, and thus covers all the EU members and a number of non-EU countries including; Norway, Switzerland and the South East European countries; Albania, Bosnia and Herzegovina, Croatia, FYROM, Montenegro and Serbia.

Within a two year period, ETSO assumes that a new and technically improved ITC mechanism should be ready. This ITC model will solve some issues not yet addressed in the current mechanism.

# 5. TRANSIT AND CROSS-BORDER FLOW

In this chapter some characteristics concerning transit and cross-border flows are discussed. First off is a discussion on the relationship between ITC and tariff regulation. In addition to this are some benefits and costs regarding cross-border flows discussed, as well as a short description of investment incentives followed by some comments regarding loop flows.

## 5.1 Tariff Regulation and ITC

There are basically two types of tariff regulation schemes in use throughout Europe, the first category include the traditional cost-of-service[12] (COS) regulation, which basically means that cost and revenue for each TSOs should balance. The second category of regulation schemes is known as incentive based regulation[13]. The characteristics behind this method imply that the regulator delegates certain pricing decisions to the firm (in this case the TSOs), which can reap profit increases from cost reduction (Vogelsang, 2002).

The following discussion[14] is based on the cost-of-return regulation (COS). It is assumed that the TSO is a state owned monopoly, with tariff systems and revenue regulations in line with the current practice in the Nordic region. The TSO is assumed to have maximization of social welfare as its economic objective, limited to the TSOs own control area (which in the Nordic region means the national borders).

The balance between cost and revenue when using a COS regulation can be expressed as:

$$\textit{Fixed cost} + \textit{Variable cost} + (\textit{ITC}) = \textit{Residual element} + \textit{Variable element}$$

### 5.1.1 Cost elements

$$\textit{Cost} = \textit{Fixed cost} + \textit{Variable cost} + (\textit{ITC})$$

The fixed cost is based on investments already done, which include the operation and maintenance cost added with the capital cost. The variable cost includes two more elements, grid losses and loss of load.

$$\textit{Variable cost} = \textit{grid losses} + \textit{loss of load}$$

The grid losses are assumed to be compensated for by the TSO purchase in the market, and thus imply a cost for the TSO. Loss of load is defined as losses imposed on grid customers because of outages, which could present a cost to society. ITC is here included on the cost side of the balance. If a TSO is allocated compensation due to ITC, the element will be negative, and vice versa if the TSO have to pay.

[12] Also known as cost-plus, or rate of return regulation (ROR)
[13] Known as performance based regulation in the U.S.
[14] The discussion is based on an example given in (Gerd Solem, 2007)

### 5.1.2 Revenue elements

*Revenue = Residual element + Variable element*

The revenue is basically defined as revenue from grid users, and as seen above split into two elements. The variable element reflects the short term marginal cost for grid usage, and is therefore dependent on load, losses and congestion.

*Variable element = Congestion rent +marginal loss factor*

When a situation where congestion occurs, the TSO receives revenue[15] which sums up as the price difference between the two areas involved multiplied with the transferred power. The losses are represented by a marginal loss factor. The residual element and the residual cost should be in balance, this is however usually not the case when regarding electricity networks. Therefore a residual element has to be added on the revenue side to cover the costs. The element should not affect grid customers operational decisions (Gerd Solem, 2007).

### 5.1.3 ITC and TSO profit

Let us investigate how the transit compensation scheme affects the elements in the COS regulation.

| | | |
|---|---|---|
| *Fixed cost* | - | *Not affected by ITC, the fixed cost is based on investments already done.* |
| *Variable cost* | - | *Supposed to be unaffected.* |
| *Variable element* | - | *Supposed to be unaffected. The variable element represents a correct short term price signal to the grid customers and therefore reflects optimal trading patterns and optimal flow when the market is assumed to be perfectly competitive. This element should thus not be affected by ITC since this would prevent optimality.* |
| *Residual element* | - | *Will be affected.* |

As can be seen will the compensation either given or received affect the residual element in the COS regulation, which implies that the compensation will be passed on to the customers in the region. The compensation will not have impact on the TSO profit.

[15] This is congestion rent, which have been discussed earlier in the report

## 5.2 General benefits and costs

### 5.2.1 Cross-border trade

There are bound to be benefits involved with cross-border trade, but participants involved might also experience a cost, although would the benefits most likely outweigh the costs. If this was not the case, then cross-border transactions would not make economic sense. Some of the benefits and costs fundamentals are discussed in this section.

One obvious benefit from increased cross-border exchange is the improved security of supply for the involved TSOs.

Another benefit that could occur from cross-border trade and which is part of the security of supply element is the sharing of reserves. The benefit of sharing reserves refers to avoided investment in various types of reserve capacity. Sharing of reserves was one of the principles utilized in 2002-2003 when Nordic countries had an energy deficiency (N-H. v der Fehr, 2005). The value of shared reserves might be compared to the cost of increasing peak capacity.

Benefits in form of operational security increases a power systems overall ability to supply electricity without interruptions and is also a part of the security of supply element. Operational security is therefore an important benefit concerning cross-border exchange. A power grid supported by exchange agreements between TSOs will certainly be better equipped to handle sudden failures.

A well integrated power system with high cross-border trade utilization would imply large regulation capacity and make the frequency increasingly stable. The extra regulation capacity would be a benefit if an interruption occurs.

From a market perspective would an increase in cross-border trade lead to a more efficient market, with increased competition and liquidity on the exchanges. The prices would be more stable, and be more in line with market participants' supply and demand.

But there can also be costly disadvantages regarding cross-border trade. There can be a risk of cascade disconnections within a large network if interruptions are not replaced with normal operation condition within a certain time frame. This would indeed be a substantial cost to society, in form of loss of power. As already mentioned before in the report is the cost of lost power suggested to be over 200 times the normal price.

Security of supply and stability in the network could also be affected in a negative manner when extreme imports and exports occur.

### 5.2.2 Transit

Transit flows is part of the cross-border term, and occurs when more than two parts are involved in cross-border exchange. The cost and benefits of transit flows in large networks are difficult if not impossible to locate without utilizing a transit compensation allocation mechanism. The principles can however be fully identified using a simple example[16].

Figure 5.1 show two networks where transit flows are identified in Country B. When considering the above network in the figure, and assuming the level of investment is given, the consequences of transit in Country B compared to a no transit situation would be: Higher losses in the local grid, and slightly higher security of supply which will result in a decrease in loss of load. Overall the cost will increase for Country B.

When ignoring the ITC allocation, Country B would increase its revenue. This happens because of two factors, internal and external customers. The revenue from these customers increase as the difference in price p2 and price p3 rises. The reason behind this is related to the internal transfer in Country B. Revenue from external customers and internal customers scale with the internal flow and external sources.  In addition to this will there be revenue originating from the price difference between p1 and p2, p3 and p4.

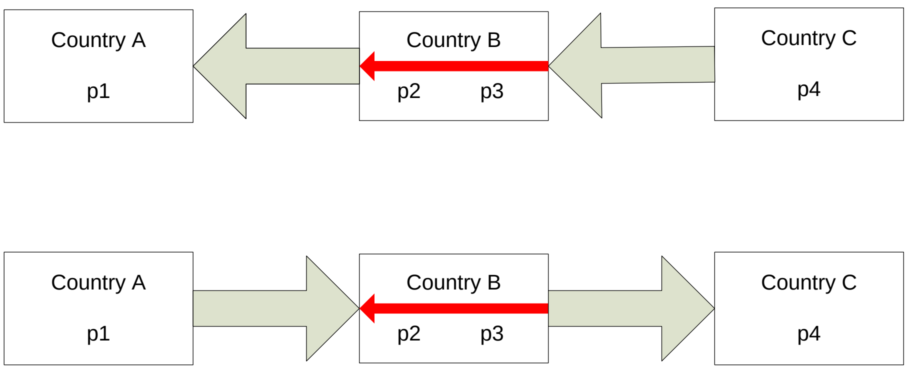


Figure 5.1 Example of transit flows through Country B

From the lower network in the figure can it be seen that the transit flow in the opposite direction than the previously mentioned example. The losses in Country B will be lower. The income from the tariff element is lowered because of the decreasing price difference between node 2 and node 1. This tariff element is reduced more than the cost of losses. However will there be net revenue in Country B as long as the direction of the power flow is from Country A to Country C.

[16] Based on a discussion in (Gerd Solem, 2007)

## 5.3 Investment incentives

The following section tries to identify what impact cross-border flows and transits can have on investment incentives in an interconnected electricity network.

### 5.3.1 Individual incentive

An example[17] is illustrated in Figure 5.1, and involves three countries with different market prices. It is assumed that the three countries are fully competitive markets. As indicated in the figure will the power flow go from Country A (which is a surplus region) via Country B and finally end up in country C (who is a deficit region). It is then assumed that a local investment in Country B allows a greater flow from the low price country to the high price country. This would have an effect on the wholesale prices in the countries:

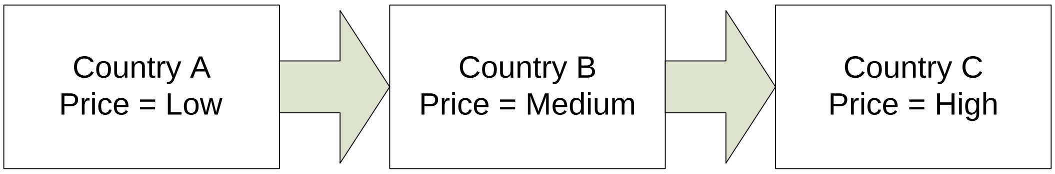


Figure 5.2 Example of interconnector flow

Country A: Prices would increase with the increased export, and the wholesale market would experience increased demand, thus requiring additional generation.

Country B: Prices would be the same as before (assumed that net import from country A and net export to country C evens out).

Country C: Prices would be reduced as a result of the cheaper electricity flow from country A via country B.

If ignoring ITC compensation and congestion rent, it would be clear that country B would incur the additional infrastructure cost in its transmission charges. The benefits and costs would be divided between the participants as followed:

Country A: The price increase would benefit producers, and be a cost for consumers.

Country B: Here the prices stay the same, but due to the increased transmission charges, consumers would experience higher costs.

Country C: The decline in price would be a cost for producers and benefit consumers.

If this increased transmission capacity in Country B would provide a net welfare increase, the investment should be undertaken. But in this situation the net welfare in Country B would

[17] Based on a example given in (Economics, 2008)

drop, as customers are experiencing increased transmission charges for no corresponding benefit. Because of this could the investment quite possible be disapproved by the regulator in country B due to the interest of its customers.

Individual incentives is therefore not always in line with the overall welfare of a power system, however was transit compensation and congestion rent ignored in the example.

### 5.3.2 Congestion rent incentive

If the investment in Country B was done on a merchant by merchant basis, the increased congestion rent on the cross–border lines due to the investment should be allocated to Country B (if not all, at least most of it). This might however be a difficult task in a well meshed network, where the required negotiating between the participants might be complicated. Even in the three country example here could this prove to be challenging. Bilateral congestion rent arrangements is based on subjective analysis, and would in some situation give investments incentives, but most cases this would not be the case.

### 5.3.3 ITC incentive

If it was assumed that transit was defined as the minimum of total exports and total imports Country B would be the winner in the three country scenario. The payers would in this situation be Country A and Country C. The increase in ITC compensation (when assuming COS regulation) would lead to a benefit for the grid customers in Country B, while customers in Country A and C would experience increased costs. This is not a “fair” situation, and could possible distort the market efficiency as participants in Country A and C would restrain from initiating cross-borders trades because of the extra cost it involves. In this example ITC allocation could have a misleading result in form of a less efficient market.

What is important in regards to the transit compensation and congestion rents is that these mechanisms make the incentive analysis complex and possible subjective, and it is not a certainty that the investment incentive problem could be addressed with an ITC allocation model.

## 5.4 Loop Flow and transit

The Regulation 1228/2003/EC states that the compensation mechanism shall be based on cross-border flows. In many situations can loop flows basically be defined as cross-border flows, and should thus be included in a compensation mechanism. It has been discussed how well ITC methods include loop flows in the compensation calculations (ERU, 2006), as these methods often only accounts for commercial transit flows as a result of reference exchange. Calculation based on reference flows are simplifications of real flows which can distort the results, and does not take loop flows into account. For countries hosting huge loop flows, the result might be congested transmission lines and limited possibility for cross-border exchange. A simplified example on the relationship between transit and loop flows can be seen in Figure 5.2.

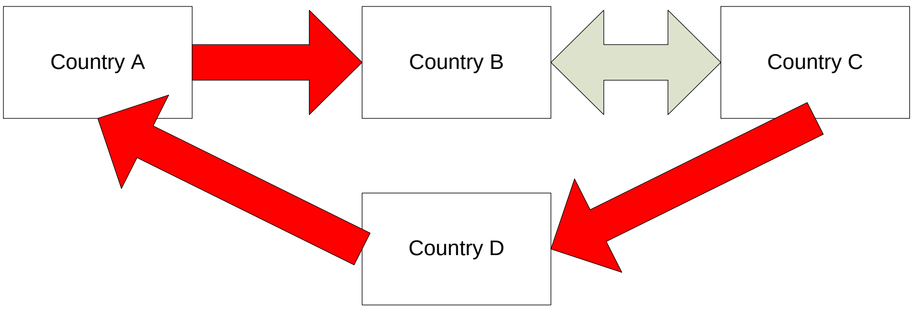


Figure 5.3 Loop flows in a network

In this situation it is assumed that a bilateral power exchange trade between Country B and Country C is active. The grey arrow in the figure indicates that Country B buys power from Country C. One would assume that the power flow would take the shortest physical route between these countries, but as already mentioned is the power flow direction in an electricity network determined by the transmission lines and its impedances. In this case the traded power takes a detour via Country D and Country A before it reaches its destination (marked by the red arrows). Even though the bilateral trade initially only involved Country B and C, Country D and A became involved because of loop flows.

Since the physical flow pattern is determined by the characteristics of the network, one would assume that the actual loss of this loop flow pattern would be less than the shortest route.

As already mentioned is the definition and discussion of loop flows closely connected to power transit, in this situation the third part (i.e. Country A and D) should be compensated. It has been suggested from parties that the ITC mechanism should include loop flow factors in order to solve these types of problems.

# 6. THEORY

This chapter gives an overview of the basic theory of the ITC allocation mechanism included in the report. In addition to this the characteristics of the 11-node power grid model is discussed. A description of the optimal power flow (OPF) method and how nodal prices can be identified is also included.

## 6.1 Model for ITC allocation

### *With and Without Transit*

The With and Without Transit (WWT) allocation method is based on a principle where a load flow situation including transit flows, are compared to a fictive situation where the transit flows are removed. This way transit can be located as cross-border flows not related to the activity of the agents within the analyzed region.

The definition of transit can be approached in various ways. The definition adopted by ETSO is often used, where transit is defined as the minimum between the total hourly flow in the import direction and the total hourly flow in the export direction (Regulation, 2005). If this definition is being used, transits can be identified by the following rules:

*Net importing region*

In a net importing region the transit is defined as export flow. In addition to this is a fraction of the import flow defined as transit as well. This fraction is obtained by dividing the total export from the region by the total import into the region. This fraction of transit is also removed when simulating the “without” scenario.

*Net exporting region*

For a net importing region, the transit can be found the opposite way. Transit is in this area defined as import flow. In addition to this is a fraction of the export flow defined as transit as well. This fraction is obtained by dividing the total import into the region by the total export out of the region. This fraction of transit is also removed when simulating the “without” scenario.

In order to quantify how much transit flows use the network of the considered TSO area, the network usage attributable to the transit has to be computed. There seems to be several ways to do this, one is discussed in (L. Olmos I. P.-A., 2006) and involves defining a global measure of network usage MW x km, and then comparing this amount in the two situations. This is the method used in this report.

For identification of allocation of costs, the WWT algorithm gives no answer. As discussed in (L. Olmos I. P.-A., 2006) is there no way of identifying which regions have to contribute to the compensation due to another region and to what extent each of them must contribute to this compensation.

Some rules regarding allocation of the compensation have however been proposed by the ETSO. Their set of rules proposes that the total compensation fund is computed by adding compensation due to all regions. The contributing to this fund should be allocated on the basis of each regions responsibility in generating cross-border/transit flows, where the proxy used to quantify the responsibility is based on the net import or export flow of each region (L. Olmos I. P.-A., 2007).

A mathematical of the WWT method is here given[18]:

An increase in line flows within a region $c$ that is believed to occur due to transit through the region in scenario $e$ can be expressed as (1).

$$\Delta\varphi_{c,e}^{-t} = PTDF_{c,e} \cdot \Delta I_{c,e}^{-t} \qquad (1)$$

Where $PTDF_{c,e}$ is the Power Transfer Distribution Factors matrix of line flows in country $c$ with respect to net power imports at the cross border lines in scenario $e$. $\Delta I_{c,e}^{-t}$ is the vector of net power imports at cross-border lines in region $c$ that are due to the transit through the simulated region in scenario $e$.

Global usage of the grid within region $c$ that is caused by transit through this region is expressed as (2).

$$\Delta NU_c^t = \sum_e (L_c \cdot \Delta\varphi_{c,e}^{-t}) \qquad (2)$$

Here $L_c$a vector expressing the length of the transmission lines within region $c$.

Thus the compensation region $c$ is entitled can be expressed as (3).

$$Com_c = RGC_c \frac{\Delta NU_c^t}{NU_c^0} \qquad (3)$$

$RGC_c$ is the total regulated annual cost of the grid, region $c$, and $NU_c^0$is the total usage made of the grid by the same region.

[18] Based on description given in (L. Olmos I. P.-A., 2007)

The total size of the global compensation fund is expressed as (4).

$$CF = \sum_j Com_j \qquad (4)$$

And contribution of each region *c* to the global compensation fund is obtained using (5).

$$Pay_c^{CF} = CF \cdot \frac{\theta \cdot I_c}{\sum_j \theta \cdot I_j} \qquad (5)$$

Here $Pay_c^{CF}$ is the contribution of region *c* to the global fund, $\theta$ is a vector that describes the number of cross-border nodes in the corresponding region, and $I_j$ is a vector describing the net power imports at the cross-border lines in region *j*.

The compensation received by region *c* can finally be computed (6).

$$NC_c = Com_c - Pay_c^{CF} \qquad (6)$$

Additional information about the calculation of ITC compensation using the With-and-Without method is given in chapter 7.

## 6.2 11-node grid

The simulations done in this report are all based on the 11-node grid example used in (R. D. Christie, 2000), although in order to include losses in the analysis, a full AC model is used instead of the original model. The example grid consists of 11 nodes located in 4 different regions, with one TSO associated to each of the regions.

The original grid system can be seen in Figure 6.1. Line data for the base case scenario can be found in Table 6.1.

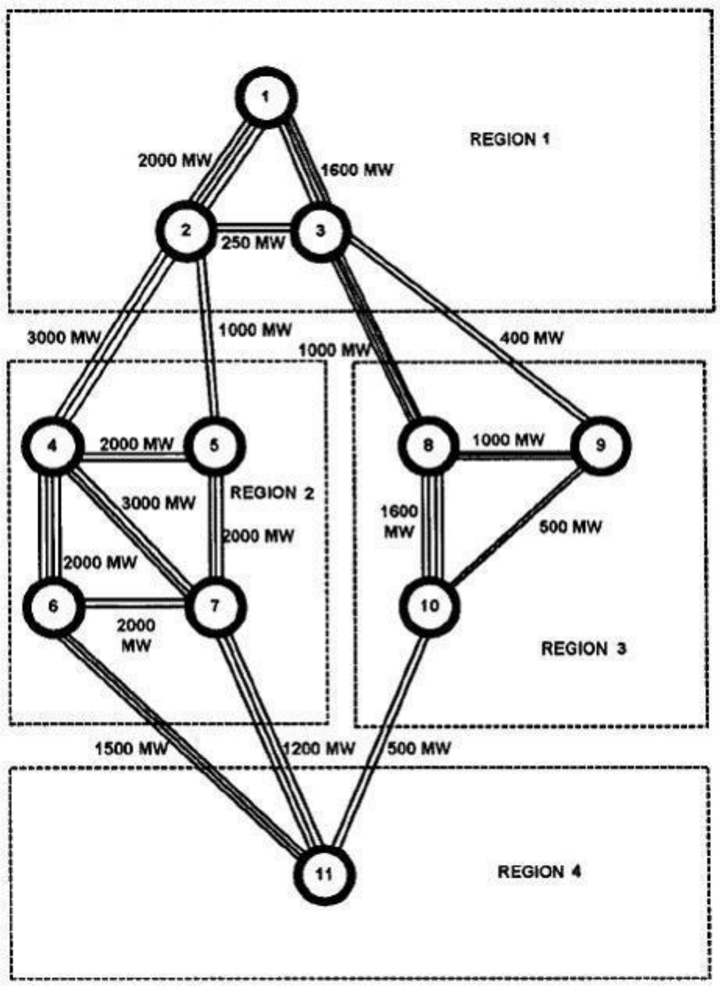


Figure 6.1 Base case grid (R. D. Christie, 2000)

| Branch | From bus | To bus | Line resistance (p.u.) | Line reactance (p.u.) | Transmission capacity (MW) |
|---|---|---|---|---|---|
| **1** | 1 | 2 | 0.008 | 0.08 | 2000 |
| **2** | 1 | 3 | 0.010 | 0.10 | 1600 |
| **3** | 2 | 3 | 0.064 | 0.64 | 250 |
| **4** | 2 | 4 | 0.004 | 0.04 | 3000 |
| **5** | 2 | 5 | 0.016 | 0.16 | 1000 |
| **6** | 3 | 8 | 0.016 | 0.16 | 1000 |
| **7** | 3 | 9 | 0.040 | 0.40 | 400 |
| **8** | 4 | 5 | 0.008 | 0.08 | 2000 |
| **9** | 4 | 6 | 0.008 | 0.08 | 2000 |
| **10** | 4 | 7 | 0.004 | 0.04 | 3000 |
| **11** | 5 | 7 | 0.012 | 0.12 | 2000 |
| **12** | 6 | 7 | 0.016 | 0.16 | 2000 |
| **13** | 8 | 10 | 0.012 | 0.12 | 1600 |
| **14** | 8 | 9 | 0.016 | 0.16 | 1000 |
| **15** | 9 | 10 | 0.032 | 0.32 | 500 |
| **16** | 6 | 11 | 0.012 | 0.12 | 1500 |
| **17** | 7 | 11 | 0.016 | 0.16 | 1200 |
| **18** | 10 | 11 | 0.032 | 0.32 | 500 |

Table 6.1 Line data for the base case

## 6.3 Optimal Power Flow and Nodal Prices

### 6.3.1 Generator costs

The objective in OPF analysis is to minimize generator operation costs. The generator cost can be represented as quadratic functions (8),

$$C_i\left(P_{G_i}\right) = a_i + b_i \times P_{G_i} + c_i \times P_{G_i}^2 \qquad (8)$$

with $P_{G_i}$ as the produced power, and *a, b* and *c* being constants. These constants imply that the marginal cost is a linear function of output.

### 6.3.2 Nodal Prices and the point-tariff system

The nodal prices can be identified utilizing an OPF simulation, in addition to this can the active and reactive power generated and purchased at each node be located. The nodal prices would in this case reflect the marginal generation and load at each node, and represent the optimal prices. These prices will maximize social welfare, and would adjust to transmission constraints.

A nodal pricing system is normally defined as a system based on central dispatch. The dispatch center receives bids from all generating and consuming units and performs an optimization leading to an optimal dispatch. This would lead to a set of nodal prices representing the value of a marginal quantity at that node (Gerd Solem, 2007). It is here assumed that this optimal condition is reached using a point tariff system.

If a point tariff system is used, there would be a link between the spot price referring to a specific hub ($p_s$), the nodal price (λ) and the variable elements of the point tariff ($a$). This would give the following relationship for **input** in node *i* (9).

$$\lambda_i = p_s - \alpha_i \qquad (9)$$

With no congestion, $\alpha_i$ would be the marginal loss between node *i* and the hub.
**Output** in node *j* would give (10),

$$\lambda_j = p_s - \alpha_j \qquad (10)$$

where $\alpha_j$ would be the marginal loss between the hub and node *j*.

This would give the difference between nodal prices at the output and the input node (11),

$$\lambda_j - \lambda_i = \alpha_j + \alpha_i = \alpha_{ji} \tag{11}$$

with $\alpha_{ji}$ as the marginal loss between $i$ and $j$. The impact of congestion in the system can be included in the variable element in the tariff ($\alpha_i$ and $\alpha_j$).

The location of the reference hub has an impact on the spot price and the tariffs, but no impact on the net revenue of the grid users (Wangensteen, 2007). But this relationship is only valid as long as one TSO is involved. In a system consisting of more than one TSO, the net revenue would depend on the reference hub. This is the case for the system used here.

# 7. SIMULATION RESULTS

In this chapter some simulations are done in order to investigate how ITC allocation is affected by implementing a bottleneck in the grid. The With-and-Without transit method has been used in calculating the results. A description of this method was given in chapter 6, but the method is further commented in this section along with the results of the calculation.

## 7.1 Impact of a bottleneck

### 7.1.1 Base case

The network which is analyzed can be seen in Figure 7.1[19]. The network is represented by four TSOs in four different regions. A load flow calculation has been done in order to identify export and import flows as well as internal flows.

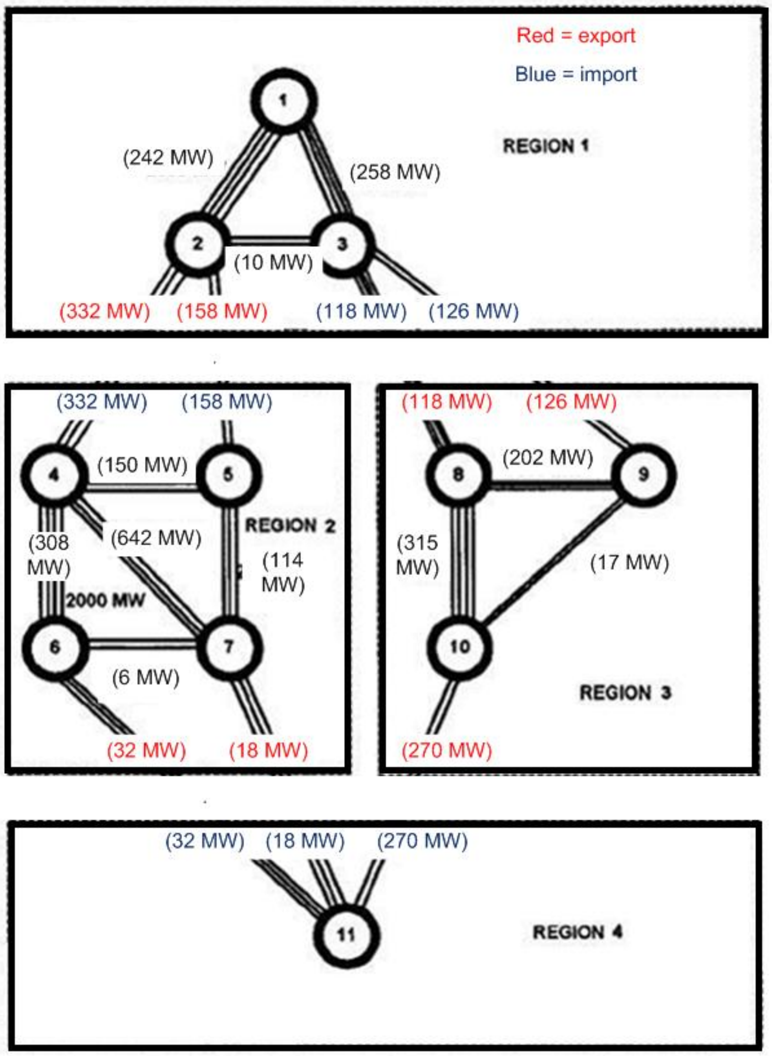


Figure 7.1 Base Case scenario with load flows

[19] The flows in the figure are only approximately correct in the figure, the following calculation is however utilized with exact values.

There are several methods for allocating compensation costs when using the WWT method, the one used here determines the total utilization of the HN in both scenarios, with and without transit, and the compares the utilization attributed to external flows. The fictional without scenario has to be solved using a load flow model[20]. When both scenarios are compared, the TSOs compensation (12) can be identified as a proportion of the total cost of the HN where the factor of proportionality is represented by the ratio between the utilization of the total cost of the HN attributable to external flows, and the total (actual) utilization of the HN (Regulation, 2005). These compensations can be added up for each TSO, and the total compensation pool can be obtained.

$$Comp_i = Cost(HN_i)\frac{U - U_{wt}}{U} \qquad (12)$$

The TSO compensation is represented by $Comp_i$ , the network utilization with transit is represented by $U$, and network utilization in the without scenario is represented by $U_{wt}$. The cost component for the horizontal network $Cost(HN_i)$ is neglected, as it is assumed that the cost factor is identical in all regions.

The formula listed in (12) is similar to formula (5) listed before, and would produce the same answer.

In order to identify the compensation allocation using the WWT method, one scenario with transit flows and one scenario without transit flows has to be simulated for each region that are defined to have transit flows within their local network. The definition of transit used in this report is identical to the once adopted by ETSO, i.e. the minimum between total import and total export.

### *Calculation of compensation Region 1*

Table 7.1 show the network utilization of the HN in Region 1, the utilization is found by multiplying the flow over each line with the length of the line. The power flow is identified using MATPOWER. For simplicity the length of each internal line is set to 100 km, while the length of the cross-border lines is set to 200 km, these lengths are valid for all calculations done on the 11-node model.

[20] The model used in this report is Matpower (MATPOWER, 2008)

| | From | To | Type | Length (km) | P (MW) | (MWkm) |
|---|---|---|---|---|---|---|
| **Line** | 1 | 2 | Internal | 100 | 242,05 | 24205 |
| **Line** | 1 | 3 | Internal | 100 | 257,95 | 25795 |
| **Line** | 2 | 3 | Internal | 100 | 10,06 | 1006 |
| **Line** | 2 | 4 | Cross-border | 200 | 332,32 | 66464 |
| **Line** | 2 | 5 | Cross-border | 200 | 158,10 | 31620 |
| **Line** | 3 | 8 | Cross-border | 200 | 118,11 | 23622 |
| **Line** | 3 | 9 | Cross-border | 200 | 126,64 | 25328 |
| | | | | | | |
| **Total utilization** | | | | | | 198040 |

Table 7.1 Network utlization Region 1 Base case, with transit

When the network utilization in the transit scenario are found, the same has to be done to the scenario where tranit flows are removed. In Region 1 import is defined as transit flows, this can easily been seen from Figure 7.1. In addiditon to this is a fraction of the export flows also defined to be transit flow, so this fraction has to be removed before the without scenario can be simulated. This fraction is calculated as (13).

$$\frac{Transit}{\sum(export\ \ or\ import\ )} \qquad (13)$$

In othre words is the transit divided by export if the transit is defined as import and vice versa if transit is defined as export. When this fraction along with the rest of the transit flows are removed, the numbers in Table 7.2 can be found. Notice that the flow on the cross-border lines 3-8 and 3-9 are nulled out because of transit. In addition to this has the transit fraction been deducted from the exporting line 2-4 and 2-5.

| | From | To | Type | Length (km) | P (MW) | (MWkm) |
|---|---|---|---|---|---|---|
| **Line** | 1 | 2 | Internal | 100 | 45,93 | 4593 |
| **Line** | 1 | 3 | Internal | 100 | 454,07 | 45407 |
| **Line** | 2 | 3 | Internal | 100 | 65,39 | 6539 |
| **Line** | 2 | 4 | Cross-border | 200 | 171,34 | 34268 |
| **Line** | 2 | 5 | Cross-border | 200 | 81,51 | 16302 |
| **Line** | 3 | 8 | Cross-border | 200 | 0,00 | 0 |
| **Line** | 3 | 9 | Cross-border | 200 | 0,00 | 0 |
| | | | | | | |
| **Total utilization** | | | | | | 107109 |

Table 7.2 Network utlization Region 1 Base case , without transit

The network utilization in the without scenario, is lower than in the original scenario. The difference between these numbers is the increased usage of the grid caused by transit, Table 7.3.

| Increased usage of the grid caused by transit | 90931 |
|---|---|
| | |
| **Compensation entitled** | 0,459155 |

Table 7.3 Compensation due to Region 1, Base case

Entitled compensation can be found using formula (12) or (5).

### *Calculation of compensation Region 2*

A similar approach is being used for each region where transit flows can be identified. Results from Region 2 can be seen in Table 7.4, 7.5 and 7.6.

| | From | To | Type | Length (km) | P (MW) | (MWkm) |
|---|---|---|---|---|---|---|
| **Line** | 2 | 4 | Cross-border | 200 | 332,32 | 66464 |
| **Line** | 2 | 5 | Cross-border | 200 | 158,10 | 31620 |
| **Line** | 4 | 5 | Internal | 100 | 150,14 | 15014 |
| **Line** | 4 | 6 | Internal | 100 | 308,70 | 30870 |
| **Line** | 4 | 7 | Internal | 100 | 642,02 | 64202 |
| **Line** | 5 | 7 | Internal | 100 | 114,00 | 11400 |
| **Line** | 6 | 7 | Internal | 100 | 6,17 | 617 |
| **Line** | 6 | 11 | Cross-border | 200 | 32,42 | 6484 |
| **Line** | 7 | 11 | Cross-border | 200 | 18,13 | 3626 |
| | | | | | | |
| **Total utilization** | | | | | | 230297 |

Table 7.4 Network utlization Region 2 Base case , without transit

The network utilization in Region 2 can be seen in Table 7.4, and 7.5. The difference between the utilization in the two scenarios is significantly lower than it was for Region 1.

| | From | To | Type | Length (km) | P (MW) | (MWkm) |
|---|---|---|---|---|---|---|
| **Line** | 2 | 4 | Cross-border | 200 | 298,04 | 59608 |
| **Line** | 2 | 5 | Cross-border | 200 | 142,05 | 28410 |
| **Line** | 4 | 5 | Internal | 100 | 154,64 | 15464 |
| **Line** | 4 | 6 | Internal | 100 | 288,06 | 28806 |
| **Line** | 4 | 7 | Internal | 100 | 626,47 | 62647 |
| **Line** | 5 | 7 | Internal | 100 | 105,78 | 10578 |
| **Line** | 6 | 7 | Internal | 100 | 12,60 | 1260 |
| **Line** | 6 | 11 | Cross-border | 200 | 0,00 | 0 |
| **Line** | 7 | 11 | Cross-border | 200 | 0,00 | 0 |
| | | | | | | |
| **Total utilization** | | | | | | 206773 |

Table 7.5 Network utlization Region 2 Base case , without transit

| | |
|---|---|
| **Increased usage of the grid caused by transit** | 23524 |
| | |
| **Compensation entitled** | 0,102146 |

Table 7.6 Compensation due to Region 1, Base case

Table 7.6, show that the entitled compensation for Region 2 is lower than for Region 1.

***Calculation of compensation Region 3 and Region 4***

As can be seen from Figure 7.1, are Region 3 and Region 4 regions where transit flows cannot be identified. Region 3 has only export flows on its cross-border lines, and opposite has Region 4 only import flows on its lines. These regions will therefore not receive any compensation, but they are not excluded from the compensation mechanism, and do have to contribute to the compensation pool.

### *Contribution to the compensation pool*

Table 7.7 show the compensation allocation between TSOs. The compensation due between the TSOs is calculated using formula (5) and (6). A minus sign means that the given TSO/Region would be a net contributor to the compensation pool. The *use by other* row represents the use of the grid of the corresponding country by others, while the *use of others* row represents use that the country makes of others grid.

| | Region 1 | Region 2 | Region 3 | Region 4 |
|---|---|---|---|---|
| **Region 1** | - | 0,016487 | 0 | 0 |
| **Region 2** | 0,132692 | - | 0 | 0 |
| **Region 3** | 0,155468 | 0,034586 | - | 0 |
| **Region 4** | 0,096885 | 0,021554 | 0 | - |
| **Use by others** | 0,385045 | 0,072627 | 0 | 0 |
| **Use of others** | 0,016487 | 0,132692 | 0,190054 | 0,118439 |
| | | | | |
| **Net use** | 0,368558 | -0,06007 | -0,19005 | -0,11844 |
| | | | | |
| **Compensation [ %]** | 100 | -16,2974 | -51,5669 | -32,1356 |

Table 7.7 Contribution to the compesation pool, base case

### 7.1.2 Bottleneck

The calculation of compensation allocation between the TSOs is done for an example where a bottleneck is implemented, and is done in a similar fashion to the section above. From Figure 7.2 can it be seen that a bottleneck has been implemented between node 2 and node 5 in the network. This is done in order to investigate what the consequences would be for the compensation allocation.

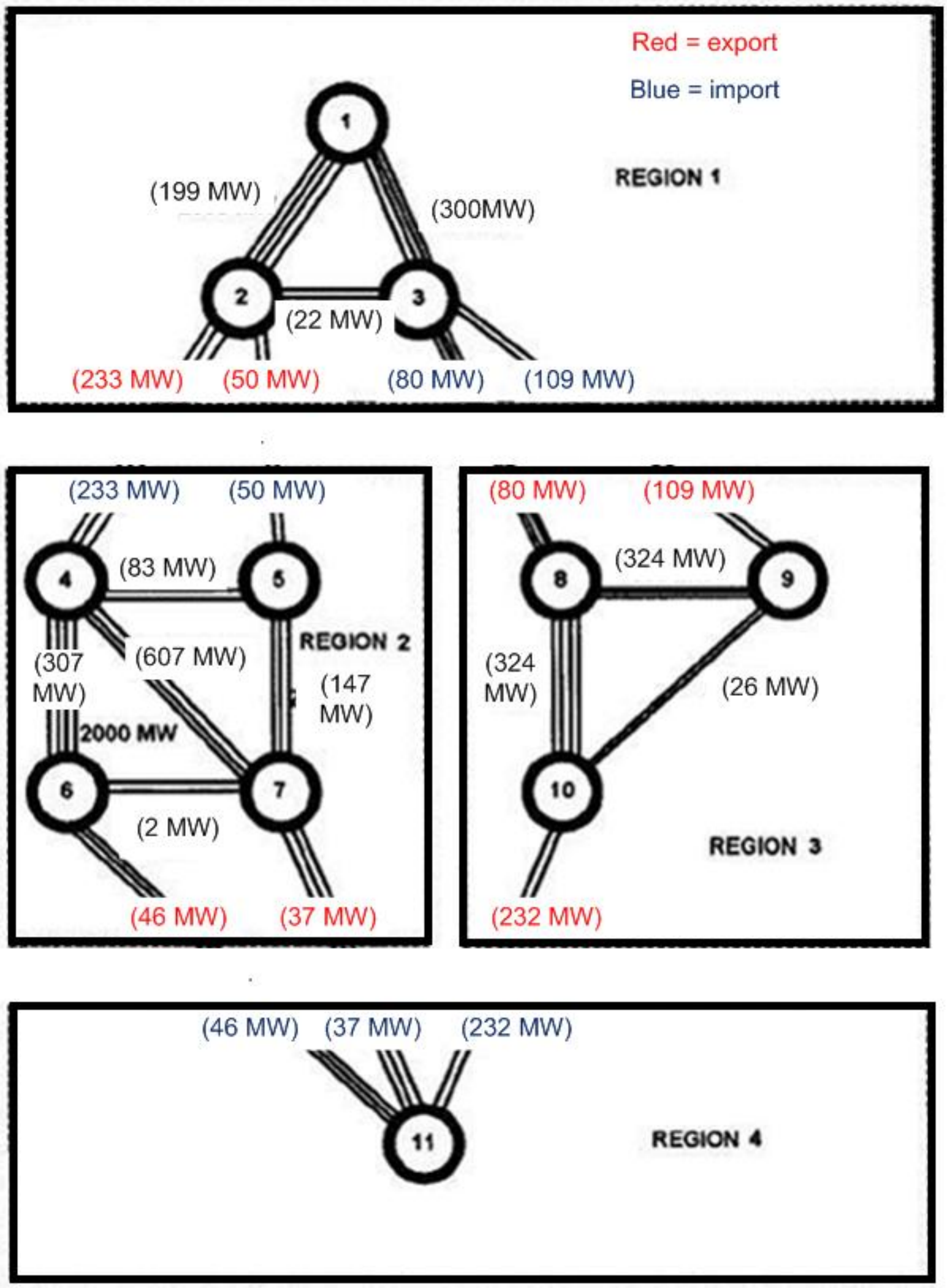


Figure 7.2 Bottleneck scenario including load flows

Detailed results from the bottleneck example can be found in the Appendix 2. The overview of the compensation allocation is however listed here, as these results are used for comparison between the two cases.

***Contribution to the compensation pool***

The allocation of contribution to the compensation pool can be seen in Table 7.8. Region 3 and 4 are still not receiving any compensation from the pool, compensation entitled has in numbers increased for Region 1 and Region 2, while Region 3 and Region 4 experience higher ITC costs due to the bottleneck. The results are further commented in chapter 7.3.

| | Region 1 | Region 2 | Region 3 | Region 4 |
|---|---|---|---|---|
| **Region 1** | - | 0,020555 | 0 | 0 |
| **Region 2** | 0,094583 | - | 0 | 0 |
| **Region 3** | 0,199687 | 0,092808 | - | 0 |
| **Region 4** | 0,149329 | 0,069404 | 0 | - |
| **Use by others** | 0,443599 | 0,182766 | 0 | 0 |
| **Use of others** | 0,020555 | 0,094583 | 0,292495 | 0,218733 |
| | | | | |
| **Net use** | 0,423044 | 0,088183 | -0,29249 | -0,21873 |
| | | | | |
| **Compensation [ %]** | 82,75067 | 17,24933 | -57,2142 | -42,7858 |

Table 7.8 Contribution to the compesation pool, Bottleneck case

## 7.2 Additional cross-border transmission line

A new 400 MW cross-border line has been introduced between node 5 and node 8 in the grid. The new flow pattern can be seen in Figure 7.3.

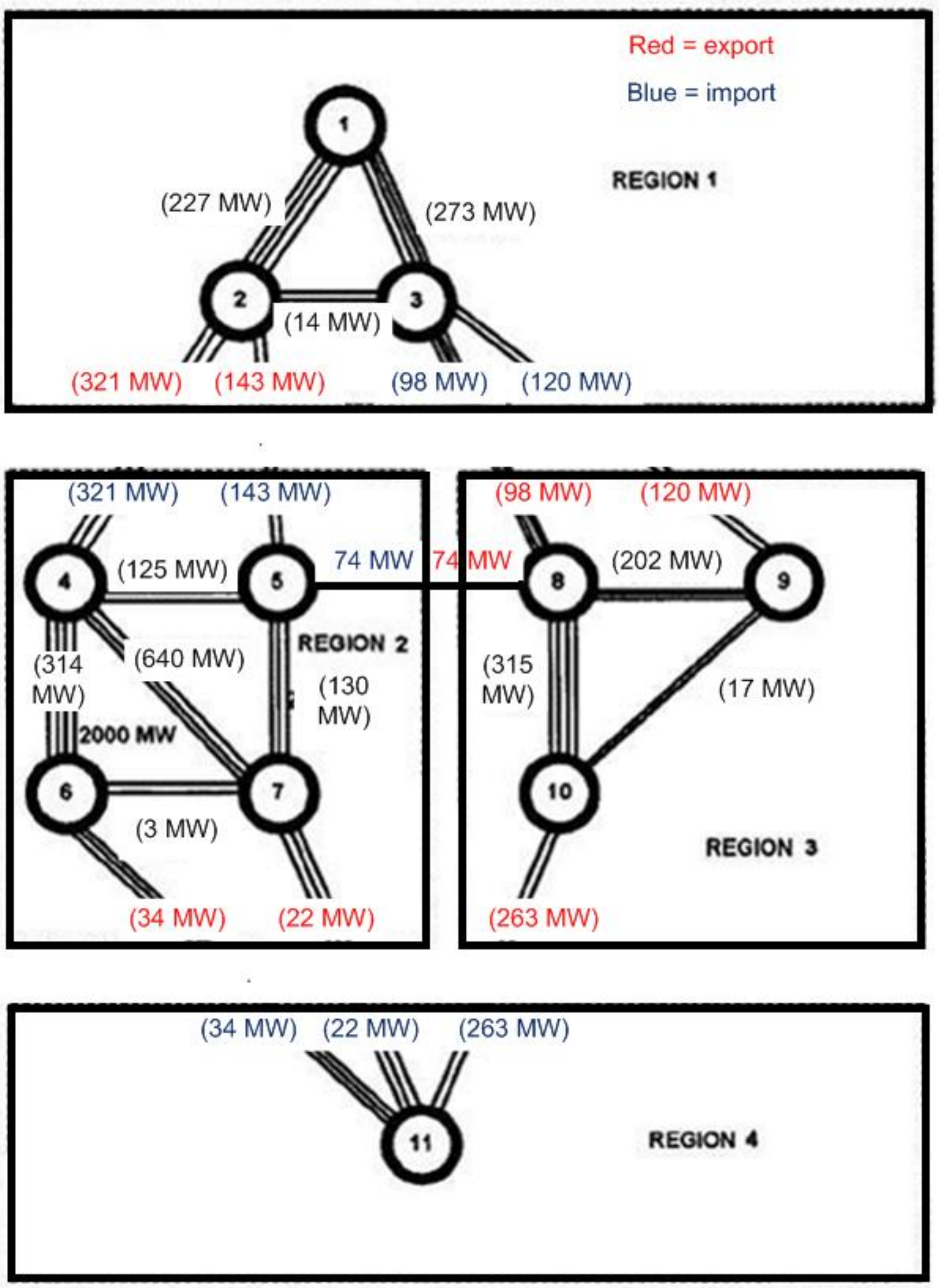


Figure 7.3 Additional 400 MW cross-border line scenario including load flows

***Contribution to the compensation pool***

As can be seen from the Table 7.9, will there in this scenario be no compensation for Region 3 and Region 4. The new transmission line is connected to on of the nodes in Region 3, however is it clear from the load flow simulation that there will be export on this line as well. And thus would there be no transit in Region 3. The flow pattern is unchanged for Region 4, who is importing on all cross-border lines.

| | Region 1 | Region 2 | Region 3 | Region 4 |
|---|---|---|---|---|
| **Region 1** | | 0,028067 | 0 | 0 |
| **Region 2** | 0,123447 | | 0 | 0 |
| **Region 3** | 0,118674 | 0,037654 | | 0 |
| **Region 4** | 0,118116 | 0,037477 | 0 | |
| **Use by others** | 0,360237 | 0,103198 | 0 | 0 |
| **Use of others** | 0,028067 | 0,123447 | 0,156328 | 0,155594 |
| | | | | |
| **Net use** | 0,33217 | -0,02025 | -0,15633 | -0,15559 |
| | | | | |
| **Compensation [ %]** | 100 | -6,0959 | -47,0626 | -46,8415 |

Table 7.9 Contribution to the compesation pool, additional cross-border line

## 7.3 Summing up results

The results from the three simulation cases are here brought together and compared for a short discussion.

### 7.3.1 Bottleneck scenario

| Cost allocation of having a bottleneck in the grid between node 2 and node 5 | [%] |
|---|---|
| | |
| **Region 1** | 0,00 |
| **Region 2** | 0,00 |
| **Region 3** | 50,53 |
| **Region 4** | 49,47 |

Table 7.10 Allocation of the extra ITC cost when having a bottleneck in the grid

The numbers in Figure 7.10 indicate how the increased ITC cost of having a bottleneck between node 2 and node 5 will be allocated. It can easily be read that the regions not physically involved with the bottleneck (i.e. region 3 and Region 4) is affected in a negative manner. The increased ITC cost as a consequence of the bottleneck is split almost evenly between these two regions. The two neighbouring regions involved with the bottleneck have no cost from this scenario, in fact they profit from the restrained cross-border line. A comparison between the Base Case and the Bottleneck Case can be seen in Table 7.11.

| | Base Case | Bottleneck | Difference |
|---|---|---|---|
| | | | |
| **Region 1** | 0,37 | 0,42 | 0,05 |
| **Region 2** | -0,06 | 0,09 | 0,15 |
| **Region 3** | -0,19 | -0,29 | -0,10 |
| **Region 4** | -0,12 | -0,22 | -0,10 |

Table 7.11 Comparison between Base Case and Bottleneck

From an incentive perspective, this would indicate that the TSOs in Region 1 and Region 2 would certainly not actively try to avoid congestions on this line, as the bottleneck proves to be a benefit for the customers in these respective regions in form of a reduced residual element (assuming COS tariff regulation). The customers in these regions could experience decreased security of supply as a consequence of reduced cross-border transmissions, but one would assume that this effect could be neglected compared to the benefit from increased ITC payment.

ITC compensation would probably only be a minor part of TSOs total revenue, extensive research has to be done in order to identify this relationship but this is outside the scope of the report.

### 7.3.2 Additional cross-border line

| Allocation of the cost of investing in a cross-border new line between node 5 and node 8 | [%] |
|---|---|
| | |
| **Region 1** | 49,5 |
| **Region 2** | 0,0 |
| **Region 3** | 0,0 |
| **Region 4** | 50,5 |

Table 7.12 Allocation of the cost when investing in a new cross-border line

If investment in an additional cross-border line between node 5 and node 8 is done, the regions will be affected as seen in Table 7.12 and Table 7.13. The increased cross-border capacity between these nodes would have a negative impact on the ITC allocation for Region 1 and Region 4, i.e. the regions not involved with the investment. On the other side would Region 2 and Region 3, who are the neighbouring regions to the transmission line experience a positive effect in form of increased ITC payment. It should be noticed that the overall size of the ITC allocation pool will decrease when this investment is done. Because of the increased cross-border flow between Region 2 and Region 3, benefits in form of increased security of supply would emerge for these two regions.

| | Base Case | Extra Line | Difference |
|---|---|---|---|
| | | | |
| **Region 1** | 0,37 | 0,33 | -0,04 |
| **Region 2** | -0,06 | -0,02 | 0,04 |
| **Region 3** | -0,19 | -0,16 | 0,03 |
| **Region 4** | -0,12 | -0,16 | -0,04 |

Table 7.13 Comparison between Base Case and Extra Line

In this case the investment incentive given by the ITC allocation mechanism is in line with the idea of an increasingly integrated market. The investment incentive should, as already mentioned before not be based on individual incentives, but rather be based on an overall increase in the social benefits, if this is the case here is however uncertain.

It seems like the ITC mechanism gives split investment incentives in these two scenarios, in the scenario with the bottleneck there is an incentive to restrain transmission investments, whereas in the second scenario the opposite is true.

### 7.3.3 Potential weakness in the simulation

There will always be a chance of potential weaknesses in simulations which may lead to misleading results, and the simulation done in this report is no exception.

First off is the 11-node network model used for simulations not a very large model, and small changes in the network properties might have large impacts on the results. In a larger model such modifications would probably have less impact on single results.

Some assumptions have also been done in order to simplify the simulation. The length of the internal lines in the network are all identical, so is the cross-border lines, in addition to this was the network cost neglected as it was assumed that the cost factors were the same in all four regions.

These simplifications, and the fact that the model only consist of 11-nodes must be taken into account when analyzing the results.

# 8. DISCUSSION AND CONCLUSION

## 8.1 Market development

With an increasingly focus on liberalizing the European electricity market the European Commission introduced the Directive 2003/54/EC and the Regulation 1228/2003/EC in 2003. The Commissions agenda has since then brought significant changes in the sector. In many of the European countries electricity prices are now market based and determined by supply and demand from the market participants. A number of exchanges have been introduced throughout Europe and liquidity on the exchanges has generally increased.

The European electricity market is however still developing and there is a long way to go before the Internal Electricity Market (IEM) will be a reality. There are significant differences in the legislation between countries and a variety of congestion management methods are being used. Even though there seems to be a shift towards market based solutions, some non-market based congestion management methods are still in use.

The development of the Internal Electricity Market will require further harmonization and coordination of market rules and operations throughout Europe. There has been positive development in some regions, especially the Nordic region, the CWE region (i.e. the trilateral market coupling between France, Belgium and The Netherlands) and in the Iberian market. This is in line with the European Commissions agenda of promoting a regional strategy as an interim step stone towards a single European electricity market.

*When trying to sum up this development it is important to understand how it started and how ambiguous the idea of an Internal Electricity Market actually is. The market has developed in the right direction, but the road ahead is a long and narrow one.*

## 8.2 Evaluation of the model

***Transit***

Currently the most common definition of transit is the one adopted by ETSO, which define transit as the minimum between exports and imports. It could be discussed if this is a generally suitable definition, and whether the transit term should be expanded in order to include economical and market principles as well. The current transit definition creates opportunities for participants to manipulate transit income, for example when buying at a low price at one side of the border and sell for a higher price at the other and thus creating transit flows which will alter the compensation allocation.

### *Inconsistency with the framework*

The Article 3, Regulation 1228/2003/EC, states that the transmission system operator shall receive compensation for costs inured as a result of hosting cross-border flows of electricity on their networks. The WWT method uses the transit definition adopted by ETSO when dealing with cross-border compensation. This creates a dilemma as purely importing and exporting countries in this case are not defined to hosting transit, and will therefore not be compensated. These countries also have flows that results from the impact of the activity of external participants, even though the flows originate or ends within the considered country. *An ITC model should try to identify these flows and include them in the compensation mechanism, and the current definition of transit should not be used when considering cross-border compensations.*

According to Article 3, shall the inter-TSO compensation be paid by the operators of national transmission systems from which cross-border flows originate or end. The WWT method is not in line with the framework when identifying the responsibilities for the network use. The WWT method bases the charges that each country has to pay on a pro rata of the net volume of imports and exports, regardless of the location and distance to the considered member state and the flow pattern. *This method for identifying network responsibilities could be considered rational as it is true that net imports and exports is one of the reason for external utilization of networks, but it is certainly not the only one.*

The ITC model used for simulation in this report does not include important benefits that could occur from cross-border flows. As stated in Article 3, should the benefit that a network incurs as a result of hosting cross-border flows be taken into account and reduce the compensation received. *Benefits that should be included may for example be increased security of supply and reduced loss of load.*

### *Transit and investment Incentives*

The result from the bottleneck scenario suggests that the neighbouring TSOs would experience reduced ITC payment. The TSOs would in other words not be given investment incentives through the ITC mechanism. A correct incentive to invest in increased transmission capacity should be based on welfare gain, i.e. the economic benefit to society. Investment in the grid might not benefit the involved TSO, but the consequences of increased transmission capacity would probably be more efficient utilization of the network. And the value of this increased efficiency would most likely be larger than the benefit the TSO would receive if it did not expand its grid. The investment could in other words increase the economic benefit to society (although this is only an assumption and whether or not the investment would lead to increased social benefit to society is not analyzed in the simulation).

A TSO should therefore be careful when considering ITC payment in investments analysis as this could very well prove to not reflect the optimal solution to society in general.

The results from the additional cross-border line scenario is however somewhat different, the TSOs involved (Region 2 and Region 3) would in this case be positively affected in terms of ITC allocation (notice that the two TSOs still are net contributors to the allocation pool, the amount has however decreased). In this case the TSOs would be given an incentive to invest in increased transmission capacity. This investment incentive would be in line with the framework given by the European Commission, and contribute to an increasingly efficient market.

*It can be concluded that the inconsistent ITC results identified in these two scenarios indicate that the ITC mechanism (in this case represented by the WWT model) cannot be regarded as relevant from an investment incentive perspective.*

### *Further work*

An interesting topic for further research on the ITC concept would be to investigate what impact this mechanism has on the actual revenue for the different TSOs. In other words if the compensation size would be large enough to be part of an investment analysis.

It should also be investigated how the total socio economic benefit is affected by ITC allocation, this way a more accurate analysis of the investment incentive dilemma could be done.

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## APPENDIX 1 – ABBREVATIONS

| | | |
|---|---|---|
| AP | - | Average Participation |
| APX | - | Amsterdam Power Exchange |
| ATC | - | Available Transfer Capacity |
| BELPEX | - | Belgian Power Exchange |
| COS | - | Cost-of-Service |
| EEX | - | European Energy Exchange |
| ETSO | - | Association of European Transmission System Operators |
| FMC | - | Flow-based Market Coupling |
| HN | - | Horizontal Network |
| IEM | - | Internal Energy Market |
| IMICA | - | Improved Model for Infrastructure Cost Allocation |
| ITC | - | Inter-TSO Compensation |
| LMP | - | Locational Marginal Pricing |
| MP | - | Marginal Participation |
| NTC | - | Net Transfer Capacity |
| OPF | - | Optimal Power Flow |
| OTC | - | Over-the-Counter market |
| PEX | - | Power Exchange |
| TLC | - | Trilateral Coupling |
| TPA | - | Third Party Access |
| TSO | - | Transmission System Operator |
| WWT | - | With-and-Without Transit |

# APPENDIX 2 – ADDITIONAL CALCULATIONS

## A2.1 Bottleneck scenario calculations

Detailed results from the bottleneck calculation can be found in this section.

### *Calculation of compensation Region 1*

Table A.1, show the network utilization for Region 1 when transit flows are included. When the transits are removed, a new load flow simulation is done and these results can be seen in Table A.2. The increased utilization of the grid due to transit flows can be seen in Table A.3, and from this the compensation entitled to Region 1 in the bottleneck case can be found.

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 1 | 2 | Internal | 100 | 199,21 | 19921 |
| **Line** | 1 | 3 | Internal | 100 | 300,79 | 30079 |
| **Line** | 2 | 3 | Internal | 100 | 22,17 | 2217 |
| **Line** | 2 | 4 | Cross-border | 200 | 233,01 | 46602 |
| **Line** | 2 | 5 | Cross-border | 200 | 49,97 | 9994 |
| **Line** | 3 | 8 | Cross-border | 200 | 80,81 | 16162 |
| **Line** | 3 | 9 | Cross-border | 200 | 108,77 | 21754 |
| **Total utilization** | | | | | | 146729 |

Table A.1 Network utlization Region 1 Bottleneck case, with transit

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 1 | 2 | Internal | 100 | 45,93 | 4593 |
| **Line** | 1 | 3 | Internal | 100 | 454,07 | 45407 |
| **Line** | 2 | 3 | Internal | 100 | 65,39 | 6539 |
| **Line** | 2 | 4 | Cross-border | 200 | 76,61 | 15322 |
| **Line** | 2 | 5 | Cross-border | 200 | 16,45 | 3290 |
| **Line** | 3 | 8 | Cross-border | 200 | 0,00 | 0 |
| **Line** | 3 | 9 | Cross-border | 200 | 0,00 | 0 |
| **Total utilization** | | | | | | 75151 |

Table A.2 Network utlization Region 1 Bottleneck case, without transit

| Increased usage of the grid caused by transit | 71578 |
|---|---|
| | |
| Compensation entitled | 0,487824 |

Table A.3 Compensation due to Region 1, Bottleneck case

***Calculation of compensation Region 2***

The same procedure is repeated for Region 2, here the results from the simulation with transit flows can be seen in Table A.4. The results when simulating without transit flows is found in Table A.5, while the entitled compensation is shown in Table A.6.

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 2 | 4 | Cross-border | 200 | 233,01 | 46602 |
| **Line** | 2 | 5 | Cross-border | 200 | 49,97 | 9994 |
| **Line** | 4 | 5 | Internal | 100 | 83,17 | 8317 |
| **Line** | 4 | 6 | Internal | 100 | 307,38 | 30738 |
| **Line** | 4 | 7 | Internal | 100 | 607,64 | 60764 |
| **Line** | 5 | 7 | Internal | 100 | 147,11 | 14711 |
| **Line** | 6 | 7 | Internal | 100 | 1,78 | 178 |
| **Line** | 6 | 11 | Cross-border | 200 | 46,54 | 9308 |
| **Line** | 7 | 11 | Cross-border | 200 | 36,69 | 7338 |
| | | | | | | |
| **Total utilization** | | | | | | 187950 |

Table A.4 Network utlization Region 2 Bottleneck case, with transit

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 2 | 4 | Cross-border | 200 | 162,41 | 32482 |
| **Line** | 2 | 5 | Cross-border | 200 | 35,25 | 7050 |
| **Line** | 4 | 5 | Internal | 100 | 59,63 | 5963 |
| **Line** | 4 | 6 | Internal | 100 | 280,20 | 28020 |
| **Line** | 4 | 7 | Internal | 100 | 567,23 | 56723 |
| **Line** | 5 | 7 | Internal | 100 | 149,29 | 14929 |
| **Line** | 6 | 7 | Internal | 100 | 1,70 | 170 |
| **Line** | 6 | 11 | Cross-border | 200 | 0,00 | 0 |
| **Line** | 7 | 11 | Cross-border | 200 | 0,00 | 0 |
| | | | | | | |
| **Total Utilization** | | | | | | 145337 |

Table A.5 Network utlization Region 2 Bottleneck case, without transit

| Increased usage of the grid caused by transit | 42613 |
|---|---|
| | |
| Compensation entitled | 0,226725 |

Table A.6 Compensation due to Region 2, Bottleneck case

*Calculation of compensation Region 3 and 4*

Transit is as already mentioned the minimum between total exports, out of a region/country and total import flow into a region/country. Because of this, Region 3 and Region 4 are not entitled any compensation from the ITC fund. These regions have either only import or only export flows on their interconnections.

## A2.2 Additional cross-border line scenario calculations

The results from simulating an investment in an extra transmission line between node 5 and node 8 can be found in this section.

*Calculation of compensation Region 1*

For Region 1, the results when simulating network utilization including transit flows can be found in table A.7. The simulation without transits is seen in Table A.8. While the compensation entitled is found in Table A.9.

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 1 | 2 | Internal | 100 | 226,69 | 22669 |
| **Line** | 1 | 3 | Internal | 100 | 273,31 | 27331 |
| **Line** | 2 | 3 | Internal | 100 | 14,40 | 1440 |
| **Line** | 2 | 4 | Cross-border | 200 | 321,73 | 64346 |
| **Line** | 2 | 5 | Cross-border | 200 | 143,07 | 28614 |
| **Line** | 3 | 8 | Cross-border | 200 | 99,71 | 19942 |
| **Line** | 3 | 9 | Cross-border | 200 | 125,45 | 25090 |
| | | | | | | |
| **Total utilization** | | | | | | 189432 |

Table A.7 Network utlization Region 1 extra cross-border line case case, with transit

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 1 | 2 | Internal | 100 | 45,93 | 4593 |
| **Line** | 1 | 3 | Internal | 100 | 454,07 | 45407 |
| **Line** | 2 | 3 | Internal | 100 | 65,39 | 6539 |
| **Line** | 2 | 4 | Cross-border | 200 | 165,57 | 33114 |
| **Line** | 2 | 5 | Cross-border | 200 | 73,91 | 14782 |
| **Line** | 3 | 8 | Cross-border | 200 | 0,00 | 0 |
| **Line** | 3 | 9 | Cross-border | 200 | 0,00 | 0 |
| | | | | | | |
| **Total utilization** | | | | | | 104435 |

Table A.8 Network utlization Region 1 extra cross-border line case, without transit

| | |
|---|---|
| **Increased usage of the grid caused by transit** | 84997 |
| | |
| **Compensation entitled** | 0,448694 |

Table A.9 Compensation due to Region 1, extra cross-border line case

***Calculation of compensation Region 2***

Once again is the process repeated, this time within Region 2. Network utilization with and without transit flows can be seen in Table A.10 and Table A.11. While the compensation entitled Region 2 is found in Table A.12.

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 2 | 4 | Cross-border | 200 | 321,73 | 64346 |
| **Line** | 2 | 5 | Cross-border | 200 | 143,07 | 28614 |
| **Line** | 4 | 5 | Internal | 100 | 125,21 | 12521 |
| **Line** | 4 | 6 | Internal | 100 | 314,07 | 31407 |
| **Line** | 4 | 7 | Internal | 100 | 640,67 | 64067 |
| **Line** | 5 | 7 | Internal | 100 | 130,16 | 13016 |
| **Line** | 5 | 8 | Cross-border | 200 | 73,96 | 14792 |
| **Line** | 6 | 7 | Internal | 100 | 3,14 | 314 |
| **Line** | 6 | 11 | Cross-border | 200 | 34,03 | 6806 |
| **Line** | 7 | 11 | Cross-border | 200 | 22,38 | 4476 |
| | | | | | | |
| **Total utilization** | | | | | | 240359 |

Table A.10 Network utlization Region 2 Bottleneck case, with transit

| | From | To | Type | Length (km) | P (MW) | |
|---|---|---|---|---|---|---|
| **Line** | 2 | 4 | Cross-border | 200 | 230,57 | 46114 |
| **Line** | 2 | 5 | Cross-border | 200 | 102,95 | 20590 |
| **Line** | 4 | 5 | Internal | 100 | 90,40 | 9040 |
| **Line** | 4 | 6 | Internal | 100 | 303,60 | 30360 |
| **Line** | 4 | 7 | Internal | 100 | 612,03 | 61203 |
| **Line** | 5 | 7 | Internal | 100 | 143,76 | 14376 |
| **Line** | 5 | 8 | Cross-border | 200 | 53,00 | 10600 |
| **Line** | 6 | 7 | Internal | 100 | 1,21 | 121 |
| **Line** | 6 | 11 | Cross-border | 200 | 39,94 | 7988 |
| **Line** | 7 | 11 | Cross-border | 200 | 28,74 | 5748 |
| | | | | | | |
| **Total utilization** | | | | | | 206140 |

Table A.11 Network utlization Region 2 extra cross-border line case, without transit

| **Increased usage of the grid caused by transit** | 34219 |
|---|---|
| | |
| **Compensation entitled** | 0,142366 |

Table A.12 Compensation due to Region 2, extra cross-border line case

***Calculation of compensation Region 3 and 4***

There is no compensation allocated to Region 3 and Region 4 in this scenario.